APPENDIX G: DISTRIBUTION PLANNING ACTIVITIES

Minnesota laws and reporting rules governing electric utilities require that electric utilities with a Minnesota service area submit to the Minnesota Public Utilities Commission ("Commission") a biennial report containing a 5-year historical summary as well as a 5-year investment plan and 10-year future outlook for the distribution system. This report is submitted biennially by November 1 of each odd year. Minnesota Power's (or the "Company") 2019 Integrated Distribution Plan ("IDP")[1] contains all of the forms and information necessary to meet this biennial requirement and is attached as part of the 2021 IRP filing. The Commission accepted the Company's 2019 IDP on May 27, 2020. Some of the content from the 2019 IDP is highlighted below, including a high-level overview, information on distribution and resource planning coordination, and the vetting of non-wires alternatives. A brief update on distribution coordination related to the Company's proposed package of distribution-connected solar projects, designed to aid in the economic recovery of the COVID-19 pandemic, is also provided.

Integrated Distribution Plan Overview

In order to meet the needs of Minnesota Power's diverse customer base, the Company built its distribution strategy upon the priorities of technology, innovation, and continuous learning. Customers expect reliable, affordable, and safe electric service, all of which are encompassed in these core distribution values. Meeting these expectations requires deploying right time/right fit distribution technology that is flexible, adaptable, and upgradable. The Company contends that equity – in all of its forms – plays a critical role in ensuring security, comfort, and quality of life for customers. Therefore, the Company has strategically positioned its distribution system for the deployment of emerging distribution technology through thoughtful planning in all areas of its business, while maintaining a focus on customers' needs, upholding its distribution values, and aligning these investments with the Company's sustainability goals. Sustainable prosperity over the long-term is ALLETE's goal. The aim of sustainable development is to balance our economic, environmental and social needs, and allowing prosperity for now and future generations. Safety, integrity, environmental stewardship, employee development and community engagement must be in the balance of every decision made and action taken.

Minnesota Power's 2019 IDP reflects key themes in alignment to our broader strategy. The Company is planning for the future of an advanced grid while also continuing to enhance the customer experience. The Company's 10-year long-term plan focuses on continued investment in infrastructure with accelerated investments in the near-term in systems and data to optimize the 21st Century power grid. Investments in data and applications will provide a greatly enhanced customer experience while providing key operational benefits for reliability and safety.

Integrated Distribution & Resource Planning

Minnesota Power's Distribution Planning and Resource Planning departments work in close collaboration with one another to ensure collaborative and robust integrated system planning is conducted. Coordinated discussions take place at regular intervals throughout the year to share information on potential supply side and demand side opportunities located at the distribution level, and the two groups coordinate in the development of the Distributed Energy Resource Scenario Analysis for the IDP. As the Company's Distribution Planning processes evolve, the

[1] Docket No. E015/M-19-684.

primary areas of active coordination in the near-term between Distribution Planning and Resource Planning will be in load forecasting and vetting of non-wires alternatives.

Non-Wires Alternatives

Generally speaking, the types of projects that lend themselves to non-wires solutions are those designed to address reliability performance or load-serving issues. Specifically, non-wires solutions may be suitable for addressing reliability performance issues where there is limited or no backup capability following loss of the primary source to a feeder. In that case, a non-wires solution may be able to provide redundancy to the feeder, enhancing restoration times and ultimately improving reliability. A non-wires solution may also be suitable for addressing a load serving issue where the capacity of a feeder or associated substation equipment, including transformers, is less than the total peak load interconnected to the feeder or substation.

While non-wires solutions are suitable in specific circumstances, the majority of distribution spend reported in the 2019 IDP is focused on the asset renewal of aging infrastructure. These types of projects are not good candidate opportunities for non-wires solutions, and Minnesota Power did not bring forward any non-wires alternatives for the 2019 IDP. Since no additional candidate opportunities for non-wires alternatives have been identified since the filing of the 2019 IDP, none have been included in this Integrated Resource Plan. Non-wires solutions will continue to be evaluated in the next IDP, due to the Commission on November 1, 2021.

Distribution-Connected Solar Projects

Minnesota Power will be installing roughly 20 MW of solar projects at three locations on the Distribution system in northern Minnesota, subject to timely Commission approval and project development. The Company's intent is to install these projects in 2021 in order to aid in the local economic recovery from the COVID-19 pandemic. These three solar installations will allow the Company to meet its obligations for the state's Solar Energy Standard mandate, and were submitted to the Commission as a package for approval on November 13, 2020.[2] The interconnection of these projects has been coordinated with the Distribution Planning and Engineering departments to ensure that they may be reliably interconnected to the Company distribution system, and that the proper system upgrades are implemented to enable their interconnection.

[2] Docket No. E015/M-20-828.

30 West Superior Street
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November 1, 2019

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: Minnesota Power's 2019 Integrated Distribution Plan
Docket No. E015/CI-18-254

Dear Mr. Wolf:

In its Order dated February 20, 2019 the Minnesota Public Utilities Commission ("Commission") directed Minnesota Power (or, "the Company") to file biennially with the Commission beginning on November 1, 2019 an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. In its February 20, 2019 Order the Commission also outlined specific requirements to be included in the Company's IDP. This 2019 IDP filing complies with all requirements included within the Order. Minnesota Power hereby submits, via electronic filing, its 2019 Integrated Distribution Plan in docket No. E015/CI-18-254.

If you have any questions regarding this filing, please contact me at (218) 355-3448 or jwarmuth@mnpower.com.

Yours truly,

Jenna Warmuth
Senior Public Policy Advisor

JW:sr
Attach.

Minnesota Power's 2019 Integrated Distribution Plan

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM/DEFINED TERM	DEFINITION
ADMS	Advanced Distribution Management System
AFR	Annual Forecast Report
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
CAGR	Compound Annual Growth Rate
C2M	Customer to Meter
CBSP	Consumer Behavior Study Plan
CHP	Combined Heat and Power
CIP	Conservation Improvement Program
CIS	Customer Information System
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
DRIVE	Distribution Resource Integration and Value Estimation
DSM	Demand-Side Management
EMS	Energy Management System
EPRI	Electric Power Research Institute
EV	Electric Vehicle
EVSE	Electric Vehicle Service Equipment
FCI	Faulted Circuit Indicators
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information Systems/Utility Network Model
IEEE	Institute of Electrical and Electronic Engineers
IHD	In-home Displays
IRP	Integrated Resource Plan
ISO	Independent System Operator
IT	Informational Technology
MDM	Meter Data Management
MISO	Midcontinent Independent System Operator
MN-DIP	Minnesota Distributed Generation Interconnection Process
Commission	Minnesota Public Utilities Commission
OH	Overhead
OMS	Outage Management System
OT	Operational Technology
PCT	Programmable Communicating Thermostats
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SGG	Smart Grid Gateway
SGIG	Smart Grid Investment Grant
SI	System Integrator
TOD	Time of Day
TOU	Time-of-Use
UG	Underground
VEE	Validation, Editing, Estimating
VVO	Volt-VAR Optimization

STATE OF MINNESOTA

BEFORE THE

MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Distribution System Planning

Docket No. E015/CI-18-254

Minnesota Power's

Integrated Distribution Plan

I. Introduction

On December 6, 2018, the Minnesota Public Utilities Commission (or, "Commission") Ordered Minnesota Power to file an Integrated Distribution Plan ("IDP" or "Plan") biennially beginning November 1, 2019. The Order adopted IDP filing requirements for the Company which are outlined in this Plan. Minnesota Power's 2019 IDP provides a vision for advancement of the Company's distribution system and highlights continuous foundational investments related to the customer, reliability and resiliency.

Serving over 145,000 residential and commercial electric customers across northeastern and central Minnesota, Minnesota Power's distribution system is comprised of 5,800 miles of distribution lines and 201 distribution substations ("distribution system"). Minnesota Power's service territory spans over 26,000 square miles from International Falls in the north to Royalton in the south, and from Duluth in the east to as far west as the Long Prairie and Park Rapids communities as shown in Figure 1 below.

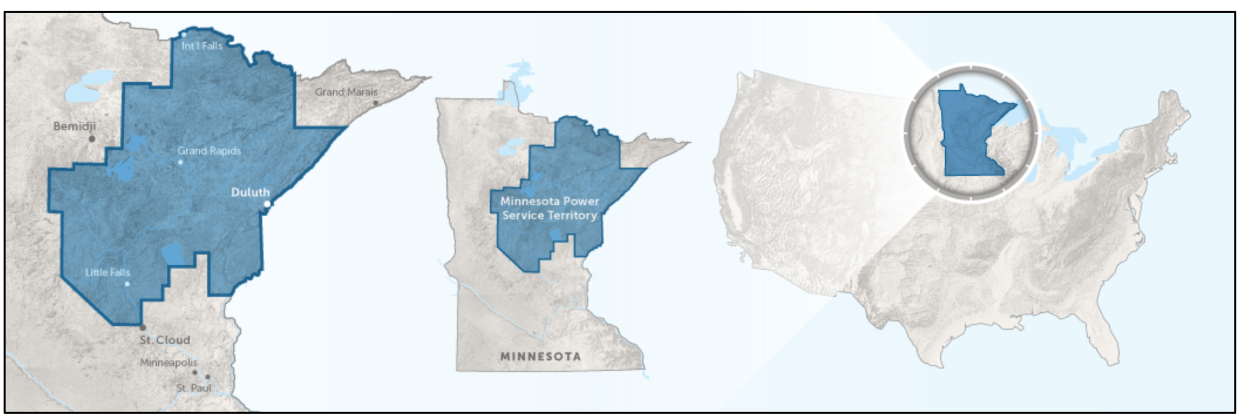


Figure 1: Minnesota Power's Service Territory

Minnesota Power is advancing the transformation of its power supply to a cleaner energy future through its Energy***Forward*** strategy and since 2009 has retired or refueled seven of its nine coal-fired generating units. Minnesota Power will generate 50 percent of its electricity from renewable sources by 2021, and reduce carbon emissions 50 percent from 2005 levels by 2021. The Company has executed this transformation of its power supply while continuing to provide safe, reliable and affordable energy for its customers.

An important aspect of Energy***Forward*** is supporting customers in their pursuit of cleaner energy. For customers that desire higher levels of renewable energy (beyond the 30 percent provided in their current energy mix), Minnesota Power offers its Renewable Source program. Renewable Source is an easy way for customers to influence how much renewable energy is delivered to the power grid. Customers pay a premium to add renewable energy to the power grid equal to a percentage of their monthly energy use. They can choose to add 25 percent, 50 percent, 75 percent or go all in at 100 percent. At the same time, the Company is positioning itself to provide a streamlined and supportive process for customers interested in installing Distributed Energy Resources ("DER") through the systems upgrades and expansion of its own utilization of distribution-sited resources, as discussed later in this Plan. Minnesota Power serves a variety of customer needs while balancing integration of cleaner, more decentralized energy sources.

Minnesota Power's customer mix is unique and distinct from most utilities in the United States as shown in Figure 2.

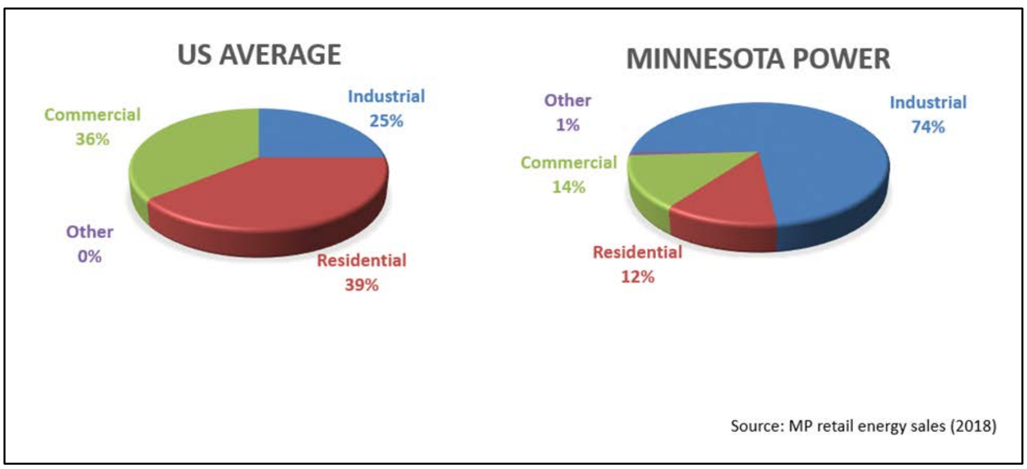


Figure 2: Minnesota Power's Customer Concentration is Unique

Minnesota Power's commercial customers account for approximately fourteen percent of regulated retail electric sales revenue and are served directly from the distribution system. A wide range of interactions occur with commercial customers including planning for new construction, service extensions, outage restoration, reliability and power quality concerns, system upgrades, and responding to a variety of other electric service and rate questions. These customers are a diverse group with varying needs and expectations depending on the business (i.e., electric costs as a percentage of total operating/production costs, power quality and reliability needs, etc.). Reliability is of utmost priority to commercial customers, and for many of these customers any interruption in electric service has the potential to stop business and immediately impact their bottom line. Customer businesses consisting of office workers may no longer have access to computers or phones and productivity drops, while retailers may lose the ability to conduct business resulting in lost revenue. For those customers with sensitive loads and technology related businesses, power quality and even momentary outages may be a significant issue.

Minnesota Power's residential customers are also served directly from the distribution system. Interactions with these customers include items such as: planning for new construction, service extensions, outage restoration, system upgrades and responding to a wide variety of other electric service and rate questions. Residential customers comprise roughly twelve percent of the Company's annual retail electric sales. However, since most of Minnesota Power's customer sales are served via transmission-level voltage, residential customers comprise a relatively large portion of Minnesota Power's distribution system load. Consequently, while residential customers comprise a small portion of the Company's overall load and revenue, they are a relatively large part of the distribution system, and an important part of Minnesota Power's business. Additionally, much of Minnesota Power's service territory consists of rural communities. These rural communities and customers present unique issues when planning for investment in the distribution system. Customers located at the end of multiple miles of line on a single feeder will have different challenges and requirements than someone located in a more populated area with feeder redundancy.

In order to meet the needs of this diverse customer base, Minnesota Power built its distribution strategy upon the core values of technology, innovation, and continuous learning. Customers expect reliable, affordable, and safe electric service, all of which are encompassed in these core distribution values. Meeting these expectations requires deploying right time/right fit distribution technology that is flexible, adaptable, and upgradable. Minnesota Power contends that equity – in all of its forms – plays a critical role in ensuring security, comfort, and quality of life for customers. Therefore, the Company has strategically positioned its distribution system for the deployment of emerging distribution technology through thoughtful planning in all areas of its business while maintaining a focus on customers' needs, upholding its distribution values, and aligning these investments with the Company's sustainability goals. Sustainable prosperity over the long-term is ALLETE's goal. The aim of sustainable development is to balance our economic, environmental and social needs, allowing prosperity for now and future generations. Safety, integrity, environmental stewardship, employee development and community engagement must be in the balance of every decision made and action taken.

The Company's 2019 IDP has been formed around three key themes of People, Resiliency, and Innovation, as depicted in Figure 3. Minnesota Power is planning for the future of an advanced grid while enhancing the customer experience. The Company's 10-year long-term plan focuses on continued investment in infrastructure with accelerated investments in the near-term in systems and data to optimize the 21st Century power grid. Investments in data and applications will provide a greatly enhanced customer experience while providing key operational benefits for reliability and safety.

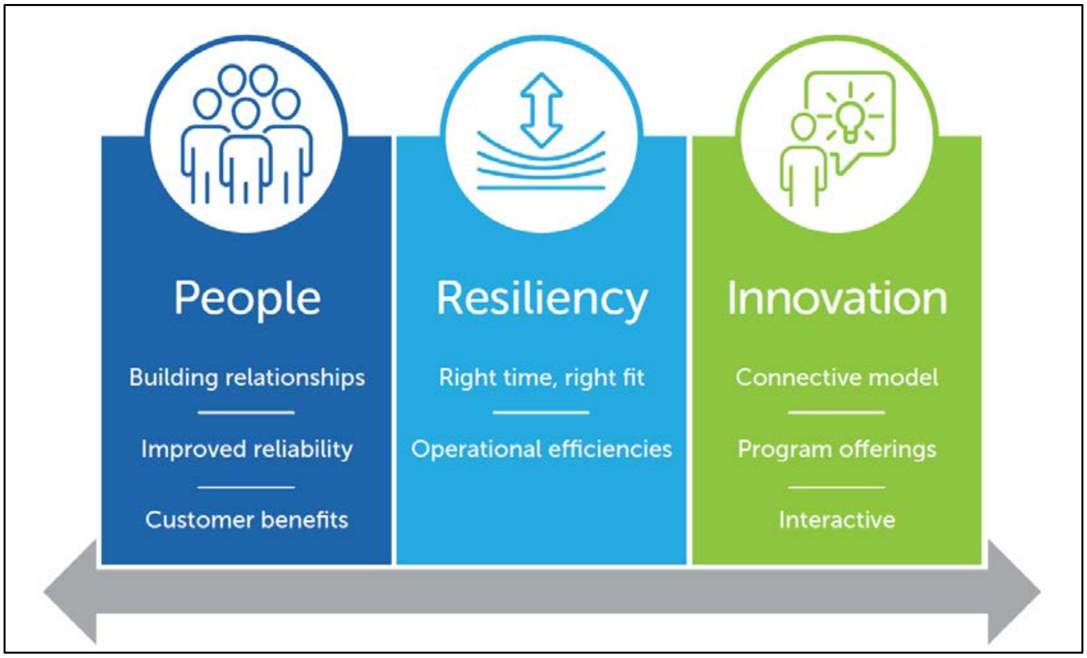


Figure 3: IDP Themes

A. People

The theme of People focuses on customer experience, building relationships, improved reliability, and consumer benefits. The Company continually strives to maintain and build relationships with its varying customer groups. Minnesota Power's approach to customer service is to continue to provide the core services customers count on as effectively as possible, while leveraging technological advances where applicable and practical to meet the modern day needs of customers. In order to meet these customer needs, the Company must ensure the right resources are working on the right priorities at the right time. Minnesota Power is committed to attracting and aligning talent with the changing customer, technology, data and analytics needs of the industry.

Minnesota Power is continuously improving the customer experience through the company's online tools, programs and services, and steady support from its Customer Care and Support team. Minnesota Power incorporates customer insights gained from customer interactions, satisfaction surveys, and benchmarking tools along with industry best practices to ensure our energy solutions meet the needs and expectations of customers today and into the future. Minnesota Power recognizes that, above all else, customers expect reliable, affordable, and safe electric service. Inherent to each of these is convenience, transparency and timeliness of service interruption updates, as well as clarity with respect to costs and program offerings.

1. Customer Feedback/Survey

Minnesota Power has historically procured survey information from J.D. Power[1] to understand how it compares relative to other utilities across the United States on customer sentiment around several areas. The most recent published survey that Minnesota Power subscribed to, from 2018, indicated that Minnesota Power customer sentiment was high for its corporate citizenship and above average for power quality and reliability, average for price, communications, and customer service. In addition to the J.D. Power research, Minnesota Power recently conducted a study in conjunction with Rapp Strategies with over 800 Minnesota Power residential customers. The customers surveyed by Rapp Strategies indicated a primary preference for safe, reliable, and affordable electricity.

As a result of the Company's surveys and engagement in industry forums, Minnesota Power is aware of the customer desire to engage in digital platforms. Consequently, the Company has launched enhancements such as online credit card payments; additional MyAccount tools for customers to start, stop and transfer service; mobile app based functionality for outage notification and MyAccount access; and a "Voice of the Customer" online discussion board to gain direct customer feedback. The Company also strives to embrace and support deployment of distributed technology through internal and customer partnerships. The systems and operational upgrades discussed through this Plan aid the Company in executing on this vision.

2. Stakeholder Engagement

Minnesota Power held a stakeholder forum on October 2, 2019 at Bent Paddle in Duluth, MN. The goal of this forum was to educate stakeholders on the Company's past and current distribution initiatives, distribution planning processes, the contents of the 2019 Integrated Distribution Plan, and to gain stakeholder feedback.

During the forum, Minnesota Power presented information regarding the following: Minnesota Power and its Distribution System, Current Distributed Energy Resources, Resiliency, DER Scenarios, 5-year Distribution System Investments, and the 10-year Long-term Distribution Plan.

The materials from the October 2, 2019 stakeholder meeting can be found in Appendix B[2]. Due to the innovative nature of the IDP filings, ongoing education and iterative dialogue with stakeholders will be crucial during the development of further/refined IDP requirements and corresponding information communicated by the Company. The Company is dedicated to continuing these valuable conversations with its stakeholders.

[1] J.D. Power provides actionable market intelligence to electric, natural gas, and water utilities serving consumers and businesses throughout the United States. J.D. Power's industry experts help these businesses measure and manage performance for ongoing improvement. https://www.jdpower.com/business/industry/utilities

[2] Some information presented in Appendix B may have been refined prior to the November 1, 2019 filing date.

B. Resiliency

The theme of Resiliency focuses on right time/right fit investments, operational efficiencies, and reliability/resiliency upgrades to enhance the customer experience as the Company continues to see an increase in extreme weather events in northern Minnesota. The systems implementation timeline communicated through this Plan (Figure 4) seamlessly integrates current customer, asset management, and operational systems under one real-time utility network model. This secure end-to-end system model will integrate all of Minnesota Power's generation sources, transmission infrastructure, and distributed assets and resources. This model will reside within a flexible, adaptable, and upgradable platform which will aid the Company to grow and respond to utility system dynamics and meet public policy goals. It will allow for a streamlined data gathering process to provide meaningful and proper data sets for stakeholders and the Company which will be utilized to advance a customer-centric, modern grid.

As technology continues to evolve, there is a growing desire on behalf of customers for more convenient and varied services, including: self-service electronic communication options; information about energy and product offerings (through efficiency and pricing or a combination of the two); and an expectation that customers' energy will come from a blend of more sustainable energy sources within Minnesota Power's overall resource mix as well as choice of renewable energy options.

C. Innovation

The theme of innovation builds upon Minnesota Power's history of finding creative ways to solve electric system problems through customer programs, partnerships, pilot projects and developing a connective network model to enhance the analytical capabilities of the distribution system. A connective network model focuses on advancing program offerings to support a more interactive relationship with Minnesota Power's customers. It will create and analyze meaningful data sets to aid in proactively developing and optimizing products and services through stakeholder driven processes. This process will create greater customer engagement, empowerment, and options for energy services. The connective model will also support the development and integration of DER technologies and enhance the value of their application as it relates to grid operations.

D. Minnesota Power Systems Overview

In the following sections, a brief overview of each of the systems critical to operation of the Company's distribution system is provided.

1. Customer Focused Systems Overview

Investments in Customer Systems have been driven from our customer's desire for more convenient and diverse products and services, including self-service electronic communication options and services; and information about energy and product offerings, generally through efficiency and pricing or a combination of the two. Minnesota Power's approach is to continue to provide the core services customers count on as effectively as possible, leveraging technology advances where applicable and practical. To meet customers' needs, the Company must continually invest in new technologies and customer facing improvements. For example, two short-term goals include implementation of a meter data management system ("MDM") to further leverage Advanced Metering Infrastructure deployment and enhancement of customer self-service through the Company's MyAccount tool, both of which will increase customer service as well as distribution system intelligence.

The systems upgrades and implementations outlined in this section are part of a holistic Customer to Meter ("C2M") solution which involves upgrading the existing Customer Information System to an Advanced Meter Billing System that includes the following modules; Customer Information Billing and Rates, Meter Data Management, Smart Grid Gateway, Meter Asset Management, and Service Order Management. More on the C2M project can be found in Section II.C.4 – Customer to Meter Project of this Plan.

Customer Information System ("CIS") – The core customer information system is designed to securely store customer information and act as the primary billing and rate engine for Minnesota Power customers. This system is currently set to be upgraded in 2019-2020 and the new upgrade will enable additional functionality through linked, specialized modules that will enhance automation and provide greater accuracy of presented customer information.

Meter Data Management ("MDM") *Planned* – MDM is the cross cutting system that provides a data engine that performs Validation, Editing, Estimating, and organized storage ("VEE") of both rate and operational information from metering systems. Metering systems include our Advanced Metering Infrastructure ("AMI"), Automated Meter Reading ("AMR"), and interconnected and industrial meters. Currently, this function is performed in a variety of systems in a limited fashion depending on the size of the customer and metering system. This investment will provide far greater consistency and accuracy with customer billing and organized operational data for system sharing. This system is slated to be installed in 2019-2020 and optimized for billing and rates through 2021.

MyAccount – This online portal allows customers to view and pay bills, look at daily and hourly usage, report outages, and perform many other account functions. This system will continue to be enhanced through modest, meaningful investment annually over the next 10 years and will leverage customer data provided by the underlying customer systems.

Since 2017, the Company has further enhanced its existing online customer portal and branded the application as MyAccount. As well as maintaining its initial purpose of providing customers with consumption and usage data, additional functionality was deployed to provide customers with the ability to view their bills and make payments on-line.

Over the next 5 to 10 years, Minnesota Power's strategy is to continue MyAccount upgrades and expand deployment with smaller investments, such as a Customer Preference Center, streamlined payment options, personalized program recommendations, and proactive alerts. The Customer Preference Center will be expanded in 2020-2021 to become the central repository for customer preference information for any or all notifications related to outages, programs and services. The MyAccount on-line portal currently provides options for customers like the ability to request a stop, start or transfer of service. Studies have shown that customers want an enhanced customer experience online by having the ability to view and manage their account with no interaction over the phone and at times that are convenient to them.

Automated Meter Reading ("AMR") – AMR is the legacy metering system that was installed at Minnesota Power from 2002-2006 utilizing first generation power line carrier technology. The system is very effective at one-way acquisition of meter reads but has limited bandwidth for supporting complex rates or real-time data capabilities. In 2009, the manufacturer deemed the system obsolete and has been self-supported by Minnesota Power since 2011. The current strategy is to fully replace this system by 2023 with the AMI system.

Advanced Metering Infrastructure ("AMI") - AMI is an advanced, two way metering system that provides metering, operational, and real-time notification of system conditions at customer premises for all retail customers. AMI has the ability to enable advanced Time of Use ("TOU") rates when combined with MDM. The current AMI system is scheduled to be fully deployed by 2023 and includes much integration with other, cross cutting systems. See further info in Section II.E.2.c – AMI.

Meter Asset Management *Planned* – Meter Asset Management systems store specific attributes related to AMI meters. Due to the specific requirements related to AMI meters (firmware management, TOU schedules, load/voltage profile structure, etc.) and specific rate data associated with managing AMI assets, Minnesota Power will be adding a Meter Asset Management system in conjunction with the MDM in 2020. This system will provide the appropriate level of information to automate some of the commands and AMI system features out of the billing system and allow for verification of meter configuration and readiness for specific rates within the MDM system.

Smart Grid Gateway ("SGG") *Planned* – In addition to Meter Asset Management, the SGG is another system that is designed to optimize the AMI system by providing an automation engine. This system utilizes capabilities through standard data models within the AMI system to allow for expansive integrations with other systems. The SGG is what enables the MDM to talk to head-end metering systems. This system will be implemented in conjunction with the MDM in 2020.

Mobile Workforce – Minnesota Power began accelerating the use of Mobile Workforce starting in 2017 with the first phase focused on interfacing with CIS field orders for Metering and Collections. This first phase has created paperless processing for nearly 30,000 customer orders annually. The second phase--which started in late 2018 and went live in 2019--focused on bringing trouble tickets from the Outage Management System into the Mobile Workforce application. This will allow an additional 4,000 tickets annually to be processed electronically within that application. The third and final phase of Minnesota Power's Mobile Workforce program for distribution, to be operational in 2020, will focus on the integration of work and asset management systems.

Outage Management System ("OMS") – The current OMS system contains all reports of power outages and predicts the failed equipment and fault location related to outages reported on the system. It is the source data for all customer-facing outage data and provides record of all outages and trouble orders for regulatory reporting. This system is slated for replacement in 2020 as upgrades have become onerous with declining software support. Detailed information can be found in Section II.C – Infrastructure 5-year Investment Plan.

2. Operational Systems Overview

Geographic Information Systems/Utility Network Model ("GIS") - Minnesota Power has utilized GIS for close to 30 years. Nearly all operational systems at the Company reference or utilize the GIS system to provide geographical and spatial aspects to operational data. In 2020, Minnesota Power will begin to move to a next generation GIS system which will integrate asset models from Generation, Transmission, and Distribution systems to create a real-time Utility Network model. This Utility Network model will be interconnected to all systems and have the accuracy to be compartmentalized and utilized securely for customer, internal, and stakeholder applications. The future GIS system will be transformed into an integral geographic and spatial base that will allow for maximum effectiveness and efficiency when implementing new systems and sharing information. Detailed information can be found in the Section II.C – Infrastructure 5-year Investment Plan.

EMS/DMS/DERMS - Minnesota Power has been utilizing an Energy Management System ("EMS") for nearly 40 years. Over that time, the capabilities and the system model of the EMS have been continually expanded and optimized to meet Minnesota Power's needs. The current version of EMS combines transmission operations and high capacity distribution substations to provide situational awareness and remote switching of equipment. The development plan for this system is to perform requirements gathering for full Distribution Management System ("DMS") capability as communication options and automation are expanded into the distribution system that will enable new capabilities such as volt/VAR optimization and conservation voltage management. Future system requirements will be determined in the 2023-2024 time frame as the Company plans for the next generation of the system. Currently, DER is not actively managed through EMS, however, small distribution-connected solar is monitored with the AMI system while larger solar (greater than 1MW) is centrally monitored and reported within EMS. Minnesota Power does not currently have a significant amount of solar connected to the distribution system, so no Distributed Energy Resource Management System ("DERMS") is necessary at this time. Nonetheless, DER growth will be monitored and the system tailored as the need for control arises within different aspects of the Company's distribution system.

Infrastructure/Distribution Asset Management - Minnesota Power has developed a plan to modernize the system and ensure reliability of service. With many assets 40+ years old, asset management programs and investments have increasingly become an area of significant focus for Minnesota Power. Asset renewal programs have been bolstered in recent years in an effort to target areas known to impact customer reliability and system resiliency. Minnesota Power has taken a strategic approach targeting key feeder and substation connected assets. At the substation level, programs have been integrated into a single substation modernization project designed to efficiently address all of the asset renewal needs at once.

Along with these asset renewal strategies, Minnesota Power has been developing its preventative maintenance and emergency replacement programs to track and enhance the health and reliability of its distribution assets. These systems are in the process of being optimized to support Minnesota Power's long-term utility asset management needs. The backbone of a healthy distribution system is communication and system management. They work in conjunction with each other to improve how information is provided and gathered, resulting in more accurate restoration times, outage statistics, and improved usability. Together, these systems allow the Company to more readily implement a future DERMS and/or an Advanced Distribution Management System ("ADMS") to control widespread use of solar and other distributed generation ("DG") sources as needed.

3. Systems Implementation Timeline:

In order to facilitate advancement towards a modernized grid and customer experience, the Company is implementing a foundational systems strategy as communicated in Figure 4. The system implementations are the building blocks for innovative programming and a smooth transition to a future with higher DER penetration. Each of these systems upgrades are discussed in detail in Section II.C - Infrastructure 5-Year Investment Plan.

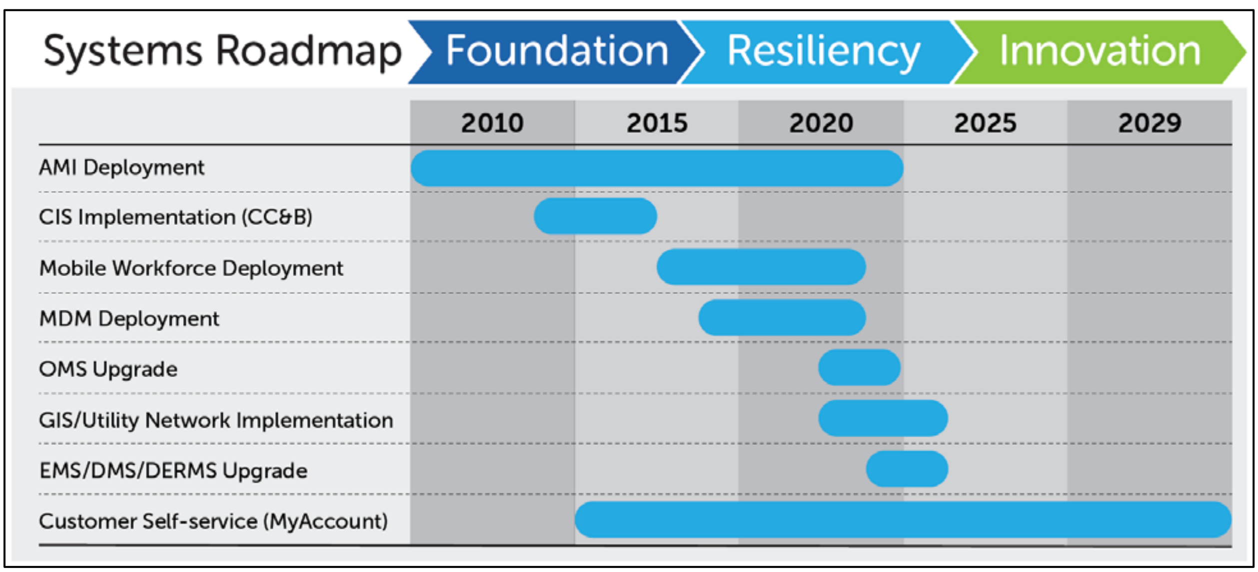


Figure 4: Systems Implementation Timeline

II. Foundational Investments

Minnesota Power has been operating and maintaining its distribution systems for many decades to serve customers in Northeast Minnesota to ensure they have access to safe, reliable and affordable service. Minnesota Power has traditionally followed a depreciation level spending pattern for its distribution system. The historical annual expenditures depicted in Figure 5 reflect depreciation level spend. Budgets were adjusted annually due to government mandated projects, increased age-related replacements and asset renewal programs, among others. Foundational investments focused on traditional system improvements and often resulted in upgrades made to underperforming areas. The foundational investments outlined in this Plan have positioned the Company for a transition to an innovative future. Going forward, the Company is increasing its investment above depreciation level spend to accelerate modernization and reliability projects as communicated in Section IV – Planning for a Resilient Future.

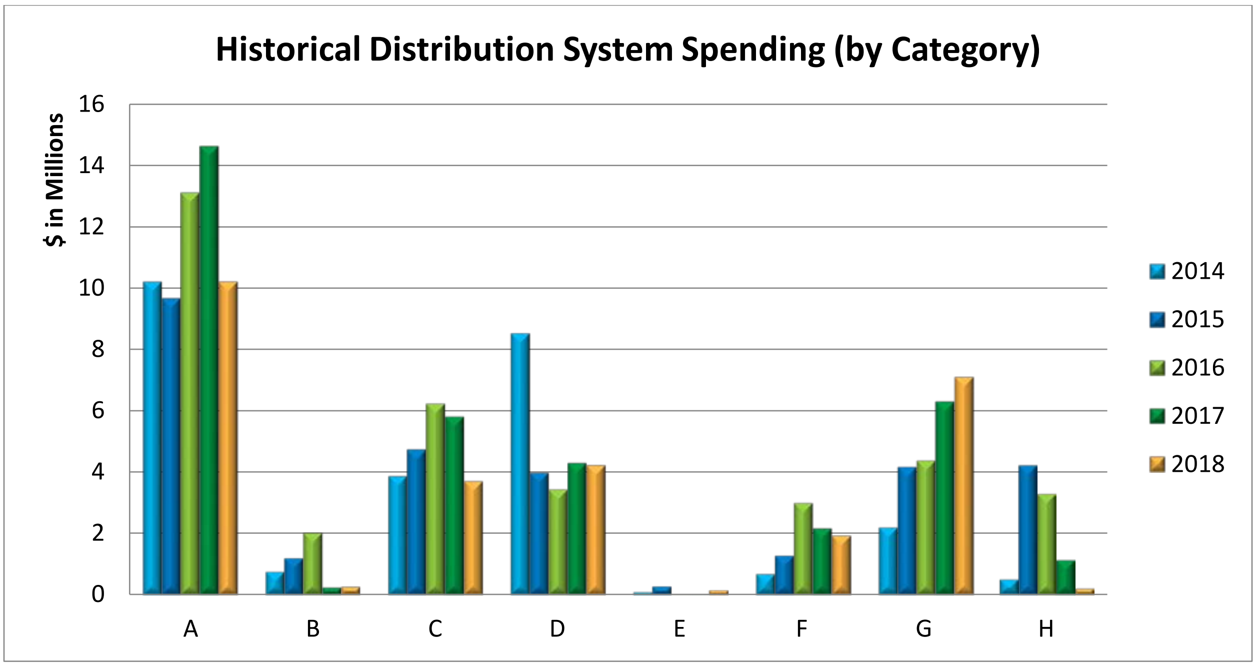


Figure 5: Historical Distribution System Spending

Table 1: Historical Distribution System Spending ($ in Thousands)

5-year Historical Spending (per Category)					
IDP Category	**2014**	**2015**	**2016**	**2017**	**2018**
A - Age Related & Asset Renewal	$10,207	$9,669	$13,127	$14,636	$10,226
B - Capacity	$753	$1,199	$2,045	$248	$267
C - Reliability & Power Quality	$3,895	$4,728	$6,260	$5,845	$3,717
D - New Customer / New Revenue	$8,525	$3,993	$3,469	$4,333	$4,242
E - Grid Modernization & Pilot Projects	$91	$278	$10	$5	$152
F - Government Requirements	$687	$1,277	$3,023	$2,185	$1,938

G - Metering	$2,214	$4,179	$4,404	$6,327	$7,107
H - Other	$507	$4,225	$3,323	$1,167	$207
Total	**$26,879**	**$29,548**	**$35,661**	**$34,746**	**$27,856**

A. Current DER Programming and Background

Minnesota Power has a longstanding history of working collaboratively with its customers as they implement Distributed Energy Resources. The Company is continuously monitoring the emerging trends of DER technology, both nationally and locally, along with its customer requirements. By enhancing customer communication efforts, Minnesota Power is helping to align customer expectations with achieved results. These efforts will aid in ensuring that DERs continue to be installed in a safe, reliable, and effective manner in Minnesota Power's service territory.

At the end of 2018, Minnesota Power had roughly 305 registered DER systems[3] as depicted in Figure 6. This represents a fairly diffuse penetration of DER on the system as a whole, but there are a few concentrated areas worth noting as outlined in Section IV.D.1 - IEEE Std. 1547-2018 Impacts. The Company's DER forecasting and analysis can be found in Section IV.C – Distribution Forecasting.

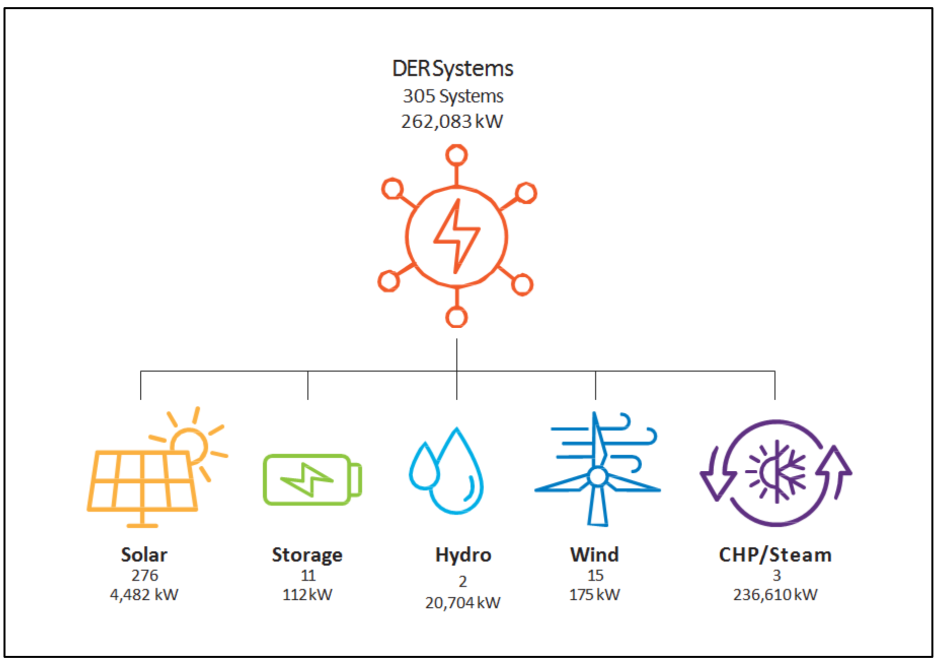


Figure 6: Current DER Systems

As depicted in Figure 6, the majority of DER on Minnesota Power's system are distributed solar systems. The dispersion of distributed solar systems on Minnesota Power's system is highlighted in Figure 7. It is important to note that in addition to tariffs and state policy,

[3] Docket No. E999/CI-19-9

Minnesota Power's SolarSense rebate program drives a large portion of solar installations. The program has been in place since 2004 but was expanded significantly in 2017 as a means of compliance with the Minnesota Solar Energy Standard. In 2018, roughly 90 percent of distributed solar installations in Minnesota Power's service territory have received a rebate. Affordability is a real and present barrier to customers in relation to accessing distributed solar energy. As highlighted in Figure 7, installations have varied greatly year-over-year depending of available incentive funding. For further information please see the System Summary Appendix C.

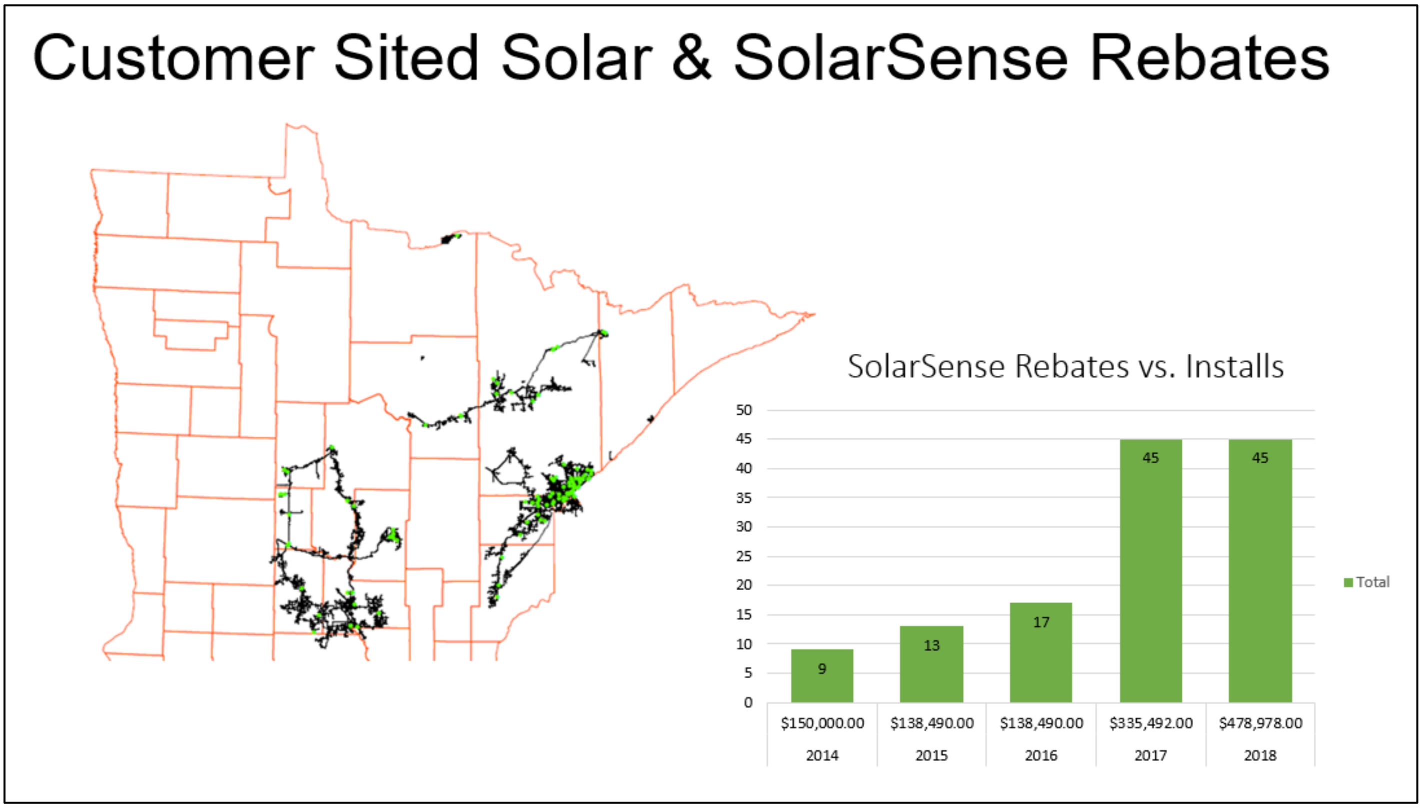


Figure 7: Customer Sited Solar in MP Territory

Minnesota Power did not charge an application fee for any solar installations in 2018 and did not track costs for processing interconnection in detail. Per Minnesota Power's Distributed Generation Interconnection Report filed in Docket No. E999/PR-19-10 on March 1, 2019, Minnesota Power customers paid a total of $62,393 for system upgrades related to DG installations.

1. <u>Demand Response</u>

Minnesota Power leads the state in the amount of demand response ("DR") as a percentage of peak demand, with 260 MW of MISO accredited DR from the Company's large industrial customers representing approximately 15 percent of peak demand.[4] In addition to DR programs for its largest customers, Minnesota Power offers a Dual Fuel rate that allows the Company to curtail the heating load of approximately 8,000 residential, commercial, and small industrial customers during times of high market energy prices or a system emergency. The customer must have a non-electric back-up heat source. Since this program deals almost exclusively with electric heat, there is minimal load to curtail in summer months - approximately 4 MW, mostly from commercial/industrial loads. The available curtailable load in winter months depends on temperature and heating loads, mostly of residential customers. Minnesota Power has an established dual fuel program with its residential and commercial customers to deliver demand response of approximately 30 MW, or approximately 2 percent of the peak load, primarily during winter heating months.

2. Electric Vehicles/Beneficial Electrification

Minnesota Power can only accurately track electric vehicles in its service territory insofar as customers enrolled in the Company's electric vehicle tariff. As reported in the Company's annual Electric Vehicle ("EV") compliance report[5] the Company currently has 4 customers enrolled in its electric vehicle tariff. Based on Minnesota Department of Transportation registrations, sorted by zip code, Minnesota Power estimates that there are currently approximately 180 electric vehicles in its service territory. Similarly, Minnesota Power can only accurately track charging stations owned by the utility. According to the Department of Energy's Alternative Fuels Data Center, there are 19 public EV charging stations in Minnesota Power's service territory, with 45 connectors. The total capacity of all the chargers is estimated to be about 1 MW.[6]

Minnesota Power submitted its Commercial EV Tariff Pilot Program to the Commission on May 16, 2019.[7] The Pilot Program proposal consists of on-and-off peak periods as well as a 30 percent cap on demand charges. The rate is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications. The Company is placing an emphasis on encouraging a growing market by reducing costs to public and fleet EV charging customers. The information gathered during the three year Pilot Program will inform future rates designed to both meet customer needs and optimize the grid benefits associated with EV charging. The Commercial EV Tariff Pilot was approved with modified peak time periods and additional reporting requirements at the Commission's September 4, 2019 agenda hearing with the written order not yet issued.

Minnesota Power also intends to expand on current efforts for Electric Vehicle Service Equipment ("EVSE") deployment. This includes identifying willing partners in communities across its service territory to install more chargers for public, work place, and multi-unit dwellings. Potential programs may include other options for trial use by customers and employees.

[4] Docket E-015/M-18-735. MPUC Staff Briefing Papers for August 1, 2019 MPUC Hearing
[5] Docket No. E015/M-15-120
[6] https://afdc.energy.gov/stations
[7] Docket No. E-015/M-19-337

The Company has dedicated significant internal resources to focus on electrification through its cross-functional, internal Electrification of Transportation Strategy Group, which works to ensure the Company executes a coordinated and appropriate response to the advancement of transportation electrification. Minnesota Power will continue to explore best practice options for alleviating customer barriers and encouraging responsible growth of the EV market from a power supply perspective.

3. Small-Scale Solar

The Company continues its longstanding support of customer-sited and small-scale solar systems with its SolarSense Customer Solar Program, which was significantly expanded in 2017.[8] The expansion includes an increase to the budget for customer-sited solar incentives, a first of its kind in Minnesota low income solar pilot program, and a solar research and development program. With thorough planning and proactive action in each pillar of the Company's solar strategy -- Utility, Community and Customer -- Minnesota Power is well positioned for compliance with its Solar Energy Standard[9] requirements in 2020. More information about the low income solar pilot program can be found in Section III.A.2 – Solar Sense Low-Income Solar Pilot.

4. Conservation Improvement Program

Minnesota Power is proud of its state-leading conservation program, which has surpassed the state energy efficiency goal of 1.5 percent year after year since its inception. Between 2013 and 2018 Minnesota Power achieved an average of 75 GWh in incremental (i.e. first year) annual energy savings with achievements ranging from 64 GWh to 85 GWh through its Conservation Improvement Program ("CIP") (Table 2). The Company had a savings total of more than 72,479,000 kWh in 2018. That is enough energy to power 8,000 homes, take 11,000 cars off the road, and save 56,000 tons of carbon in a year.

Prior to 2017, Minnesota Power reported Demand savings coincident with Minnesota Power's system peak, which typically occurs in the winter. Between 2013 and 2016, peak demand savings resulting from the CIP programs ranged from 6 MW to 9 MW. Beginning in 2017, the Company was required to start reporting peak demand savings from CIP coincident with MISO system peak, which typically occurs in the summer. The average peak demand savings reported for 2017 and 2018 was 8.3 MW.[10] Both energy and demand savings are determined based on State approved calculations and methodologies for preapproved energy efficiency measures.

[8] Docket No. E-015/M-16-485

[9] Minn. Stat. Sec. 216B.1691, subd. 2f

[10] The Company's Demand Side Management ("DSM") program provides end use load shapes. The load shapes developed through this program aid in determining the avoided marginal energy benefits of energy efficiency achievements.

Table 2: Average Total Savings

	Reported MW savings at the generator	Total MWh Savings	Percentage Savings
2013	5.72	77,631	2.5 percent
2014	9.22	76,338	2.5 percent
2015	7.23	85,611	2.8 percent
2016	9.49	64,034	2.1 percent
2017*	8.59	72,372	2.6 percent
2018	8.10	72,480	2.6 percent

*Starting in 2017, reported kW savings are coincident with MISO peak; Prior, kW savings at the generator were coincident with MP system peak and meter kW were non-coincident with system peak

Average Total Savings:	74,744 MWh

B. Modernization Investments

The keys to successful modernization investments are detailed project execution plans, project metrics, cost, and anticipated vs. actual benefits. Minnesota Power's approach to modernization has been to target pilot-scale projects that incorporate optionality and scalability. This approach has yielded benefits, including improved integration of DER, as a result of both Operational Technology and Information Technology investments that speed the process of interconnection to the distribution system.

Modernization investments are made with a continued focus on safety, reliability and affordability. Most modernization improvements begin with data-based analysis that has been collected through the Company's information management systems. The capital utilized in modernization activities can generally be broken down into two specific categories:

- Operational Technology ("OT") – Replacement of existing assets with modern asset designs that incorporate solid state components, sensors and communication technology to provide visibility, connectivity and data streams to system operations (i.e. AMI, voltage monitors, intelligent switches) that are integrated with centralized software and control systems.
- Information Technology ("IT") – Software and OT interface investments that allow for storage, reporting, control and utilization of data and information in operations.

These technology investments, combined with a customer-centric outlook, allow for prudent system evaluation based on an ever-expanding foundation of data and information. This data provides more confidence in load research, modeling and forecasting. The data can be used in rate design, class cost of service studies, new product offerings, etc.

C. Infrastructure 5-year Investment Plan

The 5-Year investment Plan includes a number of strategic projects in the Company's distribution capital budget and includes an increase in spend for key budget areas as outlined in Figure 8. These are identified as part of broader strategic Minnesota Power initiatives that most often directly benefit the Company's customers. An example of a strategic project would be the Company's deployment of AMI, a multi-year concerted effort discussed in Section II.E.2.c) – AMI and other areas throughout this Plan.

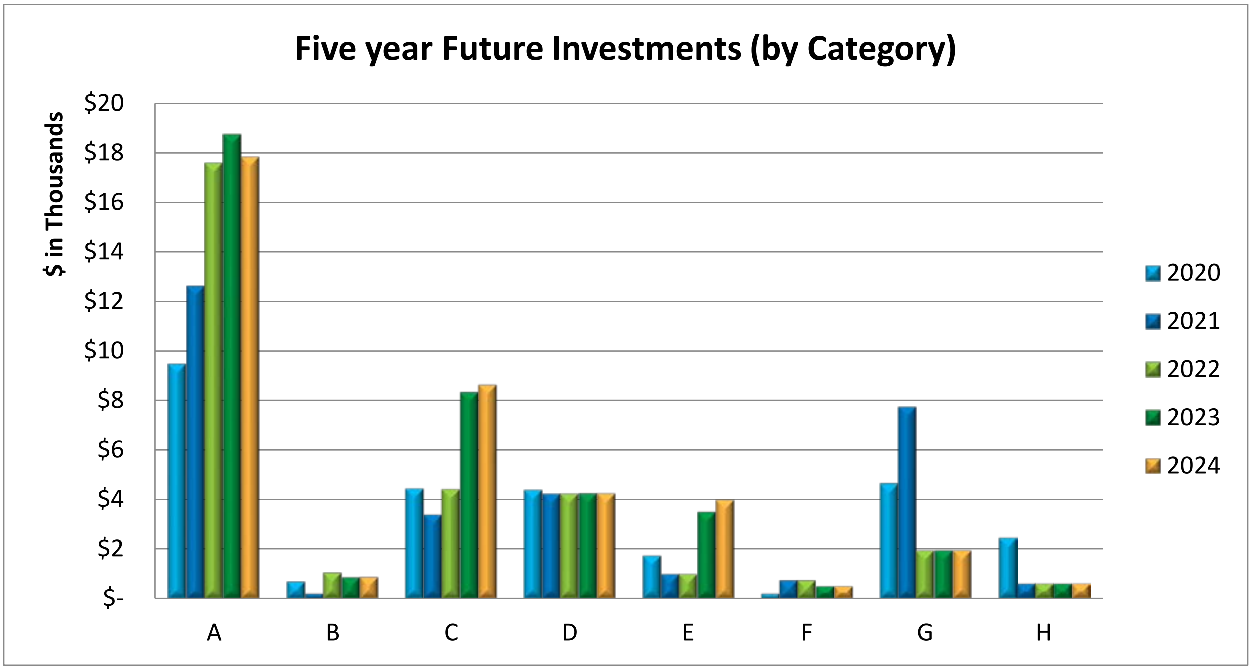


Figure 8: Five Year Future Investments (by Category)

Table 3: Five Year Future Investments (by Category, in $Thousands)

Planned Distribution Capital Investments by Category ($Thous)	2020	2021	2022	2023	2024
A - Age Related & Asset Renewal	$9.473	$12.650	$17.610	$18.760	$17.840
B - Capacity	$0.699	$0.210	$1.060	$0.860	$0.880
C - Reliability & Power Quality	$4.465	$3.400	$4.440	$8.340	$8.640
D - New Customer / New Revenue	$4.412	$4.257	$4.257	$4.257	$4.257
E - Grid Modernization & Pilot Projects	$1.750	$1.000	$1.000	$3.500	$4.000
F - Government Requirements	$0.201	$0.750	$0.750	$0.500	$0.500
G - Metering	$4.650	$7.750	$1.950	$1.950	$1.950
H - Other	$2.475	$0.605	$0.605	$0.605	$0.605
Total ($ in Millions)	**$28.125**	**$30.622**	**$31.672**	**$38.772**	**$38.672**

System Expansion Upgrade projects are driven by improvement of operational flexibility and customer reliability. If a certain area experiences exceptionally poor reliability over a short period of time, distribution engineers and planning may evaluate the local system and identify a potential reliability improvement. Field crews are also invaluable resources for feedback on areas of the system that could benefit from additional operational flexibility. With the prevalence of AMI on the system, the Company has been able to more frequently and preemptively identify areas of the system with power quality issues.

Grid Modernization Projects are efforts that go beyond the Company's baseline efforts to maintain safe, reliable, and affordable energy but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. These projects are identified and selected through analyzing reliability metrics and determining what solution or suite of solutions is best suited to improve reliability on the system. Most often, this involves the deployment of more intelligence on the distribution system such as line sensors, motor operated switches, automatic switches, fault indicators, and trip savers. Increased information from the distribution system helps improve customer communication and reliability of service.

Pilot projects are the Company's efforts to work with new and emerging applications on the distribution system. Pilots are most often projects that the Company has little to no experience with and are meant to facilitate learning and ensure that an effort is worth pursuing on a larger scale before expending large amounts of capital. The Company has pursued a number of pilot projects in the past that have resulted in tangible customer benefits, cost savings and lessons learned. Moving forward, the primary goal of pilot projects is to find more cost savings and customer benefits with new and emerging technology and applications.

1. Outage Management System

The OMS manages the detection, location, isolation, repair and restoration of faults which occur unexpectedly on the distribution system in addition to managing planned distribution outages. It provides support to operators at all stages of the outage life cycle, starting from events--customer reports, Advanced Metering Infrastructure outage notifications, Supervisory Control and Data Acquisition ("SCADA") operations, and notification from the field crews--and concluding with the restoration of electric service. The OMS is the overall coordinator of all tasks, processes and record keeping associated with the resolution of distribution outages and is the single source for communicating outage information to internal and external stakeholders.

The OMS must utilize information provided from the Geographical Information System ("GIS") for an accurate representation of the distribution system. GIS data must go through a complex mapping process before it can be utilized by the OMS. The current GIS technology is not fully compatible with the OMS leading to lost hours of productivity, which has resulted in the OMS having inaccurate and/or incomplete representation of portions of the distribution system. This in turn has limited the OMS's ability to accurately predict outages in certain locations and, in some cases, for the OMS to predict outages where none were actually present. In addition, the OMS application and the servers and databases it runs on are all approaching end of support, increasing the potential for security, functionality, and performance issues to emerge for which no solution is available from the manufacturer.

Given these issues, Minnesota Power is in the planning phases of a project to upgrade the OMS. The upgraded OMS will improve integration with the GIS to eliminate or greatly reduce the mapping errors described above. This mapping improvement, combined with the Network Utility Model project described in Section II.C.2 - Geographical Information System, will result in the OMS having a more accurate representation of the distribution system. This will reduce restoration times by locating isolated outages and improving prioritization of restoration work in multi-outage situations. Customers will be provided more accurate restoration times, potentially increasing customer satisfaction. An upgraded OMS will position Minnesota Power to more readily implement a DERMS and/or an ADMS to control widespread use of solar and other distributed generation sources if and when the need arises.

2. Geographical Information System

GIS is the suite of spatial technologies that Minnesota Power uses to store, analyze, and report on its electrical system. The purpose of the GIS at Minnesota Power is to store and analyze spatial information about the features that make up the electrical system and provide internal and external customers access to this information.

The GIS, as well as the staff that support and operate it, serve external customers in a variety of visible and unseen ways. As described above, data is translated out of the GIS and into the OMS and allows for rapid restoration of power during storms or other outages. Information from the OMS is then sent back to the GIS to support the customer outage map. This outage map was previously maintained by a third-party, but as of April 2019 it was re-designed and re-implemented as an in-house solution that could be seamlessly integrated with Minnesota Power's MyAccount tools.

The current GIS is very stable, but issues have been identified in the shift toward real-time information and mobile technologies. Both internal and external drivers are pushing the GIS to provide more information to more people in more varied locations at increasingly faster speeds. This shift in expectations has amplified issues within the current GIS model both in terms of the information it can store as well as how that information is delivered.

The Company is transitioning to a cutting edge GIS model that will lower operating costs in a number of areas. The primary benefit of the system is that it connects data across all of the systems, from generation to customer. As a result, GIS staff will no longer need to spend time transferring data between systems in order to model impacts between the various components of the electrical system. Moving to a more real-time GIS system will lower costs by removing some of the delays in current data integrations. This will allow staff to act on information faster and resolve issues in a timelier manner.

3. Customer Information System

In 2015, the Company implemented an off-the-shelf CIS to replace a highly customized mainframe-based system that was built in the late 1990's. The CIS is a shared system with Minnesota Power and Superior Water Light & Power and is considered the Company's corporate accounts receivable system, customer billing system and advanced rates engine. The main drivers for the CIS replacement were replacing obsolete technologies for one of our core business systems, increase the efficiency of business operations, target automation and integration opportunities, as well as promoting data-driven decision making. This system was implemented with the intention of laying the foundation for future initiatives such as the Customer to Meter project highlighted below.

4. Customer to Meter Project

Minnesota Power is partnering with a System Integrator ("SI") to implement a mature, flexible, highly-scalable upgraded Customer Information solution with advanced meter data management capabilities designed to meet the needs of electric, gas and water services. The project began in 2018 with the purchase of software. The estimated in-service date will be Q3 2020. The project objectives are to support key business drivers in regards to Distributed Generation, Grid Modernization, Customer Service and Meter Asset Management.

The primary aim of Customer to Meter is to implement a single software solution to provide the functionality of five systems. This means one database, one framework and application, and one, unified user interface. C2M will reduce platform costs by an estimated 25 percent and eliminate complex integrations between multiple systems. The Company will realize many benefits, including cost and efficiency, and functionality of five systems, while only installing and maintaining one. This holistic solution involves upgrading the existing CIS system to an Advanced Meter Billing System that includes the following modules; Customer Information Billing and Rates, Meter Data Management, Smart Grid Gateway, Meter Asset Management, and Service Order Management.

The C2M project will improve management of operational devices in the field such as meters and metering equipment. It will make the status of service orders more transparent and allow proactive identification and response to meter alarms and issues.

Benefits for customers include:

- Capability to automate billing for Time of Day and other time-varying rates.
- Energy use data in MyAccount will appear more clearly.
- Billing estimates will be more accurate.
- Remote service connections and disconnections will be simplified.
- New programs and rates for innovative technology such as electric vehicles will be more easily designed.

This solution will provide the foundation to respond more quickly to changing regulatory and marketing demands. It will improve the Company's understanding of its customers via data analytics, rate guidance and targeted program offerings to customers, as well as the efficiency and accuracy of the meter asset management process. Additionally it will reduce risk through elimination of the in-house developed system for distributing and analyzing meter data. The total investment in this project will be approximately $9.7 million, which includes $1 million software/hardware licensing and $8.7 million in consulting and internal labor costs.

D. Current Projects

The Company's five-year distribution capital plan includes three projects that are anticipated to have a total cost of greater than two million dollars. Minnesota Power also maintains a substation modernization program that is anticipated to include individual projects with a total cost of greater than two million dollars. The estimated cost and expected benefits of these projects are discussed in Table 4. Since all of these projects are asset renewal projects whose main driver is age-related replacement of end-of-life equipment, they are not viable candidates for non-wire alternatives, as explained in Table 4 and discussed later in this Plan.

Table 4: Distribution Projects over $2 Million

Project Name	Preliminary Projected Costs	Anticipated ISD	Project Area	Project Description
Colbyville Switchgear Replacement	$3.2M	2022	East Duluth & surrounding areas	The switchgear and outdoor breakers at the Colbyville Substation provide protection and isolation for the 13.8 kV feeders interconnected at the substation. Much of the existing distribution equipment at Colbyville has been in service for several decades and is nearing or beyond the end of its useful life. The Colbyville Switchgear Replacement Project involves coordinated replacement of end-of-life assets and modernization improvements designed to extend the life of the substation for the next several decades. Planned age-related replacements include switchgear, outdoor breakers, one transformer and associated equipment.
Gary Switchgear Replacement	$3.0M	2023	West Duluth	The switchgear at the Gary Substation provides protection and isolation for the 13.8 kV feeders interconnected at the substation. Much of the existing distribution equipment at Gary has been in service for several decades and is nearing or beyond the end of its useful life. The Gary Switchgear Replacement Project involves coordinated replacement of end-of-life assets and modernization improvements designed to extend the life of the substation for the next several decades. Planned age-related replacements include switchgear, one transformer and associated equipment.
Haines Rd Switchgear Replacement	$4.5M	2024	Hermantown & Central Duluth, Miller Hill Mall Area	The switchgear at the Haines Road Substation provides protection and isolation for the 13.8 kV feeders interconnected at the substation. Much of the existing distribution equipment at Haines Road has been in service for several decades and is nearing or beyond the end of its useful life. The Haines Road Switchgear Replacement Project involves coordinated replacement of end-of-life assets and modernization improvements designed to extend the life of the substation for the next several decades. Planned age-related replacements include two switchgear buses, two transformers and associated equipment.

Substation Modernization Program	$4.3M $2.8M $4.2M $2.0M	2021 2022 2023 2024	*Anticipated Substations*:* Meadowlands, Long Prairie, Verndale, Little Falls, Nashwauk, Wrenshall **subject to change based on asset renewal project prioritization*	Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization Program involves coordinated replacement of end-of-life assets and modernization improvements designed to extend the lives of these substations for the next several decades. Planned age-related replacements include outdoor breakers, transformers, switches and associated equipment. The Program will take a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of the many aging substations throughout Minnesota Power's system.

E. Analysis and Visibility of System Data

1. Software

Minnesota Power currently uses industry standard software to perform basic distribution analysis routines such as voltage drop, load balancing, fault current analysis, and switching studies for distribution planning. As the use and planning of the distribution system continues to evolve, Minnesota Power will evaluate available and emerging software platforms to ensure that it is implementing optimal analytical tools for its distribution planning efforts.

In late 2018, Minnesota Power also became part of the EPRI DRIVE[11] (Distribution resource integration and Value Estimation Tool) User Group in order to gain understanding of hosting capacity analysis and the data and labor requirements for performing a comprehensive system-wide hosting capacity study. While Minnesota Power's experience with the EPRI DRIVE tool has been limited to date, one of the goals of participating in the DRIVE User Group is to develop the tools and expertise needed to produce system wide hosting capacity maps, perhaps as early as the Company's 2021 Integrated Distribution Plan.

Minnesota Power uses four different methods to monitor and control its distribution system: Supervisory Control and Data Acquisition, smart sensors, automated/advanced meter collection, and manual meter reading. Each of these monitoring and control methods is discussed briefly below.

The SCADA system oversees the state and health of the distribution system on roughly half of the Company's feeders. This system brings back measurement data in the form of analog (e.g., Amps, MW, MVar, MVA, and kV) and binary (e.g., statuses, alarms, and outages) values from these feeders. The SCADA system measures analog data in 4 second intervals and binary information in 60 second intervals as well as when there is a change of state. The information is recorded in a historical database that is accessible for engineering planning and analysis. In addition, the SCADA system enables Minnesota Power's system operators to remotely operate

[11] The EPRI DRIVE™ software determines the maximum amount of DER each distribution feeder can accommodate in its current state before unacceptable reliability, power quality, protection and thermal issues start to emerge. http://www.cyme.com/software/cymeepri/

breakers and motor operated switches to isolate faulted equipment and feeder sections, greatly expediting the restoration process, enhancing reliability, and reducing customer impacts.

Smart sensors are installed on feeders that do not currently have SCADA installed. These substations are usually in remote rural areas where communication paths are limited. The smart sensors monitor voltage and current near the feeder breaker and store measured data offsite in a data historian. A secure account can be used to review and download the information for engineering and event analysis as well as restoration efforts. Minnesota Power intends to place these sensors at most substations in order to gather better data and eliminate manual reads.

Manual reads are occasionally collected by operations personnel during substation inspections. These reads collect peak amp data each month and are reset upon reading. This information is then housed in the Company's asset management system for analysis. There are a number of rural 4kV feeders on the distribution system that are not read because they are remotely located and serve a very small number of customers.

Minnesota Power has two different automated meter collection systems. The AMR system is Minnesota Power's oldest meter collection system and is being replaced with the AMI system. The AMR system records kilowatt Hour (kWh) and kilowatt (kW) information. This information is transmitted back to the collection system every 27 hours using powerline carriers. The AMI system records voltage, kW, kWh, Vars, blink counts and informs the OMS of customer outages. At present, AMI meters transmit data every 15 minutes on three phase meters and 60 minutes on single phase meters. The information is currently stored in an internally developed data warehouse. Once the Customer to Meter ("C2M") solution (outlined in the Customer Systems subsection of this Plan) has been implemented, it is anticipated that the C2M system will increase efficiency and produce cost savings by becoming the primary repository for this data and that the internally developed data warehouse will no longer be needed.

2. System Visibility – SCADA, Smart Sensors, AMI

a) SCADA

Minnesota Power currently has 360 distribution feeders throughout its service territory. Some of these are three phase feeders while others are single phase. Minnesota Power has visibility into and control of primary and 3-phase distribution. The Company currently has no visibility or control on single phase or secondary distribution. Of the Company's 360 distribution feeders, 181 feeders (50 percent) have SCADA at the feeder breaker. In 2017, Minnesota Power began implementing smart sensors on the remaining 179 distribution feeders. Through 2019, 83 distribution feeders (23 percent of total feeders) have smart sensors installed near the feeder breaker. Nine additional locations on four feeders have smart sensors installed to assist in fault locating. In 2020, Minnesota Power plans to finish the rollout of the smart sensors on distribution feeder breakers. Minnesota Power will continue installing smart sensors in multiple locations on feeders to assist in fault location, increasing real-time visibility on the distribution system and creating efficiencies.

b) Smart Sensors

Minnesota Power is currently testing control capabilities on the distribution system using the AMI backhaul smart communication network. With the aid of smart sensors and faulted circuit indicators ("FCIs"), the Company plans to continue installing remotely controlled motor operators on the distribution system in order to enhance fault isolation and system restoration capabilities. Motor operators enable Minnesota Power's system operators to remotely control feeder switches. Smart sensors and FCIs give indication to the system operators where the fault is located on the feeder. Combining motor operated switch installations with fault location information on a feeder enables Minnesota Power's system operators to utilize the motor operated switches to rapidly isolate the faulted section of the feeder and restore service to customers on the sections of the feeder without electrical faults. All of this switching can be completed by the system operators in minutes, well before a trouble crew could reach the feeder to begin to identify the cause of the fault. With the faulted section of feeder identified and isolated by the system operators, the trouble crew can then focus its efforts on only the faulted feeder section to identify and fix the cause the fault. The end result is a more rapid and efficient response to feeder-level fault events, which should greatly enhance reliability for the customers served from the feeders where this approach is implemented.

c) AMI

The AMI system allows for efficient metering access, enhanced communication and situational awareness between Minnesota Power and its customers. The meters act as "smart nodes" at each customer's premises, allowing a number of benefits including: efficient deployment of advanced time-based customer rate offerings; outage notifications; notification of service issues (such as low/high voltage, over current, and tamper warnings); improved load control; more frequent customer usage data; and the ability to more quickly reconnect customers who may have been involuntarily disconnected due to non-payment. The expansion of Minnesota Power's AMI capabilities also lays the groundwork for further grid modernization initiatives and improvements to the customer experience.

Table 5: Deployment Plan for AMI Meters

	AMI Meters Installed	**Remaining AMR Meters**
2016 Actual	11,092	92,084
2017 Actual	11,476	80,608
2018 Actual	13,155	67,453
2019 Forecast	13,500	53,953
2020 Plan	13,500	40,453
2021 Plan	13,500	26,953
2022 Plan	13,500	13,453
2023 Plan	13,453	0*

***Likely won't be "0" in 2023 due to potential opt-outs**

As of June 2019, there were 82,000 deployed AMI meters on Minnesota Power's system (roughly 60 percent of deployed meters). With the aid of a Smart Grid Investment Grant, 8,030 meters were deployed, as described in Section III.A.1 – Time-of-Day/Critical Peak Pricing of the Plan. There are 62,000 deployed meters remaining on the older AMR system. Minnesota Power is a utility leader in Minnesota for AMI implementation and has historically deployed AMI throughout its service territory at a rate of approximately 6-8 percent per year. However, the Company has chosen to supplement the AMI expansion budget to accelerate the implementation of AMI meters in its service territory. This increased spending on AMI meters through proactive deployment results in full deployment of all AMI meters system-wide by the end of 2023.

F. Cyber Security

With the advent of enhanced data and system capabilities, and increased DERs on the utility system, it is imperative that the Company ensure the security and integrity of customer and utility systems and data. Minnesota Power has built out a multi-layered cyber security program based on the Center for Internet Security's internationally accepted Critical Security Controls for Effective Cyber Defense framework to prevent, limit the impact of, and ultimately recover from outages caused by cyber threats. In practice, Minnesota Power's cyber security program addresses: Dedicated Cyber Security Program and Leadership, External Sensing, Internal Sensing, Intrusion Prevention, and Intrusion Mitigation. Detailed information on the Company's cyber security program can be found in the Company's most recent Safety, Reliability, and Service Quality Report.[12] Additionally, Minnesota Power collaborates with industry and public officials to share best practices as it relates to both cyber and physical security, as demonstrated by the Company's leadership role in organizing the first ever Minnesota Cyber and Physical Security Summit in St. Paul on October 16, 2019.

III. Demonstrating Innovation

Minnesota Power has routinely implemented technology solutions where appropriate to assist with outage detection, response time to outages, and to respond to customer expectations regarding more timely communication and transparency of operations. At the same time, the Company has piloted innovative technology in order to test the feasibility of certain applications for the distribution system, while utilizing resources wisely to gain benefits. The pilots outlined in this section are examples of how the Company continues to carefully leverage internal and external resources to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid.

[12] Docket No, E015/M-19-254

A. Current and Past Pilots

1. Time-of-Day/Critical Peak Pricing

Minnesota Power's Smart Grid Investment Grant project ("SGIG") involved the installation of advanced metering infrastructure and explored the application of distribution automation. The project was aimed at improving customer understanding of their electricity usage, reducing operation and maintenance costs, and improving awareness of and response to distribution system outages.

As part of its SGIG, Minnesota Power designed a two-phase Consumer Behavior Study Plan ("CBSP"). The CBSP, branded as the Power of One® Choice Pilot, began in the spring of 2012 and was implemented in the Duluth/Hermantown area. Phase One of the research was designed to answer questions about residential customers' interest in, use of, and benefits derived from different levels of resolution of feedback on electricity consumption—monthly, daily, and hourly. Phase Two of the research, which began in October 2014 and ran through October 2015, entailed offering a Time-of-Day ("TOD") Rate Pilot with a Critical Peak Pricing ("CPP") component to a subset of Minnesota Power customers. The installation of AMI allowed the Company to initially offer about 660 volunteer customers another rate option that includes a time aspect that better reflects the cost of providing electricity. As of August 2019 there were 381 customer remaining on the rate.

Table 6: TOD Rate Structure

Current Rate Structure May 2017 - Present	
On-Peak Hours	08:00 - 22:00 Monday - Friday
Off-Peak Hours	All other hours & designated Holidays
Summer CPP Hours	12:00 - 15:00
Winter CPP Hours	17:00 - 20:00
On-Peak Increase	$0.0487
Off-Peak Discount	-$0.0299
CPP Event Increase	$0.77

In February of 2018, the Commission ordered Minnesota Power to engage stakeholders in evaluating alternative rate designs and TOD periods for a system-wide TOD rate. A March 2018 survey revealed that, generally, Minnesota Power's TOD Rate participants believe that the TOD Rate gives them more control over their electricity costs. A substantial majority of participants like the program and chose to remain in it despite a significant increase in the on-peak rate in 2017. Despite its effectiveness and success, Minnesota Power believes its current TOD Rate

Pilot program has come to its natural conclusion and should remain closed to any new participants. The Company is currently evaluating various alternative rate structures through the stakeholder process as outlined in a separate docket.[13]

2. Solar Sense Low-Income Solar Pilot Program

The goal of the Low-Income Solar Pilot Program ("LI Solar Pilot Program") is to create a viable, long-term solar market for low-income customers in northern Minnesota by exploring innovative ways to address the solar adoption challenges commonly faced by this customer segment. These challenges can include lack of upfront capital, home ownership status, physical condition of the home, low credit scores, limited access to information and more. This first-of-its-kind in Minnesota program was intentionally designed to be flexible to encourage a wide variety of project structures, partnerships and creative solutions to address these barriers. The Company dedicated $165,000 over three years for this pilot, all of which has been awarded to qualifying low-income solar projects. A request for a one year extension of the program was filed on September 19, 2019 in Docket No. E999/M-19-276. Examples of projects funded through the LI Solar Pilot Program are outlined below:

a) AICHO Solar Project

The LI Solar Pilot Program funded a 14.4 kW solar PV installation on the roof of the American Indian Community Housing Organization ("AICHO") building in downtown Duluth. The AICHO building serves as a central hub for the Native American community in the region, providing housing services for people suffering from long-term homelessness, transitional housing for survivors of domestic abuse, and a 10-bed domestic violence shelter. They also host cultural events, art shows and performances. The energy generated by the solar array will directly serve the shelter as well as indirectly serve the tenants of 29 apartments through powering offices and the auditorium which provide services to all residents. In addition to reducing the operating costs of the facility, the installation will provide educational opportunities to residents of the building and the general public. Prior to installation of the solar array, an energy audit was performed and energy efficiency upgrades were made to the building.

b) RREAL and Tri-County Community Action Project

RREAL ("Rural Renewable Energy Alliance") and Tri-County Community Action ("TCC") submitted an application for a 20 kW solar array at TCC's headquarters in Duluth. Energy generated by the solar array will benefit up to 10 Low Income Home Energy Assistance Program ("LIHEAP") -eligible households in central Minnesota. Preference will be given to disabled veterans for this project. The system is expected to be installed in 2019.

c) Lincoln Park Solar Project

The LI Solar Pilot Program committee also recommended funding for a 40 kW project in Duluth submitted by Ecolibrium3. The project would benefit the Minnesota Assistance Council of

[13] Docket No. E015/M-12-233

Veterans in Duluth and Minnesota Power customers facing utility disconnect. Minnesota Power will continue to work with Ecolibrium3 to understand the feasibility of the site.

3. Home Area Network featuring Thermostats & In-Home Displays (2010-2012)

Minnesota Power piloted in-home technology as part of its Department of Energy Smart Grid Investment Grant[14] beginning in 2009. The company evaluated two elements of in-home technology, programmable communicating thermostats ("PCTs") and in-home displays ("IHDs"). The PCTs, leveraged an AMI module within the thermostat itself that could be controlled to cycle heat and air conditioning during peak periods. The goal of this portion of the pilot was to test effectiveness of the deployed technology for load reductions during peak periods. For IHDs, the pilot goal was to provide an IHD for customers enrolled in the Time-of-Use/Critical Peak Pricing pilot program so that energy use could be monitored during peak periods and alert customers to system critical peak events.

Cost/Benefit: The Company invested approximately $75,000 in PCT technology including field deployment and approximately $20,000 on IHD technology. Initial findings were that most electric heating customers had two major issues: 1) They had multiple zoned thermostats for hot water and in-floor radiant heat that required up to 5 thermostats and 2) Many of the thermostat wiring configurations didn't have a power supply or additional power wire that supported the needs of a PCT. With PCT cost of nearly $230 each with AMI incorporated technology, the installation of PCT's at an individual residence could exceed $2,000 with required wiring upgrades. Due to the cost profile, the lack of benefits for the associated costs, and relatively low cost of dual fuel alternatives, the decision was made to terminate this portion of the pilot.

For the IHD portion of the pilot, Minnesota Power partnered with many other DOE recipients to evaluate more than 16 different IHD providers There were many compelling use cases with this product, as the it came with both a pre-configured, personalized website that gave a home energy report and graphs, as well as performance characteristics that were beyond commercially available units. Unfortunately, our partner (who was a large international equipment manufacturer) canceled the product line and ceased development and as a result the Company cancelled this portion of the project. To date, there is not a similar product on the market that bridges AMI, local communication, and customer Wi-Fi.

4. Dual Fuel Replacement (2010-2012)

As an additional part of its Smart Grid Investment Grant, Minnesota Power began to update technology associated with its residential demand response program (i.e., Dual Fuel). The legacy system utilized a one-way technology where interruptions could not be verified other than monitoring of total load at the transmission level. With the advent of the AMI technology, which

[14] https://www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.html

utilizes a two-way infrastructure, the meter has an integrated disconnect that can be used for load control. As legacy upgrades were made with AMI meters, it was also discovered that more than thirty percent of the legacy system components (socket extenders and radios) were not fully operational.

Cost/Benefit: The original pilot targeted 1,750 load control devices out of approximately 8,000 load control devices deployed at the time. The final system investment was approximately $450,000 for the pilot with a 50 percent cost share from the U.S. Department of Energy. The legacy system maintenance budget allowed for only about 2.5 percent of the system to be replaced annually (approximately $225k).

The AMI system has reduced capital replacement costs by 80 percent and the system maintenance has been eliminated with the replacement. This system also allows a single operator to quickly identify any failed equipment and start the process of investigating and correcting issues immediately. The pilot was extremely successful in providing benefits far greater than those originally projected and was lauded as an innovative use of AMI by the U.S. Department of Energy. The Company moved forward with full replacement of the legacy systems and is approximately ninety percent complete with this project to-date.

5. EV Fleet Vehicle Lease Program

To develop the Company's internal understanding of what its EV-owning customers experience, the Company invested in two 2017 Chevrolet Bolt Battery Electric Vehicles by way of a three-year lease. Employees are encouraged to utilize the vehicles for business travel where roundtrip distances are within expected range estimates (range is impacted by outside temperature and traveling speeds) and there is access to convenient public charging along the route. Consumers view their utility as a resource when it comes to information about EVs and charging. The Company-leased vehicles provide a heightened level of credibility when speaking with customers and the public, and also serve as a conversation starter when visiting with customers.

Employee use of the vehicles is prioritized for events that provide the best opportunity to promote the vehicles (community events, expos, etc.) and, in turn, EV technology. As an additional benefit, the Company expects to experience some cost savings in respect to vehicle rental costs and employee mileage reimbursements for use of personal vehicles through the lease of these vehicles. The EVs attract attention at events and customer site visits, allowing for on-the-go public education. This face-to-face education gives customers the ability to address questions regarding EVs and for the utility to convey information on its EV offerings.

B. Integrated Distribution Planning

Minnesota Power's Distribution Planning and Resource Planning departments work in close collaboration with one another. Coordinated discussions take place at regular intervals throughout the year to share information on potential supply side and demand side opportunities located at the distribution level. Distribution Planning also provides information needed for inclusion in the distribution appendix to the Integrated Resource Plan ("IRP"), and the two groups coordinate in the development of the Distributed Energy Resource Scenario Analysis for the Integrated Distribution Plan. As Minnesota Power's Distribution Planning processes evolve, the primary areas of active coordination in the near-term between Distribution Planning and Resource Planning will be load forecasting and vetting of non-wires alternatives.

With respect to load forecasting, Distribution Planning obtains historical loading information by feeder from SCADA and meter data for the area of the system under study. This data is then provided to Load Forecasting. Load Forecasting develops projected annual growth rates by feeder based on the latest Annual Forecast Report[15] ("AFR") and supplies the growth rates to Distribution Planning to be used to develop a 5-year peak load scenario for baseline distribution planning studies. This ensures that any issues identified in the evaluation of the 5-year peak scenario are consistent with the latest load growth forecast from Resource Planning.

For the Distributed Energy Resource Scenario Analysis Section IV.F, the Load Forecasting group provided the base-case scenario for DER deployment on the distribution system. The assumptions for DER deployment in the base-case were aligned with assumptions used in the latest AFR. Load Forecasting and Distribution Planning then worked together to develop the DER outlook for the medium and high scenarios. Please refer to the Section IV.F– Distributed Resource Scenario Analysis for more details on the approach and results.

With respect to non-wires alternatives, Distribution Planning identifies candidate reliability or load-serving issues on the distribution system through regular planning assessments. (See Section III.C- Non-Wires (Non-Traditional) Solution for a discussion of how Minnesota Power determines if an issue is a good candidate for a potential non-wires solution.) If it is expected that the traditional solution to an issue will be a major project (greater than $2 million as established in the IDP Requirements), a subsequent alternatives analysis will be conducted. Within this alternatives analysis, both wires and non-wires solutions will be considered. For non-wires solutions, scoping-level information about the non-wires solutions (necessary size, location, and operational characteristics required to resolve the issue) will be developed by Distribution Planning and shared with Resource Planning in order to facilitate the identification of viable non-wires alternatives. This includes developing an anticipated cost, implementation timeline, power supply benefits, societal benefits and other potential benefits specific to locating non-wires alternatives on the distribution system. Non-wires solutions considered for the purpose of resolving distribution reliability and load-serving issues will include supply side solutions (i.e. solar and batteries) or demand side solutions (residential/commercial demand response programs).

If any non-wires alternatives identified through this exercise show potential benefits for customers and the distribution system, these alternatives could be considered as resource

[15] Docket No. E-999/PR-19-11

options in the next IRP. However, the consideration in the IRP of non-wires alternatives for distribution system issues may be impacted by the required implementation timeline associated with the particular issues being addressed. In some cases, a solution may need to be implemented for the distribution system outside of the IRP process.

C. Non-Wires (Non-Traditional) Solutions

Generally speaking, the types of projects that lend themselves to non-wires solutions[16] are those designed to address reliability performance or load-serving issues. Specifically, non-wires solutions may be suitable for addressing reliability performance issues where there is limited or no backup capability following loss of the primary source to a feeder. In that case, a non-wires solution may be able to provide redundancy to the feeder, enhancing restoration times and ultimately improving reliability. A non-wires solution may also be suitable for addressing a load-serving issue where the capacity of a feeder or associated substation equipment, including transformers, is less than the total peak load interconnected to the feeder or substation. In that case, a non-wires solution may be able to reduce the effective peak load seen by the feeder or substation to within the capacity of the existing assets, eliminating or deferring the need for infrastructure upgrades. However, non-wires solutions are only viable for these types of issues where the following conditions are also met:

- There is not a significant asset renewal need being addressed. Non-wires solutions cannot displace the need to modernize and replace aging equipment, even when the modernization project may result in increased reliability or load-serving capability. For example, if the issue is transformer capacity at a substation where the transformer is near or beyond end of life, it is very unlikely that a non-wires solution will defer the need to replace the transformer for a significant enough period of time to be a cost-effective alternative.

- The operational characteristics of the non-wires solution adequately correspond to the need. Non-wires solutions, including both supply-side and demand-side alternatives, must be available at the necessary time, with the necessary response, and for the necessary duration to address a particular reliability or load-serving issue. For example, if the reliability issue to be resolved is loss of a feeder without adequate backup capability from another distribution feeder, a non-wires solution must be available for dispatch or demand response, able to ramp up quickly, capable of following load, and sufficient for an appropriate duration based on the restoration time of the feeder.

[16] For purposes of the 2019 IDP, non-wires solutions do not encompass demand response or energy efficiency initiatives. Those programs are addressed in other sections of this Plan.

Additionally, population growth is an important consideration when discussing non-wires alternatives. Minnesota Power's service territory has experienced population decline at worst and stagnant population numbers at best during the last decade and that trend is projected to continue through 2030, as shown in Figure 9[17].

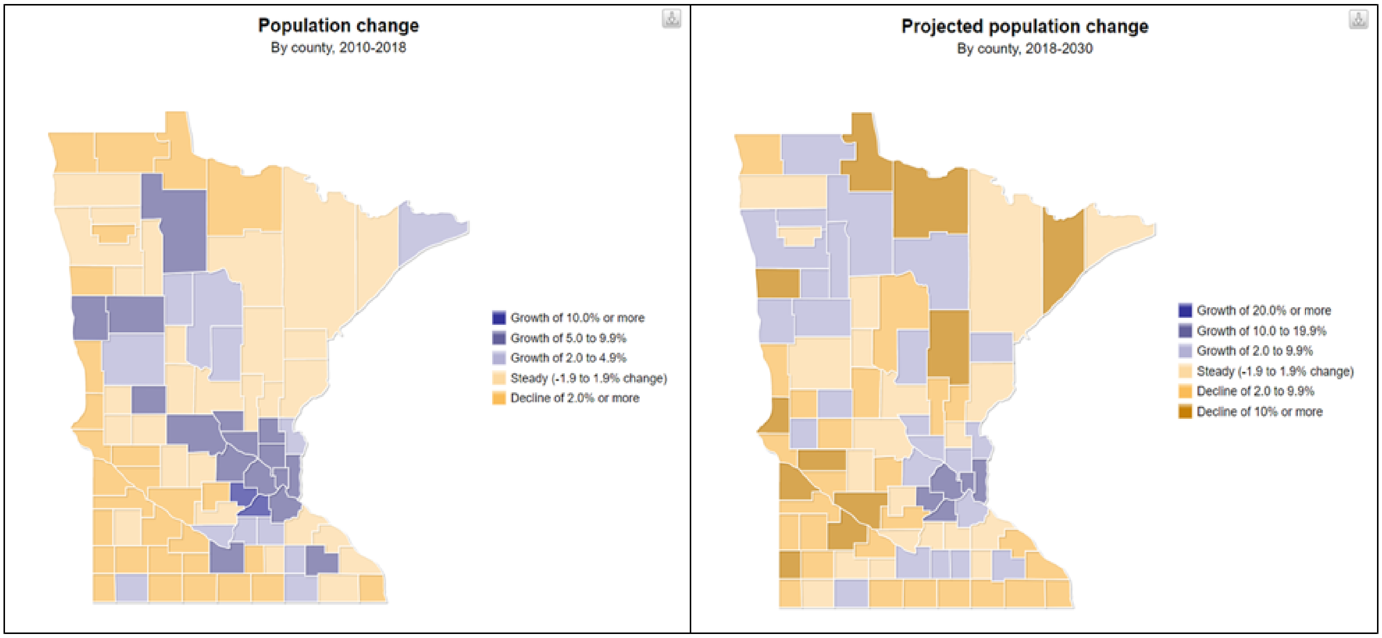


Figure 9: Population Change 2010-2030 in Minnesota

SEPA and PLMA's November 2018 "Non-Wires Alternatives Case Studies from Leading U.S. Projects" report listed the majority of case studies as siting forecasts of high load growth as contributors to the identification of the need for infrastructure upgrades and non-wires solutions. Stagnant to declining population growth in a utility's service territory presents a unique challenge when evaluating non-wires options for distribution solutions.

The amount of time necessary to identify, evaluate, justify, and implement a non-wires solution will vary depending on the scope and scale of the solution. The components of implementation timeline include:

- Internal analysis, including distribution planning assessments, targeted alternatives analysis for non-wires solutions, and integrated resource planning analysis;
- Project development, including scoping and preliminary engineering for the non-wires solution;
- Project execution, including procurement, permitting, engineering and construction.

[17] https://www.mncompass.org/

Minnesota Power does not currently have sufficient experience with the process of identifying, evaluating and implementing non-wires solutions to provide a specific timeline for this process. The Company continues to monitor development of non-wires solutions and learn from its current pilots and broader market experience. The timeline for implementing non-wires solutions will be highly dependent on several factors. The most significant factors are the scope and scale of the solution and the complexity of the issue it is designed to resolve. Larger-scale solutions, more complex technology, and/or more complex issues will naturally take more time to analyze and compare alternatives, identify and receive approval for the recommended solution, and then procure, engineer and construct. Another factor that may cause implementation timeline to vary broadly is whether or not the approval of a project is contingent on an outcome from the IIRP process. In that case, the timing of the project would be subject to the timing of the IRP, including the time needed to obtain regulatory review and approval of the Plan. This could potentially extend project development and implementation lead time for multiple years before there is enough certainty to proceed.

IV. Planning for a Resilient Future

A. Financial Planning

The Distribution long-range plan is reviewed comprehensively on an annual basis. The Distribution Planning department leads the development of the plan, working closely with distribution engineers and coordinating across departments to ensure the accurate timing of projects. Local engineering experts continually advise distribution planning on the state and condition of areas of the system that are underperforming and may require targeted replacement of assets, with reliability being central to planning efforts to identify replacements.

The long-range plan utilizes historical spending to establish amounts for routine maintenance. Specific projects are slotted into the plan based on timing and need as identified through system analysis or external constraints. Many of these specific projects require close coordination with customers, local government, or other business groups within the Company. Since many projects are dependent on timelines and needs outside of the Company's control, a fair amount of changes occur naturally in the long range plan as the Company learns more information. That being said, the Company plans to dramatically increase its capital budget for grid modernization initiatives from 2023 through 2028.

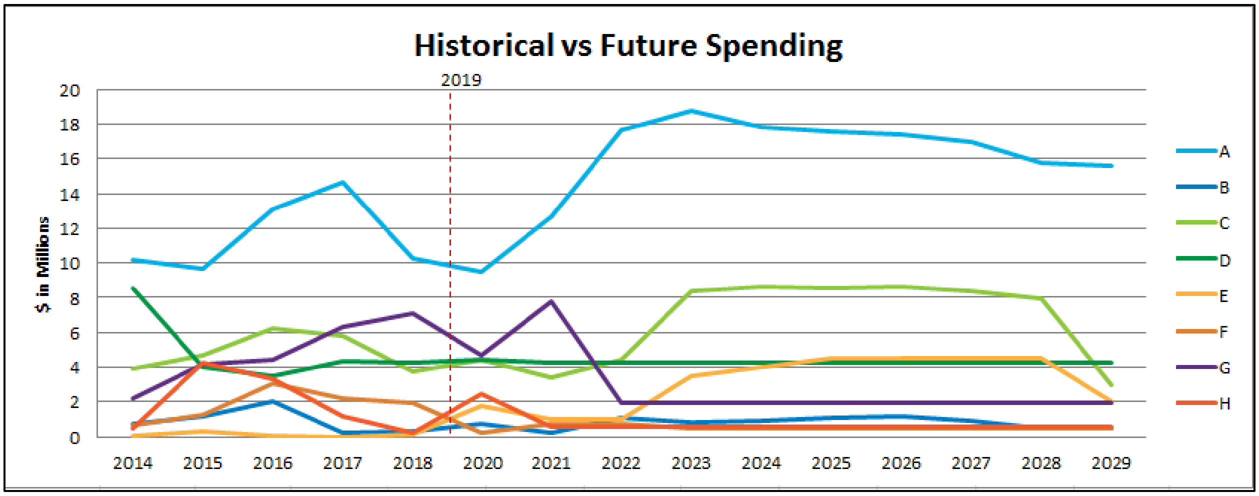


Figure 10: Historical vs. Future Spend

B. Potential Pilots – 10 Year Long-Term Plan

As communicated in Section IV.A – Financial Planning, the Company plans to dramatically increase its investment in grid modernization pilots starting in 2023. Below the Company highlights some areas of interest in regards to potential pilots.

1. Residential and Commercial Customer Demand Response

Minnesota Power has taken proactive steps to expand and modernize its demand response ("DR") programs outside of the current Dual Fuel and Large Power programs. Within the long-term plan is an investigation of commercial customer pilots for direct control of air conditioning, air source heat pumps, electric water heating, electric vehicles, and other loads that could be uniquely controlled through the existing AMI infrastructure and customer outreach. The Company sees numerous advantages in pursuing these DR programs, including gaining key insights from our customers on the role that DR can play for them and the enhanced ability to decarbonize additional modes of energy use in alignment with State policy goals.

Minnesota Power held a DR workshop for its customers in November of 2018. The workshop featured an "MP 101" presentation that provided an overview of the Company's current DR programs for residential and customer programs (namely Dual Fuel and Time of Day). The Center for Energy and the Environment ("CEE") presented on DR programs implemented elsewhere in the state and country and overall best practices for DR. The meeting also consisted of a stakeholder perspectives panel discussion with representatives from University of Minnesota-Duluth ("UMD"), Western Lake Superior Sanitary District ("WLSSD"), and Saint Louis County. The day concluded with a tour of the Saint Louis County Government Services Building where significant investments in energy efficiency and renewable energy have been made.

The workshop was attended by approximately 20 people and included representatives from the Department of Commerce, Attorney General's Office, Center for Energy and the Environment, University of Minnesota-Duluth, Western Lake Superior Sanitary District, St Louis County, Pequot Tools, MN Citizens Federation and Minnesota Power.

Key themes from stakeholder feedback:

- From a state/national perspective, Minnesota Power's ongoing investments in AMI make implementing new DR programs much easier and more cost effective than it is for other utilities with less AMI penetration (per CEE)
- Commercial customers appreciate the knowledge and relationships that they've gained through working with our CIP team, and would like a similar relationship-based approach taken with DR programming
- DR programs have to be flexible and provide both environmental and financial benefits for customers
- Customers have varying considerations, from capital available for upfront investment and payback expectations to general knowledge about DR programs and implementation
- More awareness/education/marketing could be done around our current DR offerings

Minnesota Power will incorporate the learnings and stakeholder feedback from this session as we move forward in modernizing DR programs outside of the current Dual Fuel and Large Power programs.

2. Renewable Load Optimization Programs

One of the known challenges of grid transformation is to identify and access the flexible customer loads to optimize the integration of variable renewable energy production. In addition to demand response, Minnesota Power sees the long-term need for customer facing programs to help optimize the use of renewable energy. While Minnesota Power's system is one of the most unique in the country, with large industrial customers creating a system with a uniquely high load factor, the Company is still committed to attempting to match generation to the load from residential and commercial customers on the distribution system. An example of this may be using peak renewable generation that is exceeding load for EV charging (i.e., work place charging programs). The Company will continue to evaluate the need and applicability of these types of programs as renewable generation increases.

3. Selective Customer Sub-metering Applications

The Company is positioning itself to leverage measurement infrastructure beyond the utility metering point through investments in MDM. These applications will enable informed program design and rate structures for specific electric end uses. This is becoming particularly valuable with the emergence of electric vehicles and charging infrastructure, as well as in the commercial building space. As part of the long-term evolution of our data systems and customer programs, it is evident that piloting applications using trusted sub-metering applications may be a critical part of future program designs.

4. Solar/Storage Applications

Minnesota Power has been working diligently with all distribution customer classes in the implementation of solar arrays and battery storage. This resource combination has the capability to provide many reliability and power benefits to customers through future program and system enhancements. The Company plans to investigate and engage customer groups with opportunities to deploy this technology as economical for customers.

5. EV Storage Pilot

The Company sees a great opportunity for partnership with regional fleet transportation services on both transportation electrification and off-period use of these resources for storage and peaking resources. While adoption is still relatively low, Minnesota Power believes that now is the time to make intentional and thoughtful efforts to collect data, identify barriers and opportunities, and design pilots, programs and services that meet customer needs and Company objectives and optimize the benefits associated with EV charging.

6. Conservation Voltage Reduction

Minnesota Power is considering implementing a conservation voltage reduction/volt-VAR optimization ("CVR/VVO") pilot in future years. CVR is the intentional operation of the distribution system in such a way that lowers the voltage profile along a feeder in order to reduce demand and delivered energy. The system voltage would still remain in the acceptable American National Standards Institute ("ANSI") voltage range.

In order to implement a CVR/VVO pilot the Company would need to install additional voltage control (regulators or load tap changing transformers) and reactive power management equipment (capacitor banks) which would result in additional capital spend and long-term operation and maintenance costs. In theory, these costs would be offset by reducing demand and energy on the feeder which could in turn defer capital improvement projects and open up capacity on existing feeders.

Leveraging the AMI system is critical for a successful CVR/VVO pilot as we can use customer voltage data to confidently push the voltage as low as possible while still maintaining acceptable service voltage within the range defined by the ANSI. Additionally, the AMI system and the future MDM will allow for greater data analysis which would aid in estimating the CVR potential benefits in terms of energy savings and demand reduction.

While Minnesota Power does not yet have a specific cost-benefit analysis completed for a CVR pilot as it is not fully scoped nor have deployment locations been identified, other utilities have observed a 1-4 percent savings on initial deployment. The installation and net-present value costs can be variable depending on which communication protocol is used to operate the devices, which head-end system is used to automate the system, and whether or not existing equipment in the substation and on the feeders can be retrofitted to participate in a CVR pilot. The costs and benefits of VVO also vary by the type of circuit (residential, commercial or industrial load) that the system is installed on.

C. Distribution Forecasting

Existing DER capacity located on Minnesota Power's system is taken into consideration in both the state planning processes, such as Integrated Resource Plans ("IRPs"), and the Midcontinent System Operator's ("MISO") resource adequacy module[18] (Module E-1). There are two methods Minnesota Power uses in IRPs and for MISO Module E-1 to account for DER resources. The method Minnesota Power uses to account for a DER is dependent on the type of DER. The two methods are:

- The DER is accounted for in the load forecast by reducing customer demand based on historical DER usage or product, or
- The DER is accredited as capacity resource and used to meet the Planning Reserve Margin Requirement in MISO Module E-1/IRP. To avoid double counting of capacity, DER resources receiving an accredited capacity value are not taken into consideration in the customer demand outlook by reducing demand.

The method used to incorporate a specific DER into planning considerations is consistent between the IRP and MISO Module E-1, and the above listed methods should be sufficient to capture DER impacts in resource planning and forecasting functions going forward.

Minnesota Power recently filed its 2019 Annual Forecast Report[19], which includes several methodological enhancements meant to improve the Company's longer-term DER forecasting capabilities. Specifically, the Company developed methodologies to project increased loads from electric vehicle adoption and decreased loads from distributed solar generation. The 2019 AFR's forecast methodologies for electric vehicle adoption and decreased loads from Distributed Solar generation are described below.

Distributed Solar Generation Forecasting – In past forecasts, the Company did not make explicit, exogenous assumptions for Distributed Generation: Solar ("DG Solar"), but noted that "it may become possible/necessary to account for this transition in the load forecast."[20] Minnesota

[18] https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc
[19] Docket No. E-999/PR-19-11
[20] In section 1B iv "Treatment of Demand-Side Management (DSM), Conservation Improvement Programs (CIP), and Distributed Generation (DG)" of AFR's 2018 and 2017.

Power has identified a viable methodology for this transition, has projected DG Solar adoption, and has adjusted the energy sales and peak demand forecasts per this DG Solar outlook.

New DG Solar installations were projected using the exponential growth observed in recent years where the number of new residential solar installations has grown by about 20 percent per year and new commercial installations has expanded by about 40 percent per year. This outlook for the number of new installs is combined with assumptions for the sizing (kW capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for new installs (i.e. installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company projects that about 1,350 new DG Solar installations will be connected to the Minnesota Power grid by 2030 (i.e. installed in years 2019-2030)—generating about 15,000 MWh per year and reducing sales by an equivalent amount.

Electric Vehicle Adoption Forecasting – Minnesota Power recognizes the potential load growth that could result from this new electric end-use and has incorporated an outlook for Electric Vehicle adoption into the residential energy sales and peak demand forecasts.

Fleet vehicles and commercial charging are not addressed in AFR 2019. Fleet EV adoption in Minnesota Power's territory is too limited to gauge the pace of organic adoption or draw meaningful parallels between local and national adoption rates. Projecting public EV charging usage will also require further study. For the sake of simplicity in this inaugural attempt at modeling EV impacts on the Minnesota Power system, the Company attributes all new electric vehicle usage to the residential class. Minnesota Power will continue to gather data and refine its methods to model and incorporate new electric end-uses like EVs into the annual forecast.

The Company projected residential EV (light-weight vehicle) adoption based on a national-level outlook[21] that's been scaled to the Minnesota Power region. The energy and demand requirements of EVs adopted in the forecast timeframe (2019-2033) are added to the energy sales and peak demand outlooks. The effects of currently-owned EVs are presumed to be embedded in the econometric forecast.

[21] Bloomberg (https://data.bloomberglp.com/bnef/sites/14/2017/07/BNEF_EVO_2017_ExecutiveSummary.pdf) published a projection of US take-rate in its 2017 Electric Vehicle Outlook (but not in the 2018 Outlook), which could be combined with IHS Global Insight's outlook for Light Vehicle sales to produce an estimate of EV sales by year. Sales were cumulated and divided by U.S. household count to infer an overall saturation rate. The 2019 Electric Vehicle Outlook (EVO) was released too late in the forecast's development to be included in the 2019 AFR, but the overall adoption rate does not differ significantly from the 2017 adoption outlook.

Currently, the Company estimates there are about 180 light-weight (i.e. non-fleet) EVs registered in Minnesota Power's retail service territory,[22] which equates to an approximate 0.2 percent penetration level among residential customers and an estimated 350-450 MWh of energy consumption in 2018. This level of consumption represents just 0.05 percent of all sales to residential customers.

By 2030, EV saturation among Minnesota Power customers is projected to just exceed 7 percent, which equates to about 8,000 EVs and 20,000 MWh in additional energy requirements from the residential sector. This also equates to increases of about 2.5 MW and 7.2 MW in the 2030 Summer and Winter peaks (respectively).

D. Processes and Tools

Minnesota Power's current processes and tools for distribution planning and interconnection analysis are tailored to current distribution planning needs. Regular distribution planning assessments focus on peak load model snapshots and reliability issues such as phase balancing, capacitor placement, capacity, voltage support, and redundancy. Distribution generation interconnection requests are screened per the Minnesota Distributed Generation Interconnection Process ("MN-DIP") requirements and in-depth studies are conducted as needed. Minnesota Power participates in the EPRI DRIVE User Group and is working toward producing feeder hosting capacity heat maps within the next 2-3 years. These heat maps will further augment the distributed generation interconnection process.

Increased adoption of distributed energy resources will impact both of these planning processes. Regular distribution planning assessments will become more complex, and identifying the location and characteristics of individual DERs or groups of DERs on a feeder will become necessary to adequately evaluate the system. Pockets of aggregated DERs will need to be evaluated as part of regular planning assessments to understand their impacts on feeders and substations. Additional analysis will be required to identify load and generation conditions that may stress the system, and additional model snapshots will likely have to be evaluated beyond the traditional peak load model. Such analysis may require additional modeling tools beyond the traditional snapshot in time models that Minnesota Power presently utilizes, perhaps to the point where tools are needed to simulate hourly generation and load characteristics. For each additional system condition and each new type of analysis, the time and resources required to complete the analysis will increase. This will lead to a need for additional engineering resources beyond the equivalent of one dedicated distribution planning engineer presently staffed by Minnesota Power.

[22] IHS Global Insight and Polk provided a total count of EVs registered by zip code for the zip codes fully or partially served by Minnesota Power. In many cases, the Company only serves a small share of households in a particular zip code (per Census data), so some estimation/scaling of the EV count data was required. An exact count of EVs owned by Minnesota Power customers is not available.

More direct impacts are expected on the processes and tools required to manage distributed generation interconnections. A substantial increase in the volume of interconnection requests would create additional administrative and technical work as the requests are processed and studied. As DER adoption grows, it is likely that more individual interconnection requests will fail the MN-DIP screens and require detailed technical analysis, due to the amount of DERs already connected to the feeder or the size of the individual DERs. This additional analysis will also lead to an increase in the administrative and engineering resources necessary to manage the process. Increasing complexity on the distribution system may also lead to additional technical analysis that is not presently needed on a regular basis – such as electromagnetic transient studies and control system coordination studies to ensure that DERs do not have a negative impact on end-use customers or other connected generators. Additional modeling programs or additional technical consultant studies may be required to perform this work. Minnesota Power will have to expand its engineering resources, modeling and evaluation tools, and technical expertise as DER adoption grows significantly beyond recent adoption rates on the distribution system.

1. IEEE Std. 1547-2018[23] Impacts

Advanced inverter functionality is a great new tool that can potentially be utilized to mitigate DER system impacts and accommodate the integration of more DERs on the system. The standard requires that DER is capable of consuming or producing reactive power, which allows for additional options for efficient interconnection. Currently, DERs are integrated on Minnesota Power's system at unity power factor but there have been cases where an off-nominal setting would have been beneficial. There are various other control modes outlined in the standard that may prove useful as DER penetration increases.

Existing Distribution Planning tools are insufficient for accurately modeling advanced inverter functions. The Company is making progress on integrating EPRI's DRIVE tool into the planning and interconnection processes as detailed in the Analysis and Visibility of System Data - Section II.E of this Plan. But an additional tool may be needed in order to fully understand, model, and analyze the potential impacts and benefits of advanced inverter functions on the distribution system.

The Company currently has fairly low DER penetration on its system. The vast majority of current interconnections are small-scale solar which have not, to date, caused voltage or other bulk distribution system issues. During the interconnection process, system conditions are evaluated to protect the reliability and safe operation of the system to ensure the interconnecting customer, and other customers, are not negatively impacted by the DER. That being said, there have been specific instances where operational issues were discovered after

[23] https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/IEEE%20SCC21_1547_Overview_NERC_SPIDERWG_01072019.pdf

https://www.cooperative.com/programs-services/bts/Documents/Reports/NRECA-Guide-to-IEEE-1547-2018-March-2019.pdf the interconnection application was approved and the DER went online. For example, at the Company's 40kW community solar farm, the transformer tap needed to be adjusted to ensure proper operating voltage of the inverter. Utilizing advanced inverter functionality could have mitigated this issue. In another case, the Company used an off-unity power factor setting in order to accommodate a solar interconnection reliably. As penetration levels of DERs increase across the distribution system, we anticipate that utilizing advanced inverter functionality to reliably integrate resources will become more commonplace.

Minnesota Power presently has two feeders, Blanchard 508 feeder and Wrenshall 411 feeder, which have solar installations with a nameplate capacity larger than the feeder's daytime minimum load. The Blanchard 508 feeder circuit includes Camp Ripley, which has installed approximately 10 MW of nameplate solar behind the meter. This feeder circuit has a daytime minimum load of only 0.94 MW. Similarly, Minnesota Power has a 1 MW nameplate solar garden on Wrenshall 411. This feeder circuit has a daytime minimum load of 0.97 MW.

The Company considers this to be a relatively high level of penetration for a feeder as this demonstrates the potential for power flow to be reversed on the feeder. When DER penetration reaches the point of being able to reverse the power flow on a feeder, additional analysis and monitoring is needed to ensure proper voltage and power quality is being supplied to all customers. Furthermore, a reverse in power flow might impact voltage regulators, capacitor banks, protective devices, and other standard distribution equipment that were originally designed and installed for radial, one-direction power flow. If reverse power flow from one or more feeders aggregated to a single transmission-to-distribution substation becomes significant enough, it can impact substation transformers or even the transmission system.

While DER's can have negative system impacts on areas of the system with "low" overall penetration, these installations when aggregated have yet to cause impacts to the bulk three-phase delivery system. As mentioned previously, each proposed installation on the Company's distribution system is screened or studied in accordance with Minnesota's Distributed Energy Resources Interconnection Process.

E. Preliminary Hosting Capacity Data

The Company currently does not perform hosting capacity analysis but is moving towards being able to do so through its involvement in the EPRI DRIVE User Group. Peak load information is gathered biennially in order to perform baseline planning studies on the distribution system. The Company's peak coincident load for the distribution system (as measured between the transmission and distribution system) happened on January 7th, 2015 at 668.33 MW. This information is taken from historical loading data and billing data collected between January 1st, 2015 and May 31st, 2018. SCADA information is only available on approximately 181 of the Company's feeders. As explained in other sections of this Plan, additional ways to gather load, voltage, and current information are being implemented across the system. Minimum load data is gathered as part of the hourly data collection, but getting to the actual daytime minimum load value requires manual filtering of the data to ensure that the feeder is not in an abnormal state. The Company currently does not track and update minimum loads across the system.

While minimum loads are not actively tracked, The Company does utilize daytime minimum load data if available and necessary to evaluate specific DER interconnections during a study process. For example, when performing the system study for a 10 MW solar project to be interconnected on Blanchard 511 as part of the Energy*Forward* Resource Package,[24] both the feeder and the substation daytime minimum load were identified in order to adequately assess the impact of the interconnection. The internal gathering and use of minimum load data is resource intensive and therefore minimum load data is presently only gathered on an as-needed basis.

The Company currently does not track and update peak load at the individual feeder for all circuits. Consequently, for the purposes of the preliminary hosting capacity data, the Company has assumed that the minimum load on the feeder is 20 percent of peak.

F. Distributed Energy Resource Scenario Analysis

The Company used its internally-developed projections of Distributed Solar and Electric Vehicle adoption as its Base Case forecasts as described in the Distribution Forecasting Section IV.C of this Plan. The “medium” and “high” scenarios for DER adoption rates were developed by accelerating the adoption rates in the Base Case outlook.

The Distributed Solar base case outlook was developed based on recent trends in actual observed solar installs, and the medium and high scenarios were developed by applying a simple adder to the base case outlook’s adoption rates.

The base case outlook projects a compound annual growth rate (“CAGR”) of about 18 percent in the installed capacity of distributed solar installations from present levels to projected 2030 levels. The medium scenario applies a 2.5 percent adder to the annual growth rates and results in an overall CAGR of about 20.5 percent from present installed capacity to projected 2030 capacity. The high scenario applies a 5 percent adder, resulting in a present-to-2030 CAGR of 23 percent.

The Electric Vehicle base case outlook was developed by scaling a national EV adoption outlook to the Minnesota Power customer base. The Company observed that Minnesota Power customers’ EV penetration rate lags the National average by about 4 years, and the base case forecast assumes Minnesota Power continues to lag the nation by 4 years.

[24] Docket No. E-015/AI-17-568

The medium and high scenarios assume Minnesota Power customers' EV penetration levels "catch-up" to the national average over the course of the forecast. In the medium scenario, Minnesota Power's EV penetration levels are only 2 years behind the national average by 2025, but remains 2 years behind the nation for the remainder of the forecast. In the high scenario, Minnesota Power's EV penetration level catches up to the national average by 2034 (the last year of the current long-term forecast). See Appendix E to this Plan for the Company's complete DER Scenario Analysis.

G. DER System Impacts and Benefits

Minnesota Power continues to investigate DER options as part of its broad utility planning process to consider non-wires alternatives. Applications such as solar and storage continue to be explored in this broad planning effort. The opportunities are considered in collaboration with the Company's resource, transmission, and distribution planning teams.

As these alternatives begin to demonstrate broader application for the system it will be necessary to integrate and provide visibility through software, tools and communication infrastructure Minnesota Power will address these opportunities in their upcoming IRP, rather than outlining resource investment in this filing. The Company will provide a general overview of current impacts and benefits in the sections below.

1. EV Impacts

Electric Vehicles present vast potential benefits for most utilities. However, if charging infrastructure is unmanaged, it has potential to cause costly impacts to the distribution system. For example, customers installing Level 2 home charging equipment, with about 10 kW of load, can put stress on transformers or cause line voltage issues. This is particularly true if many homes begin installing chargers and then charge at the same time. However, if managed through advanced metering infrastructure and/or smart charging EVSE, these loads could be managed effectively. With the current penetration level of EVs in Minnesota Power's service territory, the Company has not experienced any of these issues to-date. It is prudent to consider customer programming that encourages and incentivizes customers to install smart chargers, which can be effectively utilized in conjunction with off-peak EV rate structures. In addition, utilities in general must continue to develop internal expertise, software systems, and protocols for engaging with these new DERs.

There are additional potential benefits related to EVs as they gain the ability not only to charge, but to discharge onto the system. This is an emerging area that will require significant investment in regulations, software platforms, charging equipment, and equitable rate structures. Minnesota Power, as highlighted in previous sections, is taking the first steps to provide a base for new rate structures and customer interactions through its internal EV efforts, system integrations and C2M implementation.

2. Solar PV Impacts

Solar is being deployed on widely varying scale from street lights to utility scale power plants. It offers many values to the distribution system while also presenting some challenges. The value of small-scale solar is that it may offer resiliency to the system if deployed in a distributed manner. Geographically dispersed solar arrays avoid taking large amounts of generation offline during various meteorological events like cloud cover and storms. In addition, during outages geographically dispersed and well-designed distribution systems may be able to isolate and repower sections not directly affected by system outages. An example may be a solar powered retail center or housing development designed to isolate itself during an outage event. The potential cost and benefits of these systems still require many resources and extensive research to determine the best path forward and socialized benefits have yet to be well defined.

The cost and benefits of any programmatic planned system wide deployment of solar will require ongoing analysis with inputs from many stakeholders. The cost of deploying small-scale solar arrays for specific segments of the distribution system versus larger centralized solar plants must be weighed against the benefits of having generation sources closer to load centers along with initial capital costs, ongoing fleet maintenance and operational costs. The benefits are not currently well understood on a case-by-case basis for most utilities. This will require clear policy frameworks for leveraging resources to investigate and plan for DER integration in a well-managed and advantageous manner.

The primary technical concern with distributed solar PV is the potential for reverse power flow at the feeder-level. Historically, the distribution system has been designed for unidirectional power flow from the substation breaker to consumer loads. Bi-directional and reverse power flow conditions could negatively impact feeder voltage and system equipment that has been designed for, and is protected by schemes designed for, unidirectional flow. For individual DER installations the potential impacts are examined during the interconnection process. The Company has already experienced some system impacts from small-scale solar installations, such as having to modify regulator settings on a feeder to account for a potential reverse power flow condition. Increasing penetration levels over the planning horizon will likely result in more feeders with reverse power flow conditions. Future mitigation options may include utilizing advanced inverter options.

3. Barriers to DER Integration

At present there are few incentives for utilities and businesses to work together on a holistic system-wide approach to DER integration. Without net metering and tax incentive programs new DER developments aren’t currently cost effective for most customers. For example, one barrier to DER integration is the high cost of entry. Developers and customers who want to interconnect to the distribution system bear all costs for upgrades required to accommodate the proposed interconnection. Because of this, there may be some developers or customers who choose not to pursue interconnection.

Extended timeframes for program development and technology implementation are also barriers to deployment. An example is the Company's current efforts to modernize its metering infrastructure. Until the meter rollout is complete, it is not possible to fully realize the many potential benefits and programs enabled by advanced metering and the development costs tend to be high for these types of programs. Along with this, how various DER technologies like wind, solar, EVs, and storage will all work in tandem on the grid will require significant analysis, planning and stakeholder interaction.

4. FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators)

Federal Energy Regulatory Commission ("FERC") Order No. 841

> "direct[s] regional grid operators to remove barriers to the participation of electric storage in wholesale markets. By directing the regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, the Order affirms that storage resources must be compensated for all of the services provided and moves toward leveling the playing field for storage with other energy resources. Order 841 creates a clear legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs."[25]

Order No. 841 established reforms to remove barriers to the participation of electric storage resources in the Regional Transmission Organization and Independent System Operator markets (RTO/ISO markets). FERC found that RTO/ISO market rules employed obstacles for electric storage resources to participate in the market.

Minnesota Power generally supports FERC Order 841 in regards to transmission level storage assets. However, the Company has reservations in regards to the treatment of distribution connected battery storage and DERs. The ability of electric storage resources to participate in the wholesale market at the distribution level and behind the meter will have implications for local distribution operators. In particular, the provision of Order 841 that encompasses DER resources, not just battery storage, is problematic. There are metering, operational, and wholesale market issues that arise due to the possible participation of DERs in wholesale RTO or ISO markets.

As a result, Minnesota Power would most likely file a tariff with FERC to address DER participation in wholesale markets. At a high level these tariffs would address distribution system upgrade costs, metering capability, reliability assurance mechanisms, and cost recovery.

[25] http://energystorage.org/policy/regulatory-policy/overview-ferc-order-841

V. Conclusion

Minnesota Power's first IDP provides an overview of the Company's current distribution planning processes and future investment plans. Historical spend and planning has positioned the Company for a seamless transition to an innovative future to meet customers' needs and expectations. The foundational investments are built upon the Company's Core Values and distribution strategy of technology, innovation, and continuous learning. The Company has demonstrated these values by focusing on right time, right fit investments and by thoughtfully leveraging internal and external resources in a cost conscious manner to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid.

The results of this customer focused, thoughtful planning are evidenced by Minnesota Power's leadership in the state of Minnesota in AMI implementation, exceedance of the state's energy-savings goals year-over-year, and piloting of innovative rate structures such as Time-of-Day. These initiatives are coupled with the lowest residential rates in Minnesota and the Company's steady progress towards carbon reduction and increased renewable generation. The Company's renewable energy percentage is currently 30 percent (higher than any other utility in Minnesota), and we are on-track to provide 50 percent renewable energy by 2021, transforming from just 5 percent renewable in 2005. Minnesota Power has moved further and faster than most other utilities in transforming its energy supply.

Moving towards the future, the Company is executing upon its distribution values and focusing its ongoing efforts on the three strategic areas of focus of People, Resiliency, and Innovation. Customers expect reliable, affordable, and safe electric service, all of which are encompassed in Minnesota Power's distribution values. The connective model system investments currently taking place provide a base for the Company to continue advancing innovative customer programming along with additional investment in grid modernization pilots and initiatives. This will create greater customer engagement, empowerment, and options for energy services. This connective model will also support the development and integration of DER technologies and enhance the value of their application as it relates to grid operations. Minnesota Power's vision for the future is demonstrated in this 2019 Integrated Distribution Plan.

Dated: November 1, 2019

Respectfully submitted,

Jenna Warmuth

Senior Public Policy Advisor

218-355-3448

jwarmuth@mnpower.com

APPENDIX A

Section	Heading	MPUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254)	Location
2	Stakeholders Meeting	Minnesota Power 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 that modifications to the MN-IDP can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Minnesota Power's should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) the anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years, (3) 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	I.A.2, Appendix B
3.A.1	Baseline Distribution System and Financial Data: System Data	Modeling software currently used and planned software deployments	I.D.1,2,3; II.B, II.C.1,2,3,4; II.E.1,
3.A.2	Baseline Distribution System and Financial Data: System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	II.E.2
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	II.E.2
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	I.D.1,2,3; II.C.4, II.E.2
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	III.B
3.A.6	Baseline Distribution System and Financial Data: System Data	Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology	III.B
3.A.7	Baseline Distribution System and Financial Data: System Data	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations	IV.D.1
3.A.8	Baseline Distribution System and Financial Data: System Data	Distribution system annual loss percentage for the prior year	Appendix E
3.A.9	Baseline Distribution System and Financial Data: System Data	The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring system	IV.E
3.A.10	Baseline Distribution System and Financial Data: System Data	Total distribution substation capacity in kVA	Appendix C Figure 11
3.A.11	Baseline Distribution System and Financial Data: System Data	Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.	Appendix C Figure 11

APPENDIX A

Section	Heading	MPUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254)	Location
3.A.12	Baseline Distribution System and Financial Data: System Data	Total miles of overhead distribution wire	Appendix C Figure 11
3.A.13	Baseline Distribution System and Financial Data: System Data	Total miles of underground distribution wire	Appendix C Figure 11
3.A.14	Baseline Distribution System and Financial Data: System Data	Total number of distribution customers	I
3.A.15	Baseline Distribution System and Financial Data: System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category	II.A
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 costs should be broken down by category in which they were incurred	II.A
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	Appendix C Figure 11, Table 7
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	Appendix C Figure 11, Table 7
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	Figure 6
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	Appendix C Table 7
3.A.21	Baseline Distribution System and Financial Data: System Data	Total number of electric vehicles in service territory	II.A.2
3.A.22	Baseline Distribution System and Financial Data: System Data	Total number and capacity of public electric vehicle charging stations	II.A.2
3.A.23	Baseline Distribution System and Financial Data: System Data	Number of units and MW/MWh ratings of battery storage	Figure 6, Appendix C Table 7
3.A.24	Baseline Distribution System and Financial Data: System Data	MWh saving and peak demand reductions from EE program spending in previous year	II.A.4
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)	II.A.1

APPENDIX A

Section	Heading	MPUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254)	Location
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 (road-relocations, etc.) g. Metering h. Other	Figure 5, Figure 10,
3.A.27	Baseline Distribution System and Financial Data: Financial Data	All non-Minnesota Power 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).	II.A
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	Figure 8, Table 3 Figure 10, Table 4
3.A.29	Baseline Distribution System and Financial Data: Financial Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, and 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	Figure 8, Table 3 Figure 10,
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	III.C, Table 4
3.A.31	Baseline Distribution System and Financial Data: 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.)	Figure 6, Figure 7, II.A
3.A.32	Baseline Distribution System and Financial Data: DER Deployment	Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	IV.D.1, IV.F
3.A.33	Baseline Distribution System and Financial Data: DER Deployment	Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.	IV.D.1, IV.G.2
3.B.1	Preliminary Hosting Capacity Data	Provide an Excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified)	IV.E
3.C.1	Distributed Energy Resource Scenario Analysis	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 the distribution system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Minnesota Power distribution system in the locations Minnesota Power would reasonably anticipate seeing DER growth take place first.	IV.F Appendix D

APPENDIX A

Section	Heading	MPUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254)	Location
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 percent and 25 percent 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.	IV.F Appendix D
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.	IV.D, IV.G.1,2,3,4
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)	IV.G.4
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Minnesota Power 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 scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis.	III.C, IV.F Figure 8, Figure 10, Table 3, Table 4 Table 5
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Minnesota Power 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 Minnesota Power is currently using	III.C, IV.B, IV.C, IV.D.1, IV.E, IV.F, IV.G.1,2,3,4; Figure 10,
3.E.1	Non-wires Alternatives Analysis	Minnesota Power shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	Table 4 II.C
3.E.2	Non-wires Alternatives Analysis	Minnesota Power shall provide information on the following: a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) b. 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) c. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed d. 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	Table 4, II.C

Minnesota Power Integrated Distribution Plan
October 2, 2019

Bent Paddle

1832 W Michigan St, Duluth, MN 55806

Agenda

10:00-10:10pm	Welcome, Intro's, Overview
10:10-11:10pm	IDP Presentation
11:10-11:20pm	BREAK
11:20- 12:00pm	IDP Presentation
12:00-12:30pm	Wrap-up, Next Steps, & Lunch
~~12:30-1:30pm~~	~~Optional Reliability Presentation & Substation Tour~~
1:30pm	ADJOURN

APPENDIX B

Some information proivided in this presentation was refined and may differ from information reported in the 2019 IDP narrative

MINNESOTA POWER'S 2019 INTEGRATED DISTRIBUTION PLAN

Stakeholder Meeting – October 2019

minnesota power
AN ALLETE COMPANY

EnergyForward

APPENDIX B

In the event of an emergency….

911 Contact – Jenna Warmuth

First Aid/CPR –

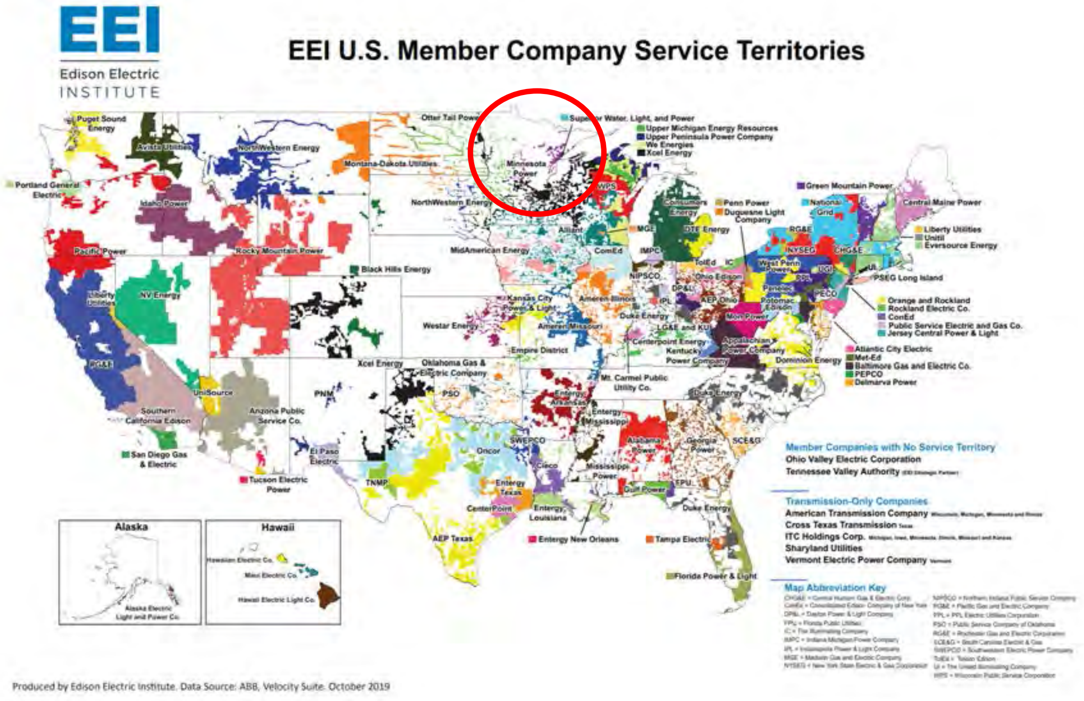
AED –

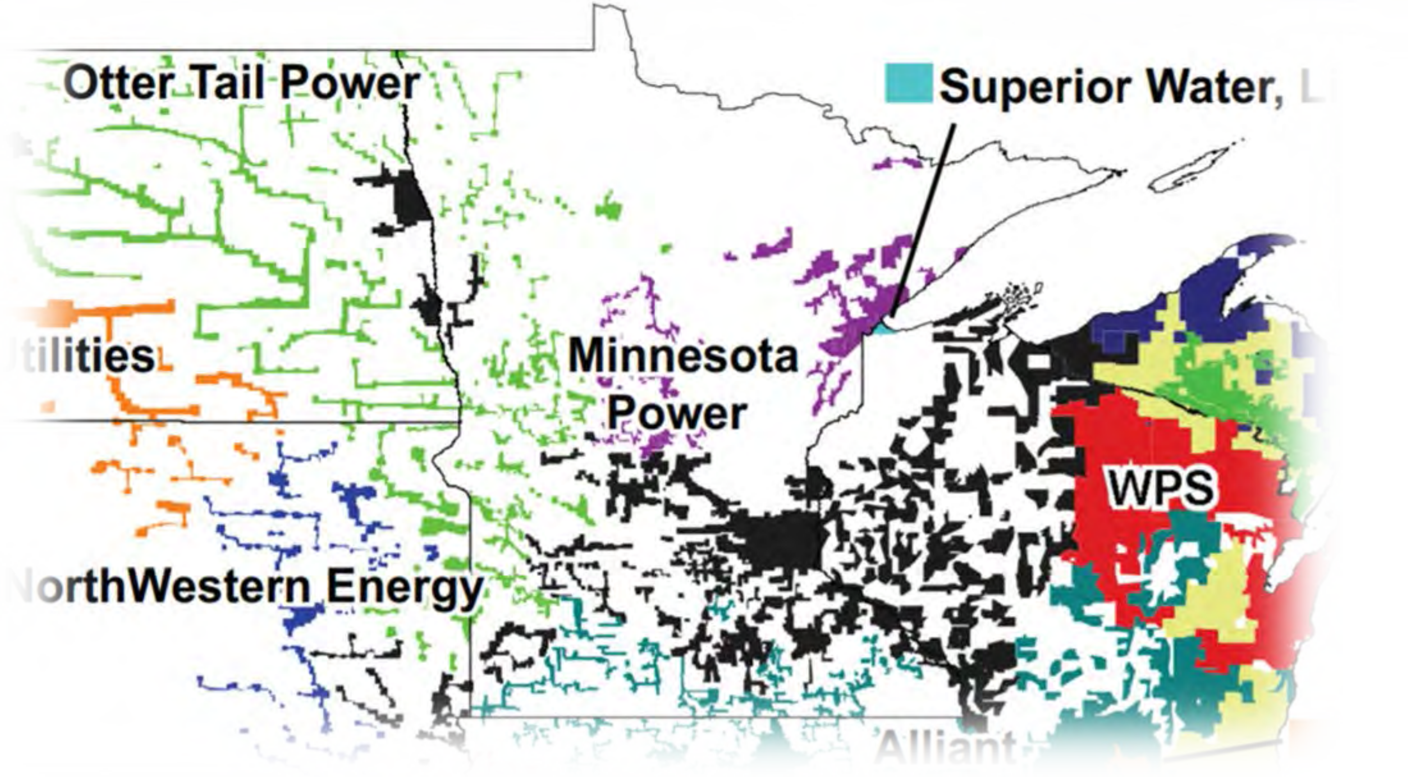
Fire Extinguisher –

OVERVIEW

- Minnesota Power and its Distribution System
- Current Distributed Energy Resources
- Resiliency
- DER Scenarios
- 5-year Distribution System Investments
- 10-year Long-term Distribution Plan

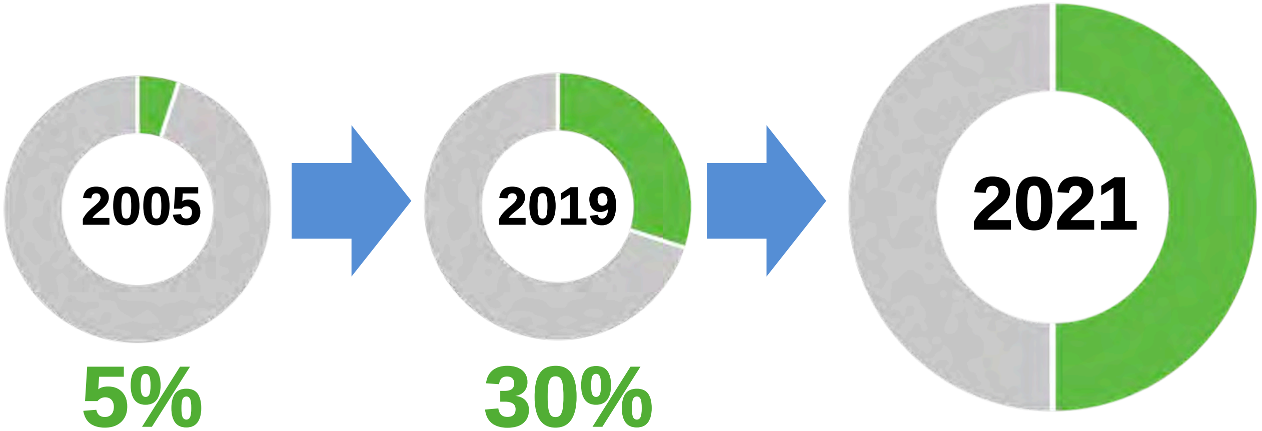
MINNESOTA POWER’S SERVICE TERRITORY





MINNESOTA POWER IS UNIQUE

Leading MN in Renewables



5%
Renewable

30%
Renewable

No. 1 in Minnesota
No. 2 in the Midwest*

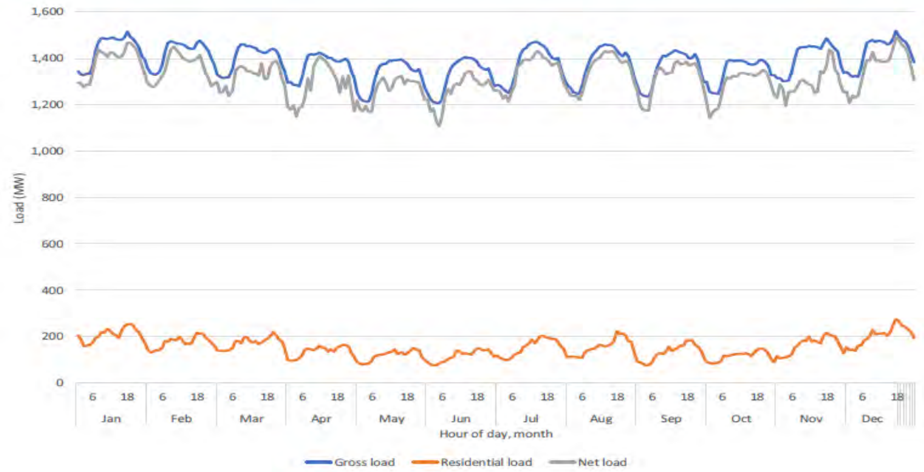
50%
Renewable

Duluth, MN	Headquarters
26,000	Square-miles
145,000	Customers
13%	Residential sales
74%	Industrial sales
15	Municipalities

*Source: Navigant Consulting

MINNESOTA POWER IS UNIQUE CONT'D

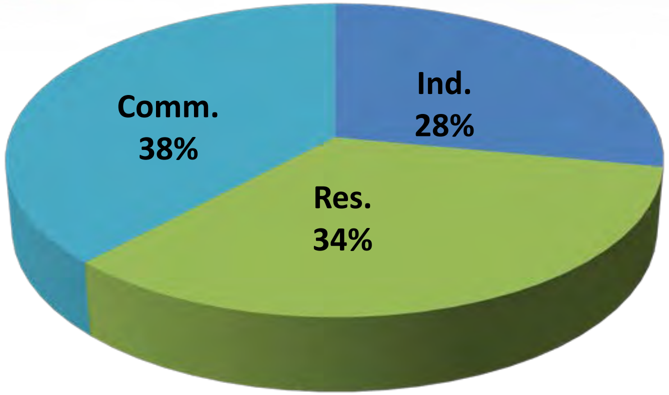
PEAK LOAD
BY TIME OF DAY AND MONTH - 2020



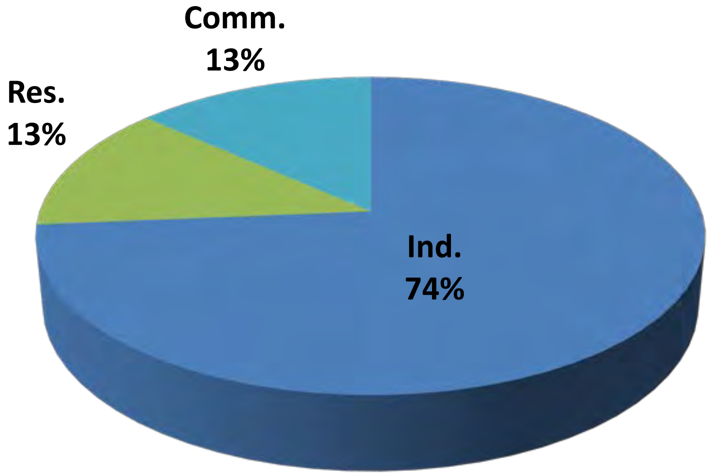
- Residential load makes up less than 10% of gross load, a small share when compared with other utilities

NAVIGANT

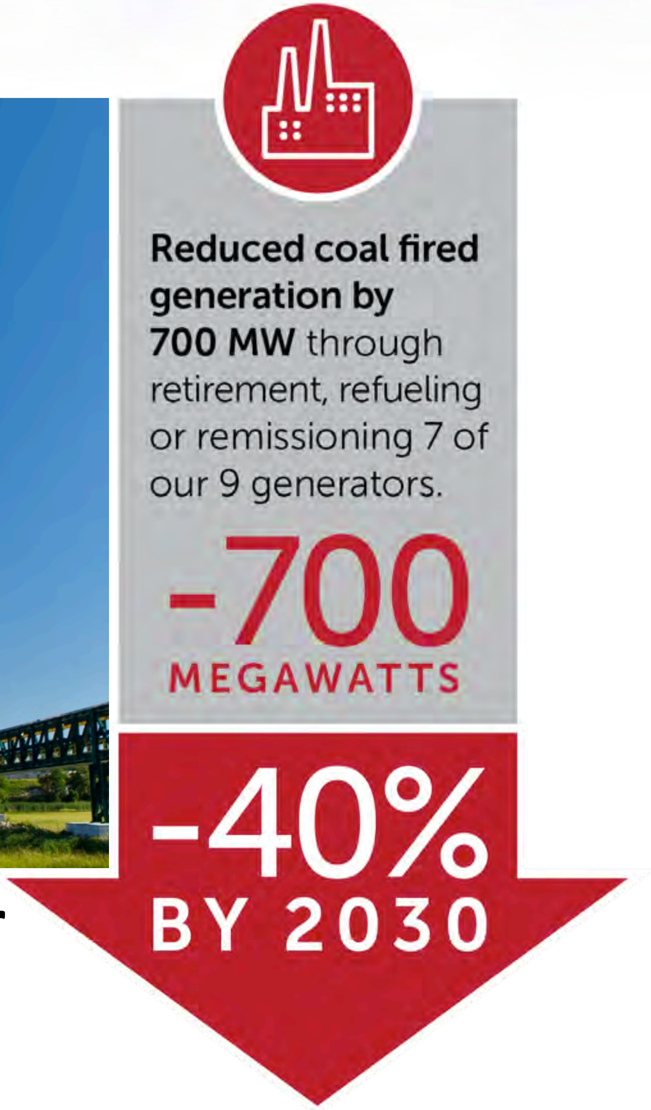
US Average



Minnesota Power



REDUCING CARBON



Retirement of Boswell Units 1 and 2 last year removed 135 MW from the system

PURPOSE OF IDP:

- 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;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility'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

ELEMENTS:

- Baseline Distribution System Data
- Baseline Financial Data
- Baseline DER Data
- Preliminary Hosting Capacity Data
- DER Scenario Analysis
- Non-Wire or Non Traditional Alternatives
- 5-10 Year System Modernization and Infrastructure Plan

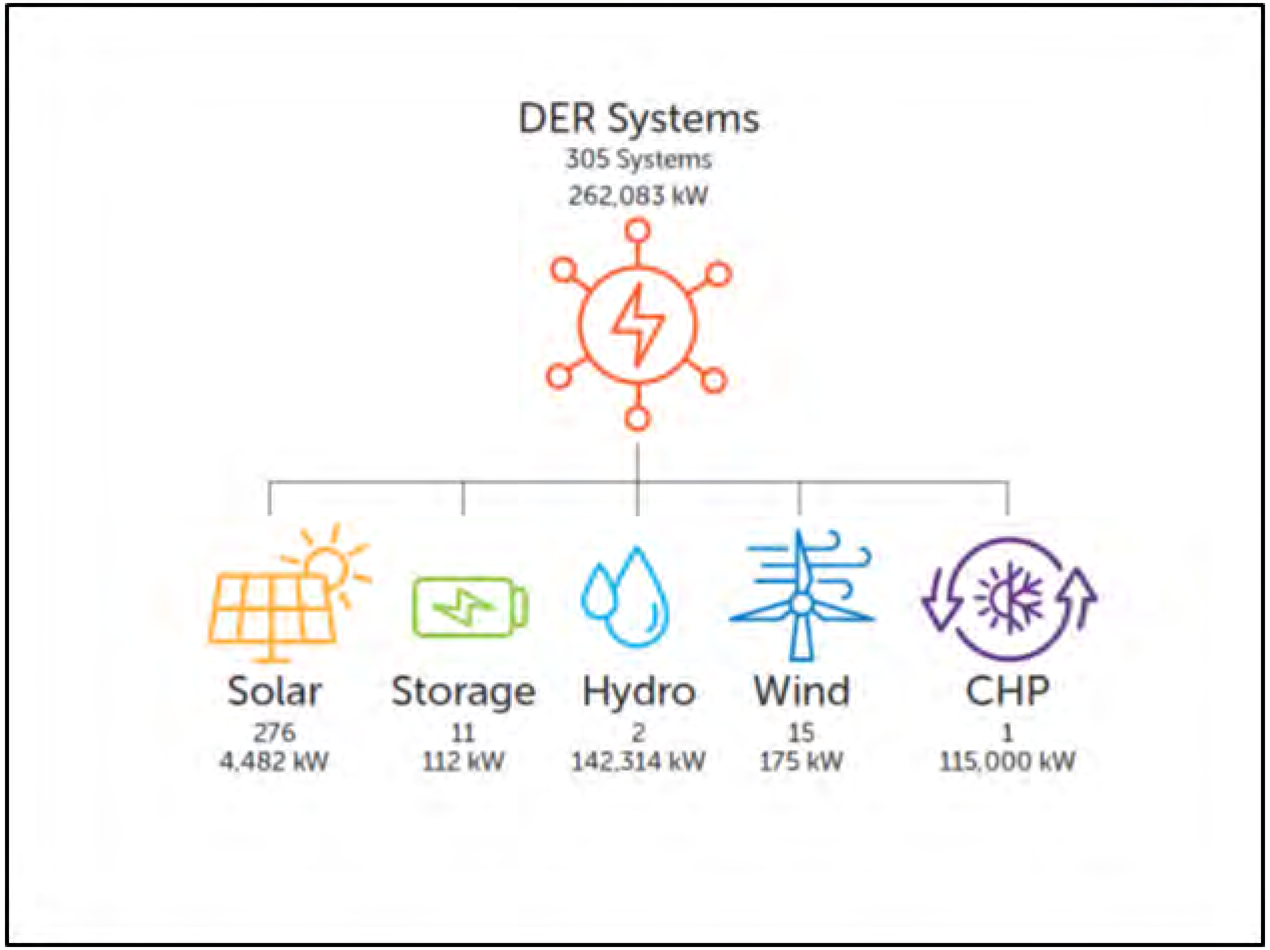
KEY THEMES


People
Building relationships
Improved reliability
Customer benefits
Resiliency
Right time, right fit
Operational efficiencies
Innovation
Connective model
Program offerings
Interactive

DISTRIBUTED ENERGY RESOURCES, PILOTS & PROGRAMMING

APPENDIX B

DER Systems

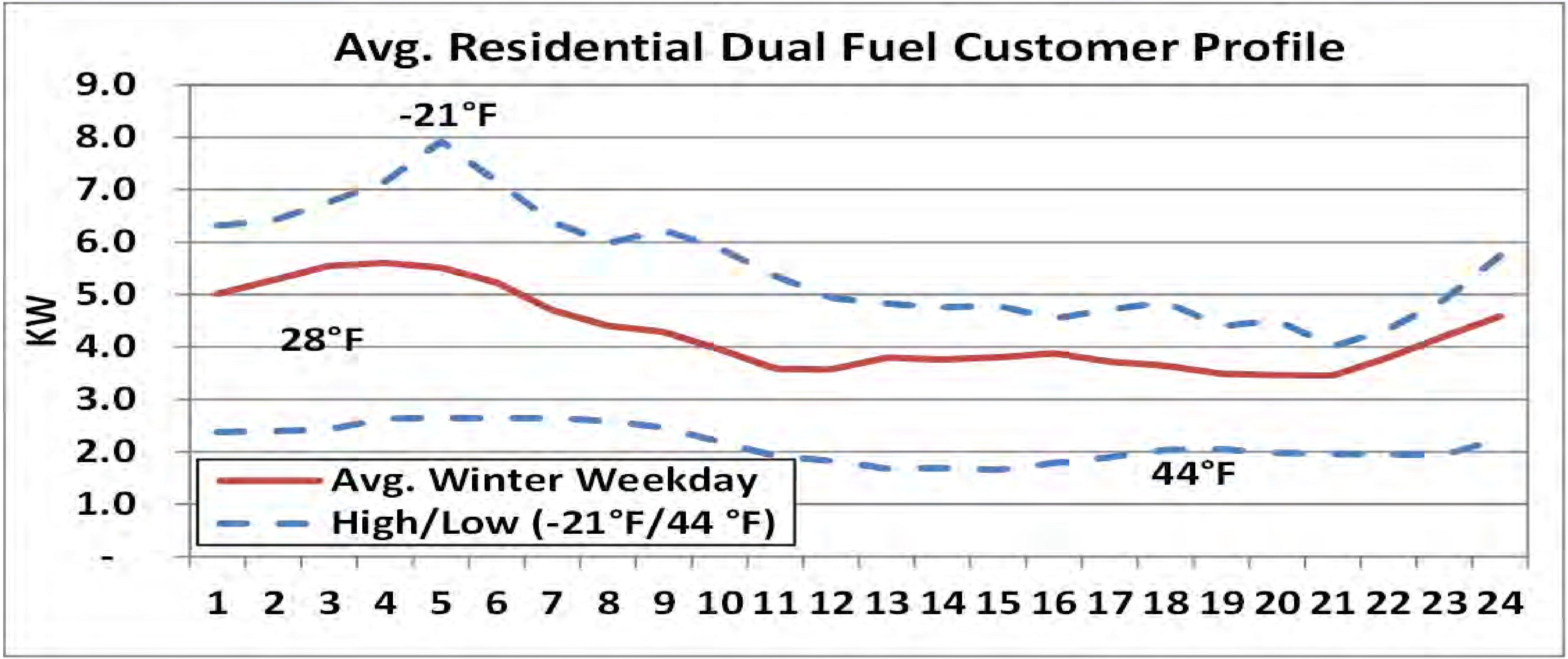


APPENDIX B

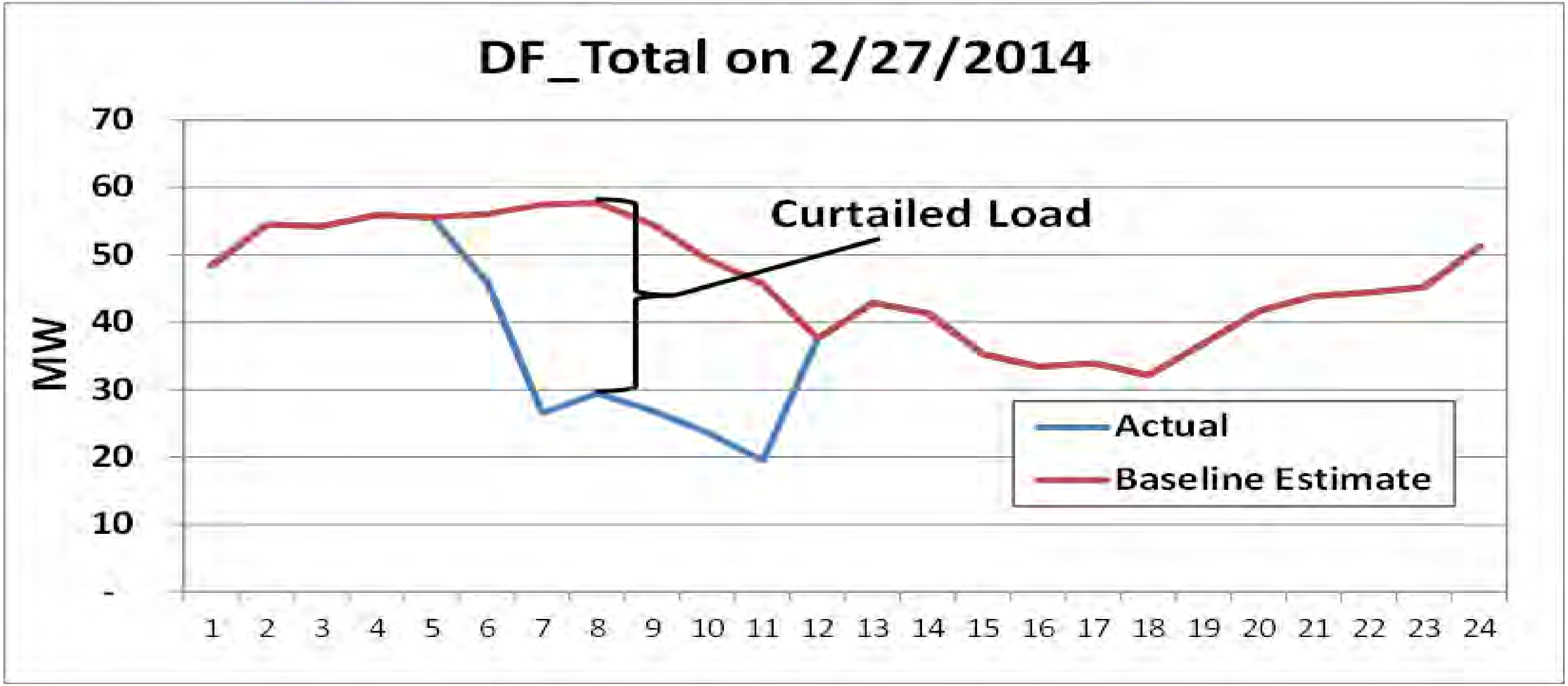
INNOVATION – PILOTS & PROGRAMMING

DISTRIBUTION RESILIENCY

DEMAND RESPONSE



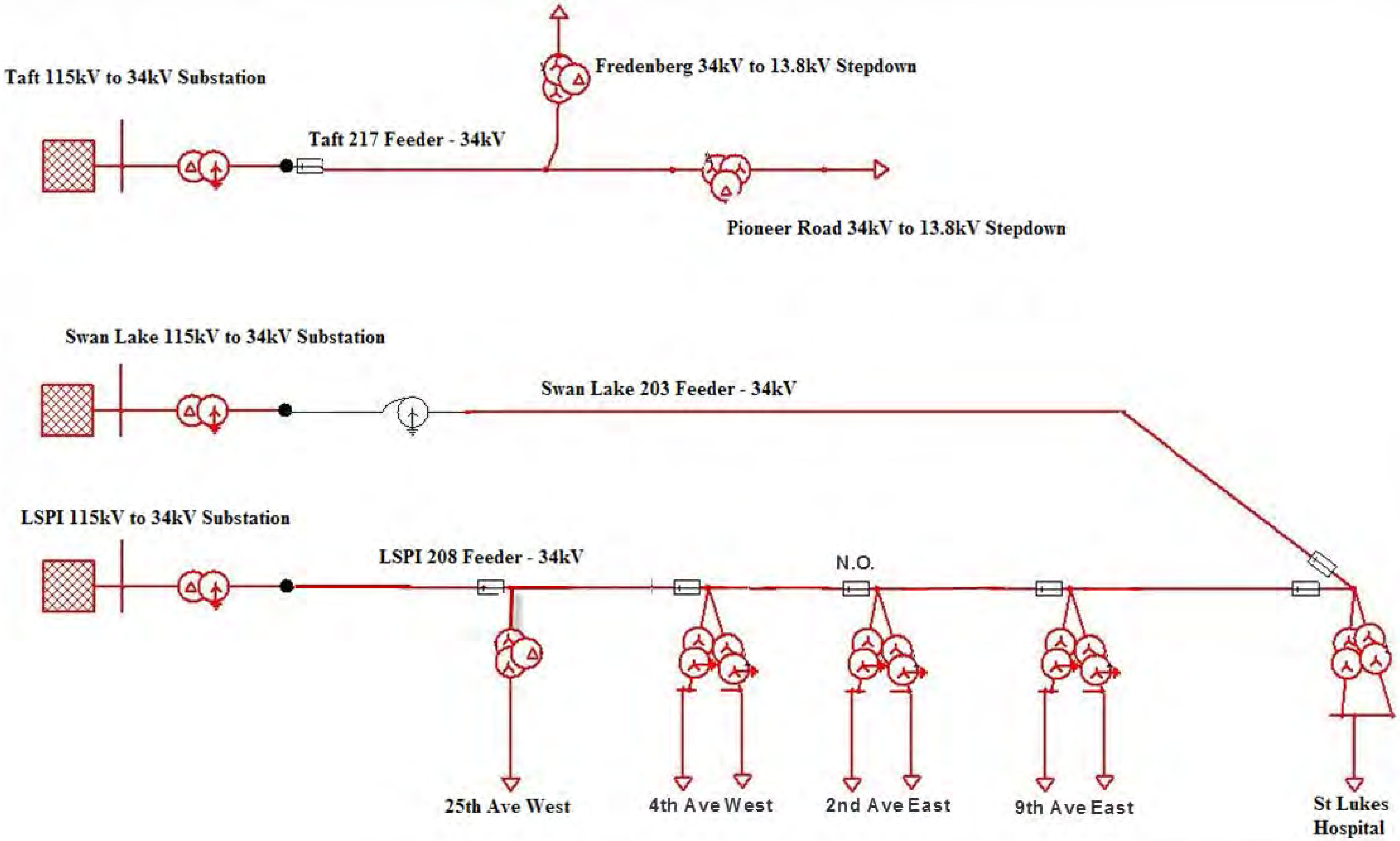
DEMAND RESPONSE RES. AMI EVENT ANALYSIS (-3H/-21L)



DISTRIBUTION RESILIENCY

- 35kV Backbone and new Step Down substations
- 1920s Lead Cable replacement and replace Duct Banks on Michigan and Superior Street
- 15th Ave West substation rebuild
- Automation – FLISR Program initiated in 2010 for Duluth Feeders
- Automation – Trip Saver Tap Re-closer program started in 2016
- Increased investments in motor-operator remote switching on Distribution Circuits
- Planned upgrades of outlying stepdown substations & transformers

34.5KV BACKBONE



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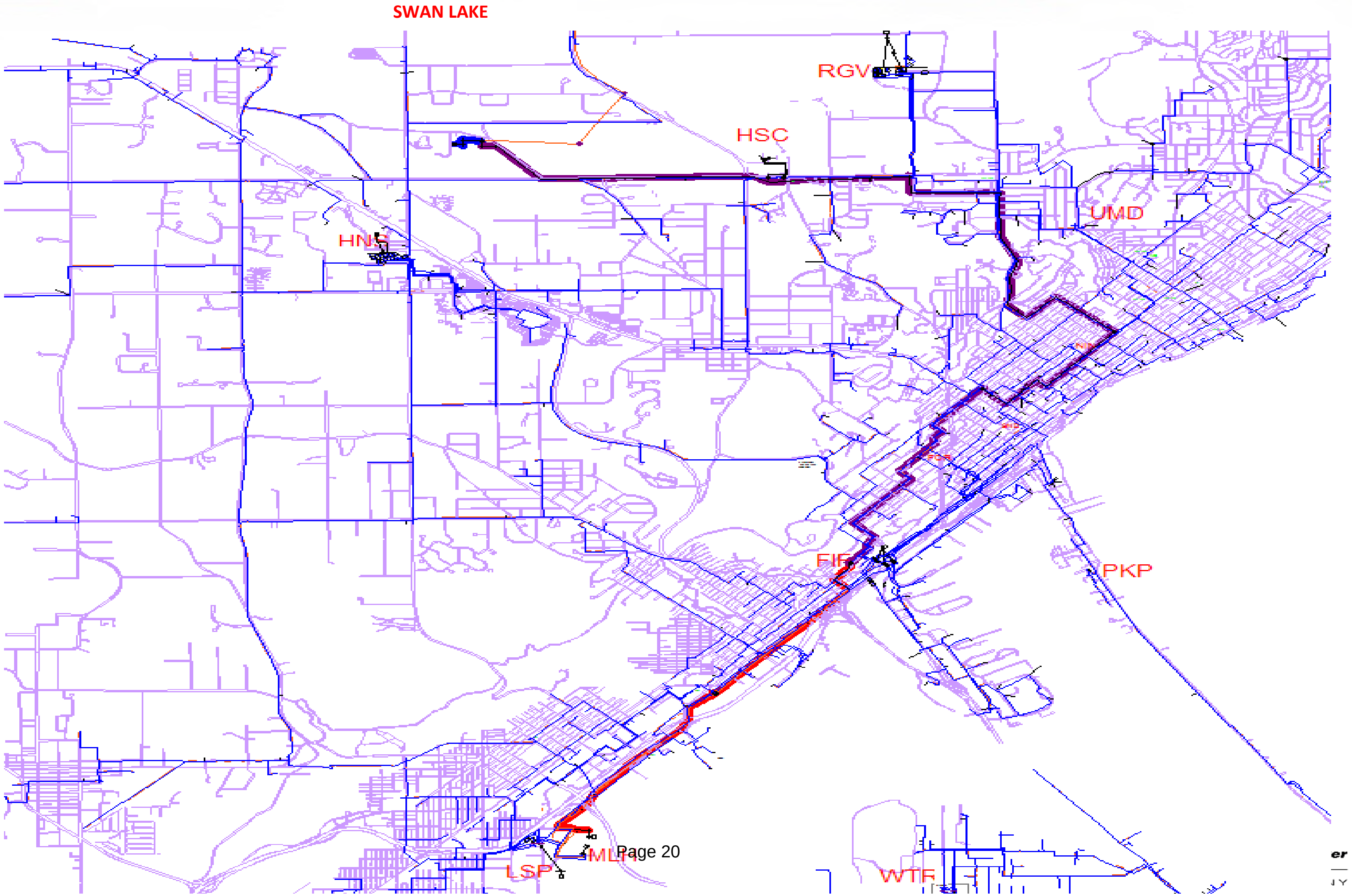
EnergyForward

34.5KV BACKBONE



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APPENDIX B

2ND AVE E 13.8KV STEPDOWN

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FAILED LEAD CABLE

MANHOLE AND DUCT BANK REPLACEMENT

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APPENDIX B

MANHOLE AND DUCT BANK REPLACEMENT

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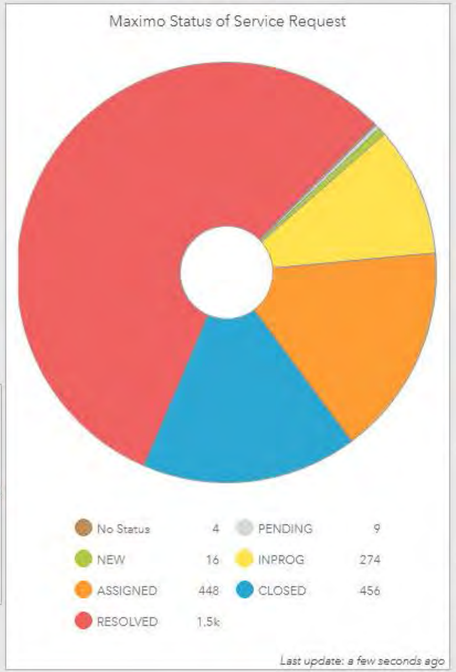
MANHOLE AND DUCT BANK REPLACEMENT

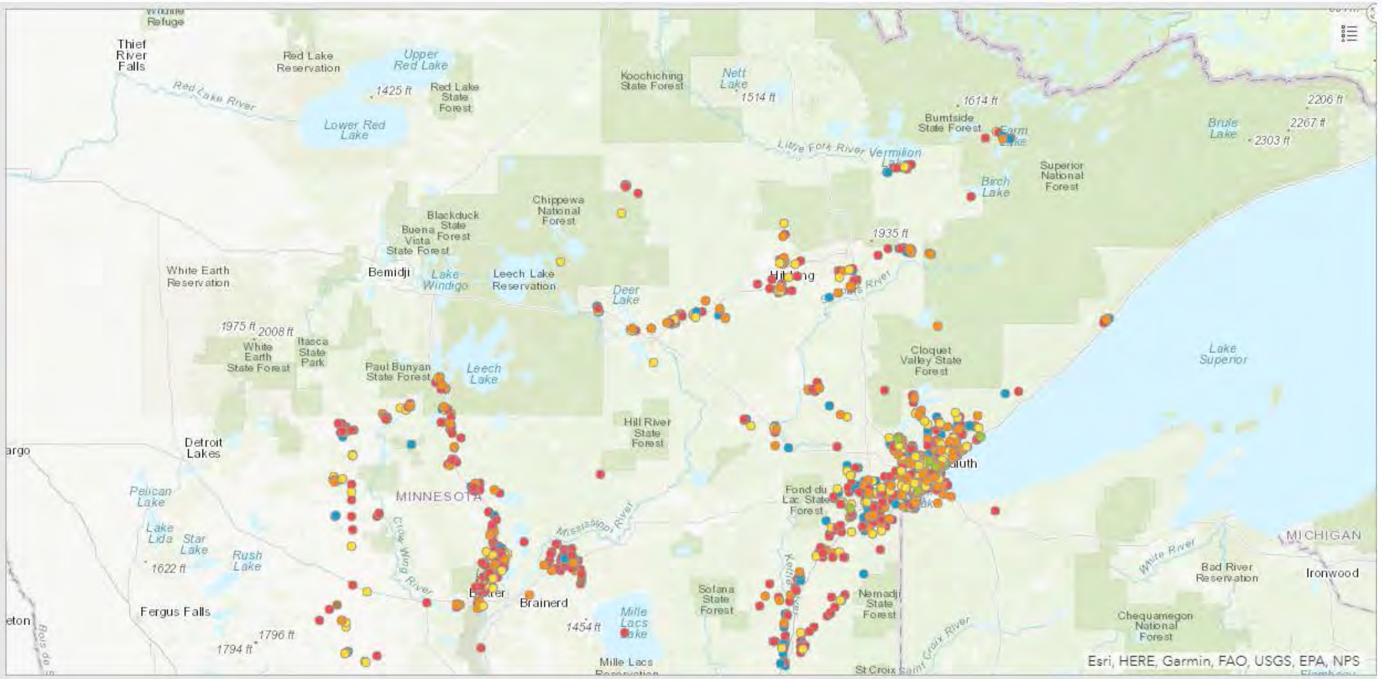
15TH AVE W SUBSTATION REBUILD

RELIABILITY TARGET AREAS

- Automation
- Mapping
- Groundline
- Vegetation Management
- AMI integration
- Maintenance

SERVICE REQUEST – TROUBLE ORDERS



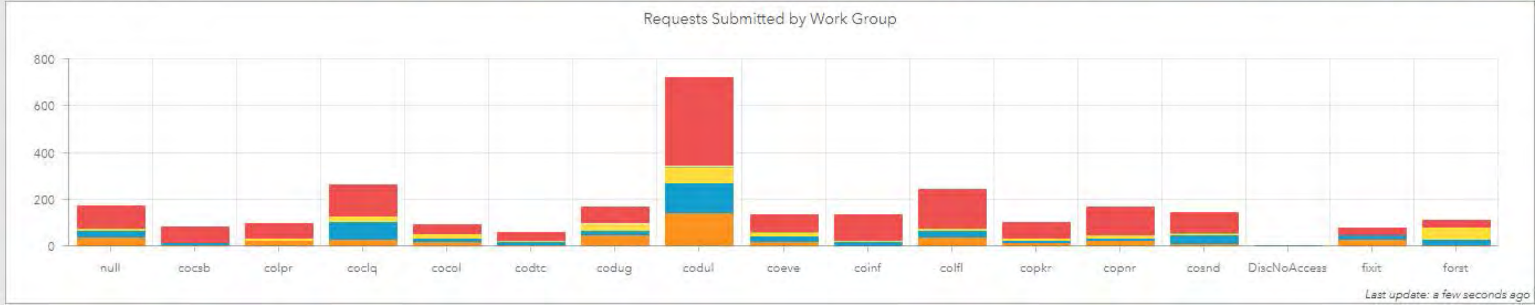


2,749 Submitted

1,998 Finished

73%

Last update: a few seconds ago



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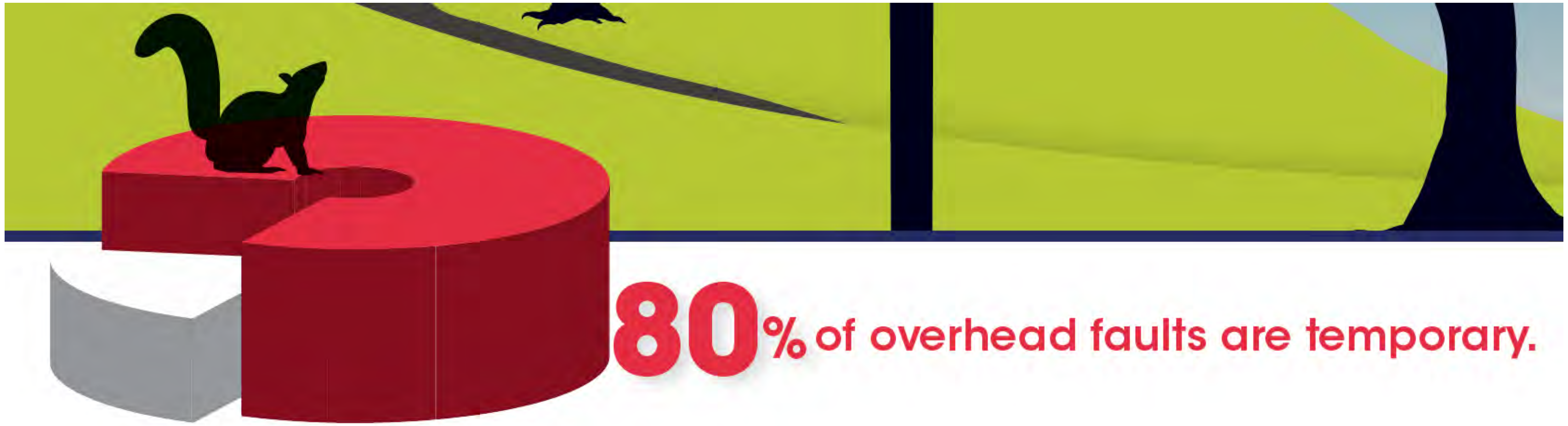
TRIP SAVERS

- Recloser in a cutout body.
  - 9 installed in 2017.
  - 44 installed in 2018.
  - 180 installed in 2019.
  - Proven technology to clear temporary faults without rolling a truck



INTELLIRUPTERS

- FLISR technology
- Auto-restore customers
- Continue to rollout IntelliRupters.
- Targeting areas for increased reliability.

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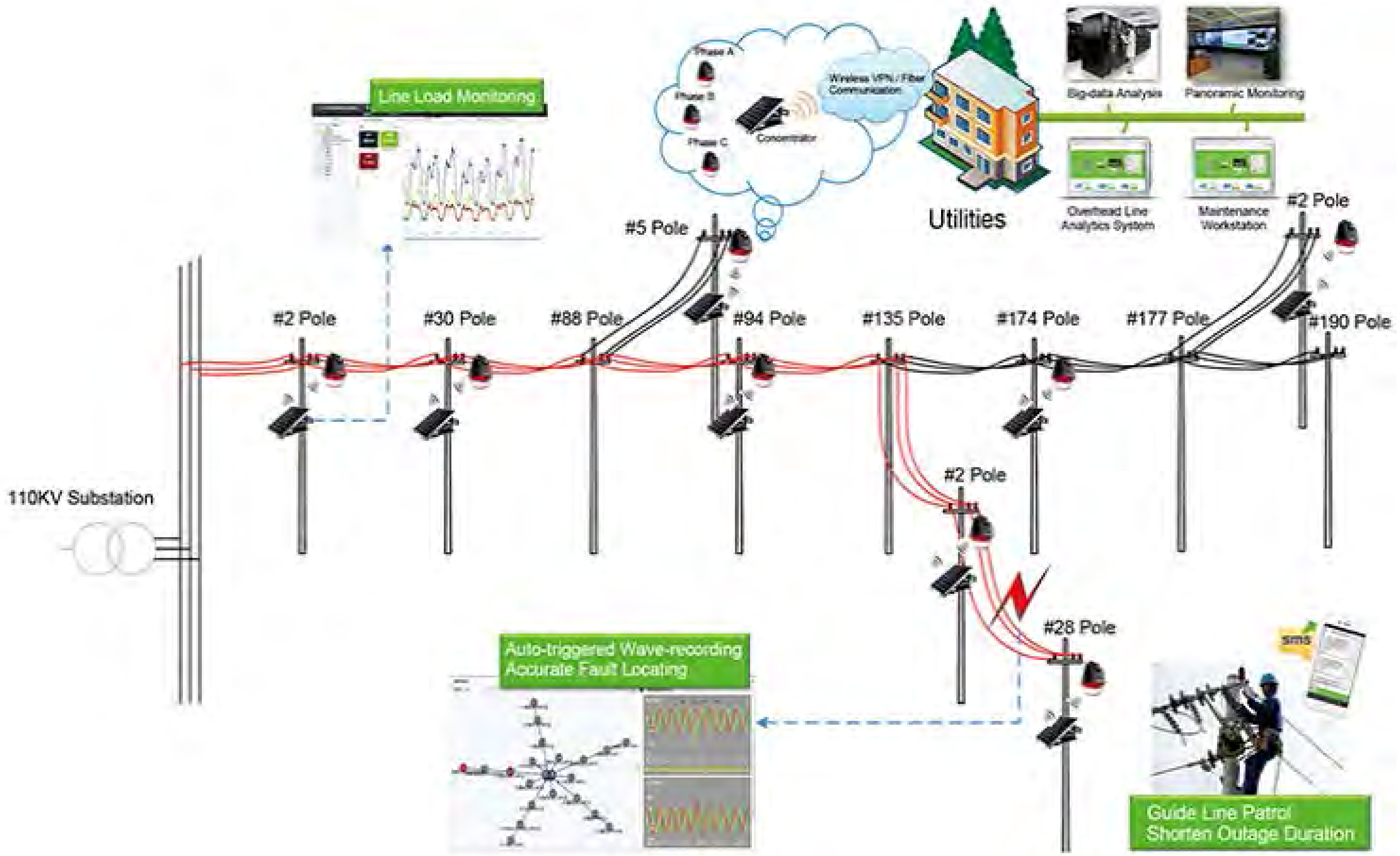
SMART SENSORS

- 2018 Pilot for fault locating



MOTOR OPERATED SWITCHES

- Investing communications options
- Reduces response time
- Integrate with smart sensors
- 2020 and forward initiative

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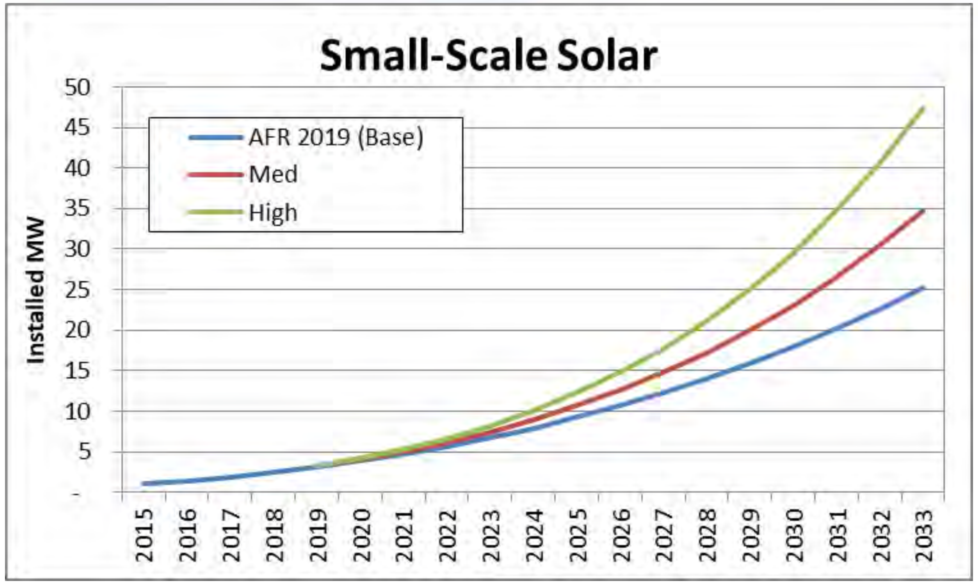
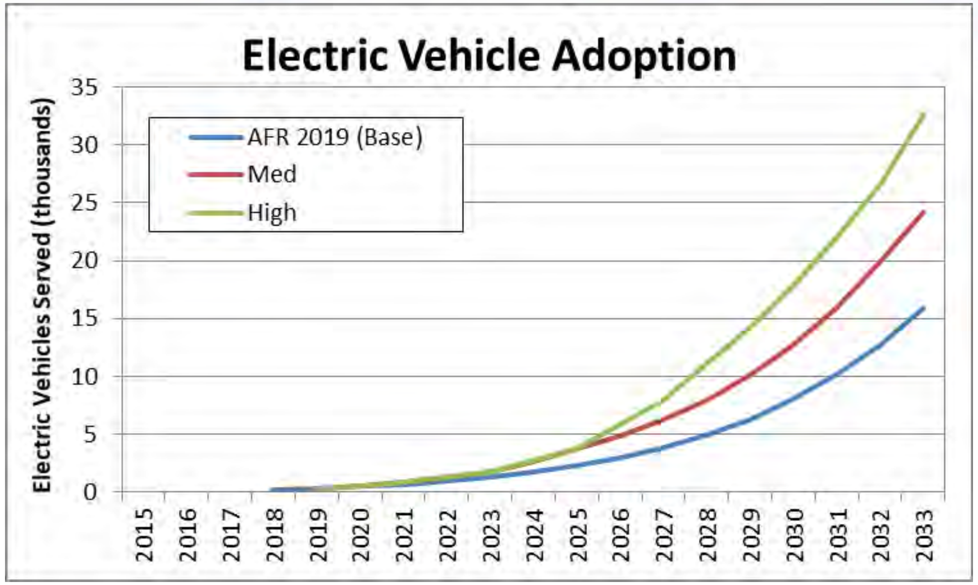
STRATEGIC UNDERGROUNDING

- 2020 and forward initiative
- Target heavy tree areas
- Improve reliability

DER SCENARIO ANALYSIS

DER SCENARIO ANALYSIS





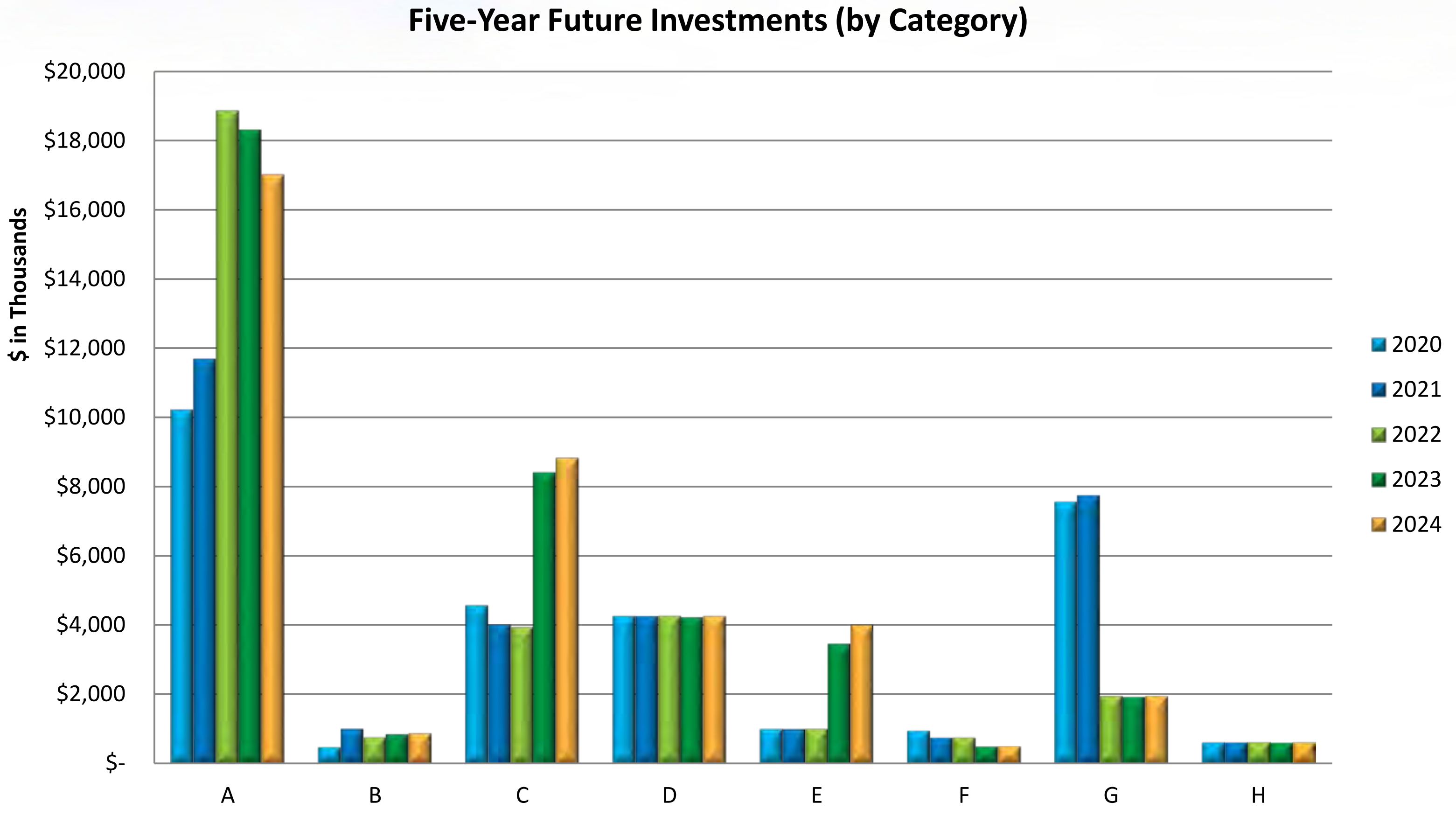
Summary of High DER Scenario Estimates

Type	Total KW	Notes
Small-Scale Solar (under 40kW)	43,714	Assumed variable growth rate as high as 30%, see tables
Large-Scale Solar (greater than 40kW)	71,000	
Grid-Scale Storage	30,000	Three 10 MW peak, 40 MWhr install
Small-Scale Storage (Residential storage, exclusing PHEV's)	5,000	1,000 Power Wall Equivalents (each 5 kW cont., 13.5 kWh)
Plug-in electric vehicles	37,500	7,500 Tesla Model S Equivalents (each 5 kW*, 75 kWh)
Time of Day		30,000 Residential Customers @ avg. CPP curtail of 180 W

5 YEAR & LONG-TERM INVESTMENT PLANS

APPENDIX B

5 YEAR INVESTMENT PLAN



IDP 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

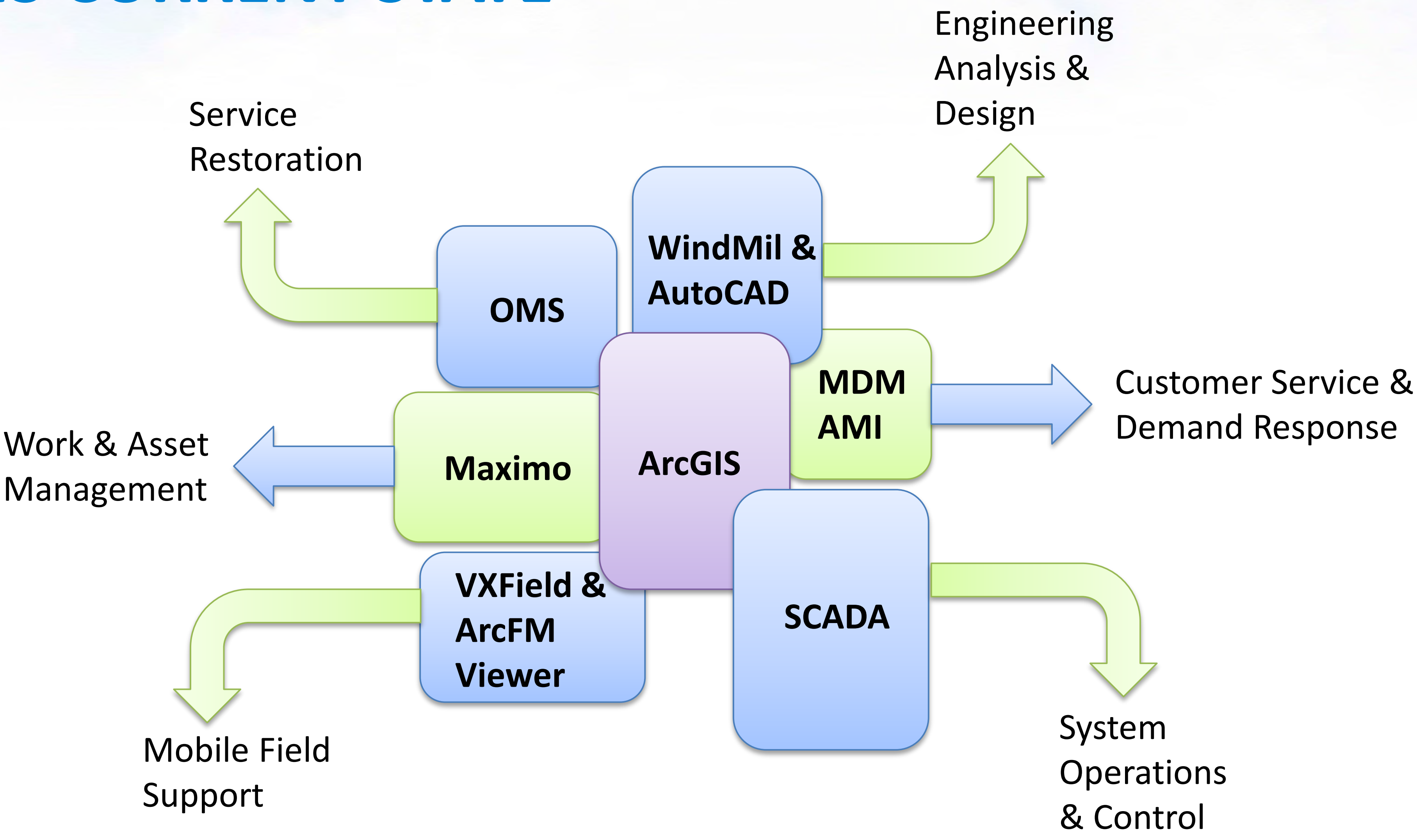
E - Grid Modernization and Pilot Projects

F - Projects Related to local (or other) government requirements

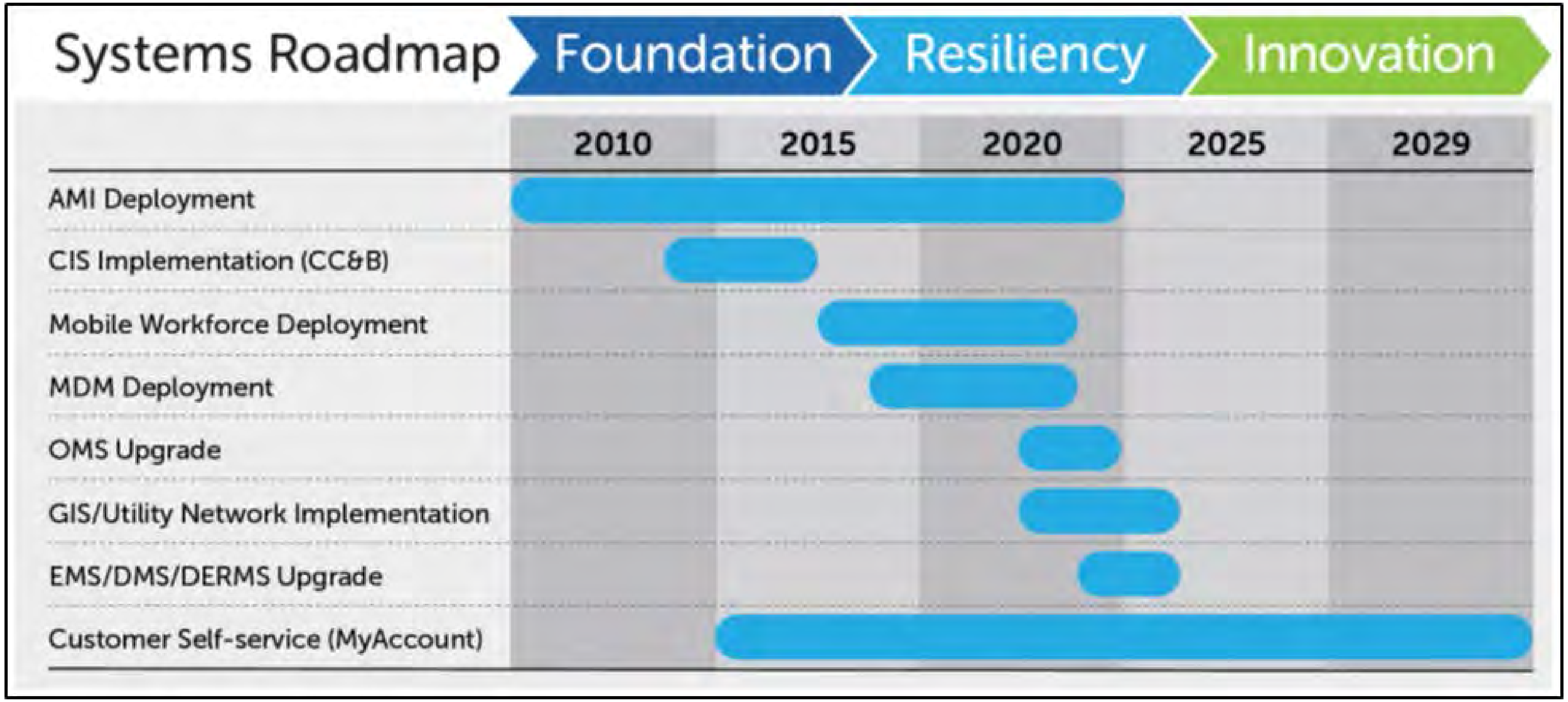
G - Metering

H – Other

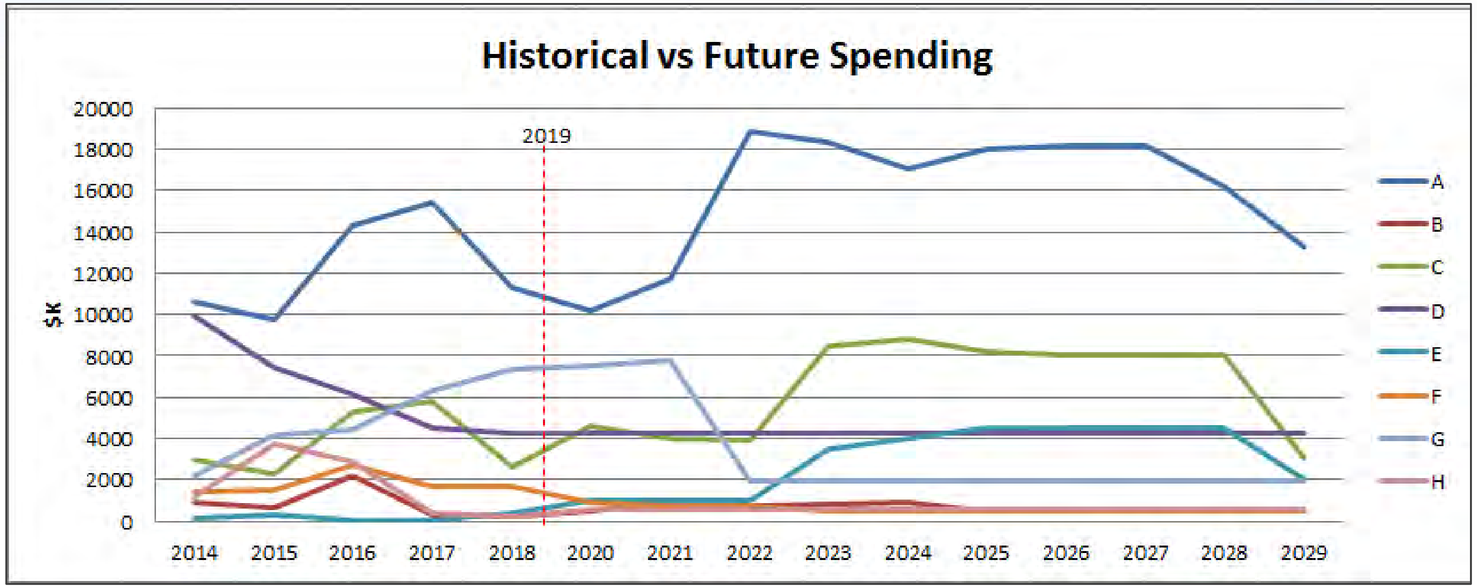
SYSTEMS CURRENT STATE



SYSTEMS FUTURE STATE & INNOVATION



LONG-TERM INVESTMENT PLAN



IDP Category	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
A - Age-Related Replacements and Asset Renewal	10217.5	11690	18867	18317	17017	17987	18157	18157	16157	13300
B - System Expansion or Upgrades for Capacity	475	1010	760	860	880	510	510	510	510	510
C - System Expansion or Upgrades for Reliability and Power Quality	4567.5	4010	3940	8440	8820	8245	8075	8075	8075	3075
D - New Customer Projects and New Revenue	4257	4257	4257	4257	4257	4257	4257	4257	4257	4257
E - Grid Modernization and Pilot Projects	1000	1000	1000	3500	4000	4500	4500	4500	4500	2000
F - Projects Related to local (or other) government requirements	950	750	750	500	500	500	500	500	500	500
G - Metering	7550	7750	1950	1950	1950	1950	1950	1950	1950	1950
H - Other	605	605	605	605	605	605	605	605	605	605
Total Check ($K)	**29622**	**31072**	**32129**	**38429**	**38029**	**38554**	**38554**	**38554**	**36554**	**26197**

Questions?

THANK YOU!

APPENDIX C

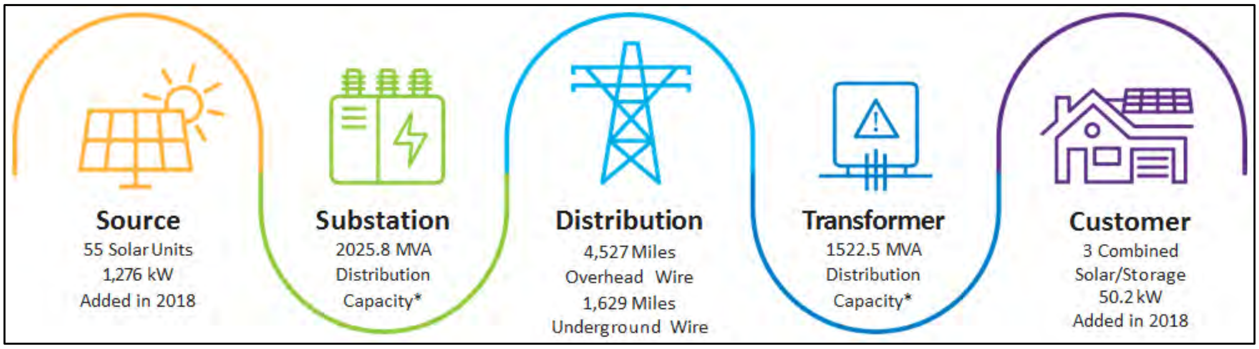


Figure 1: System Summary 2018

**Note:* Continuous current ratings of substation equipment, like circuit breakers, switches, and bus, could limit the nameplate capacity of a transformer if the equipment is rated lower. Nameplate transformer capacity could also be limited by the distribution feeder conductor rating.*

Table 1: Minnesota Power Distributed Energy Resource Status

Minnesota Power Distributed Energy Resource Completed Interconnections in 2019		
DER Technology Type	**Nameplate Rating**	**Interconnections**
Solar	1276.8 kW	50
Combined Solar/Storage	50.2 kW	3
Battery Storage	112.6 MW	11

Minnesota Power Distributed Energy Resource Interconnection Queue (as of 8/15/2019)			
Application Completion Date	**Proposed DER Capacity (kW)**	**DER Type**	**Application Status**
7/10/2019	7.6	Solar	Construction
7/16/2019	7.6	Solar	Construction
7/16/2019	10	Solar	Construction
8/6/2019	4	Solar	Initial Review

APPENDIX D

Summary of Baseline DER Scenario Estimates		
Type	**Total KW**	**Notes**
Small-Scale Solar (under 40kW)	10,685	Assumed that installs per year would stay flat at 35
Large-Scale Solar (greater than 40kW)	31,000	known installs, plus conservative estimated future
Grid-Scale Storage	-	
Small-Scale Storage (Residential storage, exclusing PHEV's)	500	100 Tesla Power Wall Equivalents (each 5 kW cont., 13.5 kWh)
Plug-in electric vehicles	2,500	500 Tesla Model S Equivalents (each 5 kW*, 75 kWh)
Dual Fuel		
Time of Day		5,000 Residential Customers @ avg. CPP curtail of 180 W

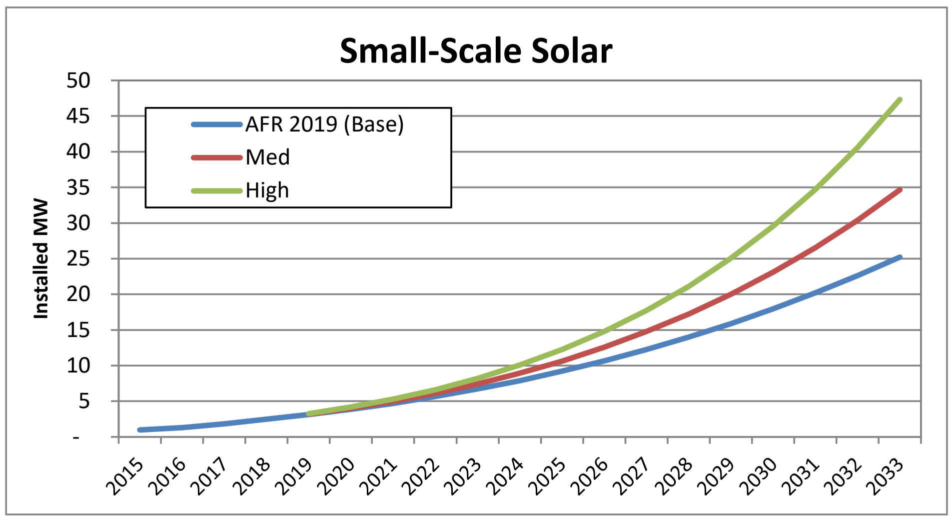
Summary of Medium DER Scenario Estimates		
Type	**Total KW**	**Notes**
Small-Scale Solar (under 40kW)	24,149	assumed 10% increase per year in terms of installs
Large-Scale Solar (greater than 40kW)	41,000	
Grid-Scale Storage	10,000	One 10 MW peak, 40 MWhr install
Small-Scale Storage (Residential storage, exclusing PHEV's)	1,500	300 Power Wall Equivalents (each 5 kW cont., 13.5 kWh)
Plug-in electric vehicles	10,000	2000 Tesla Model S Equivalents (each 5 kW*, 75 kWh)
Dual Fuel		
Time of Day		10,000 Residential Customers @ avg. CPP curtail of 180 W

Summary of High DER Scenario Estimates		
Type	**Total KW**	**Notes**
Small-Scale Solar (under 40kW)	43,714	assumed variable growth rate as high as 30%, see tables
Large-Scale Solar (greater than 40kW)	71,000	
Grid-Scale Storage	30,000	Three 10 MW peak, 40 MWhr install
Small-Scale Storage (Residential storage, exclusing PHEV's)	5,000	1000 Power Wall Equivalents (each 5 kW cont., 13.5 kWh)
Plug-in electric vehicles	37,500	7500 Tesla Model S Equivalents (each 5 kW*, 75 kWh)
Dual Fuel		
Time of Day		30,000 Residential Customers @ avg. CPP curtail of 180 W

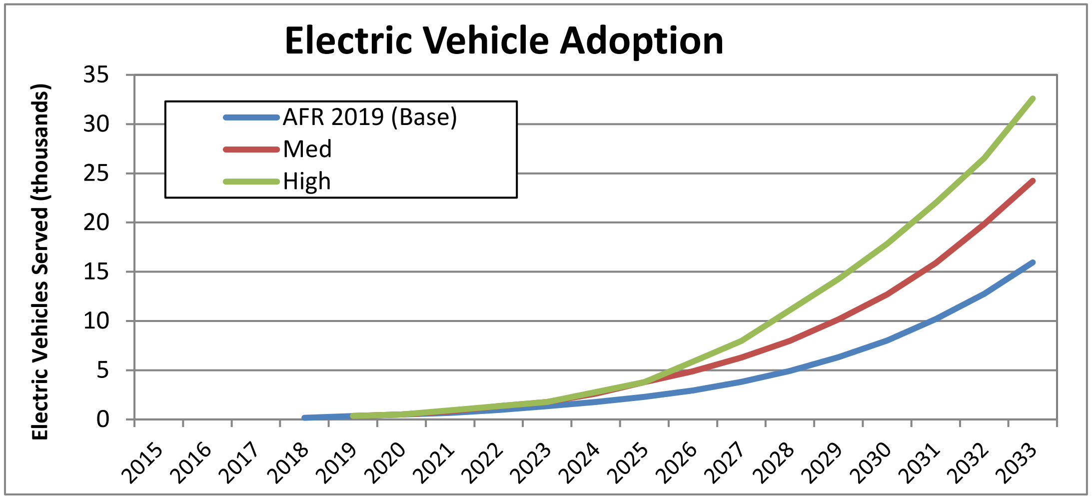
APPENDIX D

	Distributed KW Installed (<60 KW)			PV Installation Count			Summer Peak Impact (MW)			Avg Installation Size	
	AFR 2019 (Base)	Med	High	AFR 2019 (Base)	Med	High	AFR 2019 (Base)	Med	High	Res	Com
2015	**975**									9	21
2016	**1,319**										
2017	**1,835**									Yr Installation Count	
2018	**2,484**			276			(1.4)			Res	Com
2019	3,128	3,191	3,253	331	338	345	(1.7)	(1.8)	(1.8)	43	13
2020	3,866	4,023	4,182	395	411	428	(2.1)	(2.2)	(2.3)	50	14
2021	4,705	4,996	5,299	468	497	527	(2.6)	(2.8)	(2.9)	57	16
2022	5,651	6,126	6,630	551	597	646	(3.1)	(3.4)	(3.7)	65	18
2023	6,713	7,430	8,206	644	713	787	(3.7)	(4.1)	(4.6)	73	20
2024	7,896	8,925	10,063	748	846	953	(4.4)	(5.0)	(5.6)	82	22
2025	9,209	10,632	12,240	864	997	1,148	(5.1)	(5.9)	(6.8)	92	24
2026	10,658	12,571	14,778	992	1,170	1,375	(5.9)	(7.0)	(8.2)	102	26
2027	12,251	14,763	17,724	1,133	1,366	1,640	(6.8)	(8.2)	(9.9)	113	28
2028	13,994	17,233	21,132	1,288	1,586	1,945	(7.8)	(9.6)	(11.7)	124	31
2029	15,894	20,004	25,059	1,457	1,834	2,297	(8.8)	(11.1)	(13.9)	136	33
2030	17,959	23,104	29,568	1,641	2,111	2,702	(10.0)	(12.8)	(16.4)	148	36
2031	20,197	26,559	34,730	1,841	2,421	3,166	(11.2)	(14.8)	(19.3)	161	39
2032	22,613	30,401	40,621	2,057	2,765	3,695	(12.6)	(16.9)	(22.6)	175	41
2033	**25,215**	**34,659**	**47,326**	**2,290**	**3,148**	**4,298**	**(14.0)**	**(19.3)**	**(26.3)**	189	44

Pct Growth Adder =	**2.5%**	**5%**



	MP Customer Vehicle Count			Energy Consumption Impact (MWh)			Summer Peak Impact (MW)		
	AFR 2019 (Base)	Med	High	AFR 2019 (Base)	Med	High	AFR 2019 (Base)	Med	High
2015									
2016									
2017									
2018	165			416			0.05		
2019	358	358	358	486	486	486	0.06	0.06	0.06
2020	493	493	493	827	827	827	0.10	0.10	0.10
2021	667	819	914	1,264	1,647	1,887	0.16	0.21	0.24
2022	972	1,336	1,336	2,034	2,950	2,950	0.25	0.37	0.37
2023	1,338	1,767	1,767	2,956	4,038	4,038	0.37	0.50	0.50
2024	1,770	2,607	2,780	4,045	6,154	6,591	0.50	0.77	0.82
2025	2,287	3,796	3,796	5,347	9,150	9,150	0.67	1.14	1.14
2026	2,939	4,895	5,884	6,991	11,919	14,413	0.87	1.48	1.80
2027	3,808	6,298	7,980	9,181	15,455	19,694	1.14	1.93	2.45
2028	4,911	7,994	11,117	11,960	19,728	27,599	1.49	2.46	3.44
2029	6,319	10,160	14,265	15,509	25,186	35,531	1.93	3.14	4.43
2030	8,020	12,708	17,828	19,796	31,608	44,511	2.47	3.94	5.54
2031	10,194	15,896	21,991	25,272	39,642	55,001	3.15	4.94	6.85
2032	12,749	19,850	26,553	31,711	49,606	66,498	3.95	6.18	8.28
2033	**15,949**	**24,242**	**32,600**	**39,775**	**60,675**	**81,735**	**4.96**	**7.56**	**10.18**



APPENDIX D

	New DG Solar Impact		
	Res (MWh)	Com (MWh)	MW Installed
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019	378	258	0.64
2020	816	547	1.38
2021	1,320	871	2.22
2022	1,893	1,230	3.17
2023	2,542	1,628	4.23
2024	3,271	2,067	5.41
2025	4,085	2,548	6.72
2026	4,988	3,074	8.17
2027	5,986	3,646	9.77
2028	7,083	4,268	11.51
2029	8,284	4,942	13.41
2030	9,594	5,669	15.48
2031	11,018	6,451	17.71
2032	12,560	7,292	20.13
2033	14,226	8,192	22.73
2034	16,113	9,203	25.67

	Electric Vehicle MP System Impact					Peak Impact	
	Total Res	Standard/AE	Res PEV	EV's Per Household	Residential PEV MWh	Winter (MW)	Summer (MW)
2007	118,870	106,276					
2008	119,301	106,364					
2009	121,216	107,659					
2010	121,235	107,710					
2011	121,251	107,035					
2012	120,697	107,163					
2013	121,314	107,708					
2014	119,789	107,970					
2015	121,515	107,908					
2016	121,836	108,332					
2017	122,253	108,612					
2018	122,557	109,260	165	0.2%	416		0.05
2019	122,642	109,336	358	0.3%	486	0.18	0.06
2020	122,907	109,572	493	0.5%	827	0.30	0.10
2021	123,183	109,818	667	0.6%	1,264	0.46	0.16
2022	123,399	110,011	972	0.9%	2,034	0.74	0.25
2023	123,621	110,208	1,338	1.2%	2,956	1.08	0.37
2024	123,829	110,394	1,770	1.6%	4,045	1.48	0.50
2025	124,006	110,552	2,287	2.1%	5,347	1.95	0.67
2026	124,201	110,726	2,939	2.7%	6,991	2.55	0.87
2027	124,406	110,908	3,808	3.4%	9,181	3.35	1.14
2028	124,617	111,097	4,911	4.4%	11,960	4.36	1.49
2029	124,824	111,281	6,319	5.7%	15,509	5.66	1.93
2030	125,036	111,470	8,020	7.2%	19,796	7.22	2.47
2031	125,245	111,656	10,194	9.1%	25,272	9.22	3.15
2032	125,439	111,829	12,749	11.4%	31,711	11.57	3.95
2033	125,660	112,026	15,949	14.2%	39,775	14.51	4.96
2034	125,881	112,223	19,920	17.8%	49,783	18.16	6.20

Month	Peak Hour	Usage Seasonal %	Coincidence Factor
1	18	5%	0%
2	19	7%	0%
3	11	8%	46%
4	11	10%	57%
5	12	9%	55%
6	15	10%	48%
7	15	11%	56%
8	15	11%	56%
9	17	10%	23%
10	19	6%	0%
11	18	6%	0%
12	18	6%	0%

Month	Peak Hour	Usage Seasonal %	Coincidence Factor	MWh/Yr/EV
1	18	10%	12%	2.52
2	19	10%	12%	
3	11	9%	2%	
4	11	8%	2%	
5	12	8%	3%	
6	15	7%	6%	
7	15	7%	6%	
8	15	7%	6%	
9	17	7%	10%	
10	19	8%	12%	
11	18	9%	12%	
12	18	10%	12%	

APPENDIX D

Electric Vehicle MP System Impact						Peak Impact		% Charging at Peak		US EV Saturation
	Total Res	**Standard/AE**	**Res PEV**	**EV's Per Household**	**Residential PEV MWh**	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	
2007	118,870	106,276								
2008	119,301	106,364								
2009	121,216	107,659								
2010	121,235	107,710								
2011	121,251	107,035								
2012	120,697	107,163								
2013	121,314	107,708								
2014	119,789	107,970								0.2%
2015	121,515	107,908								0.3%
2016	121,836	108,332								0.5%
2017	122,253	108,612								0.6%
2018	122,557	109,260	165	0.2%	416					0.9%
2019	122,642	109,336	358	0.3%	486	0.18	0.06	11.1%	3.8%	1.2%
2020	122,907	109,572	493	0.5%	827	0.30	0.10	11.1%	3.8%	1.6%
2021	123,183	109,818	819	0.7%	1,647	0.60	0.21	11.1%	3.8%	2.1%
2022	123,399	110,011	1,336	1.2%	2,950	1.08	0.37	11.1%	3.8%	2.7%
2023	123,621	110,208	1,767	1.6%	4,038	1.47	0.50	11.1%	3.8%	3.4%
2024	123,829	110,394	2,607	2.4%	6,154	2.25	0.77	11.1%	3.8%	4.4%
2025	124,006	110,552	3,796	3.4%	9,150	3.34	1.14	11.1%	3.8%	5.7%
2026	124,201	110,726	4,895	4.4%	11,919	4.35	1.48	11.1%	3.8%	7.2%
2027	124,406	110,908	6,298	5.7%	15,455	5.64	1.93	11.1%	3.8%	9.1%
2028	124,617	111,097	7,994	7.2%	19,728	7.20	2.46	11.1%	3.8%	11.4%
2029	124,824	111,281	10,160	9.1%	25,186	9.19	3.14	11.1%	3.8%	14.2%
2030	125,036	111,470	12,708	11.4%	31,608	11.53	3.94	11.1%	3.8%	17.8%
2031	125,245	111,656	15,896	14.2%	39,642	14.46	4.94	11.1%	3.8%	21.6%
2032	125,439	111,829	19,850	17.8%	49,606	18.10	6.18	11.1%	3.8%	25.8%
2033	125,660	112,026	24,242	21.6%	60,675	22.14	7.56	11.1%	3.8%	30.2%
2034	125,881	112,223	29,008	25.8%	72,684	26.52	9.05	11.1%	3.8%	34.5%
										38.5%

Month	**Peak Hour**	Usage Seasonal %	Coincidence Factor	MWh/Yr/EV
1	18	10%	12%	2.52
2	19	10%	12%	
3	11	9%	2%	
4	11	8%	2%	
5	12	8%	3%	
6	15	7%	6%	
7	15	7%	6%	
8	15	7%	6%	
9	17	7%	10%	
10	19	8%	12%	
11	18	9%	12%	
12	18	10%	12%	

APPENDIX D

Electric Vehicle MP System Impact

						Peak Impact		% Charging at Peak		US EV Saturation
	Total Res	**Standard/AE**	**Res PEV**	**EV's Per Household**	**Residential PEV MWh**	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	
2007	118,870	106,276								
2008	119,301	106,364								
2009	121,216	107,659								
2010	121,235	107,710								
2011	121,251	107,035								
2012	120,697	107,163								
2013	121,314	107,708								
2014	119,789	107,970								0.2%
2015	121,515	107,908								0.3%
2016	121,836	108,332								0.5%
2017	122,253	108,612								0.6%
2018	122,557	109,260	165	0.2%	416					0.9%
2019	122,642	109,336	358	0.3%	486	0.18	0.06	11.1%	3.8%	1.2%
2020	122,907	109,572	493	0.5%	827	0.30	0.10	11.1%	3.8%	1.6%
2021	123,183	109,818	914	0.8%	1,887	0.69	0.24	11.1%	3.8%	2.1%
2022	123,399	110,011	1,336	1.2%	2,950	1.08	0.37	11.1%	3.8%	2.7%
2023	123,621	110,208	1,767	1.6%	4,038	1.47	0.50	11.1%	3.8%	3.4%
2024	123,829	110,394	2,780	2.5%	6,591	2.40	0.82	11.1%	3.8%	4.4%
2025	124,006	110,552	3,796	3.4%	9,150	3.34	1.14	11.1%	3.8%	5.7%
2026	124,201	110,726	5,884	5.3%	14,413	5.26	1.80	11.1%	3.8%	7.2%
2027	124,406	110,908	7,980	7.2%	19,694	7.19	2.45	11.1%	3.8%	9.1%
2028	124,617	111,097	11,117	10.0%	27,599	10.07	3.44	11.1%	3.8%	11.4%
2029	124,824	111,281	14,265	12.8%	35,531	12.96	4.43	11.1%	3.8%	14.2%
2030	125,036	111,470	17,828	16.0%	44,511	16.24	5.54	11.1%	3.8%	17.8%
2031	125,245	111,656	21,991	19.7%	55,001	20.07	6.85	11.1%	3.8%	21.6%
2032	125,439	111,829	26,553	23.7%	66,498	24.26	8.28	11.1%	3.8%	25.8%
2033	125,660	112,026	32,600	29.1%	81,735	29.82	10.18	11.1%	3.8%	30.2%
2034	125,881	112,223	38,668	34.5%	97,026	35.40	12.09	11.1%	3.8%	34.5%
										38.5%

Month	**Peak Hour**	Usage Seasonal %	Coincidence Factor	MWh/Yr/EV
1	18	10%	12%	2.52
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4	11	8%	2%	
5	12	8%	3%	
6	15	7%	6%	
7	15	7%	6%	
8	15	7%	6%	
9	17	7%	10%	
10	19	8%	12%	
11	18	9%	12%	
12	18	10%	12%	

APPENDIX E

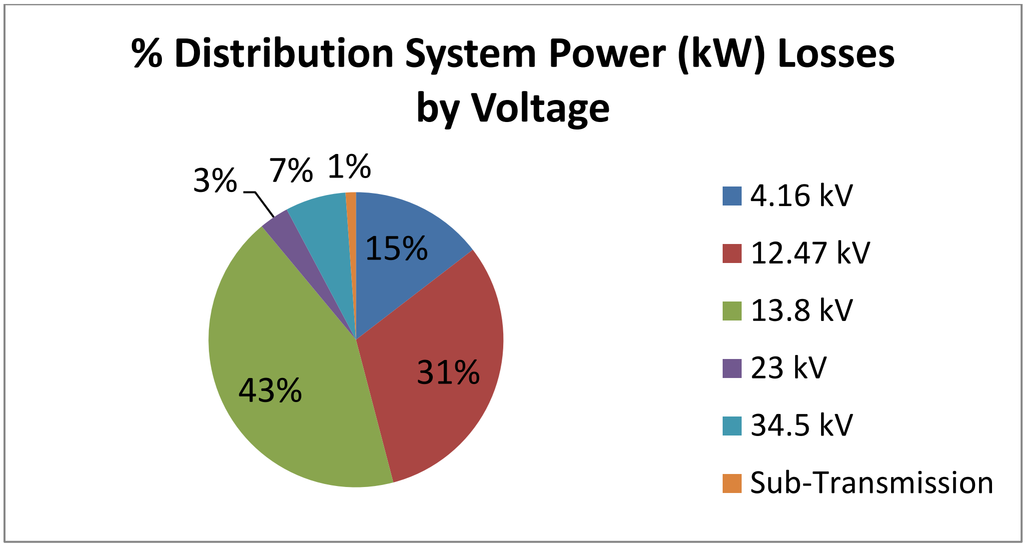
Internal Study completed in May 2016. This is the most recent loss study for the distribution system. Minnesota Power will work to update the distribution loss study for the 2021 IDP.

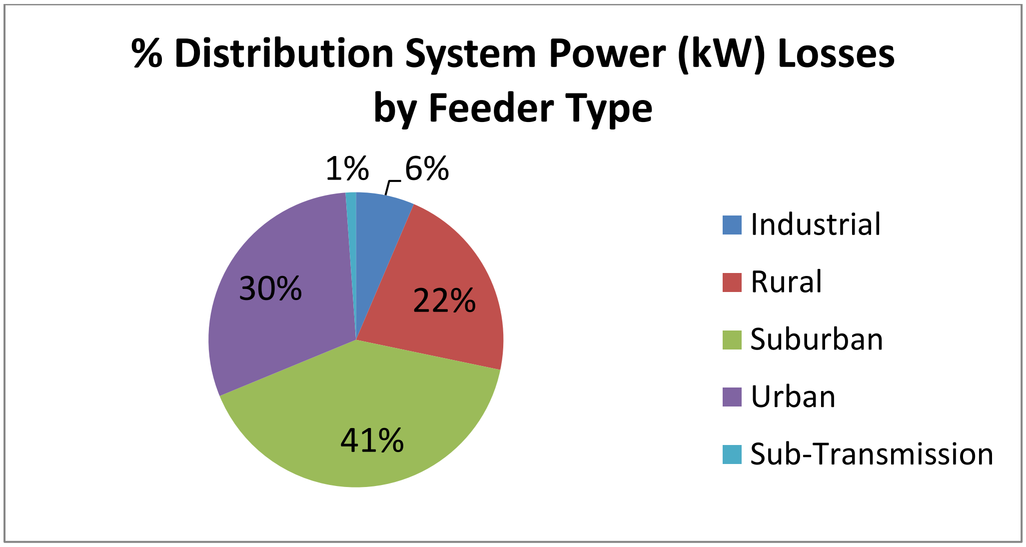
OVERALL RESULTS:

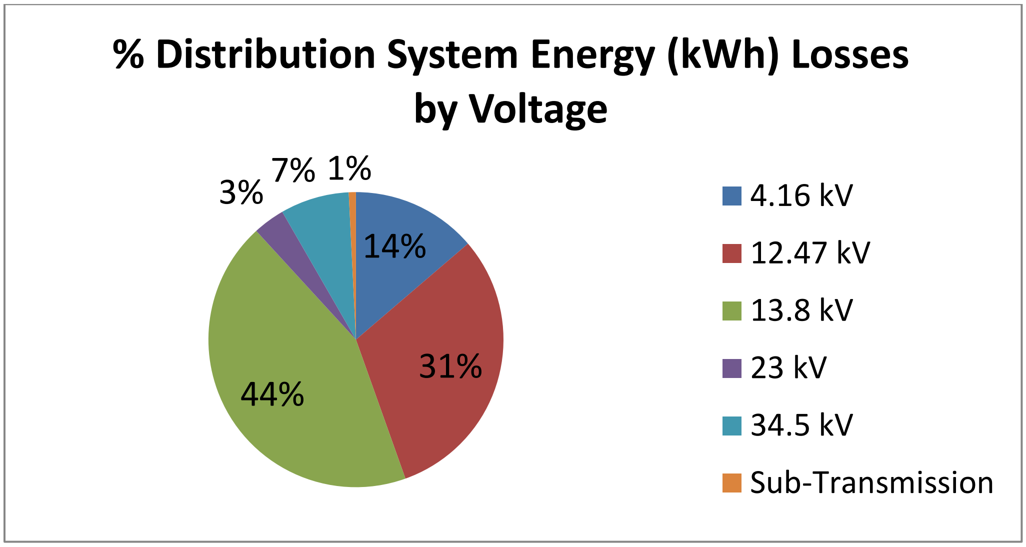
MINNESOTA POWER DISTRIBUTION SYSTEM TOTAL ELECTRICAL LOSSES:

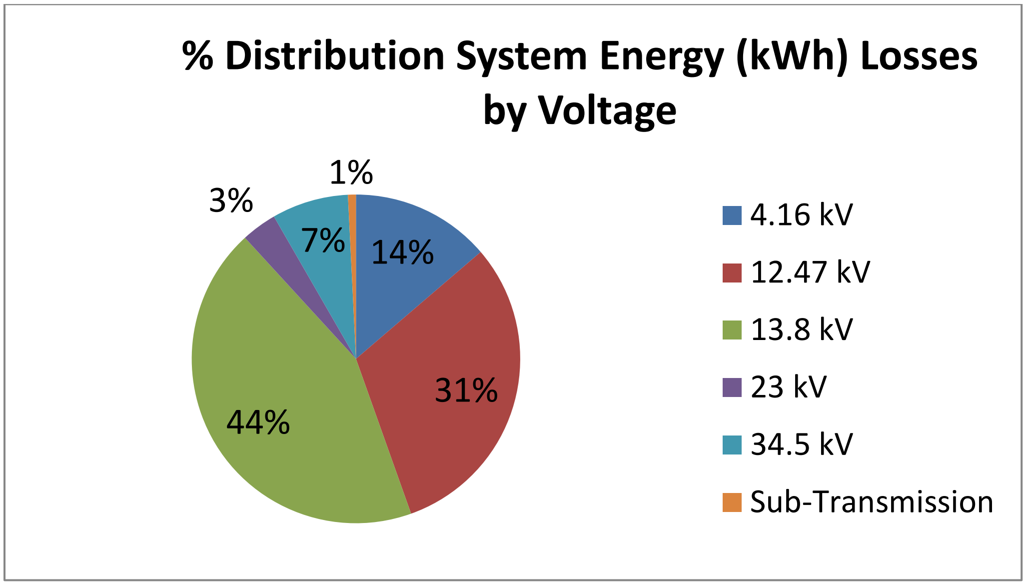
- **Power (kW) Loss: 6.39 percent**
- **Energy (kWh) Loss: 5.75 percent**

The information contained in this section is high level, results are obtained from the completion of the distribution system loss study. This report describes the methodology, models, and calculations used to obtain these results. There is also more detailed loss data and in-depth analysis contained within **DETAILED RESULTS** section of this report.









DISTRIBUTION SYSTEM LOSS STUDY

Purpose:

The purpose of this project is to accurately model and power losses within Minnesota Power's distribution system. This effort is to contribute to the basis for which Minnesota Power builds a rate case to the Minnesota Public Utilities Commission.

Scope:

Distribution losses are modeled from the customer meter up to the substation feeder exit. This will include transformer losses as well as primary and secondary line losses. System losses within generation, substation and high voltage transmission (above 46 kV) are not included. This study pertains to only Minnesota Power distribution feeders only. Distribution losses within other companies, cooperatives, and municipalities will only be modeled up to the point of the primary service point. As part of this study, loss models will be developed and applied to all feeders in an effort to estimate the percent of total distribution loss.

Approach:

Due to the large scope, the project work to complete the loss study can be broken into 3 distinct stages. Below is a high level summary of each stage, but more detailed information can be found in **APPENDIX C**.

Stage 1 – Model Development

The Distribution Engineering department did not have any readily available software tools, integrated with the GIS system, to perform loss calculations. Given the short timeline to perform the study, there simply wasn't enough time to integrate and commission a full-scale software package. The decision was made to create an original tool, using Microsoft Excel VBA that could organize feeder data, map out load flow, and accurately calculate feeder losses. Details on how this code was constructed can be found in the **MODELING TOOL** section.

Stage 2 – Model Application to Sample Feeders

After the modeling tool is created and fully tested, the next stage applies the tool to the distribution feeders. While the tool greatly speeds up the task, modeling complex radial feeders is still a heavily involved process that may take a full day or two per feeder to complete. This provides the motivation to only apply the tool to a representative sample of feeders. This study divided feeders into 5 categories:

1. Urban
    - Feeders with high population density. These would be lines serving loads in the centers of cities and towns.
2. Rural
    - Feeders with low population density, such as lines serving farms and cabins, etc.
3. Suburban
    - Feeder densities that falls in between urban and rural. These types of feeders would include housing developments, lakeshore communities, etc. This metric somewhat is subjective, as there are not firm lines between these feeder types.
4. Industrial
    - Feeders with high load versus customer ratio. Customers found on industrial feeders are typically large facilities that draw major loads.

These lines often include primary metering to some facilities.

5. Sub-Transmission
   - These lines operate at voltages 23 kV – 46 kV. These lines to facilitate the power flowing on the network between distribution substations. They were modeled differently from the other feeders as they were typically just point-to-point lines. Simple primary line loss calculations were applied to this type of feeder.

As part of this study, a total of 9 feeders made up the representative sample. Feeders from the Urban, Rural, Suburban, and Industrial categories were selected and fully modeled. The detailed process of applying the modeling tool and calculating loss is described below in the **FEEDER APPLICATION** section.

Stage 3 – Feeder Loss Generalization and Extrapolation

After a sample feeder loss base has been built, the final stage is to generalize the feeder losses based on high level characteristics. The characteristics of the fully modeled feeders can then be compared against each remaining distribution feeder in the Minnesota Power electric system. From these comparisons, a highly informed extrapolation can be applied to the unknown feeders, and an estimated loss can be established. Details concerning the feeder characteristics for generalization and loss estimation are described in the **LOSS GENERALIZATION** section.

Assumptions:

The following are a list of assumptions used to define the operating parameters, justify estimations, and limit the scope of the loss study.

1. Data in GTI View database is accurate
   a. Transformers are associated with the correct service points
   b. Primary feeders are drawn accurately
   c. Conductor information is listed correctly
   d. Transformer demand is accurate and coincidence has already been factored in
   e. Customer demand is accurately reported

2. High level feeder overlays on the state map are scaled correctly

3. Loads along feeder sections are uniformly distributed and balanced between phases

4. Feeders are only serving their own customer load and not tied to other feeders

5. Effect of capacitor banks and line regulators are ignored

6. Transformer losses are approximate and generalized
   a. Actual transformer percent impedances are not included in the model

b. Transformer losses are based on typical NL and LL values per ORNL – 6525 publication. Refer to transformer loss evaluation section and References section for details.
c. For transformer loss evaluation, the voltage on the primary side of all transformers was set to 1.025 per unit (2.5 percent above nominal).

7. Secondary line losses are calculated on a 120 volt basis

8. All secondary lines are modeled as #2 AL Triplex

9. Feeder voltage at substation source is percent5 above nominal

10. Voltage regulators that are placed in-line, far downstream of the substation will regulate the feeder at nominal voltage.

11. Distribution feeders that do not serve any customers are modeled as sub-transmission lines.
    a. Losses in these lines are added into the total percent loss of the distribution system.
    b. Sub-Transmission lines and Primary metered customers are represented as primary line loss only.
12. Feeder coincidental factor was assumed to be 2.0 for all feeders.

13. Feeder power factor is equal to unity.

Modeling Tool

In order to perform the necessary loss calculations on multiple complex feeders, a tool needed to be created that could appropriately organize and link data points together and facilitate loss calculations for the radial systems. Within this tool, the framework and general rules of our models were created for the purpose being able to quickly and accurately calculate losses for any distribution feeder.

Using data from GTI, the tool may be used to extract customer load and transformer information for each specific feeder. From the data imports, the following information may be obtained:

- Individual Customer Loading
- Transformer Loading
- Transformer Size
- Number of Phases
- Unique Identifiers for each service point

However, this information does not provide any information for the layout of the feeder, and how the customer load is dispersed along the feeder branches. Specifically, the information that is missing from the GTI customer data is the following:

- Primary Line Length
- Line Type
- Branch line relationships (Feeder Structure)
    - i.e. which metered points are at the head of a feeder branch, and which ones follow it down the line.

These missing pieces will have to be input into the modeling tool manually. The most important step in using the tool is to accurately link the data points together in a way that logically represents the feeder topology. The feeder needs to be traced manually to look for any taps or new branches that may form as the lines move away from their source.

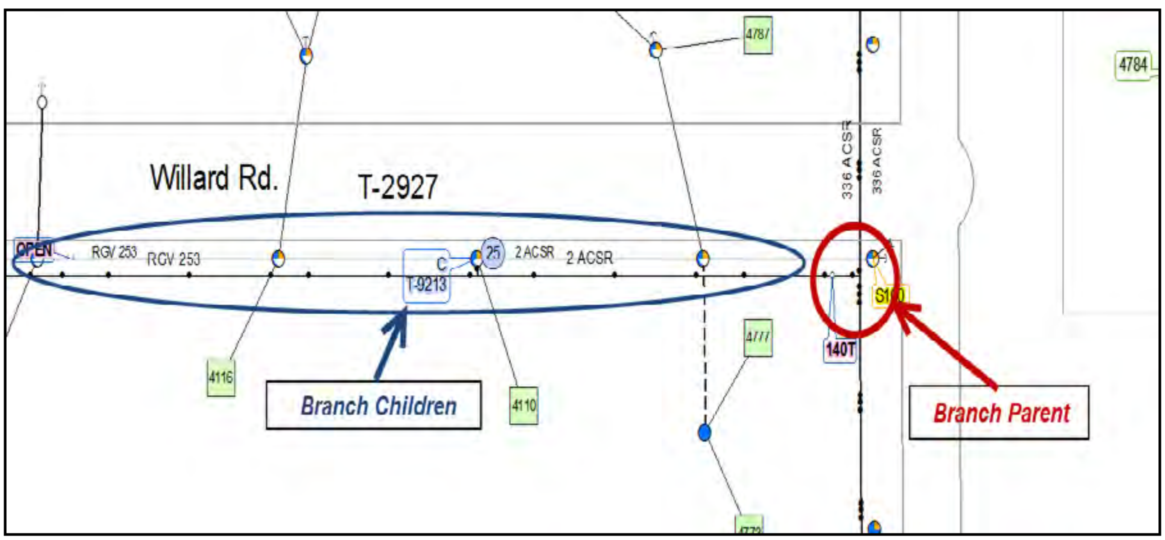


FIGURE 1: Parent/Child Branch Relationship

When a new branch is discovered, the user must designate a load at the head of the branch as the parent. As shown in **FIGURE 1**, all subsequent service points downstream of the branch parent, are designated as branch children. These loads will logically point back to the parent, and will allow the feeder structure to be built up in the modeling tool. Once the each branch parent and children have been mapped, the line length and line type also need to be input for each branch.

Once all of this information has been compiled, the tool can then automatically reorganize the feeder data to match the logical branch/child structure. This accurate topology will allow the model to iteratively determine the demand observed on each branch. The tool will start from the end of the feeder and accumulate all loads its way back to the head of the feeder at the substation. This will allow the model to accurately determine all downstream loads at each branch point. **FIGURE 2** below illustrates an example of how these relationships are used to determine power flow.

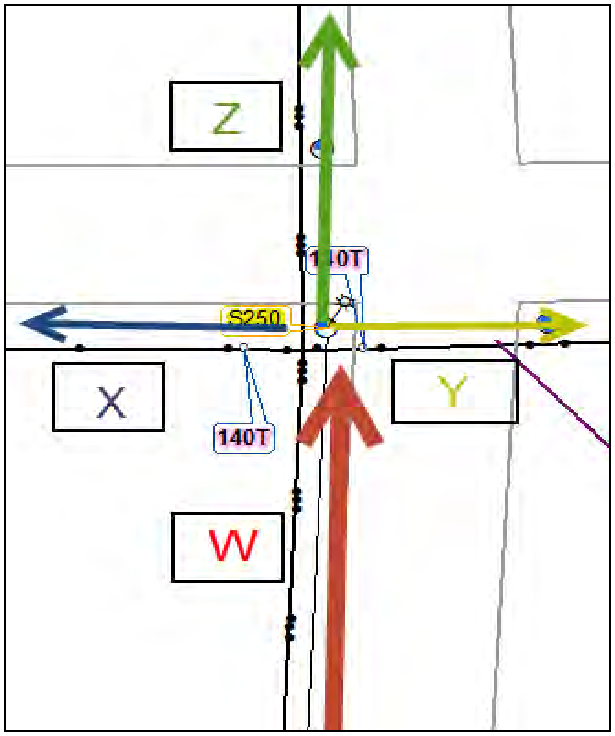


FIGURE 2: Power Flow at Branches

In this example, ***X***, ***Y***, and ***Z*** will each have an observed downstream load due to their branch children. Because branches ***X***, ***Y***, and ***Z*** are downstream of the main branch ***W***, these are all seen as children to ***W***, and so their load points back**.** Therefore load observed in branch ***W*** will be the summation of these ***XYZ*** loads, plus any other services points between the head of branch ***W*** and the splitting point.

This backward sweep will allow the tool to completely model how the load is dispersed throughout the entire feeder. This information will then allow us to calculate all line currents, voltage drops, and subsequent feeder losses. The details for how the system losses are determined can be found in the **CALCULATIONS** section.

The complexities and nuances of the tool and the detailed code can be found in **APPENDIX D.** This appendix includes links to the tool, along with fully functional examples and instructions for tool use.

Feeder Application

APPENDIX E

The feeder loss modeling tool is designed to be general so it can be reapplied to any distribution feeder. The following describes in detail each step to model and execute loss calculations:

1. Customer data import:

Using GTI View, a list of customers for each feeder is compiled and exported to an Excel spreadsheet. This information is then copied and imported into the template for the feeder loss model. The tool will then automatically sort by address and provides a unique identifier for each customer service point.

2. Feeder Mapping:

The feeder now needs to be manually traced and all branches need to be identified. Each service point must also be looked at to determine which branch parent it should point to. This is the most time-consuming process in the feeder model. Once all points have been processed, the tool automation will logically link all feeder parents to children to determine how many children are in each branch, and setup pointers to restructure the database.

3. Import Transformer information:

Using GTI View again, the tag, size, and load information for all transformers associated with the feeder needs to be imported into the model. This will allow the model to link customers together by transformer, and will be a key part in determining branch loads.

4. Organize Feeder into logical branch structure:

The tool will now automatically restructure the customer database to follow the logical electric connections mapped out in step #2. This will also pull in and link the transformer data to the customer points. Setting up the correct feeder order is key to accurately calculating loads and feeder losses.

5. Determine the primary line lengths and wire types for the feeder branches:

The tool will generate a list of feeder branches that the user will need to manually enter line lengths and conductor types for. This is in order to determine the total line resistances in each branch. This is vital in the determination of primary line losses. This step also gives the user a chance to verify that the feeder has been properly structured. If the lines being evaluated are not following the actual feeder path, then a linking error has been made in step #2 that needs to be remedied. This section also allows the user to specify if there are in-line voltage regulators, which need to be factored into the branch voltages.

6. Input starting feeder voltage and secondary length as calculation variables:

These are the missing variables necessary to execute the loss calculations

7. Run the calculations

Finally, the tool will run the final automation sequence that will calculate the primary, secondary, and transformer load losses in the feeder. This process starts by accumulating all of the loads in each branch from the end of the feeder, and back-sweeping towards the source. This provides downstream demand information at each branch in the feeder. It is critical the feeder was accurately mapped, or else the load information will not be correct. Once the observed loads have been determined, the tool will execute the calculations described in the **CALCULATIONS** section below. The result of the calculation will be the percent power loss in the feeder.

Calculations

Primary Line Losses

Primary line losses are based on a Uniformly Distributed Load model, described in section 3.4 in the "Distribution System Modeling and Analysis" textbook by William H. Kersting. See **APPENDIX A** for full details on the model.

First, voltage drop must be examined. Voltage drop in these calculations is defined as the difference between the voltage at the head and end of a feeder branch. The voltage drop will be tracked throughout the feeder starting at the source and calculated for each subsequent branch. The calculated voltage at the end of one feeder branch may be used as the head value for the next branch down the line. By following this method, voltages may be modeled through the feeder:

VARIABLES:

L = Length of the feeder branch

*R= Resistance of the line in Ω/mile (**SEE APPENDIX B**)*

n = number of customers in branch

$$I_t = Total\ current\ per\ phase\ into\ feeder\ branch$$

$D_{Branch} = Total\ demand\ seen\ at\ head\ of\ branch\ (kW)$

$V_{drop} = Voltage\ drop\ across\ branch\ (kV)$

$V_b = Voltage\ at\ branch\ head\ (kV)$

$\#P = Number\ of\ phases\ in\ branch\ (1 - 3)$

VOLTAGE DROP AND BRANCH CURRENT CALULATION

Voltage drop is a simple ohms law calculation based on the load being evenly distributed along the branch.

$$V_{drop} = \frac{|I_t|}{2} RL \qquad (Eq. 1)$$

The current flowing through a branch is based on the voltage at the head and the observed demand downstream. In **FIGURE 3** below, there is an example for how the branch currents and voltage drops, and the voltages of the downstream branches are calculated.

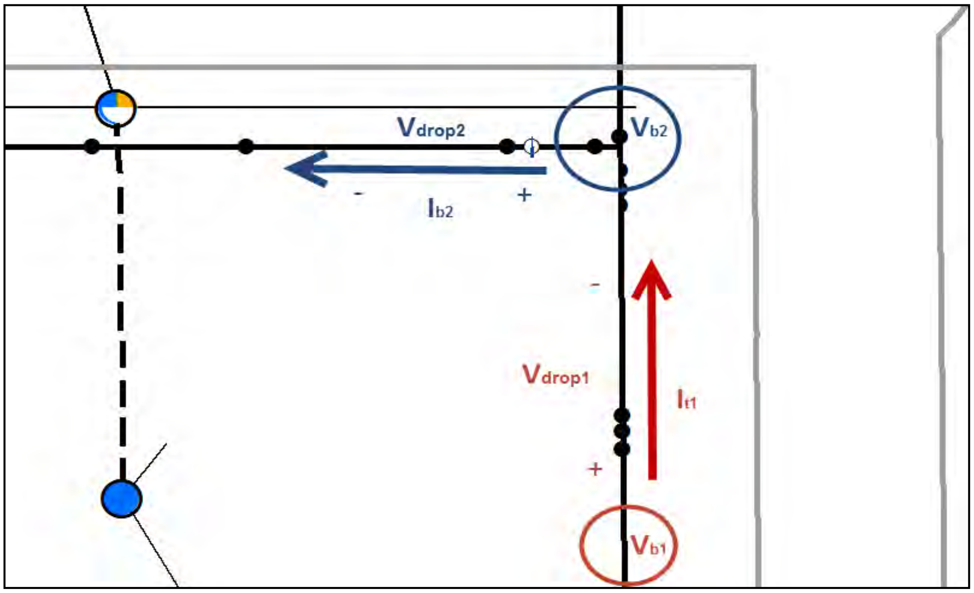


FIGURE 3: Voltage Drop and Branch Currents

$$|I_{t(1)}| = \frac{D_{Branch(1)}}{(\#P)V_{b(1)}} \qquad (Eq.2)$$

$$V_{drop(1)} = \frac{|I_{t(1)}|}{2}RL \qquad (Eq.3)$$

$$V_{b(2)} = V_{b(1)} - V_{drop(1)} \qquad (Eq.4)$$

$$|I_{t(2)}| = \frac{D_{Branch(2)}}{(\#P)V_{b(2)}} \qquad (Eq.5)$$

PRIMARY LINE LOSS CALULATION

Once the branch currents, voltage drops, and subsequent branch voltages have been determined, the power losses in the primary lines can be calculated in ***Eq. 6***.

$$P_{loss} = \#P|I_t^2|RL \qquad (Eq.6)$$

Transformer Losses

Since it is nearly impossible to accurately calculate the actual efficiencies vs. load for all transformers on the system, transformer losses are based on a representative set of transfomers.

VARIABLES:

$D_{Trans} = Demand\ on\ transformer\ (kW)$

APPENDIX E

$T_{KVA} = Transformer\ kVA\ Rating$

$T_{Capatity} = Scaled\ ratio\ that\ based\ on\ demand\ vs.transformer\ size$

$NL = Trasformer\ noload\ loss\ value\ that\ is\ independent\ of\ transformer\ demand$

$LL = Load\ Loss\ value\ when\ transformer\ is\ operated\ at\ 100\ percent\ rated\ capacity$

TRANSFORMER LOSS CALCULATION

The power loss in the transformer (***Eq. 8***) is the total loss seen on the transformer. The transformer demand from the database already has coincidence factors included in the value.

$$T_{capacity} = \frac{D_{Trans}}{T_{KVA}} \qquad (Eq.7)$$

$$T_{loss} = NL + LL \times \left(T_{Capacity}\right)^2 \quad (Eq.8)$$

Below is a table from an Oak Ridge National Laboratory titles publication "Supplementary to the 'Determination Analysis' (ORNL-6847) and Analysis of the NEMA Efficiency Standards for Distribution Transformers". To account for the variation of age of the transformers in MP's system, the NL and LL values of the evaluated and non-evaluated lists are averaged to provide blended values.

APPENDIX E

Table 4.1. Base case design loss parameters: medium-voltage liquid-immersed distribution transformers

Single-phase						Three-phase					
Size (kVA)[a]	Evaluated		Nonevaluated		% eval.	Size (kVA)[a]	Evaluated		Nonevaluated		% eval.
	NL	LL	NL	LL			NL	LL	NL	LL	
10	31	193	44	237	85	15	63	204	94	356	85
15	40	212	53	323	85	30	104	366	156	623	85
25	58	312	90	460	85	45	141	489	224	868	85
37.5	81	412	108	615	85	75	227	759	319	1,353	85
50	101	540	153	670	85	112.5	268	1,117	443	1,853	85
75	133	718	217	944	85	150	312	1,650	450	2,100	85
100	166	873	271	1,201	85	225	396	1,998	647	3,172	85
167	256	1,350	384	2,059	85	300	587	2,577	822	4,126	85
250	361	1,888	543	2,950	85	500	721	4,021	1,178	5,738	85
333	429	2,867	746	3,797	66	750	1,053	5,973	1,900	8,000	85
500	608	4,050	1,062	5,060	62	1,000	1,337	6,486	1,946	11,306	68
667	739	4,391	1,273	6,063	60	1,500	1,747	8,841	2,721	14,470	60
833	876	5,239	1,528	7,231	60	2,000	2,197	14,464	3,369	18,961	60
						2,500	2,619	15,023	4,041	21,985	60

Sources: Barnes et al. 1994, 1996; NEMA letters to P. R. Barnes, September 15, 1995, and October 28, 1996; EEI utility survey (see Barnes 1994, Appendix A); and ORNL/NEMA surveys of manufacturers in 1996.

Note: NL = no-load losses in watts; LL = full-load losses in watts.

[a]Nameplate capacity of the transformer in kilovolt-amperes.

Secondary Losses

Secondary losses follow the same concept of I^2R losses. Since this is just an approximation, model will generalize secondary lengths according to what type of feeder is the customers are on. On average, customers on rural feeders will have longer secondary lines than those in urban areas. 120 volt service and #2 ACSR Triplex secondary is assumed for all loads. These are approximations are in the interest representing the average secondary, as there is no readily accessible way to determine this information for each individual customer.

VARIABLES:

$D_{Cust} = Demand\ from\ customer\ (kW)$

$V_{Sec} = Secondary\ Voltage$

$I_C = Current\ in\ customer\ secondary$

$R_{sec} = Resistance\ of\ secondaryin\ \Omega/mile$

$L_{sec} = Length\ of\ secondary\ (miles)$

SECONDARY LOSS CALCULATION

$$|I_c| = \frac{D_{Cust}}{V_{Sec}} \qquad (Eq. 9)$$

$$P_{Sec\_loss(per\ cust)} = |I_C^2| R_{sec} L_{Sec} \qquad (Eq. 10)$$

Verification

In all stages of this project, the feeder loss calculations need to be verified for reasonable accuracy. The biggest issue that needs to be addressed is what criteria should be used to evaluate the calculated load losses.

Minnesota Power has telemetered data that provide values for how much power has been metered by customers on the feeder, and how much power has been sourced by the feeder.

$$P_{loss} = P_{Source} - P_{Metered}$$

Assuming the points that have been metered are accurate, and all loads are being metered, the losses in the feeder should approximate the difference between supplied power and billed customer load. It is likely that all loads have not been metered, which means that the observed load loss from the meters is actually higher than it should be. Therefore, the models should reflect losses close to, but not more than metered losses.

$$P_{loss} \leq P_{Source} - P_{Metered}$$

This verification method was applied to all of the sample feeders that were fully modeled. Each feeder passed the scrutiny of reasonable verification. Furthermore, the calculated losses were approximately equivalent to other searchable distribution loss studies from the industry. This provides high confidence that the model being used is valid.

Loss Generalization

Using the losses from the sample base, the remaining feeder losses may be estimated by comparing some key feeder metrics to the fully modeled feeders. These metrics include:

1. Feeder Type
2. Number of Customers

3. Line Length
4. Total Load
5. Nominal Voltage

Feeders with similar characteristics as the known models will have similar loss profiles. Feeders with different metrics can expect to have a different loss estimate. For example a feeder with a similar Feeder Type, Customers, Line Length, and Total load but a lower nominal voltage than a known feeder, will have higher losses associated.

By grouping the feeders by type and comparing to known feeder of that type, and scaling by the nominal voltage, the system losses can be reasonably predicted based on the number of services, line length, and total demand on a feeder.

Detailed Results

Total Distribution System Power Loss: **6.39 percent**

The following is a list of detailed results from the losses of all distribution feeders in the Minnesota Power electric system. The spreadsheet which details individual losses may be found in **APPENDIX E**.

Loss Data By Voltage Level

4.16 kV Feeders:

percentLoss:	8.53 percent
percentContribution to Total Load:	10.91 percent
percentContribution to Total Loss:	14.56 percent

12.47 kV Feeders:

percentLoss:	6.93 percent
percentContribution to Total Load:	28.94 percent
percentContribution to Total Loss:	31.36 percent

13.8 kV Feeders:

percentLoss:	6.05 percent
percentContribution to Total Load:	45.44 percent
percentContribution to Total Loss:	6.18 percent

23 kV Feeders:

percentLoss:	4.92 percent
percentContribution to Total Load:	4.24 percent
percentContribution to Total Loss:	6.18 percent

34.5 kV Feeders:

percentLoss:	4.06 percent

percentContribution to Total Load: 10.46 percent
percentContribution to Total Loss: 6.64 percent

SUB-TRANSMISSION LOSSES:
(23-46 kV lines that fall under distribution but are not serving load: Line Losses Only)
percentContribution to Total Loss: 1.13 percent

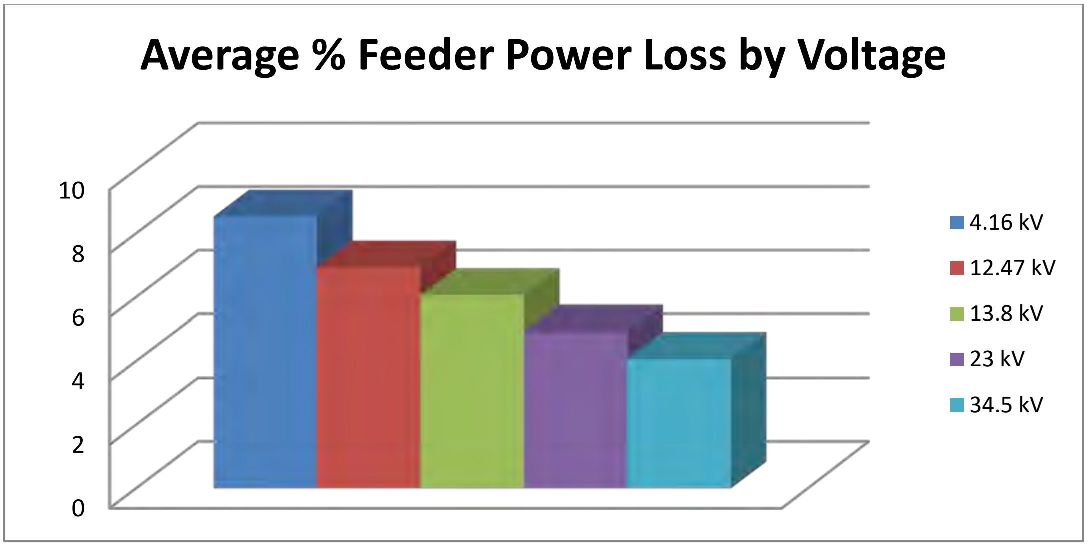


CHART 1: AVERAGE FEEDER POWER LOSSES BY VOLTAGE

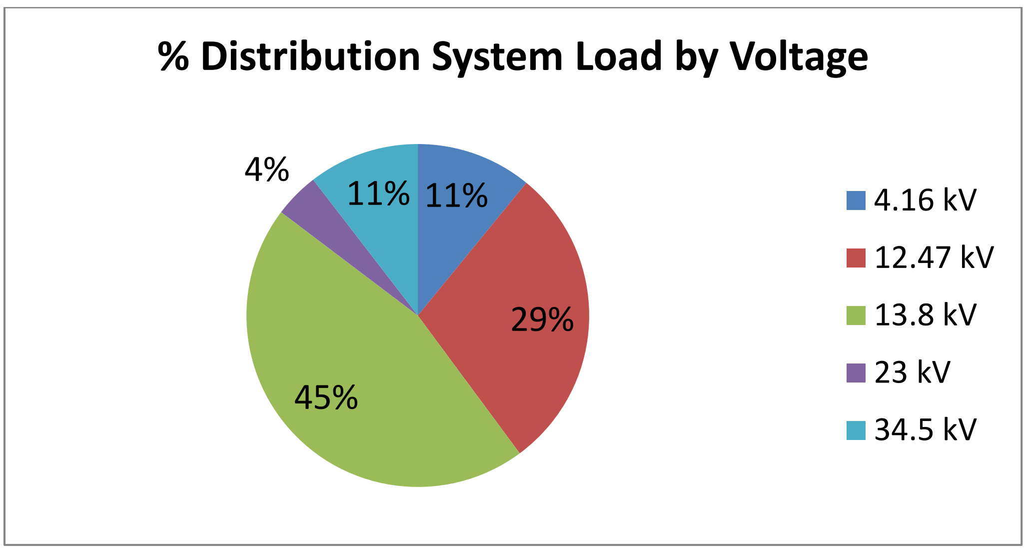


CHART 2: DISTRIBUTION SYSTEM LOAD BY VOLTAGE

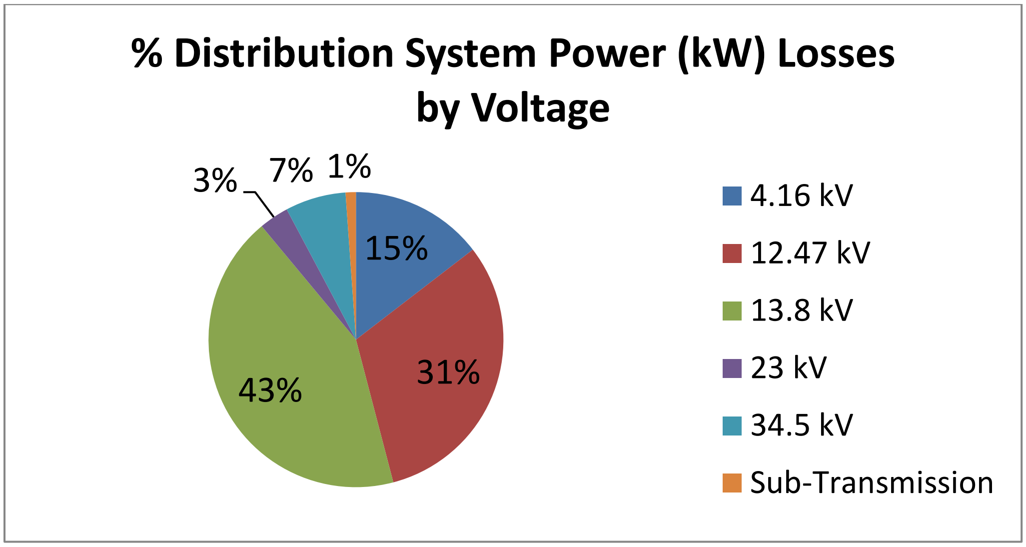


CHART 3: DISTRIBUTION SYSTEM POWER LOSSES BY VOLTAGE

<u>Total Distribution Energy (kWh) System Loss</u>: **5.75 percent**

The following is a list of detailed results from the energy (kWh) losses of all distribution feeders in the Minnesota Power electric system. The energy loss was estimated utilizing the Load Factor method. A loss factor was estimated using system load factor. Just as load factor adjusts the maximum demand (kW) on a system to an annualized energy (kWh), a loss factor changes a peak power (kW) loss on a system to an annualized energy (kWh) loss. The loss factor only applies to the load dependent power loss. As a result, the no-load losses (e.g. transformer core losses) are removed from the peak loss prior to applying the loss factor. Once the loss factor has been applied, the no-load losses are added back into the loss to calculate the total energy loss. For more information, refer to “Loss Estimation: A Load Factor Method” as referenced.

<u>Energy (kWh) Loss Data By Voltage Level</u>

4.16 kV Feeders:

percentLoss:	7.23 percent
percentContribution to Total Load:	10.91 percent
percentContribution to Total Loss:	6.18 percent

12.47 kV Feeders:

percentLoss:	6.12 percent
percentContribution to Total Load:	28.94 percent
percentContribution to Total Loss:	30.83 percent

13.8 kV Feeders:

percentLoss:	5.52 percent
percentContribution to Total Load:	45.44 percent
percentContribution to Total Loss:	43.03 percent

23 kV Feeders:

percentLoss:	4.92 percent
percentContribution to Total Load:	4.24 percent
percentContribution to Total Loss:	3.26 percent

34.5 kV Feeders:

percentLoss:	4.06 percent
percentContribution to Total Load:	10.46 percent
percentContribution to Total Loss:	6.64 percent

SUB-TRANSMISSION LOSSES:
(23-46 kV lines that fall under distribution but are not serving load: Line Losses Only)
percentContribution to Total Loss: 0.78 percent

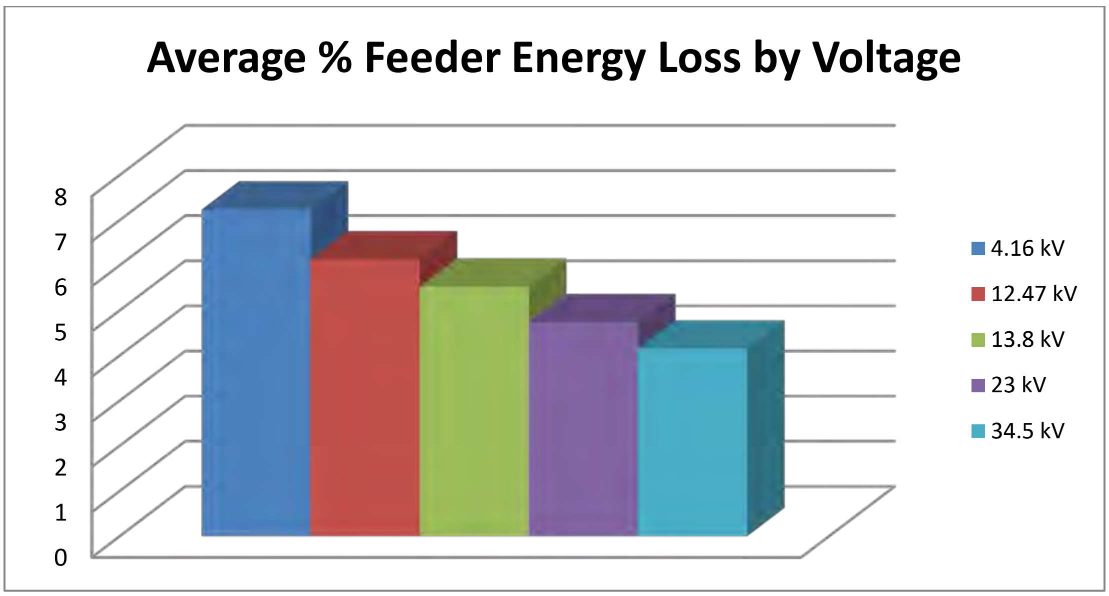


CHART 4: AVERAGE FEEDER ENERGY LOSSES BY VOLTAGE

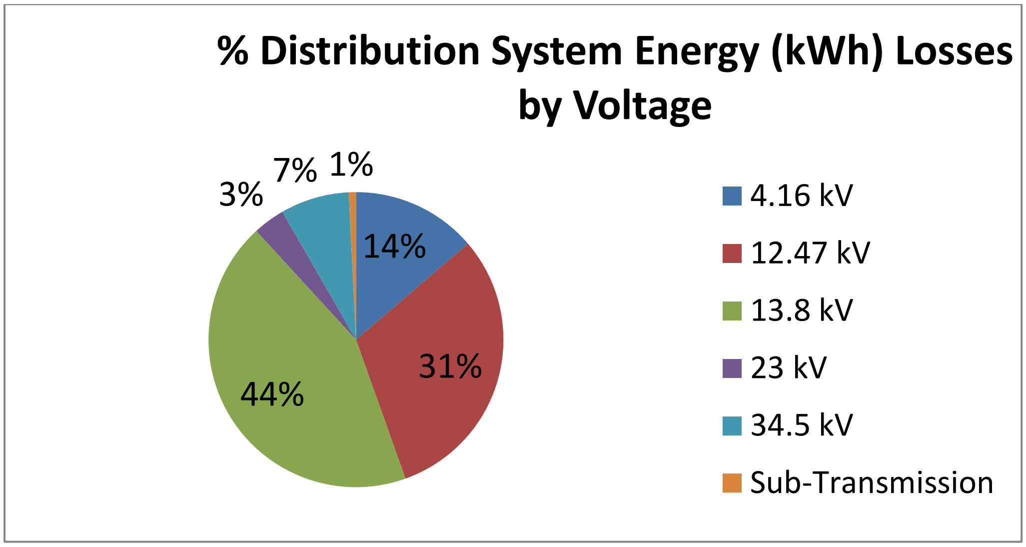


CHART 5: DISTRIBUTION SYSTEM ENERGY LOSSES BY VOLTAGE

Power (kW) Loss Data By Feeder Type

An unexpected result from this study shows that feeders running through rural areas actually have less percent losses than the feeders running through the more population dense areas. This can be attributed to the fact that rural feeders are mostly operating at voltage levels 12.47 kV or higher, and many of the urban loads from towns and cities in the Northern area are still on 4.16 kV.

Industrial Feeders :

percentLoss:	4.44 percent
percentContribution to Total Load:	9.23 percent
percentContribution to Total Loss:	6.42 percent

Rural Feeders :

percentLoss:	6.32 percent
percentContribution to Total Load:	22.01 percent
percentContribution to Total Loss:	21.85 percent

Suburban Feeders -

percentLoss:	6.16 percent
percentContribution to Total Load:	42.03 percent
percentContribution to Total Loss:	40.51 percent

Urban Feeders :

percentLoss:	7.22 percent
percentContribution to Total Load:	26.63 percent
percentContribution to Total Loss:	30.09 percent

SUB-TRANSMISSION LOSSES:

(23-46 kV lines that fall under distribution but are not serving load: Line Losses Only)

percentContribution to Total Loss: 1.13 percent

APPENDIX E

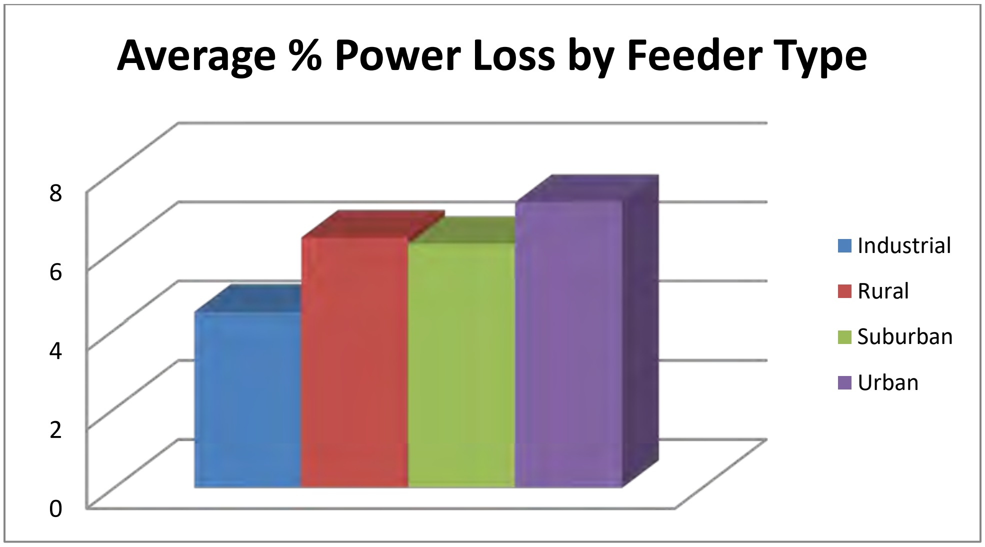


CHART 6: DISTRIBUTION SYSTEM POWER LOSS BY FEEDER TYPE

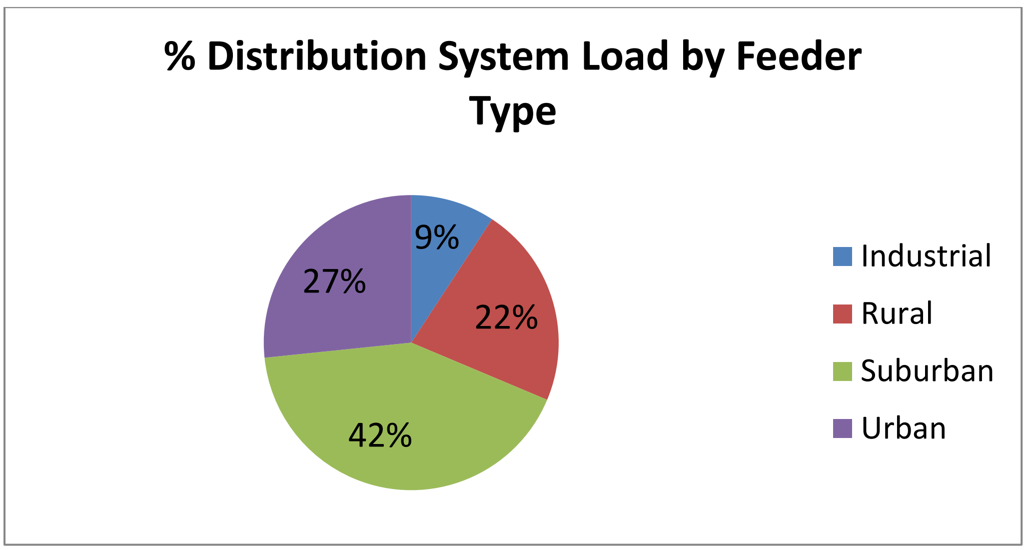


CHART 7: DISTRIBUTION SYSTEM LOAD BY FEEDER TYPE

APPENDIX E

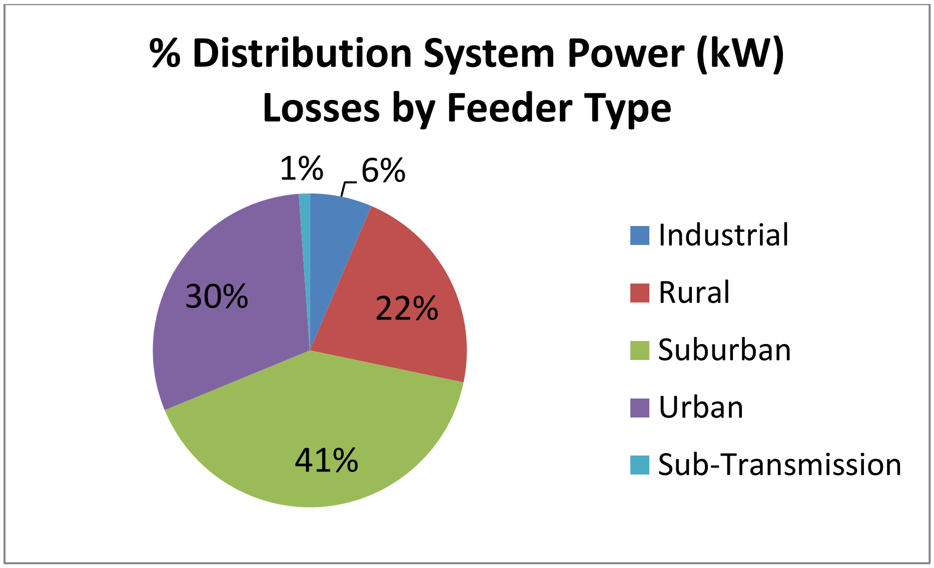


CHART 8: DISTRIBUTION SYSTEM POWER LOSS BY FEEDER TYPE

<u>Energy (kWh) Loss Data By Feeder Type</u>

Industrial Feeders :

percentLoss:	4.41 percent
percentContribution to Total Load:	9.23 percent
percentContribution to Total Loss:	7.08 percent

Rural Feeders :

percentLoss:	5.71 percent
percentContribution to Total Load:	22.01 percent
percentContribution to Total Loss:	21.93 percent

Suburban Feeders -

percentLoss:	5.59 percent
percentContribution to Total Load:	42.03 percent
percentContribution to Total Loss:	40.90 percent

Urban Feeders :

percentLoss:	6.33 percent
percentContribution to Total Load:	26.63 percent
percentContribution to Total Loss:	29.31 percent

SUB-TRANSMISSION LOSSES:

(23-46 kV lines that fall under distribution but are not serving load: Line Losses Only)

percentContribution to Total Loss: 0.78 percent

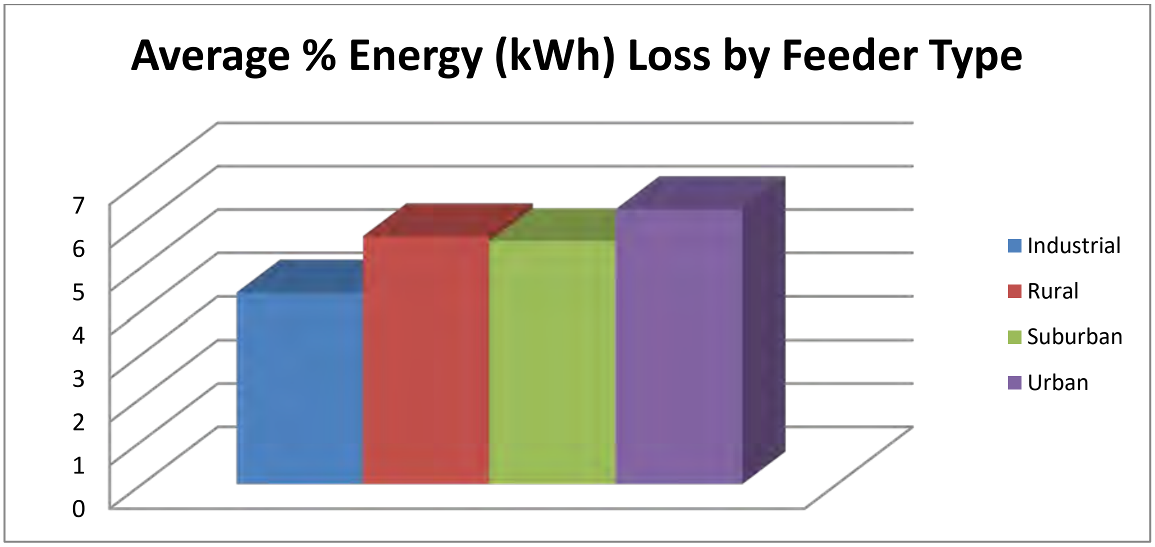


CHART 9: DISTRIBUTION SYSTEM ENERGY LOSS BY FEEDER TYPE

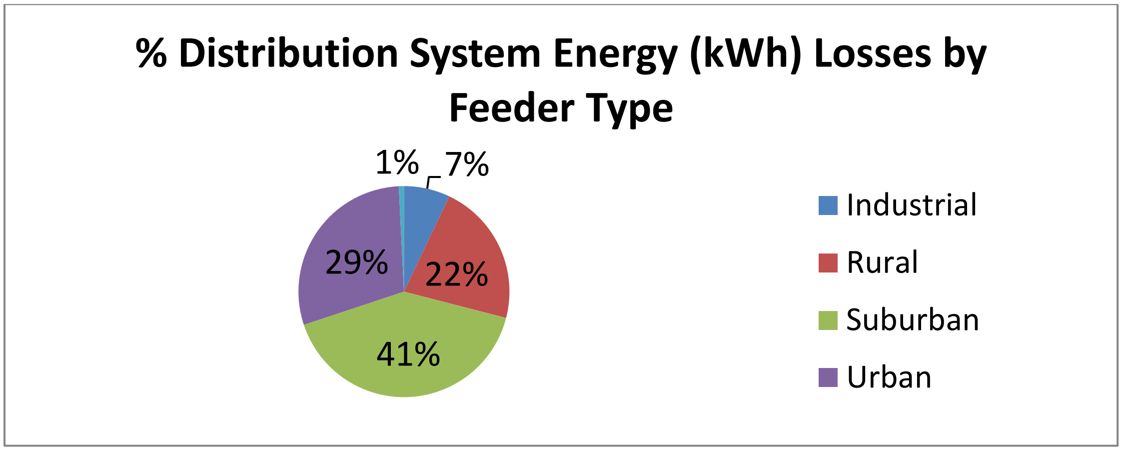


CHART 10: DISTRIBUTION SYSTEM ENERGY LOSS BY FEEDER TYPE

Conclusions

The study shows approximately 6 percent of the power and energy loss over Minnesota Power's electric distribution system. The results of the data are very reasonable and follow sound logic in modeling methods and calculations. The loss results are indicative of the state of the system and help to point out specific areas that could be investigated to reduce future losses.

Future Applications

Efforts put forth in this system loss study may be of assistance for future applications or projects. For example, the tool being developed to automatically sort and organize a feeder will be compatible with the System Phasing project. Besides the stated purpose, other potential uses for this project include:

- Methods for calculating losses on any feeder

- Sanity check for Distribution Modeling Software (MilSoft)
- Feeder Balancing
- Locations for future monitoring devices – (At feeder branch heads)
- Voltage Support Study

In addition to this short list, there could be many other benefits from reusing the data and tools from this loss study.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	)ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

SUSAN ROMANS of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **1st** day of **November, 2019**, she served Minnesota Power's 2019 Integration Distribution Plan in **Docket No. E015/CI-18-254** on the Minnesota Public Utilities Commission and the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

Susan Romans

Susan Romans