Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2018

—Via Electronic Filing—

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

RE: INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/CI-18-251

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Integrated Distribution Plan (IDP) per the Commission's August 30, 2018 Order in the above-referenced docket.

As discussed in the IDP, we held stakeholder workshops to discuss the components of this report. We also heard interest in having additional meetings after this report is filed – and before initial comments are due – to discuss the report, and answer questions once parties have had a chance to review. If the Commission agrees these stakeholder discussions could provide value, extending the comment period to approximately February would allow for these meetings to occur.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Jody Londo at jody.l.londo@xcelenergy.com or (612) 330-5601 or me at bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service List

INTEGRATED DISTRIBUTION PLAN (2019-2028)

ADVANCING THE GRID AT THE SPEED OF VALUE

NOVEMBER 1, 2018

Docket No. E002/CI-18-251

EXECUTIVE SUMMARY

On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an Integrated Distribution Plan (IDP) annually beginning on November 1, 2018. We have prepared and are submitting an IDP that includes our planned distribution investments and the other information required in the Commission's August 30, 2018 Order. We discuss the planning landscape and summarize the contents of the Company's IDP below.

The IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value and that the fundamentals of our distribution business remain sound.

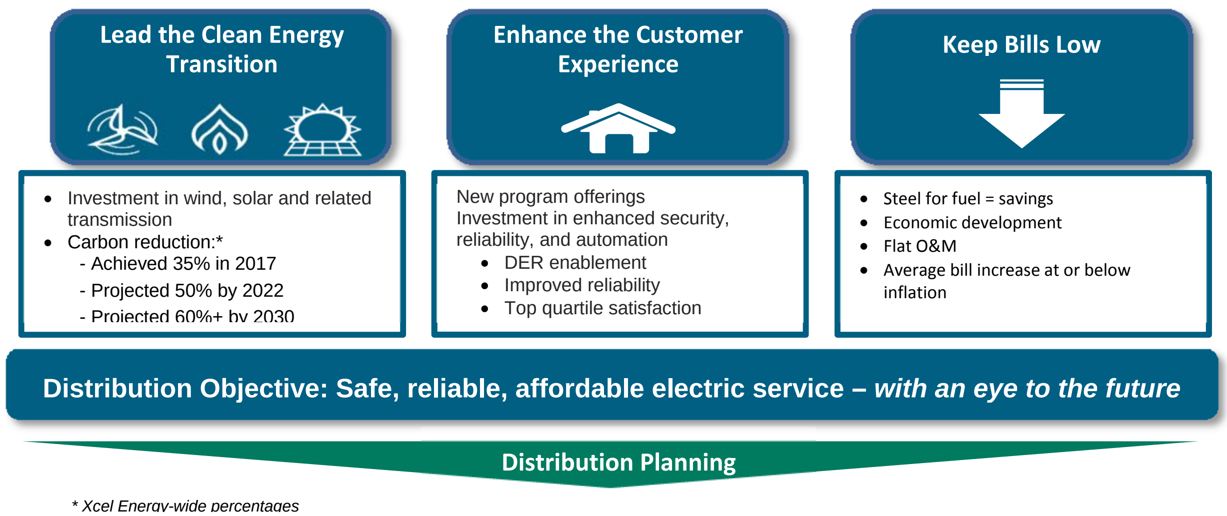
I. Planning Landscape

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 1: Xcel Energy Strategic Priorities – Applied to Distribution



Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

Now, instead of planning just for load, utilities will need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business will require utilities to plan their systems differently, which will involve not only new processes and methodologies but also new and different tools and capabilities.

Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning and, as such, are taking steps to align and integrate our distribution, transmission, and resource planning processes. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

And, although increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like Integrated Resource Planning (IRP), charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP.

Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is today to address the challenges – and harness the benefits – of DER.

II. Xcel Energy IDP Summary and Highlights

With this background, we note that Minnesota is unique from other states implementing IDP in that we are not currently undergoing sizable additions of DER on our system. Rather, Minnesota is ahead in its planning and therefore able to take a measured approach and pace to IDP that allows the requirements to be implemented in a cost-effective, systematic manner that is in the public interest for all Minnesota customers.

It is in this context that we prepared our first IDP – and the first IDP in the state of Minnesota. In advance of this IDP filing, we conducted two stakeholder workshops to – in addition to complying with IDP requirements – educate and build a better understanding of both our work and stakeholders' needs. Our goal for the workshops was to begin an iterative and ongoing dialogue to build a mutual understanding of our processes and the IDP, both for this initial report as well as future reports.

We have worked hard to meet all of the IDP requirements and believe we have done so. Our IDP recognizes the emergent state of the industry and availability of enhanced distribution planning tools, Minnesota's specific circumstances, and the building-block approach we are taking to modernize and equip our system to increase our visibility, control, and planning capabilities. We believe this report is robust and meaningful and provides substantial transparency into our distribution function and planning.

Our report provides historical actual and budgeted expenditures, discusses many of our planning practices, charts our advanced grid roadmap, and establishes present and forecasted levels of DER. In the limited circumstances where we were not able to meet a requirement due to the compressed timeframe of this IDP, or where we did not have the systems or tools to produce the information, we have fully explained the reasons. From this foundation, our capabilities will mature. We believe this measured approach appropriately recognizes the present nascent circumstances in Minnesota and the compressed procedural timeline for this first report.

To highlight some of the key aspects of our report, we summarize below our advanced grid plans, capital investment and O&M budgets, and the current state and forecasts for DER on our system.

A. Advanced Grid Initiative

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative to address them. In addition to the significant steps we have taken to implement and improve our hosting capacity analysis, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide the visibility and control necessary for enhanced planning and significant DER integration. We are also implementing a Time of Use (TOU) pilot which implements new residential TOU rates, and the installation of AMI meters, in two communities in the Twin Cities metropolitan area, providing select customers with pricing specific to the time of day energy is consumed. This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.

We also are poised to propose further foundational advanced grid capabilities, including a full Advanced Metering Infrastructure (AMI) implementation, a secure and robust Field Area Network (FAN), and significant reliability improvements for customers through Fault Location, Isolation, and Service Restoration (FLISR).

In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. As an example, FLISR and ADMS will reconfigure the grid to reduce the numbers of customers affected by an outage and provide better information to outage restoration crews to speed up their response or avoid those outages in the first place. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

We recognize however, that a corresponding customer strategy is essential to fully leverage the value of these investments. At this time, we are still determining the details of this strategy, and a variety of investment decision points that we expect may impact both cost and implementation timeline. Therefore, we are not yet seeking certification of these three investments in conjunction with this IDP. Rather, we provide a detailed discussion of our current internal plans, budgets, and considerations in the interest of transparency into our advanced grid initiative and grid modernization strategy.

We envision that our customer strategy will leverage the more refined customer usage data captured by AMI meters and communicated to utility systems through the FAN to enable new rate, billing, and program options that allow customers to adjust their usage to save money or participate in cost saving programs, using their devices. AMI and FAN also will improve our existing customer portal (MyAccount) information to provide more personalized insights to help customers understand how and where energy is being used and provide ways to help them save money.

Additionally and fundamentally, we must replace our present Automated Meter Reading (AMR) system – and now is an opportune time to do so. Our present AMR system has delivered substantial value for customers since it was implemented in the mid-1990s. Our vendor has announced that the technology will no longer be supported after the early-2020s – and they plan to discontinue support for AMR technology entirely in the mid-2020s. At the same time, the AMI technology and market have matured, which has driven many other vendors to also discontinue support of AMR. According to the U.S. Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollouts have flattened. Our present AMI plan for Minnesota is to complete the implementation no later than the end of 2023, well before the end of our present service agreement.

As vendors are phasing out AMR, many of the alternatives to AMI are antiquated, manual-read systems that will not move the Company forward in terms of advancing the grid. It is, therefore, an opportune time to replace the legacy AMR system with AMI. In addition to the enhanced capabilities and new offerings described above, AMI will deliver quantifiable savings or benefits for capital, O&M, and other areas. The capital savings include distribution system management, outage management efficiency, and avoided capacity infrastructure. The O&M savings relate to meter reading costs, field and meter-service costs, improvements in customer care, and distribution management and outage management savings. Additionally, we anticipate savings related to reduced customer outages, revenue protection, reduced consumption on inactive premises, reduced uncollectible and bad debt expense above and beyond what we can achieve with AMR today.

We expect three primary outcomes from our deployment of advanced grid infrastructure and advanced technologies: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities.

Transformed customer experience. Advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will utilize this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. These options will provide customers greater convenience and control to save money, access to rates and billing options that suit their budgets and lifestyles, and more personalized and actionable communications. We expect our early initiatives will focus on the execution of services that benefit all customers. Other customer choice programs enabled or enhanced by advanced grid initiatives may include smart thermostats, home area networks, rooftop solar, community solar gardens, optimized EV charging, and other DER offerings.

Improved core operations and capabilities. We also will improve our core operations, making investments to more efficiently and effectively deliver the safe and reliable electricity that our customers expect. While we have historically provided reliable service, we need to continue to invest in new technologies to maintain our performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources, and as industry standards continue to improve.[1] Our advanced grid investments provide technologies to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics, and automation. This will benefit customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

[1] See Leading the Energy Future 2017 Corporate Responsibility Report, Page 85, Xcel Energy (May 2018).

Facilitation of future capabilities. Designing for interoperability enables a cost-effective approach to technology investments and means we are able to extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks (such as the Department of Energy's Next Generation Distribution Platform (DSPx) framework).[2] It also allows us to sequence the investments to yield the greatest near- and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

Adherence to industry standards also allows us to better secure the grid and the devices we have connected to it. The increasing number of interfaces associated with grid modernization increases our cybersecurity exposure. As we move forward into the next generation of intelligent, interactive electric distribution, every facet of the electric network must be evaluated for cybersecurity risk. All aspects of the advanced grid must be inventoried, securely configured, and monitored regularly and thoroughly.

These investments also will produce a wealth of customer and grid data, which will, in turn, enable us to provide the new services described here and enhance existing services. These data-related efforts have begun, and next steps will include identifying the analytics capabilities needed to add additional value to customer offerings or improve utility operations. Data analytics in the utility industry continues to mature, so as grid modernization investments are deployed, these capabilities will evolve as well.

As noted above, we are not seeking certification of any advanced grid investments under Minn. Stat. § 216B.2425 at this time because we are still determining the details of our customer strategy, which will impact a variety of investment decision points. Rather, the advanced grid information we provide in this IDP is a discussion of our current internal plans, budgets, and considerations in the interest of transparency into our advanced grid initiative and grid-modernization strategy. All costs and other representations, such as the range of expected benefits from AMI contained herein, are intended to be directional and used as a point of context subject to change as we

[2] See Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

continue to refine our strategy and investment plans. We will bring the costs and benefits associated with these projects to the Commission for approval through a future certification request in the grid modernization/IDP filings or through a general rate case.

B. Five-Year Budgets – Capital and O&M Expenditures

Distribution budgets are evolving based on the future of electric distribution and customers' increasing expectations for control, options, and ease of doing business. Additionally, our capital investment plans generally reflect our advanced grid initiative, as we have discussed it above. Historically, however, the overwhelming majority of our distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

The distribution budget process prioritizes projects based on the Company's goal of providing our customers with smart, cost-effective solutions, recognizing that customers want reliable and uninterrupted power.

Although the immediacy of customer safety and reliability is a reality and our primary focus, in addition to these core activities, our investment plan now reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. We also are planning for investments in enhanced distribution planning tools. These tools will equip our system planners with enhanced capabilities to consider DER adoption scenarios and non-wires alternatives (NWA) in the analyses we perform to ascertain the best way to meet system capacity needs.

Table 1 below provides an overview of our 5-year capital budget in the IDP categories.

Table 1: Distribution Capital Expenditures Budget – State of Minnesota Electric Jurisdiction

Expenditure Category	Bridge 2018	Budget 2019	2020	2021	2022	2023	Budget Avg 2019-2023
Age-Related Replacements and Asset Renewal	$67.2	$57.9	$60.1	$64.5	$73.0	$66.7	$64.4
New Customer Projects and New Revenue	$37.4	$25.4	$28.2	$26.9	$27.6	$28.4	$27.3
System Expansion or Upgrades for Capacity	$17.4	$14.5	$35.0	$40.2	$33.7	$35.4	$31.8
Projects related to Local (or other) Government-Requirements	$17.9	$50.2	$45.0	$36.1	$32.7	$32.7	$39.3
System Expansion or Upgrades for Reliability and Power Quality	$27.1	$21.4	$27.4	$113.4	$116.4	$68.4	$69.4
Other	$36.5	$28.3	$33.4	$41.0	$42.1	$30.9	$35.1
Metering	$5.9	$5.9	$5.1	$3.9	$3.5	$3.1	$4.3
Non-Investment/CIAC	($12.0)	($3.6)	($3.7)	($3.7)	($3.8)	($3.8)	($3.7)
TOTAL	$197.4	$200.0	$230.3	$322.3	$325.1	$261.8	$267.9

Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Other includes Fleet, Tools, Communication Equipment, Locating and Transformer Purchases; Reliability includes placeholder investments for a new reliability program (Incremental Customer Investment); and Non-investment/CIAC includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections.

In terms of grid modernization, our current projected capital costs for implementation of AMI and FAN are expected to be in the range of $450 to $600 million. However, final costs will depend on the final customer and data management strategy and related investment decision points, which are currently pending. We have previously presented estimated capital costs for FLISR (approximately $66 million), the certified Time of Use rate pilot (approximately $10 million), and the certified ADMS (approximately $69.1 million).[3] Note that the TOU pilot and FLISR are enabled by ADMS and the FAN infrastructure, as will ultimately other advanced grid initiatives.

We are also considering a program for undergrounding existing overhead facilities within public rights-of-way. The program would be in partnership with local jurisdictions and would give them control for undergrounding facilities as they deem necessary for improved reliability, resiliency, and aesthetics.

In terms of O&M, large planned projects and programs to support our ongoing provision of regulated utility service are budgeted by function, and are key drivers of the O&M budgets. Programs include operational activities such as: *Vegetation Management,* which includes the work required to ensure that proper line clearances are

[3] For the TOU Pilot and FLISR, *see* Xcel Energy Grid Modernization Report pages 23 and 34 respectively, Docket No. E002/M-17-776 (November 1, 2017). For ADMS, *see* Xcel Energy TCR Petition Attachment 1A page 19, Docket No. E002/M-17-797 (November 8, 2017).

maintained, maintain distribution pole right-of-way, and address vegetation-caused outages; *Fleet and Tools Management* represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system. The O&M component includes annual fuel costs plus an allocation of fleet support. The *Damage Prevention* category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents.

Table 2 below provides a snapshot of our 2019-2023 O&M distribution budget by Cost Element.

Table 2: Distribution O&M Expenditures Budget – NSPM Electric Jurisdiction

Expenditure Category	Bridge 2018	Budget 2019	2020	2021	2022	2023	Budget Avg 2019-2023
Labor	$43.0	$42.5	$42.1	$42.7	$43.5	$43.9	$42.9
Labor (overtime/other)	$10.8	$10.8	$10.8	$10.8	$10.8	$10.9	$10.8
Cont. Outside Vendor/Contract Labor	$14.5	$13.8	$14.7	$14.8	$16.1	$16.6	$15.2
Damage Prevention Locates	$6.2	$6.2	$6.2	$6.2	$6.2	$6.2	$6.2
Vegetation Management	$31.5	$32.4	$32.5	$32.3	$32.3	$32.3	$32.4
Employee Expenses	$3.0	$2.7	$2.7	$2.6	$2.6	$2.7	$2.7
Materials	$8.2	$8.5	$8.4	$8.2	$8.2	$8.3	$8.3
Transportation Costs	$8.1	$8.3	$8.2	$8.0	$8.0	$8.1	$8.1
First Set Credits	($7.9)	($8.0)	($8.1)	($8.1)	($8.1)	($8.2)	($8.1)
Misc. Other	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
TOTAL	**$119.4**	**$119.3**	**$119.5**	**$119.7**	**$121.7**	**$123.0**	**$120.6**

Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

In terms of grid modernization, our current projected O&M costs for implementation of AMI and FAN are expected to be in the range of $110 to $150 million. However, final costs will depend on the final customer and data management strategy and related investment decision points, which are currently pending. We have previously presented estimated O&M costs for FLISR (approximately $6 million), the certified Time of Use rate pilot (approximately $3.5 million), and the certified ADMS (approximately $13.4 million).[4] Note that the TOU pilot and FLISR are enabled by

[4] For the TOU Pilot and FLISR, *see* Xcel Energy Grid Modernization Report pages 23 and 34 respectively, Docket No. E002/M-17-776 (November 1, 2017). For ADMS, *see* Xcel Energy TCR Petition Attachment 1A page 23, Docket No. E002/M-17-797 (November 8, 2017).

ADMS and the FAN infrastructure, as will ultimately other advanced grid initiatives.

Finally, we clarify that in the IDP context, while our budget process has generally proven to be an accurate gauge of overall budget levels, it is important to understand that plan details – exclusive of large and strategic investments approved for implementation by the Commission, when needed, and our internal governance process, will be inconsistent year-to-year. As we have explained, the Distribution budget is an ongoing and iterative process that is largely driven by the immediacy of reliability and other emergent circumstances that are the practical reality of the distribution business. The distribution system is the connection to our customers, and we must respond to these circumstances to meet our obligation to serve and ensure we provide adequate service. This means that long-term plans, which, in a distribution context, include five-year action plans, have a much shorter shelf-life.

C. Existing and Forecasted DER

For purposes of IDP in Minnesota, DER is defined as supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers, whether it is installed on the customer or utility side of the electric meter. The definition further clarifies that for IDP, DER may include, but is not limited to distributed generation, energy storage, electric vehicle, demand side management, and energy efficiency resources.

Xcel Energy has one of the longest-running and most successful Demand Side Management (DSM) programs in the country. Between 2005 and 2017, we spent over $1 billion (nominal) on our Minnesota energy efficiency efforts, and saved more than 5,560 GWh of annual energy and 1,012 MW of demand. Our annual DSM achievements have often outpaced Minnesota's 1.5 percent of sales goal. Our Upper Midwest Demand Response programs have 889 MW of registered, controllable customer load under contract, which is one of the largest portfolios of DR in the Midcontinent Independent System Operator (MISO) footprint – and we are on track to add an additional 400 MW to our portfolio by 2023.

We have the largest community solar gardens program in the country, with 445 MW from 134 projects online. We anticipate this growing to 500 MW or more by the end of 2018. Finally, we recently announced a proposal to build on our clean energy leadership by investing more than $25 million to increase access to electric vehicles (EV) and help drivers and fleet operators start driving electric. Our proposal includes a range of innovative programs that expand upon our vision for supporting the growth of EVs that will benefit drivers, customers, the environment, and the state.

Customer adoption of other DER in our Minnesota service area is otherwise relatively nascent. As of September 2018 there were approximately 44 MW of non-CSG distributed solar, 12 MW of distributed wind systems installed, and six distributed storage projects interconnected to our system. Table 3 below summarizes distribution-interconnected DER and how much is in the interconnection queue.

Table 3: Distribution-Connected Distributed Energy Resources – State of Minnesota
(as of September 2018)[5]

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Solar PV				
Rooftop Solar	44	3,696	23	934
Community Solar[6]	445	145	372	275
RDF Projects	13	30	3	12
Grid Scale (Aurora)	103	19	0	0
Wind	12	60	<1	7
Storage/Batteries[7]	N/A	6	N/A	34
Energy Efficiency	1,012	N/A	N/A	N/A
Demand Response	658	668,314	N/A	N/A
Electric Vehicles	N/A	5,693[8]	N/A	N/A

Note: Energy Efficiency and Demand Response are portrayed in Gen MW; Energy efficiency is cumulative since 2005.

At a system level, tools and methodologies to forecast DER adoption are similarly nascent in the industry. These forecasts rely on predicting customer behavior based on macro-economic factors, understanding potential based on topography and weather, and incorporating policy- and rate-based incentives or disincentives.

The IDP requirements that are emerging in various states often require some form of DER analysis and forecasting – and incorporation of the results into distribution planning analyses. Traditional distribution planning involves forecasting loads for

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[5] Energy Efficiency and Demand Response are as of December 31, 2017.
[6] Community Solar Gardens are limited to 1 MW applications. However, prior to September 25, 2015, garden operators were allowed to submit applications to co-locate up to 5 MW per site. Projects in this table are by site, not application.
[7] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.
[8] We do not have information that ties our customer accounts to electric vehicle users. *Source*: Xcel Energy Compliance Filing, IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON RESIDENTIAL ELECTRIC VEHICLE (EV) CHARGING TARIFF, Attachment A at page 1, Docket No. E002/M-15-111 (June 1, 2018).

each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecast by type because each type of DER has different characteristics and differing impacts on the grid. Forecasting DER penetration at a granular *feeder* level for purposes of informing distribution planning is exponentially more complex than doing so at a *system* level. We are unsure about the level of accuracy provided by any tools in such a nascent market and how refined we can get geographically without losing accuracy.

Industry tools and methodologies to incorporate DER into annual distribution plans and planning processes are emergent and immature. Nationally, regulators, utilities, stakeholders, service providers, and others are working to determine methodologies, processes, and tools that will meet the forecasting needs that are emerging in states such as California, New York, and Hawaii. To provide perspective, in New York, the Reforming the Energy Vision (REV) effort has been underway since 2014. As early as 2015, the five investor-owned utilities (collectively known as the Joint Utilities of New York) noted the challenges associated with DER forecasting. In their initial and reply comments to the guidance for their Distribution System Implementation Plans (DSIPs – similar in content requirements to the Minnesota IDP), the Joint Utilities noted:

- "The proposed DSIP Guidance reflects the inherent tension between providing as much information as possible as soon as possible to inform DER locational value and the fact that the models and data necessary to support increased DER penetration do not yet exist."[9]
- The "enhancements necessary to produce valid demand and DER forecasts are likely to evolve over several years."[10]

In its latest DSIP, Consolidated Edison noted, "Con Edison is refining its forecasting methodologies to include DER at more granular levels, using a combination of top-down and bottom-up forecasting"[11] There is currently no detail on how granular these forecasts will get or a timeline for when the more granular level forecasts will be incorporated into the load forecasts.

And while we used our present tools and methodologies to inform overall system DER forecasts in this IDP, we will need enhanced planning tools to understand the locational and temporal impacts of DER. Toward that end, we are evaluating one of

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[9] *See* Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case 14-M-0101, Page 8, Initial Comments of the Joint Utilities on the October 2015 Staff Proposal: Distributed System Implementation Plan Guidance (December 2015).
[10] Ibid, page 18.
[11] Consolidated Edison New York, Distributed System Implementation Plan, page 56, (July 2018).

the early software tools for potential purchase. The good news from a distribution planning perspective is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. Further, our present tariffs require interconnecting parties to mitigate adverse impacts identified in the interconnection application process. For this IDP requirement particularly, it will be essential for the Commission to consider the state of the industry. Minnesota is unique from other states implementing IDP in that we are not currently experiencing sizable additions of DER on our system. Rather, Minnesota is ahead in its planning and therefore able to take a measured approach and pace to IDP that allows the requirements to be implemented in a cost-effective, systematic manner that is in the public interest for all Minnesota customers.

III. Action Plan Summary

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, and FLISR, and securing enhanced system planning tools to advance our abilities to incorporate DER and NWA analysis into our planning. We will continue to finalize the details of our customer strategy and related advanced grid investment plan – and in 2019, we will bring the costs and benefits to the Commission for approval through a future certification request in the grid modernization/IDP filings or through a general rate case. Pending Commission action, we will implement our advanced grid plan.

TABLE OF CONTENTS

ATTACHMENTS

Number	Name
A	Compliance Matrix
B	Planned Capital Projects
C	Capital Profile Trend
D	O&M Profile Trend
E	Plymouth and Medina Electrical System Assessment
F	Action Plan Roadmap
G	Load Growth Assumptions for Smaller Portions of the NSPM Geography in Minnesota
H	Net Present Value Calculation of the Distribution Function

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
BTM	Behind the Meter
BYOD	Bring your Own Device
CAIDI	Customer Average Interruption Duration Index
CIP	Conservation Improvement Program
CPE	Customer Premise Equipment
CPUC	California Public Utilities Commission
CRS	Customer Resource System
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DG-PV	Photovoltaic Distributed Generation
DOE	Department of Energy
DR	Demand Response
DRIVE	Distribution Resource Integration and Value Estimation
DRMS	Demand Response Management System
DSIP	Distribution System Implementation Plan
DSM	Demand Side Management
DSPx	Next Generation Distribution System Platform
EE	Energy Efficiency
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
ETR	Estimated Time of Restoration
EV	Electric Vehicle
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FLP	Fault Location Prediction
GIS	Geographic Information System
HAN	Home Area Network
HECO	Hawaiian Electric Company
HEM	Home Energy Management
HPUC	Hawaii Public Utilities Commission
ICT	Innovative Clean Technology
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol

ISO	Independent System Operator
IT	Information Technology
IVVO	Integrated Volt VAr Optimization
LBNL	Lawrence Berkeley National Laboratory
LCR	Local Capacity Resource
LTC	Load Tap Changers
MDMS	Meter Data Management System
MISO	Midcontinent Independent System Operator
MPUC, PUC, or Commission	Minnesota Public Utilities Commission
M&V	Measurement and Verification
NIC	Network Interface Card
NIST	National Institute of Standards and Technology
MCOS	Marginal Cost of Service
MNS	Network Management System
NSPM or Company	Northern States Power Company Minnesota (exclusive of North Dakota and South Dakota)
NWA	Non-wire Alternatives
NYPSC	New York Public Service Commission
OMS	Outage Management System
PSCo	Public Service Company of Colorado
PSIP	Power Supply Improvement Plan
PTMP	Point-to-Multi-Point
PV	Photovoltaic
QoS	Quality of Service
REV	Reforming the Energy Vision
RTO	Regional Transmission Operator
R&D	Research and Design
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SEPA	Smart Electric Power Alliance
SVC	Static VAr Compensators
TOU	Time of Use
VEE	Validation, Estimation, Editing
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.

I. INTRODUCTION

On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an Integrated Distribution Plan (IDP) annually beginning on November 1, 2018. We have prepared and are submitting an IDP that includes our planned distribution investments and the other information required in the Commission's August 30, 2018 Order.

The IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The first five years of our action plan are focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including advanced metering infrastructure (AMI), a robust Field Area Network (FAN)that will facilitate communications between and among advanced distribution grid equipment and AMI meters, and significant reliability improvements for our customers through a Fault Location, Isolation, and Service Restoration (FLISR) initiative. We expect to also secure enhanced system planning tools to advance our abilities to incorporate Distributed Energy Resources (DER) and NWA analysis into our planning – and to facilitate a greater alignment and integration of our distribution-transmission-resource planning.

We are continuing to finalize the details of our customer strategy and related advanced grid investment plan – and in 2019, we intend to bring the costs and benefits to the Commission for approval through a certification request in the grid modernization/IDP filings or through a general rate case.

A. Planning Landscape

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

IDPs are an emerging industry practice that is intended to give regulators and other stakeholders a more transparent view into the planning process of the distribution grid through a standardized process. IDP first appeared in states where public policies were driving substantive changes to distribution business models and grids, including the need for utilities to integrate greater and significant levels of DER. Although DER are occurring in Minnesota, present levels and the adoption rate are lower than other states that have adopted IDP. This gives utilities and stakeholders the advantage of time and taking a measured approach to implement the tools, models, and processes that ensure the grid is prepared for a more distributed future – while also balancing the costs and other implications associated with such a future.

Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

Now, instead of planning just for load, utilities will need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business will require utilities to plan their systems differently, which will involve not only new processes and methodologies but also new and different tools and capabilities.

Over time, IDP in Minnesota is intended to facilitate scenario-based, integrated resource-transmission-distribution planning to ensure a reliable, efficient, robust grid that will flexibly meet the challenges of a changing and uncertain future. Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning and, as such, are taking steps to align and integrate our distribution, transmission, and resource planning processes. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

And, although increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, today there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs that will need to evolve over time. Distribution planning is primarily concerned with location, and resource planning is primarily concerned with size, type and timing of resources – with transmission planning somewhere in the middle. Before a greater integration of these planning processes can occur, distribution planning tools and distribution system capabilities will need to advance.

We have begun this transition. This IDP presents a detailed view of how we plan our system to meet our customers' current needs and how we intend to evolve for the future. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so. We are however, also planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

B. Background

In 2015, the Commission opened an investigatory docket on grid modernization (Docket No. E999/CI-15-556) and issued the *March 2016 Staff Report on Grid Modernization*. Of various potential options outlined in the Staff Report, the Commission supported examining distribution system planning as the most reasonable and actionable way to assist in the forthcoming grid evolution. In doing so, the Commission also supported the staff-proposed principles as its Planning Objectives to guide further work, as follows:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies,
- Enable greater customer engagement, empowerment, and options for energy services,
- Move toward the creation of efficient, cost-effective, accessible grid platforms

for new products, new services, and opportunities for adoption of new distributed technologies, and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In August 2016, the Commission received the ICF International report, *Integrated Distribution System Planning*, and in October 2016, held a workshop seeking stakeholder input and discussion on a Minnesota-based distribution system planning framework. In April 2017, the Commission issued a Notice to utilities and stakeholders seeking to understand (1) how utilities currently plan their systems, (2) the status of current-year utility plans, and (3) recommendations for improvements to present planning practices. Xcel Energy submitted comments responsive to the Notice and stakeholder comments June 21, 2017, August 21, 2017 and September 21, 2017.

In January 2018, Commission staff proposed next steps to the Commission at a planning meeting – and in April 2018, established individual utility dockets and released proposed individual utility IDP filing requirements for Commission review; requirements for Xcel Energy were developed in Docket No. E002/CI-18-251. The Commission directed Staff to meet with each utility to discuss and clarify the proposed filing requirements – and afterward, release draft utility-specific IDP filing requirements for comment in June 2018. Xcel Energy submitted its comments June 20, 2018 and reply comments on July 20, 2018. The Commission determined final IDP requirements for Xcel Energy at its August 9, 2018 Agenda Meeting, and issued its Order containing the final requirements on August 30, 2018.

Xcel Energy's first IDP is due November 1, 2018 and annually thereafter. Like development of the IDP requirements, the Order acknowledges IDP as envisioned by the planning objectives will be an iterative process – set in motion with the Company's initial IDP. In setting the requirements, the Commission acknowledged the compressed timeline between the determination of final IDP requirements and the Company's initial report – and included an option for the Company to explain any gaps in its ability to fulfill each requirement. The filing requirements also include the Company conducting a minimum of one stakeholder meeting be held in advance of its initial filing that addresses (at a minimum): (1) the load and DER forecasts, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next five years, including consistency with the Commission's Planning Objectives, and (4) any other relevant areas proposed in the IDP.

We held two stakeholder meetings – September 12, 2018 and September 26, 2018 – and considered and incorporated that stakeholder feedback as we prepared this IDP.

C. Report Outline

This report is organized as follows:

Section	Title	Content Summary
I.	Introduction	Overview of the planning landscape and genesis of IDP in Minnesota.
II.	Distribution System Plan Overview	Summary of our near- and long-term distribution system plans, including summary-level budget information and drivers.
III.	Budget Development Framework	Provides snapshot of budget history and forecast.
IV.	System Overview	Provides snapshot of system statistics.
V.	System Planning	Describes the process of analyzing the distribution system's ability to serve existing and future loads.
VI.	Non-Wires Alternatives Analysis	Discusses project types, timelines, and screening process considerations for NWA as well as related analysis.
VII.	Asset Health and Reliability Management	Describes annual capacity planning and roadmap to mature capacity planning capabilities. Outlines reliability statistics and ongoing system health assessment processes.
VIII.	Distribution Operations	Discusses operational processes, such as vegetation management and escalated operations/storm response.
IX.	Grid Modernization	Describes grid modernization strategy and short- and long-term plans.
X.	Customer and Operational Data Management	Outlines data management strategy and objectives.
XI.	Distributed Energy Resources	Explains how DER is treated in load forecasts, present and forecasted DER levels, and DER scenario analysis.
XII.	Hosting Capacity, System Interconnection, and Advanced Inverters/IEEE 1547	Summarizes our hosting capacity analysis in the context of our overall interconnection processes. Provides interconnection statistics and related discussion.
XIII.	Existing and Potential New Grid Modernization Pilots	Provides projects related to grid modernization.
XIV.	Action Plans	Outlines 5-year and long-term action plans.
XV.	Stakeholder Engagement	Describes stakeholder efforts related to the preparation of this IDP.
XVI.	Integrated Distribution-Transmission-Resource Planning	Discusses present state of D-T-R planning and longer-term view of deeper process alignment.
	Conclusion	

We provide as Attachment A to this IDP, a summary table of the IDP Order Requirements that references locations in the IDP document where we responded to the requirement. Some of these are more specific than others, which depends on the nature of the requirement. For example, our grid modernization plans are referenced generally as a section; the number of customer premises is referenced by page number. We also embedded the various requirements throughout this IDP, to signal to the reader when we would be generally or specifically responding to that requirement.

II. DISTRIBUTION SYSTEM PLAN OVERVIEW

In this Section, we provide a summary of our near- and long-term distribution system plans, including summary-level budget information and drivers. We first begin with a discussion of the policy goals underlying the development of our distribution system plan. We then discuss the Company's objectives in developing a distribution system plan and the framework of the Company's distribution system plan, and the development of the budget for the distribution system plan. Finally, we provide a summary of the distribution system plan, including the five-year and long-term action plans.

A. Distribution System Policy Goals

Federal and state policies and requirements – and customers – determine the key goals of regulated utilities. We believe the regulatory construct and the attributes of our service that our customers value are aligned around reasonable and affordable rates, reliable service, customer service and satisfaction, and environmental performance.

The principal source of state policy with respect to energy, utilities, and the environment are Minnesota statutes. Indeed, in the Legislative Findings section of Minn. Stat. Chapter 216B, the legislature provided a topline summary of state policy with respect to utility regulation:

> *It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail customers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result*

in inconvenience or diminish efficiency in service to the consumers.[12]

We have a similarly strong record on reliability, ranking in the first or second quartile nationally in terms of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) – and have received national recognition for our storm response efforts. Also, significantly, we are achieving these outcomes with total residential customer bills that are 26 percent below the national average and 14 percent lower than the Minnesota utility average. In fact, our Minnesota residential customers have actually experienced a *decrease* in their total bill since 2013. Additionally, our recent efforts in the wind and biomass space will deliver over $2.2 billion in savings to our customers.

We have one of the longest-running and most successful DSM programs in the country. Our customers have saved over 5,500 GWh of annual energy and 1,000 MW of demand since 2005, thereby avoiding the construction of several power plants. We have the most registered Demand Response (DR) capability (nameplate) of all MISO investor owned utilities by a significant margin[13] – and are on pace to significantly increase those resources by 2023.[14] We are finding new and better ways to communicate with our customers, including redesigning our website to be customer-centric, developing a state-of-the-art storm center and outage notification system, and rolling out a mobile application. Finally, we recently announced a proposal to build on our clean energy leadership by investing more than $25 million to increase access to EVs and help drivers and fleet operators start driving electric.

As we discuss below, the goals of our Distribution business are aligned with the regulatory construct, Minnesota state policy objectives, and our customers' interests.

B. Distribution System Plan Objectives

The energy landscape is evolving. Supply resources are becoming less carbon-intensive and more diverse; decentralization is accelerating – driven by advances in technology and new business models. While this evolution has been occurring at a system level, distribution systems – the portion of the system that connects directly

[12] Minn. Stat. § 216B.01

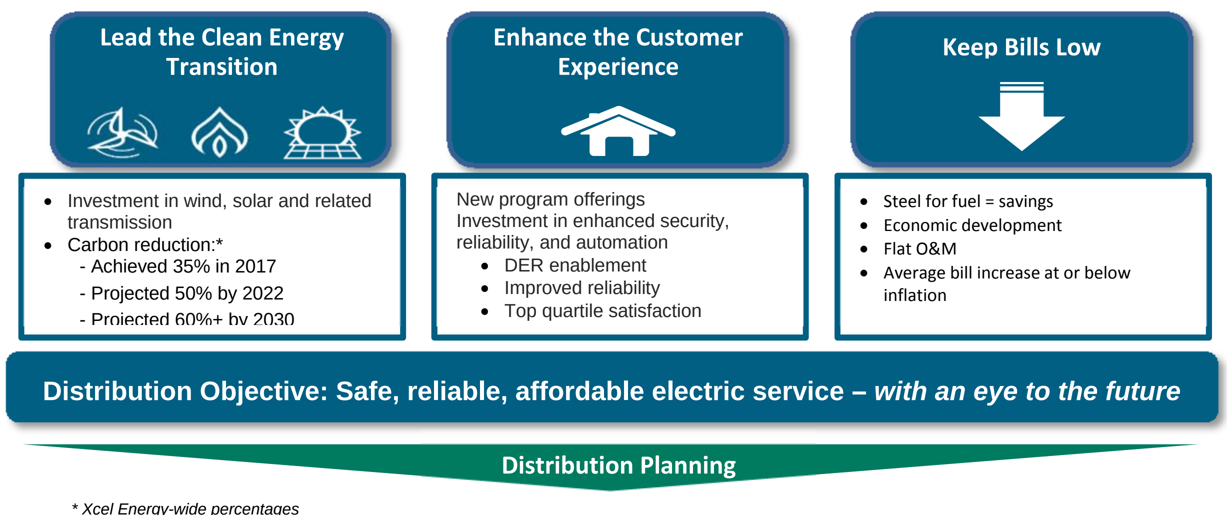
[13] *Source and Notes*: Brattle analysis of FERC, 2012 Assessment of Demand Response and Advanced Metering, and EIA 861 load data. Capability of dispatchable DR, so excludes impacts from static TOU rates. NSP's capability calculated as current portfolio divided by 2016 peak load.

[14] Brattle analysis of FERC, *2012 Assessment of Demand Response and Advanced Metering*, and EIA 861 load data. Based on capability of dispatchable DR (830 MW), so excludes impacts from static TOU rates. Capability calculated as current portfolio divided by 2016 peak load.

with each and every customer – have also begun to advance. We are correspondingly planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value and that the fundamentals of our distribution business remain sound.

Xcel Energy's strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 2: Xcel Energy Strategic Priorities – Applied to Distribution



The Company's Distribution organization is responsible for operating, maintaining, and constructing the distribution system to ensure that the delivery of power to our customers is safe and reliable. In fact, the Distribution organization is the frontline group out in the field implementing the key Company priorities that drive our operations on a daily basis; namely reliability, safety, and customer focus.

In terms of reliability, customers want quality, uninterrupted power – and their expectations continue to evolve and increase. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. Based on this analysis, we develop programs and work plans to both support our customers' needs for reliable service today – and also to lay groundwork for the grid of tomorrow.

We also must make significant investments to support system capacity needs due to increased loads from existing or new customers. For example, each year we evaluate substation transformer and feeder loads to identify overload risks and potential reliability issues, which drives the capacity-related projects that we plan. We update existing infrastructure, such as our recent initiative to install new energy-efficient LED streetlights – and we respond to increases in new business such as extending service to new housing developments, which are often driven by factors outside of our control.

In terms of safety, we make investments that support both the safety of our workforce and our customers. For example, our capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently. Other examples include:

- Our vegetation management program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our damage prevention program that helps the public identify and avoid underground electric infrastructure,
- Our pole replacement program that ensures our lines and equipment are supported by quality wood poles, and
- Our LED street lighting program improves nighttime visibility, which in turn improves overall safety for both drivers and pedestrians.

Finally, we focus on service to our customers. For example, with certain investments in our distribution system such as in System Control and Data Acquisition (SCADA) capabilities and AMI, we enhance our capabilities to better monitor and respond to system conditions such as outages – and we can provide customers more choices related to their energy use. Additional examples are our industry-leading storm response, and our efforts to improve the estimated restoration times (ERT) we provide to customers.

The Distribution business area's goal is to provide safe, reliable, and affordable electricity to our customers in the near- and long-term. As such, our distribution investment and maintenance plans are designed to reduce risk, improve reliability, manage costs, and advance the grid at the speed of value to our customers. As discussed below, we plan and budget our distribution system investments in alignment with these goals.

C. Distribution System Planning Framework

The Distribution system is the portion of the electric system that delivers energy from the transmission system to our approximately 1.5 million electric customers across the Northern States Power Company-Minnesota (NSPM) operating company service area, including approximately 1.3 million customers in Minnesota.[15] The NSPM distribution system is composed of approximately 1,200 feeders that connect a network of over 26,000 miles of distribution lines that are used to provide safe and reliable electricity to our customers.

The key functions of the Distribution organization include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. To provide these key services, the Distribution organization is structured around four functional areas: Operations, Engineering, Business Operations, and Planning and Performance. The key responsibilities of these areas include:

- *Operations*. Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response;
- *Engineering*. Provides technical support and system planning, including addressing distribution-related customer service issues;
- *Business Operations*. Responsible for several areas, including vegetation management, outdoor lighting, metering systems and support, facility attachments, and the builders call-line.
- *Planning and Performance*. Provides business planning, consulting, analytical services and performance governance and management.

Distribution makes capital investments to improve the reliability of the system, improve functionality and modernize the distribution system, extend electric service to new customers, and relocate existing facilities in response to road construction projects. We also incur O&M costs to maintain the components of the existing distribution system, such as poles, wires, and transformers, and to replace this equipment due to age or weather-related events.

[15] NSPM provides service in Minnesota, North Dakota, and South Dakota.

Given our priorities of providing safe, reliable, and affordable electricity to our customers, the Distribution organization must not only proactively maintain the system by making capital improvements when necessary to improve reliability and safety for our customers – it must also manage our established budgets to react to outages caused by storms and other economic conditions that cannot be budgeted for with a high degree of accuracy. For example, the actual amount NSPM spent in O&M on storms in 2013 was $6.35 million, which is $4.3 million over the preceding five-year historic storm average (and $5.6 million over what we budgeted for storms in 2013). Similarly, the storm-related capital repairs for NSPM in 2013 totaled $27.07 million (Minnesota alone totaled $20 million), which can be compared to the previous five-year average of $6 million.

In this way, the Distribution organization is unique from many other business units. While we are confident in our overall level of budgeting and our ability to manage within those annual budgets, the realities of our business require some flexibility within those budgets to respond to changing economic conditions, weather events, and evolving priorities. That being said, we are proud of our successful storm response efforts, reputation for reliable service, and our ability to manage our budget within its bounds and react and reprioritize as necessary each year to ensure our customers continue to receive safe and reliable electric service.

We annually develop a 5-year Distribution budget, with capital projects falling into five capital budget groupings depending on the primary purpose of the project, as follows: (1) Asset Health and Reliability, (2) New Business, (3) Capacity, (4) Fleet, Tools, and Equipment, and (5) Grid Modernization.[16] Distribution operating and maintenance (O&M) budgets are generally categorized as follows: (1) Internal Labor, (2) Contract Labor, (3) Fleet, (4) Materials, and (5) Other.

For purposes of the IDP, we are required to report and discuss distribution system spending in the following categories: (1) Age-Related Replacements and Asset Renewal, (2) System Expansion or Upgrades for Capacity, (3) System Expansion or Upgrades for Reliability and Power Quality, (4) New Customer Projects and New Revenue, (5) Grid Modernization and Pilot Projects, (6) Projects related to local (or other) government-requirements, (7) Metering, and (8) Other.
For purposes of this IDP, we portray our capital costs in these IDP categories. We note that we are unable to similarly portray our O&M costs in these categories, which

[16] Although investments in system capabilities and customer enhancements, such as information systems, new customer programs, and communications, may be related to the Distribution function/service, all or portions of these expenditures may be budgeted by other/non-Distribution Xcel Energy functional business areas.

we discuss in more detail below.

D. Distribution Financial Overview

Distribution budgets are evolving based on the future of electric distribution and customers' increasing expectations for control, options, and ease of doing business. Additionally, our capital investment plans generally reflect our advanced grid initiative, as we have discussed it above. Historically, however, the overwhelming majority of our distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

These three requirements are intertwined, and we respond to them by providing the following capital and O&M discussion, historical actuals, and 5-year budgets that respond to the related IDP requirements.

1. Overview

Distribution makes capital investments to improve the reliability of the system, improve functionality and modernize the distribution system, extend electric service to new customers, and relocate existing facilities in response to governmental directives, which often involve relocating our facilities for road construction projects. Distribution also expends O&M costs to maintain the components of the existing distribution system, such as poles, wires, and transformers, and to replace equipment due to age or weather-related events.

The distribution budget process prioritizes projects based on the Company's goal of providing our customers with smart, cost-effective solutions, recognizing that customers want reliable and uninterrupted power. Although the immediacy of customer safety and reliability is a reality and our primary focus, in addition to these core activities, our investment plan now reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. We also are planning for investments in enhanced distribution planning tools. These tools will equip our system planners with enhanced capabilities to consider DER adoption scenarios and NWA in the analyses we perform to ascertain the best way to meet system capacity needs.

2. *Specific Budget Information*

IDP Requirement 3.A.26[17] requires the following:

> *Historical distribution system spending for the past 5-years, in each category:*
> *a. Age-Related Replacements and Asset Renewal*
> *b. System Expansion or Upgrades for Capacity*
> *c. System Expansion or Upgrades for Reliability and Power Quality*
> *d. New Customer Projects and New Revenue*
> *e. Grid Modernization and Pilot Projects*
> *f. Projects related to local (or other) government-requirements*
> *g. Metering*
> *h. Other*
>
> *For each category, provide a description of what items and investments are included.*

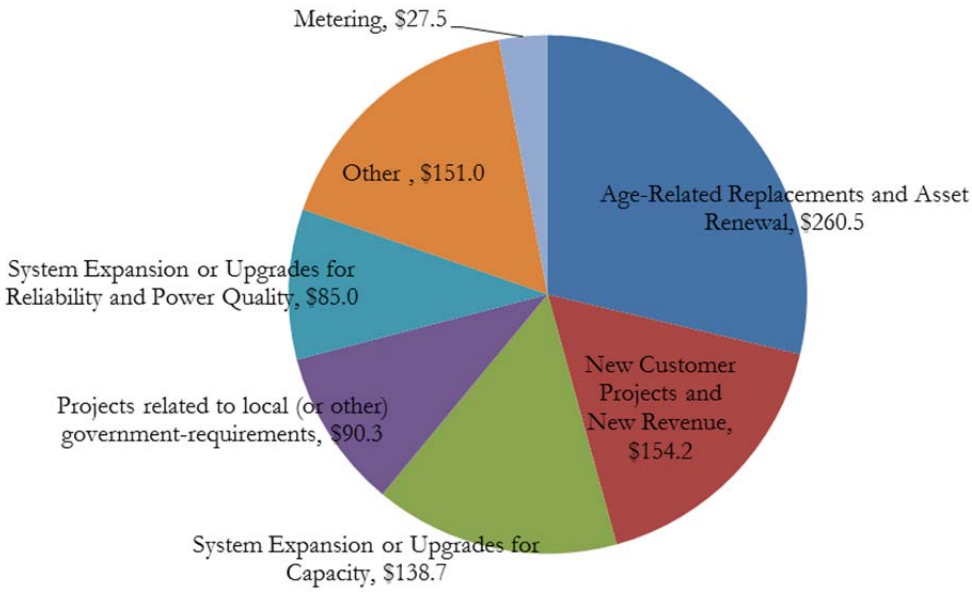
a. Capital – Historic Actual and Budgeted Expenditures

As noted above, we have categorized our historic actuals and 5-year budgeted amounts into the IDP categories with the exception of Grid Modernization and Pilot Projects. For the reasons we discuss in the Grid Modernization section of this IDP, we portray our planned advanced grid investments in the form of a capital and O&M range for each of the near-term investments.

Figures 3 and 4 below provide a summary of historic actual and budgeted capital expenditures in the IDP categories.

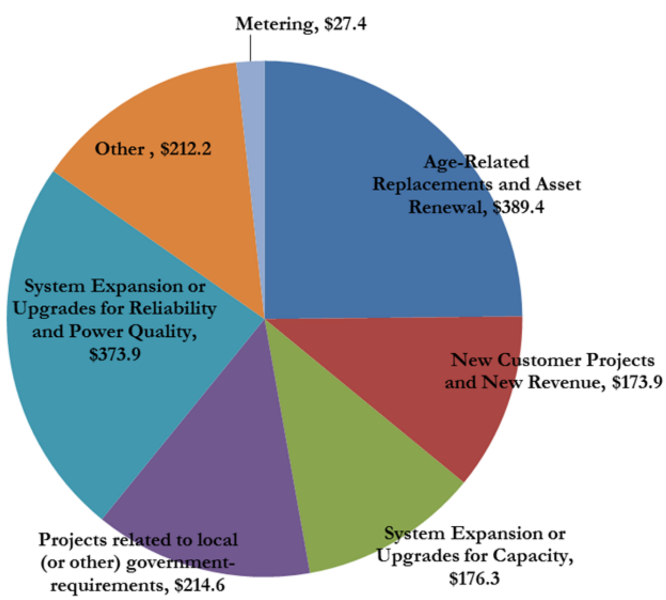
[17] This IDP Requirement also provides that the Company may include in the IDP any 2018 or earlier data in the following rate case categories: (a) Asset Health; (b) New Business; (c) Capacity; (d) Fleet, Tools, and Equipment; and (e) Grid Modernization.

Figure 3: Actual Historic Distribution Capital Profile by IDP Category State of Minnesota – Electric Jurisdiction (2013-2017)
(millions)



Note: excludes non-investment amounts.

Figure 4: Budgeted Distribution Capital Profile by IDP Category State of Minnesota – Electric Jurisdiction (2018-2023)
(millions)



Note: excludes non-investment/CIAC amounts.

IDP Requirement 3.A.28 requires the following:

Projected distribution system spending for 5-years into the future for the categories listed [in 3.A.26], itemizing any non-traditional distribution projects.

Table 4 below provides an overview of our 5-year capital budget in the IDP categories. We provide a list of planned projects as Attachment B to this IDP. We understand "non-traditional distribution projects" to include projects such as a NWA in place of a traditional distribution infrastructure investment, such as a new feeder or substation. Accordingly, we clarify that do not have any specific non-traditional distribution projects in our 5-year budget.

Table 4: Distribution Capital Expenditures Budget – State of Minnesota Electric Jurisdiction

Expenditure Category	Bridge 2018	Budget 2019	2020	2021	2022	2023	Budget Avg 2019-2023
Age-Related Replacements and Asset Renewal	$67.2	$57.9	$60.1	$64.5	$73.0	$66.7	$64.4
New Customer Projects and New Revenue	$37.4	$25.4	$28.2	$26.9	$27.6	$28.4	$27.3
System Expansion or Upgrades for Capacity	$17.4	$14.5	$35.0	$40.2	$33.7	$35.4	$31.8
Projects related to Local (or other) Government-Requirements	$17.9	$50.2	$45.0	$36.1	$32.7	$32.7	$39.3
System Expansion or Upgrades for Reliability and Power Quality	$27.1	$21.4	$27.4	$113.4	$116.4	$68.4	$69.4
Other	$36.5	$28.3	$33.4	$41.0	$42.1	$30.9	$35.1
Metering	$5.9	$5.9	$5.1	$3.9	$3.5	$3.1	$4.3
Non-Investment/CIAC	($12.0)	($3.6)	($3.7)	($3.7)	($3.8)	($3.8)	($3.7)
TOTAL	**$197.4**	**$200.0**	**$230.3**	**$322.3**	**$325.1**	**$261.8**	**$267.9**

Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Other includes Fleet, Tools, Communication Equipment, Locating and Transformer Purchases; Reliability includes placeholder investments for a new reliability program (Incremental Customer Investment); and Non-investment/CIAC includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections.

We clarify here that the Metering category above reflects 'business-as-usual' metering costs – not metering expenditures associated with our AMI plans. In terms of grid modernization, our current projected capital costs for implementation of AMI and FAN are expected to be in the range of $450 to $600 million. However, final costs will depend on the final customer and data management strategy and related investment decision points, which are currently pending. We have previously presented estimated capital costs for FLISR (approximately $66 million), the certified Time of Use rate pilot (approximately $10 million), and the certified ADMS (approximately $69.1 million).[18] Note that the TOU pilot and FLISR are enabled by ADMS and the FAN infrastructure, as will ultimately other advanced grid initiatives.

IDP Requirement 3.A.29 requires that we provide our planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending – with the driver categories aligning with the IDP distribution spending categories. We provide this information as Attachments B and C to this filing.

b. O&M – Historic Actuals and Budgeted Expenditures

Unlike capital, we were not able to categorize our O&M historic actuals and 5-year budgeted amounts into the IDP categories. As we explained in our July 6, 2018 Comments on the *proposed* IDP requirements, the now-final IDP categories do not correspond with our internal system tracking for capital or O&M. However, the issue for O&M goes deeper, which we also explained and we repeat here.

The O&M budget is composed of labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention, which is primarily provided by contractors. Finally, it includes the fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. We therefore generally track our Distribution O&M expenditures in the following groupings: (1) Internal Labor, (2) Contract Labor, (3) Fleet, and (4) Materials.

Unlike our capital budgets, where it was possible but labor-intensive to undertake a manual process to assign projects to the proposed investment categories, the O&M budget does not lend itself to such a manual process. The Distribution O&M budgets are a compilation of many thousands of small expenditures, most of which are associated with operating or maintaining existing facilities. While there is often a small O&M component associated with capital projects, the amount is typically small, ranging from two to seven percent of project costs, on average, for distribution. This results in voluminous small O&M charges dispersed over many projects than cannot be aggregated in the now-required categories.

[18] For the TOU Pilot and FLISR, *see* Xcel Energy Grid Modernization Report pages 23 and 34 respectively, Docket No. E002/M-17-776 (November 1, 2017). For ADMS, *see* Xcel Energy TCR Petition Attachment 1A page 19, Docket No. E002/M-17-797 (November 8, 2017).

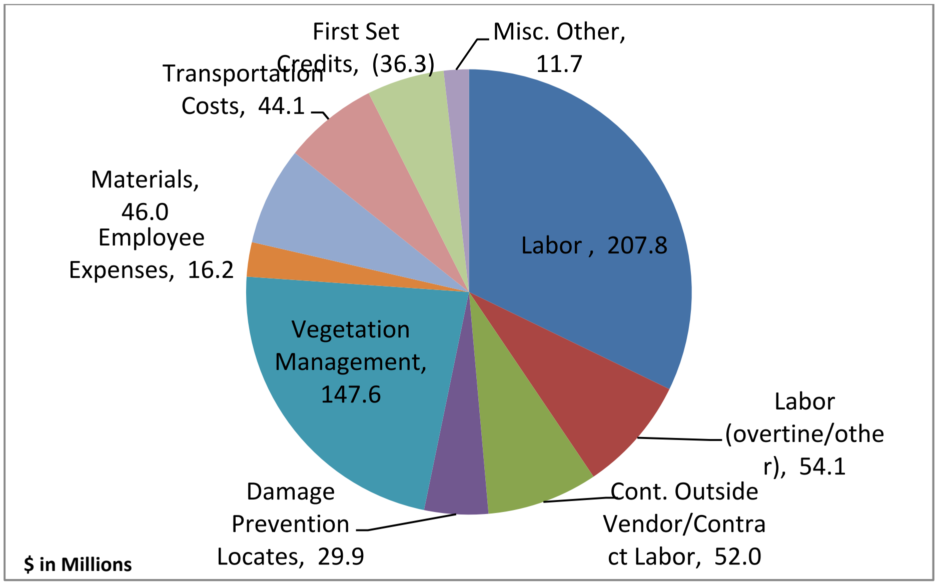
We have however been able to provide a partial "functional" view of both historic actuals and 5-year budgeted amounts. We additionally note that, as we have done for capital, we have excluded AGIS costs from the 5-year budget view, the reasons for which we discuss in the Grid Modernization section of this IDP. AGIS costs for planned initiatives are portrayed in the form of a capital and O&M range for each of the near-term investments.

Additionally, while both the capital and O&M information we provide in this IDP are of the "Distribution Function," the O&M are for the NSPM operating company and the capital costs are for the State of Minnesota, so are not fully comparable.[19] Portraying O&M costs by state would require a jurisdictional cost of service analysis, such as we would do for a rate case. We did not undertake this level of analysis for this IDP due to the compressed timeframe and the fact that the IDP is not intended to support cost recovery. Additionally, an NSPM view of historic and budgeted O&M provides a directionally accurate view of the O&M costs for the state of Minnesota, as Minnesota represents the overwhelming majority of the NSPM operating company.

For our 2019 IDP, we will further evaluate potential other ways to report the O&M portion of the Distribution budget, including how FERC accounts, which as a utility underlay everything we do, might align with the IDP categories. That said, Figures 5 and 6 below provide a summary of historic actual and budgeted O&M costs in the most descriptive way that we were able to portray them given the reasons we have discussed. Following these Figures, we provide a description of the categories. Although only required for capital under IDP Requirement 3.A.29, we provide a similar view of our O&M costs over time, along with a brief narrative regarding year-over-year changes as Attachment D to this IDP

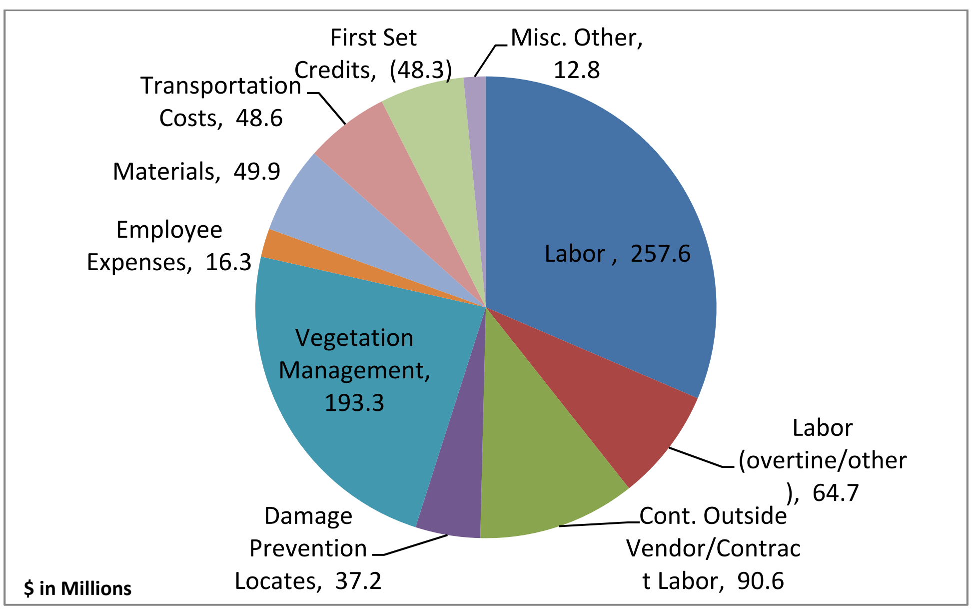
[19] A "functional" view of a business area, in this case Distribution, are costs directly associated with that function, so will not include allocations for items such as shared services.

Figure 5: Actual Historic Distribution O&M Costs by Cost Element NSPM Operating Company – Electric Jurisdiction (2013-2017)
(millions)



Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $30.6M and $6.1M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Figure 6: Budgeted Distribution O&M Costs by Cost Element NSPM Operating Company – Electric Jurisdiction (2018-2023)
(millions)



Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $30.6M and $6.1M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Labor and Labor (overtime/other). This category includes the labor and labor overtime associated with Xcel employee's to operation and maintain our electric distribution system. The labor pertains to the maintenance and operations of our electric distribution system. Overtime is primarily associated in response to outages, line faults, damages to our system and customer requested orders.

Contract Labor/Consulting. This category includes staff augmentation and contract outside vendors performing operations and maintenance work on our distribution systems. This also includes the delivery services for meters and transformers along with ancillary services such as barricades, flaggers, restoration, sand and gravel, etc.

Damage Prevention/Locating. This category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents.

Vegetation Management. This category includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages.

Employee Expenses. This category includes the costs associated with expenditures for training, safety meetings, travel and conferences associated with our electric distribution systems.

Materials. This category represents costs associated with miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system.

Transportation. This category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) necessary to build out, operate, and maintain our electric distribution system, including annual fuel costs plus an allocation of fleet support.

Miscellaneous Other. This category represents the O&M expenditures that include office supplies, janitorial costs, dues, donations, permits, electric use costs, electric safety clothing for the crews, permits and other various items minor costs.

The First Set Credits. This category is the credit for the costs (labor, materials, transportation) in O&M associated with the installation of new meters and transformers.

Table 5 below provides a snapshot of our 2019-2023 O&M distribution budget in these same categories

Table 5: Distribution O&M Expenditures Budget – NSPM Electric Jurisdiction

Expenditure Category	Bridge 2018	Budget 2019	2020	2021	2022	2023	Budget Avg 2019-2023
Labor	$43.0	$42.5	$42.1	$42.7	$43.5	$43.9	$42.9
Labor (overtime/other)	$10.8	$10.8	$10.8	$10.8	$10.8	$10.9	$10.8
Cont. Outside Vendor/Contract Labor	$14.5	$13.8	$14.7	$14.8	$16.1	$16.6	$15.2
Damage Prevention Locates	$6.2	$6.2	$6.2	$6.2	$6.2	$6.2	$6.2
Vegetation Management	$31.5	$32.4	$32.5	$32.3	$32.3	$32.3	$32.4
Employee Expenses	$3.0	$2.7	$2.7	$2.6	$2.6	$2.7	$2.7
Materials	$8.2	$8.5	$8.4	$8.2	$8.2	$8.3	$8.3
Transportation Costs	$8.1	$8.3	$8.2	$8.0	$8.0	$8.1	$8.1
First Set Credits	($7.9)	($8.0)	($8.1)	($8.1)	($8.1)	($8.2)	($8.1)
Misc. Other	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
TOTAL	**$119.4**	**$119.3**	**$119.5**	**$119.7**	**$121.7**	**$123.0**	**$120.6**

Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

In terms of grid modernization, our current projected O&M costs for implementation of AMI and FAN are expected to be in the range of $110 to $150 million. However, final costs will depend on the final customer and data management strategy and related investment decision points, which are currently pending. We have previously presented estimated O&M costs for FLISR (approximately $6 million), the certified Time of Use rate pilot (approximately $3.5 million), and the certified ADMS (approximately $13.4 million).[20] Note that the TOU pilot and FLISR are enabled by ADMS and the FAN infrastructure, as will ultimately other advanced grid initiatives.

E. Distribution System Plan Summary

We summarize our near-term and long-term action plans below, and discuss them in more detail in Section XIV of this IDP.

1. 5-Year Action Plan

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, and FLISR, and securing enhanced system planning tools to advance our abilities to incorporate DER and NWA analysis into our planning. We will continue to finalize the details of our customer strategy and related

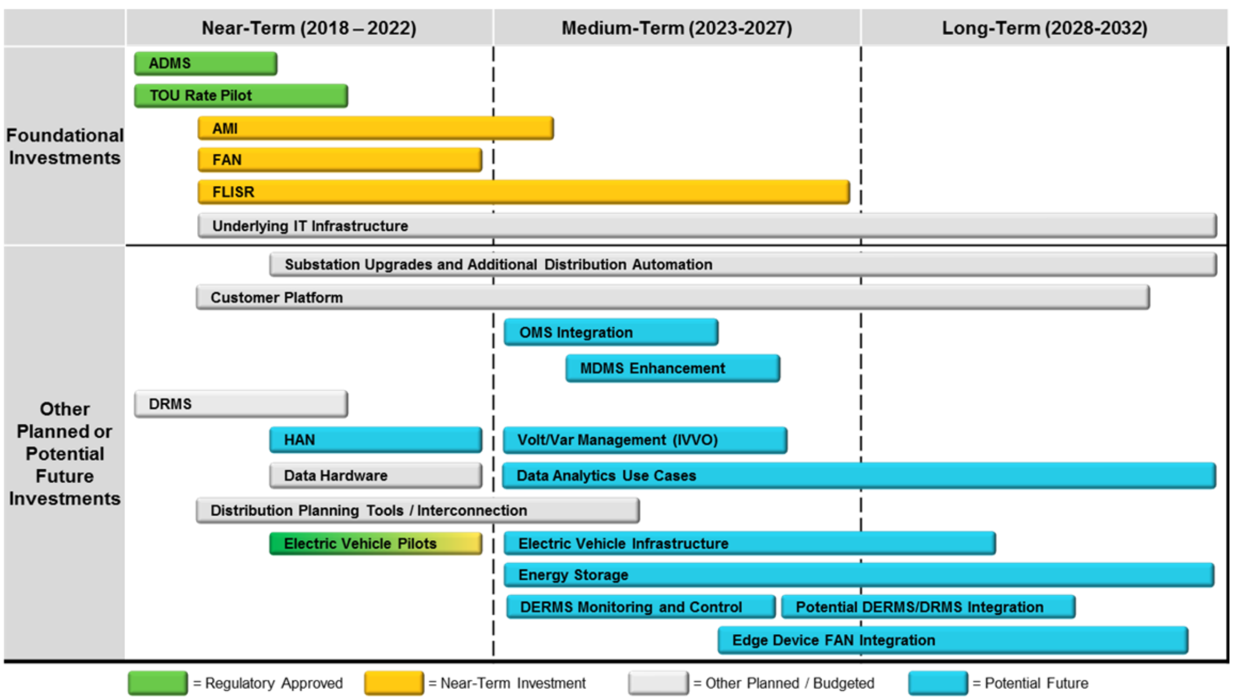
[20] For the TOU Pilot and FLISR, *see* Xcel Energy Grid Modernization Report pages 23 and 34 respectively, Docket No. E002/M-17-776 (November 1, 2017). For ADMS, *see* Xcel Energy TCR Petition Attachment 1A page 23, Docket No. E002/M-17-797 (November 8, 2017).

advanced grid investment plan – and in 2019, we will bring the costs and benefits to the Commission for approval through a future certification request in the grid modernization/IDP filings or through a general rate case.

2. *Long-Term Action Plan*

Long-term, we are focused on continuing to provide our customers with reliable and safe service – and advancing the grid at the speed of value for our customers. In terms of grid advancement, Figure 7 below shows the sequencing of planned and potential advanced grid investments over time and constitutes our advanced grid roadmap.

Figure 7: Advanced Grid Initiatives 15-Year View



In addition to discrete advanced grid investments, our corporate Information Technology (IT) infrastructure will require attention and investment on an ongoing basis to continue to meet increasingly demanding cybersecurity, data traffic, reliability, and compliance requirements along with the service expectations of our customers. Many of the investments discussed within this report involve additional data and communication needs, and a current IT infrastructure is critical to supporting those efforts. Shown in Figure 7 above as a single foundational investment, this is actually composed of a series of investments in data management hardware, systems integrations, and cybersecurity protections.

Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities.

3. *Projected Customer and System Impacts*

Figure 8 shows how customers will benefit from potential investments over time.

Figure 8: Customer Benefits Achieved Over Time

	2018 – 2022 Near-Term	2023-2027 Medium-Term	2028-2032 Long-Term
Benefits Realized	• Avoided and shortened outages through greater system visibility and faster problem location, isolation, and restoration • Timely proactive outage communication with improved restoration estimates • Continued reliable electric service by managing a dynamic environment of two-way power flows • Demonstrate savings potential of non-traditional grid solutions through NWA pilot • Streamlined interconnection processes for customers installing DG, like rooftop solar	• Enhanced power quality • Reduced costs through reduced fraud and theft • Reduced carbon emissions through DER and transportation electrification • Cost effective deferral of traditional grid infrastructure through NWA solutions • Continued interconnection process improvement through increased study automation	• More effective utilization of customers' DERs, for the benefit of all customers • Continued operational efficiency gains through more efficient maintenance and inspections of field devices • Reduced carbon emissions through continued transportation electrification
Potential New Offerings for Customers	• More pricing and rate options • Bill forecasting and goal setting • Customized payment dates and bill pre-pay • Engaging energy insights and benchmarking • Proactive communication on consumption and options to control • Ability to share usage data with other service providers • Expanded Electric Vehicle offerings • Partnerships to support energy services • Customer participation in NWA pilots	• Further pricing and rate offerings that suit customers' lifestyle and budget • Personalized energy saving recommendations and control based on customer behavior • Managing bill with home automation • Improved Smart EV charging • Remote connect/disconnect services	• More sophisticated solutions and revised policy and regulatory mechanisms to integrate DER • Orchestration of home and business devices • Continued evaluation and use of technology and deployment partners that enhance customer experience
Enabling Data	• Interval meter data • Field device sensing • Customer outage data • TOU pilot results • EV pilot results • Storage pilot results	• Grid edge operational awareness • DER performance data • Asset health data • Enhanced system diagnostics • More accurate DER benefits and costs • Disaggregated usage data	• TBD – expect enhancements based on evolving data capabilities and industry maturity related to operational experience

Data Maturity

III. BUDGET DEVELOPMENT FRAMEWORK

This section discusses Xcel Energy's overall budget development, as well as the Distribution organization's specific budget development processes.

A. Overview of Xcel Energy's Overall Budgets

Electric and gas utilities are long-term, capital intensive businesses. Every year, we prepare a five-year financial forecast that is used to anticipate the financial needs of each of the Xcel Energy operating utility companies, including NSPM. The five-year forecast provides the information necessary to make strategic and financial decisions to address these needs, and to develop supportable and attainable financial plans for each operating utility subsidiary and for Xcel Energy overall. Key components of the five-year financial forecast are the O&M and capital expenditure five-year budgets for each of Xcel Energy's operating utility subsidiaries, including the NSPM.

When a five-year budget is created and approved, the first year budget is essentially "locked in." However, budgets for the subsequent years 2-5 will be reevaluated in the next budgeting cycle, and will necessarily change in response to new developments and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period, and forecasted expenditures are adjusted accordingly.

To a large extent, the O&M and capital budgeting process are the same. The capital budget process however, requires additional steps and approvals for capital projects with expenditures over $10 million. Likewise, capital projects with expenditures over $50 million also require additional steps. In terms of review and oversight of expenditures after budgets are finalized, we conduct the same monthly review and variance analysis for both O&M and capital expenditures. However, we conduct an additional comprehensive review of capital expenditures on a quarterly basis.

B. Distribution Budget Framework

Below we discuss the steps in the distribution budget development.

1. Capital Budget Development

Specifically in Distribution, once all areas identify their priority projects, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage; and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.)

The overall budget process recognizes that customers want reliable and uninterrupted power. We therefore must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by severe weather, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

The factors used to prioritize investments are as follows:

- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities;
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated;
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable;
- *Legal* – Evaluation of compliance before and after the risk is mitigated; and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc., and identification of avoided costs such as quality of service pay-outs and failure repairs.

While the immediacy of customer reliability is a reality and our primary focus, in addition to these core activities, our investment plan reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. We are also planning for enhanced distribution planning tools that will equip our system planners with the capabilities to perform DER scenario analysis in our annual planning processes, better facilitate our incorporation of NWA into the analysis we perform to ascertain the best way to meet system capacity needs, and begin in earnest the integration of planning activities at all levels of the grid.

Distribution groups its investments in the following five capital budget groupings:

Asset Health. Projects in this category are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting the reliability of service and increasing O&M expenditures needed to repair this equipment. When poor performing assets are identified, projects that will improve asset performance are included in the budget. Projects in this category include replacement of underground cable, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their life. This category also captures replacements due to storms and public damage. Additionally, this category covers projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public projects such as road widening or realignment. These projects, often referred to as "mandates," generally follow municipal and state funding availability. These mandate projects generally result in updated distribution infrastructure.

Capacity. While our overall sales have remained rather flat, we do have several pockets of peak demand growth on our distribution system that require additional facilities to accommodate this load growth. Our capacity investments include all distribution system projects associated with upgrading or increasing capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.

New Business. This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, and service laterals. Although our sales have remained relatively flat in recent years, our capital additions in this category are increasing as compared to prior years as the economy continues to improve and more new homes and businesses are constructed. This category also includes replacement of existing streetlights with more energy-efficient and safer LED lights.

Fleet, Tools, and Equipment. This category includes fleet, tools, equipment, right-of-way, land communications, and locate costs associated with modifications or additions to the distribution system or supporting assets. Fleet costs include costs associated with the necessary replacement of vehicles and equipment that have reached their end of life. Right-of-way costs include capital additions associated with obtaining rights-of-way and easements.

Grid Modernization. Traditionally, we included investments to advance the grid in our Asset Health budget category. This fit well, when these investments were primarily associated with incremental technology improvements that were often considered in the asset replacement decision, such as whether the functionality of a particular asset could or should be enhanced to promote grid modernization. For instance, we replaced electro-mechanical relays with solid-state relays, which are not only communication-enabled – but are also capable of providing fault data that has enabled us to more quickly identify faults on our system and improve our response time.

Another example is regulators, which now when they require replacement, we purchase with controls that identify reverse-power flow and react accordingly. This will allow us to more easily incorporate distributed generation onto our system. Beginning in 2018 with the launch of our AGIS initiative, we separated these investments into a Grid Modernization category. However, for purposes of this IDP, we discuss a range of costs for our near-term planned AGIS investments.

2. O&M Budget Development

Our O&M budgeting process takes into account our most recent historical spend in all the various areas of Distribution and applies known changes to labor rates and non-labor inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities and/or maintenance projects embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (e.g., excessive storm activities or one-time O&M projects). We then couple that normalized historical spend information with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year.

For example, for our major maintenance programs such as cable fault repairs and vegetation management, we review annual expected units/line-miles to be maintained and ensure required O&M dollars are adjusted accordingly. We also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we continuously are working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies.

Given that no year transpires exactly as predicted or forecasted, we typically update our O&M expenditure forecasts during the year. As with our capital investments, one of our largest annual sensitivities for O&M expenditures is severe weather. The amount of O&M we spend on weather-related events, such as storm restoration and floods, can vary greatly from one year to the next. In addition, the Distribution business area will periodically respond to requests from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. When a greater need for expenditures in a particular area is identified, we try our best to re-prioritize and reallocate our budgeted O&M dollars while still operating within our overall O&M budget. However, there are times where circumstances dictate that, in order to maintain safe, reliable service at the levels our customers expect, we will need to spend more than our overall budget would allow to properly address certain items that come about during a given budget year.

3. Distribution Budget Prioritization

Because no business has unlimited funding to meet its objectives, budgeting always requires balancing to meet the needs of the business while also advancing the business through strategic objectives. As we have described, one of Xcel Energy's strategic priorities is keeping customer bills low. In light of this and other business objectives, tremendous effort goes into balancing the various operational budgets to meet the needs of business – even as requirements change, and emergent circumstances become apparent. Our goal is always to provide our customers with the greatest value.

Further, while our budget process has generally proven to be an accurate gauge of overall budget levels, as we have noted, the Distribution budget is an ongoing and iterative process that is largely driven by the immediacy of reliability and other emergent circumstances that are the practical reality of the distribution business. The distribution system is the connection to our customers, and we must respond to these circumstances to meet our obligation to serve and ensure we provide adequate service.

This means that long-term plans, which, in a distribution context, include five-year action plans, have a much shorter shelf-life. That said, the highest priority in the Distribution budget process is given to projects that must be completed within a given budget year to ensure that we meet regulatory and environmental compliance obligations, and to connect new customers. Annual Distribution budgets are funded in descending order – beginning with those work activities that are required and for which all aspects may not be within our control. This includes government-required work, costs related to serving new customer loads, and outage restoration.

Government-required work in the *Asset Health* budget grouping includes public right-of-way conflicts where we are required to move our facilities – often in conjunction with a road widening or other civic improvement. We base these amounts on historic levels of spending, as well as projects we are aware of from our work with communities and other governmental entities.

The budget section surrounding *New Business* includes customer-driven work to either support increased loads from existing customers or new customer loads. Again, budgeted amounts incorporate our historic experience, as well as information we have from our work with customers and developers. We note that some of this work is subject to customer contribution-in-aid-of-construction (CIAC) payments. This also includes meters to support new business, as well as replacement of existing meters to support ongoing maintenance and testing programs.

We also need to budget for outage restoration and equipment replacement under the *Asset Health* budget grouping. This addresses aging infrastructure and other asset health work including failure and maintenance mitigation. Again, there are sub-categories of funding, as follows: (1) Rebuild blankets, which are relatively small dollar, short-term reactive work identified by local areas during the budget year, (2) program-driven, which stem from programmatic, ongoing work to address an issue or trend over time; examples include age-driven pole replacements, (3) failure reserves, which are unallocated funds set aside for failures that may occur during the budget year; examples include storm restoration and other equipment failure, and (4) discrete projects that are subject to a risk ranking prioritization process that assesses failure risk and reliability risk.[21]

Another category that we fund is for other activities related to base construction in the *Fleet, Tools and Equipment* budget grouping, including fleet purchases, tools, logistics, locating, communications equipment, and transformer purchases.

Once these fundamental priorities are funded, we turn our attention to *Capacity Projects* – first to general capacity work that we expect will be needed, based on our historic experience. This category is funded in three parts: (1) Amounts that are not project-specific at the time they are budgeted, are relatively small dollar, short-term reactive work identified by local areas during the budget year, (2) discrete, projects specific to serve new load from a single customer, and (3) specific projects to mitigate system risk (overload or contingency), based on current load forecast. This last category of capacity funding is subject to a risk ranking prioritization process.

Strategic objectives like our advanced grid initiative fits into Xcel Energy's overall budget processes independently as they are identified – just like strategic investments in other aspects of our business, such as wind projects to provide our customers with low cost energy, and our previous CapX transmission initiative to ensure a robust regional grid for the future.

IV. SYSTEM OVERVIEW

In this Section, we provide an overview of Xcel Energy and a snapshot of distribution system statistics for the Company, as well as a financial overview of the Distribution business area and budgets.

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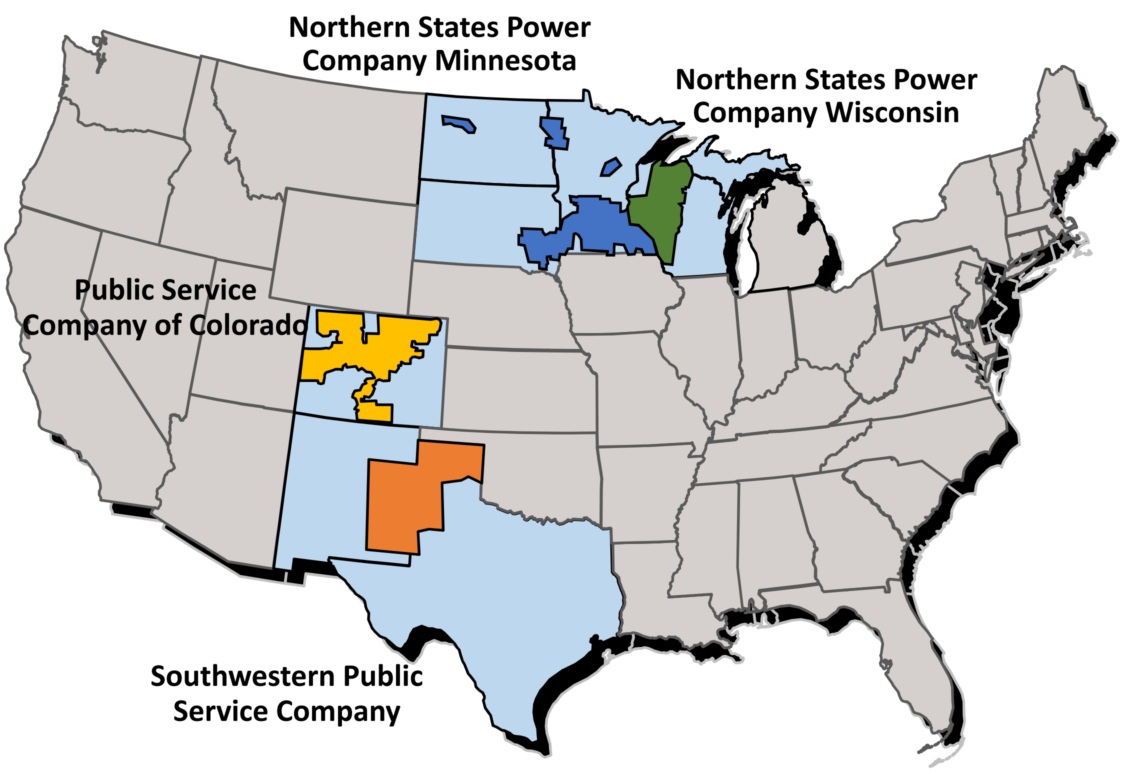
[21] This sub-category also includes discrete maintenance risk projects that are not part of the risk ranking prioritization.

A. Xcel Energy Overview

Xcel Energy is a major U.S. electric and natural gas company based in Minneapolis, Minnesota. We have regulated operations in eight Midwestern and Western states – Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin – where we provide a comprehensive portfolio of electricity- and natural gas-related products and services to approximately 3.6 million customers. Our Upper Midwest service area is part of an integrated system of generation and transmission made up of two operating companies – NSPM, which serves Minnesota, North Dakota and South Dakota; and Northern States Power Company-Wisconsin (NSPW), which serves Michigan and Wisconsin – collectively referred to as the NSP System.

Xcel Energy serves nearly 1.9 million electricity and natural gas customers in its NSP service areas – with 1.6 million in its NSPM operating company. Figure 9 below illustrates Xcel Energy's nationwide territory.

Figure 9: Xcel Energy Operating Company Service Areas



Approximately 88 percent of NSPM customers are residential, with commercial and industrial customers comprising most of the remaining 12 percent.

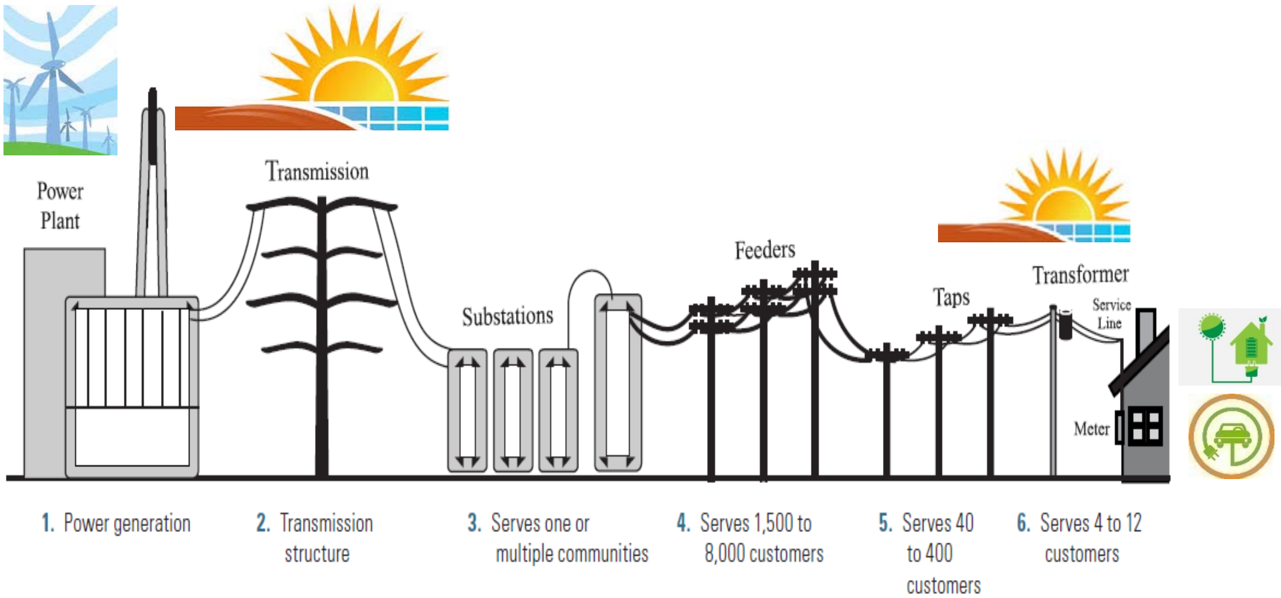
We strive as a company to be responsive to the diverse interests and needs of our customers, and our corporate priorities are to lead the clean energy transition, enhance the customer experience, and keep customer bills low. Our record on environmental performance is exemplary. Our Upper Midwest system is on track to have a generating fleet that is 63 percent carbon-free by 2030 – and we have articulated an aspirational goal to reduce emissions by 85 percent by 2030. We have been named the number one wind provider in the United States by the American Wind Energy Association in more than ten of the last 15 years, and we are on pace to become the first company in the nation to have more than 10,000 MWs of wind.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system. It is our vision to be the preferred and trusted provider of the energy our customers need. We recognize that energy is fundamental to the quality of people's lives and the economic health of our communities. We are committed to customer satisfaction by continuously improving our planning and operations to be a low-cost, reliable, environmentally sound energy provider. We have been successfully proving this to our customers for more than 130 years and will work hard to continue this commitment in the future.

B. Distribution System Overview

The electrical grid is composed of generating resources, high voltage transmission, and the distribution system, which is the vital final link that allows the safe and reliable flow of electricity to serve our customers. See Figure 10 below.

Figure 10: Illustrative Electrical Grid



As illustrated above, the poles, lines, and cables that comprise the distribution system connect individual residents and business to the larger electrical grid.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota) – and is composed of 1,177 Feeders, approximately 15,000 circuit miles of overhead conductor, and over 11,000 circuit miles of underground cable.[22] The distribution portion of the grid, and the services that the Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers. In terms of reliability, we rank nationally in the top of the 2nd quartile – near the 1st quartile threshold.[23]

Key Distribution functions include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. We are also out in the community during and after severe weather events as part of our industry-leading storm response efforts to ensure safety, and to promptly restore service to customers.

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[22] In this context, the number of customers is based on the number of electric meters.
[23] Results for the NSPM operating company, as measured by SAIDI and SAIFI. *See IEEE Benchmark Year 2018, Results for 2017 Data* at: http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf

To provide these key services, the Distribution organization is structured around four functional areas: (1) *Operations* – responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response, (2) *Engineering* – provides technical support and system planning, including addressing distribution-related customer service issues, (3) *Business Operations* – responsible for several areas, including vegetation management, outdoor lighting, metering systems and support, facility attachments, and the builders call-line, and (4) *Planning and Performance* – provides business planning, consulting, analytical services and performance governance and management.

Key overall 2018 Electric Distribution business priorities are:

- *Operational Excellence.* Improve reliability performance level.
- *AGIS/Grid Modernization.* Install key equipment and systems to operate the new modern grid including monitoring and control, Advanced Distribution Management System, and system efficiency. Targeted renewal of aging, unreliable, or obsolete components and systems (i.e. underground cable, poles, 4kV systems)
- *System Health.* Targeted maintenance of key assets designed to improve reliability and safety – wood poles, substations transformers & breakers, vegetation management.
- *System Capacity Additions.* Installation or reinforcement of key substations and feeders to serve new load and provide backup under emergency conditions (focus on high consequence events).

C. Distribution System Statistics

The Commission's Order setting the IDP requirements includes several distribution system statistics, which we provide below. Where more detail is involved in providing the information, we refer to a corresponding Attachment to this filing.

1. Summary of existing system visibility, measurement, and control capabilities

IDP requirement 3.A.2 requires the following:

> *Percentage of substations and feeders with monitoring and control capabilities, planned additions.*

IDP requirement 3.A.3 requires the following:

A summary of existing system visibility and measurement capabilities (feeder-level and time-interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual).

These two requirements are intertwined with each other because they both pertain to system visibility. Therefore, we have combined the information required in Items 3.A.2 and 3.A.3 into Table 6 below.

Table 6: Feeder Load Monitoring – State of Minnesota

FLM Type	% of subs	Measurement	Measurement Interval	Automated /Manual	Frequency of reads	Min/ Max	Daytime/ Nighttime
Full FLM	40%	3 phase Amps, MW, MVar, MVA, kV	Hourly	Auto	Continuous[1]	Yes- *Manual effort*	Both
Partial FLM	21%	Has some or most of the above data points, varies by location	Hourly	Auto	Continuous[1]	Yes- *Manual effort*	Both
No FLM	39%	Only manual reads available (provides 3 phase Amps)	Varies	Manual	Varies	No	Neither

Note: Approximately 90% of our customers are served by substations and feeders that have Full or Partial FLM.
[1] While there is continuous data flow to the operation center, only hourly data is maintained in the data warehouse.

Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. This includes control and data of our system, and we frequently refer to the data acquisition portion as Feeder Load Monitoring (FLM). A substation that has SCADA almost always contains both FLM and control. However, there may be substations where we do not have FLM, but we do have control.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels over an entire year as the inputs to our planning process. Ideally, this includes three phase Amps, MW, MVar, MVA, and Volts. However, not all of these data points are available for all locations. For internal tracking and reporting purposes, when all three-phase Amps, MW, MVar, and kV are included on all feeders and two of the following three for the substation transformers (MW, MVar, or MVA) then that counts as Full FLM. If we are missing one or more data points at the substation then it will fall under Partial FLM. If we have nothing, then it falls under No FLM. Our SCADA-enabled substations and feeders serve approximately 90 percent of our customers (Note: Most of our non-SCADA substations are in rural areas).

Our SCADA also collects enough information throughout the course of a year to determine daytime minimum load for all feeders equipped with this functionality, but it takes extra manual effort to derive a daytime minimum load. Consequently, we do not track and update minimum loads for our system at this time.

For No FLM and some Partial FLM substations, on approximately a monthly basis, field personnel collect data, including peak demands for feeders and transformers. Peak load values are recorded in the field and entered into a database that engineering accesses and uses for planning purposes. After the recordings are documented, field personnel reset the peak load register, so the following period's data can be accurately captured without influence from the previous period. Because this is a manual process, the data may have gaps or may not occur at precise monthly intervals.

We additionally note that we have control capabilities at 62 percent of our substations. Similar to customers served from substations and feeders with Full- or Partial-FLM, approximately 90 percent of our customers are served by substations and feeders that have control capabilities.

Given the importance of SCADA capabilities to reliability and load monitoring (for planning and due to increasing levels of DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at 3-5 substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA.

2. *Numbers of AMI Customer Meters and AMI Plans*

IDP requirement 3.A.4 requires the following:

> *Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available.*

We presently have no AMI meters installed in Minnesota. We discuss our AMI plans and expected functionality in the Grid Modernization Section of this IDP.

3. *Estimated System Annual Loss Percentage*

IDP requirement 3.A.8 requires the following:

> *Estimated distribution system annual loss percentage for the prior year.*

The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system.

Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class' total peak is reached.

There are five categories or distribution subsystems where specific losses occur. Within these categories there may be load and no-load losses, as summarized in Table 7 below.

Table 7: Categories of Load and No-Load Losses

Category	Load Losses	No-Load Losses
Distribution Primary Transformers	Yes	Yes
Primary Distribution Lines	Yes	No
Distribution Secondary Transformers	Yes	Yes
Service Lines and Drops	Yes	No
Meters	No	Yes

For example, transformers have both load and no-load losses. Load losses are function of the transformer winding resistance and the load current through the transformer; sometimes these losses are called copper losses. Transformers and electric meters have also no-load losses which are a function of voltage. Voltages in US power systems are relatively constant, so no-load losses are considered relatively constant. Sometimes no-load losses are called iron or excitation losses.

Losses are estimated using engineering calculations and load research class customer load profiles, because advanced technologies and equipment to specifically measure actual losses across the transmission and distribution systems have historically been cost-prohibitive to implement.

Advanced technologies have been implemented on the transmission system that makes actual calculations of transmission losses more of a practical reality within the next year or so. However, advancements like this at the distribution level lag transmission due to the nature of the distribution system, which requires the advanced technologies to be implemented on a much more wide scale. However, our investments in AMI, FAN, and grid sensing and controls technologies as part of our advanced grid initiative will further our capabilities to mature this analysis over time.

The engineering analysis underlying our calculated losses used Company equipment records to determine numbers and sizes of distribution system lines and transformers, and engineering models to calculate losses from average loadings based on metered sales data through various distribution system components.

The average loading method calculates losses based on the ratio loading on each of the following system components to the maximum of the components:

- Distribution substation transformers
- Primary lines
- Primary to primary voltage
- Transformers
- Distribution line transformers
- Secondary distribution lines

From this analysis, we perform calculations monthly to update the loss percentages for each system level, and then apply those percentages to sales.

The process to update the loss percentages is as follows:

1. Gather five years of monthly MWh energy and sales by state.
2. Calculate the difference of energy and sales for each of the months in the 5-year timeframe.
3. Calculate a MWh loss percentage from the original MWh energy values by month in the 5-year history.
4. Calculate a 5-year average by month, using the values derived in step 3.
5. At this point, calculate an annual average by month using the values from step 4.
6. The values from step 5 are then used to represent current losses in each given state.
7. The overall losses by state described in step 6 are then used to update losses at each voltage level the engineering loss study completed.

This process resulted in the 2017 loss percentages for the state of Minnesota, as provided in Table 8 below.

Table 8: 2017 System Loss Percentages – State of Minnesota

Voltage Level	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bulk(UT)	0.9730	0.9725	0.9704	0.9707	0.9741	0.9759	0.9750	0.9750	0.9747	0.9735	0.9727	0.9725
Bulk(T)	0.9672	0.9668	0.9645	0.9651	0.9688	0.9706	0.9695	0.9696	0.9697	0.9684	0.9670	0.9668
Tran(UT)	0.9618	0.9614	0.9591	0.9600	0.9641	0.9656	0.9643	0.9646	0.9653	0.9639	0.9617	0.9613
Tran(T)	0.9601	0.9598	0.9575	0.9585	0.9627	0.9641	0.9627	0.9632	0.9639	0.9625	0.9601	0.9596
Subtran(UT)	0.9523	0.9521	0.9497	0.9510	0.9562	0.9571	0.9554	0.9564	0.9574	0.9563	0.9525	0.9517
Subtran(T)	0.9466	0.9464	0.9439	0.9452	0.9502	0.9508	0.9488	0.9500	0.9514	0.9506	0.9467	0.9459
Primary	0.9331	0.9342	0.9325	0.9335	0.9361	0.9322	0.9278	0.9312	0.9368	0.9380	0.9336	0.9325
Lg secondary	0.9202	0.9208	0.9183	0.9192	0.9227	0.9190	0.9147	0.9180	0.9230	0.9235	0.9201	0.9195
Sm Secondary	0.9114	0.9117	0.9092	0.9095	0.9106	0.9050	0.8998	0.9049	0.9108	0.9135	0.9108	0.9105

4. SCADA Capabilities and Maximum Hourly Coincident Load (kW)

IDP Requirement 3.A.9 requires the following:

> *For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system.*

The NSP System peak in 2017 was 8,546 MW, which occurred at 6:00 p.m. on July 17, 2017. The Minnesota portion of this peak was 6,484 MW.

We have SCADA capabilities that enable the Company to measure the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system at substations serving approximately 90 percent of our Minnesota customers. We have thus calculated the 2017 peak coincident load at 5,742 MW for the Minnesota portions of the distribution system with sufficient SCADA capabilities.

We clarify that in order to provide this information we must manually pull the maximum hourly load for each SCADA-enabled substation for the date and time of the NSP System. Due to the manual effort to fulfill this requirement, it would be helpful to understand how stakeholders intend to use this information – as there may be other information we could provide that would require less manual effort to meet that need.

5. Total Distribution Substation Capacity in kVA

IDP Requirement 3.A.10 requires the following:

> *Total distribution substation capacity in kVA.*

Distribution Substation Capacity = 14,873,148 kVA or 14,873 MVA

The total distribution substation capacity is reflective of substations that are presently active, functional, and owned by the Company. We calculated this by summing each individual distribution transformer's nameplate power rating across our Minnesota service area.

6. *Total Distribution Transformer Capacity in kVA*

IDP Requirement 3.A.11 requires the following:

> *Total distribution transformer capacity in kVA.*

As noted in our Comments and Reply Comments on the proposed IDP Requirements, we understand this requirement to be the total distribution substation transformer kVA.[24] Given that understanding, please see our response to 3.A.10 above.

7. *Total Miles of Overhead Distribution Wire*

IDP Requirement 3.A.12 requires the following:

> *Total miles of overhead distribution wire.*

As of September 30, 2018, we approximated our overhead conductor at 14,968 circuit miles for the NSPM operating company.

8. *Total Miles of Underground Distribution Wire*

IDP Requirement 3.A.13 requires the following:

> *Total miles of underground distribution wire.*

As of September 30, 2018, we approximated our underground cable at 11,297 circuit miles for the NSPM operating company.

9. *Total Number of Distribution Premises*

IDP Requirement 3.A.14 requires the following:

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[24] *See* Xcel Energy Comments, Attachment A at page 3, Docket No. E002/CI-18-251 (July 6, 2018) and Reply Comments, Attachment A at page 3, Docket No. E002/CI-18-251 (July 20, 2018).

Total number of distribution premises.

We clarify that a premise is a unique combination of meter number and address. As of September 30, 2018, we had 1,474,906 electric premises in the NSPM operating company, with 1,285,876 of those in our Minnesota service area specifically.

V. SYSTEM PLANNING

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We see this changing as our planning processes evolve, to analyze future electricity *connections*, rather than just loads. However, in this section we describe our present processes.

The purpose of these assessments is to proactively plan for the future and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0 operation) and *single contingency* (N–1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully-functional. Single contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service.

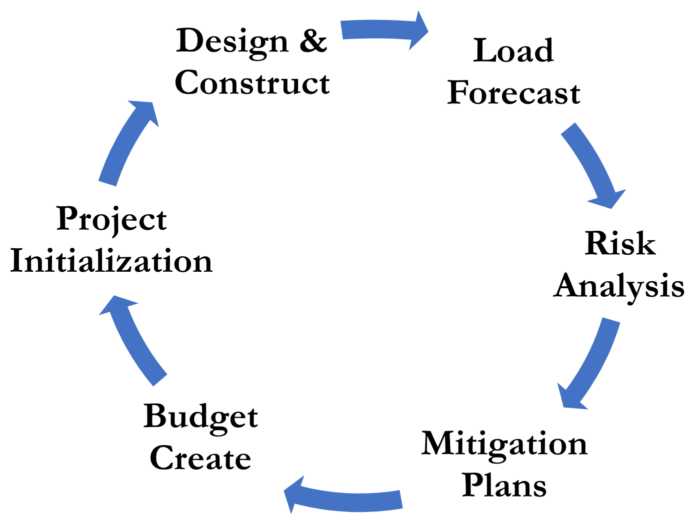
Corrective actions identified as part of the planning process may include a new feeder or substation, adding feeder tie connections, installing regulators, capacitors, or upsizing substation transformers. As our planning processes evolve and technologies mature, we will continue to consider non-wires alternatives. For each project, we develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors including operational requirements, technical feasibility and future year system need. Proposed projects are funded as part of an annual budgeting process, based on a risk ranking methodology that also funds other distribution investments and expenditures including asset health, grid modernization, and emergent issues such as storm response and mandated projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public projects such as road widening or realignment.

In this Section, we describe the Company's distribution system planning approach, including planning processes and tools used to develop the annual plans.

A. Overall Approach to System Planning

We analyze our distribution system annually and conduct additional analyses during the year in response to new information, such as new customer loads, or changes in system conditions. In the fall of each year we initiate the planning process, beginning with the forecast of peak customer load and concluding with the design and construction of prioritized and funded capacity projects, as summarized in Figure 11 below.

Figure 11: Annual Distribution Planning Process



As part of our annual distribution planning process, we thoroughly review existing and historical conditions, including:

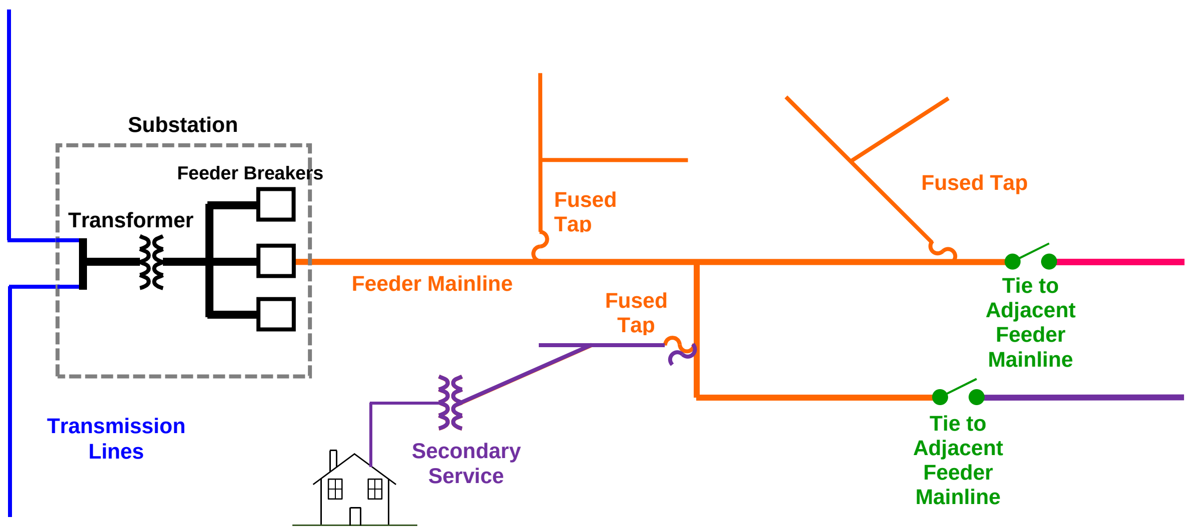
- Feeder and substation reliability performance,
- Any condition assessments of equipment,
- Current load versus previous forecasts,
- Quantity and types of DER,
- Total system load forecasts, and
- Previous planning studies.

We begin our annual plans in the fourth quarter, using measured peak load data from the current year, as well as historic peak information to forecast the loads on our distribution system over a five-year time horizon. We then perform our risk analysis based on loads near the middle of the forecast period. Tangibly, in Q4 2018, we will use 2018 actuals and historical peak information along with any known system changes to forecast the 2019 to 2023 peaks, and perform our risk analysis based on the forecasted 2021 peak.

1. *Feeder and Substation Design*

Distribution feeders for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system, within established standards for reliability, which typically measure the average duration (System Average Interruption Duration Index or SAIDI) and frequency (System Average Interruption Frequency Index or SAIFI) of interruptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour. Foundational components in distribution system design and planning are substations and feeders.

Figure 12: Distribution System: Basic Design Schematic of Typical Radial Circuit Design



We plan and construct distribution substations with a physical footprint sized for the ultimate substation design, which is based on anticipated load, but can occasionally be limited by factors such as geography and available land. The maximum ultimate design capacity established in our planning criteria is three transformers at the same distribution voltage. There is one exception to this criterion. In downtown Minneapolis, we have one substation that houses four transformers to serve the significant load. This maximum size balances substation and feeder costs with customer service, customer load density, and reliability considerations.

Cost considerations include the transmission and distribution capital investment in the lines, load losses (which are generally proportional to line length), land cost, and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access, and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to ultimate design capacity. Higher levels DER will affect substation capacity, system protection, and voltage regulation.

Figure 13: Distribution Substation

Feeders are sized to carry existing and planned customer load. Where possible, we design-in redundancy, which has a positive impact on reliability. Feeders have a "range," like a mobile phone service tower, where they can effectively serve. For 15kV, which is common in the Twin Cities metro area, the range is approximately three miles. In rural areas where system load is less geographically dense, the range is higher – approximately one mile per kV. Thus, if customer load density remains the same, then higher voltages can serve a proportionately greater distance.

Feeders typically serve approximately 1,500 customers, though this varies based on voltage, location, customer load density, and the utilization of the feeder. The industry benchmark for feeder capacity is approximately 600 amps, which provides an efficient balance of the costs of conductors, capacity, losses, and performance. This translates to a maximum load-serving capability of about 15 MVA on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

2. *Planning Criteria and Design Guidelines*

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all customer electric load under normal and first contingency conditions. Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate first contingency capacity allows for restoration of all customer load by reconfiguring the system by means of electrical switching, in the event of the outage of any single element. For example, we strive to load feeders to approximately 75 percent of maximum capacity, which provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Adequate substation transformer capacity, no normal condition feeder overloads, and adequate field tie capabilities for feeder first contingency restoration are key design and operation objectives for the distribution system. To achieve these objectives, we use distribution planning criteria to achieve uniform development of our distribution systems. Distribution Planning considers these criteria in conjunction with historical and projected peak load information in annual and ongoing assessment processes.

While the distribution guidelines vary depending on the specific distribution system attribute, there are several basic design guidelines that apply to all areas of our distribution system, as follows:

- Voltage at the customer meter is maintained within five percent of the customer's nominal service voltage, which for residential customers is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to three percent. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.
- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.
- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75 percent of capacity.[25] We developed this standard to

[25] 34.5 kV follows a 50 percent loading rule.

help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss, because adding load to the remaining feeder circuits would cause them to overload.[26]

All distribution system equipment has capacity, or loading, limits that must factor into our planning processes. Exceeding these limits stresses the system, causes premature equipment failure, and results in customer outages. Our planning processes primarily focus at the substation and feeder levels, but also consider limitations and utilization of other system components such as cable, conductors, circuit breakers, transformers, and more.

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost-effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in our Electric Distribution Standards. We generally discuss our Electric Distribution Standards function in Section VII below.

When we add new feeder circuits to a mature distribution system, we are not always able to maintain minimum spacing between feeder circuit mainline cables due to right-of-way limitations or a high concentration of feeder cables. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks." When feeder circuits are concentrated in duct banks they experience mutual heating, therefore those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use software tools to determine

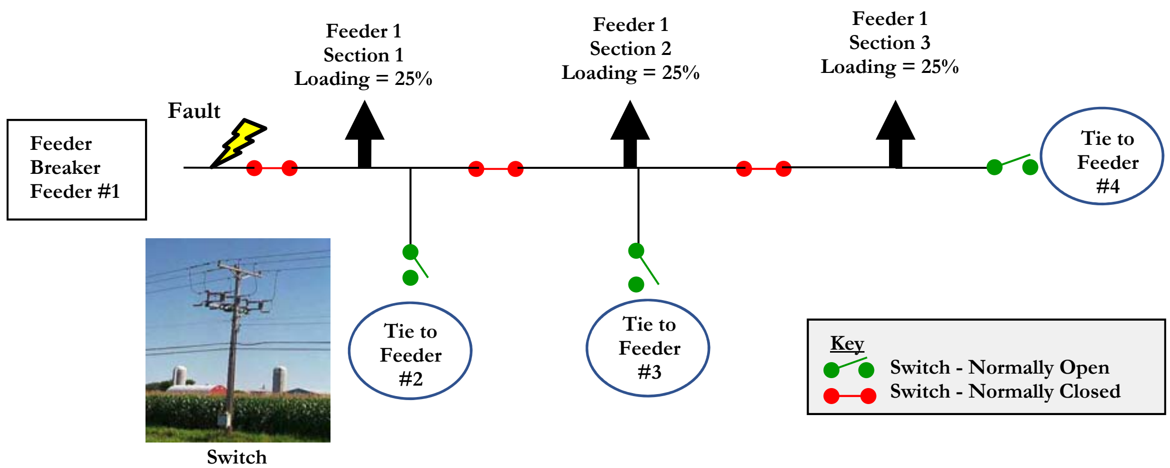
[26] By targeting a 75 percent loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A feeder circuit capable of delivering 12 MVA, for example, should be normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct lines, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted. This would require constructing facilities from a different area to serve this load.

As we have noted, our planning criteria aims to maintain feeder utilization rates at or below 75 percent to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. Therefore, to assess the robustness of the system over time, Planning Engineers analyze the historical utilization rates and projected utilization rates based on forecast demand. They generally apply the 75 percent loading guideline when assessing the system across a larger area as part of an area study. The 75 percent guideline is appropriate for these larger area studies because it is often not practical to analyze the section and tie-transfer breakdowns for each individual feeder in each of the identified solution options similar to what is done in our annual planning process. Since the section and tie-transfer breakdowns are highly detailed and specific to the geography and topology of the individual feeders, it is easier to compare and articulate the differences between solution options with a 75 percent loading guideline.

Figure 14 below illustrates this concept with a mainline feeder. The feeder shows the three sections equally loaded to 25 percent of the total feeder capacity. The green and red symbols represent switches that can be operated to isolate or connect the sections of the feeder in the case of a fault. In that circumstance, the feeder breaker in the substation will operate to isolate the feeder where the fault is detected. Then, the normally closed section switches are opened to isolate the section of the feeder in which the fault is detected. Isolating the fault allows a portion of the customers served by that feeder to remain in service while we repair the fault and return the feeder to normal operation.

Figure 14: Typical Mainline Distribution Feeder with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations Mainline Feeder No. 1



In this circumstance, Feeders 1 to 4 all have the same capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders 2, 3, and 4 through the corresponding tie switches. This reconfiguration results in Feeders 2, 3, and 4 each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder #1 sections). This reconfiguration capability maintains electric service to customers while we repair the fault to the feeder and return the system to normal operation.

Area studies are typically initiated on a case-by-case basis, when Distribution Planning identifies a high number of individual risks or loading constraints within a localized area. These localized area studies vary in size, scope, and scale based on the issues identified, and can encompass a single substation, an entire city, or an entire geographic region. When the 75 percent guideline is applied in an area study, it provides an efficient means of approximating how much additional capacity is needed in that area. When the total feeder circuit utilization within the study area exceeds 75 percent (as calculated using Figure 15 below), it is generally no longer effective to perform more simple solutions – such as load transfers, or installing new feeder tie connections between existing feeders.

Figure 15: Total Feeder Circuit Utilization in Study Area

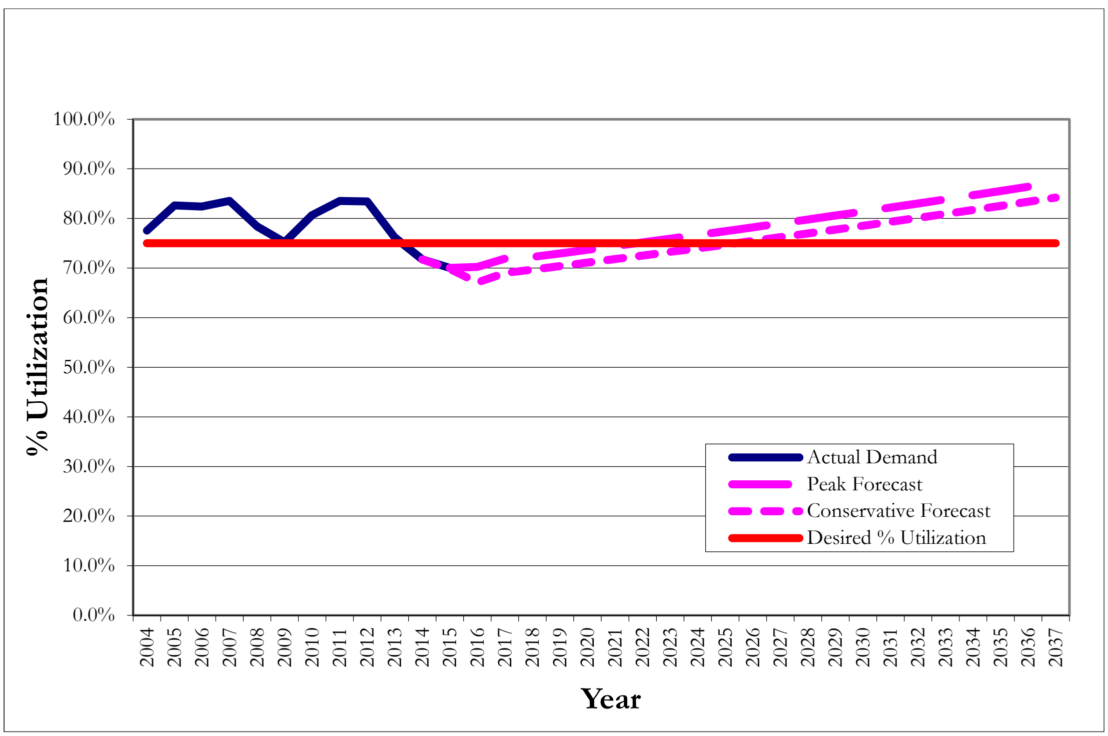
$$\text{Total Feeder Circuit Utilization} = \frac{\sum \text{Feeder Circuit Load in Area}}{\sum \text{Feeder Circuit Capacity in Area}}$$

These simple solutions merely patch a capacity-deficient portion of the system temporarily; rather than solve the issue, they often result in shifting the overloads or contingency risks from one feeder to another. However, when the total feeder circuit utilization is within a reasonable margin beneath 75 percent, there is generally enough capacity in the area for simple solutions to be viable for resolving any remaining risks.

While a generalized 75 percent utilization is ideal, it may not be feasible depending on system configurations. Feeder utilization in Minnesota is on average 66 percent; approximately 38 percent of the feeders are above 75 percent utilization. When we analyze feeders and transformers, we use the specific loading and configuration to determine the N-0 and N-1 overloads. Because of the wide variety of system configurations, the evaluation may show certain transformers or feeders may be loaded to higher utilization without causing an overload.

Figure 46 below shows an example of total feeder circuit utilization for feeders in a study area over the timeframe of the study period.

Figure 16: Total Feeder Circuit Utilization in Study Area – Historical Peak Demand and Peak Demand Forecast



The feeder circuit load history is the actual non-coincident peak loading of all feeder circuits in the study area measured at the beginning of the feeder circuits in the substation. We compare the sum of the individual feeder circuit peak to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. We calculate average load growth for the time period by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period. A peak load forecast starting from the historic peak level provides an upper forecast limit.

Isolated feeder overloads, which can be characterized by an individual feeder overload that occurs when average feeder utilization percentage is *less* than 75 percent, typically occur when there is new development or redevelopment that increases load demand within a small part of the distribution system. Widespread feeder overloads, which can be characterized by one or more individual feeder overloads that occur when average feeder utilization percentage is *more* than 75 percent, typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or community initiatives.

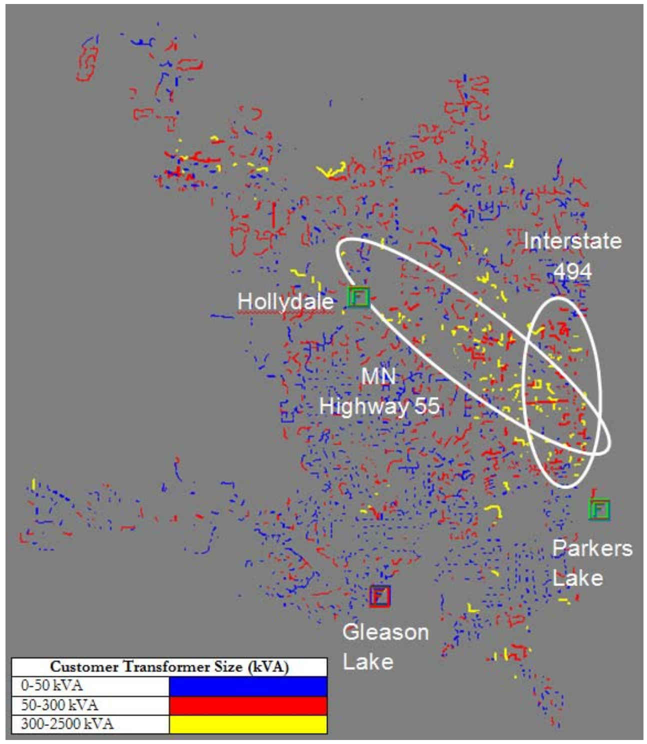
Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

In addition to feeder peak loads, Distribution Planning examines existing feeder load density by studying the distribution transformers serving the customers. Distribution transformers are the service transformers that step the voltage down from feeder voltages to the voltage(s) that the customer receives at their point of service. As customer load grows in developed areas, we change distribution transformers to higher capacity equipment when customer demand exceeds the capacity of the original transformer.

Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand, and are used to help validate the growth that is observed and forecasted in the annual peak demand and load forecast analysis.

Figure 17 below is an example of distribution transformer installation by size from a prior analysis we completed for western Plymouth. This view is helpful to understand present customer load density.

Figure 17: Distribution Transformer Installation by Size



Developed using Synergi Electric

After examining feeder circuit peak demands, we look at the loading levels for the transformers housed at the substations.

Transformers have nameplate ratings that identify their capacity limits. Our internal Transformer Loading Guide (TLG) provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The TLG is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard for transformer loading, ANSI/IEEE C57.92. The TLG consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures, which are the criteria used by Substation Field Engineers to determine normal and single-cycle transformer loading limits that planning engineers use for transformer loading analysis.

A transformer's *normal* loading limit is called the transformer "loadability," which represents the maximum loading that the transformer could safely handle for any length of time. A transformer's *single-cycle* loading limit represents the maximum loading that the transformer could safely handle in an emergency for at most one load cycle (24 hours), and is what we use for our substation transformer N-1 contingency analysis. When internal transformer temperatures exceed predetermined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life." Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

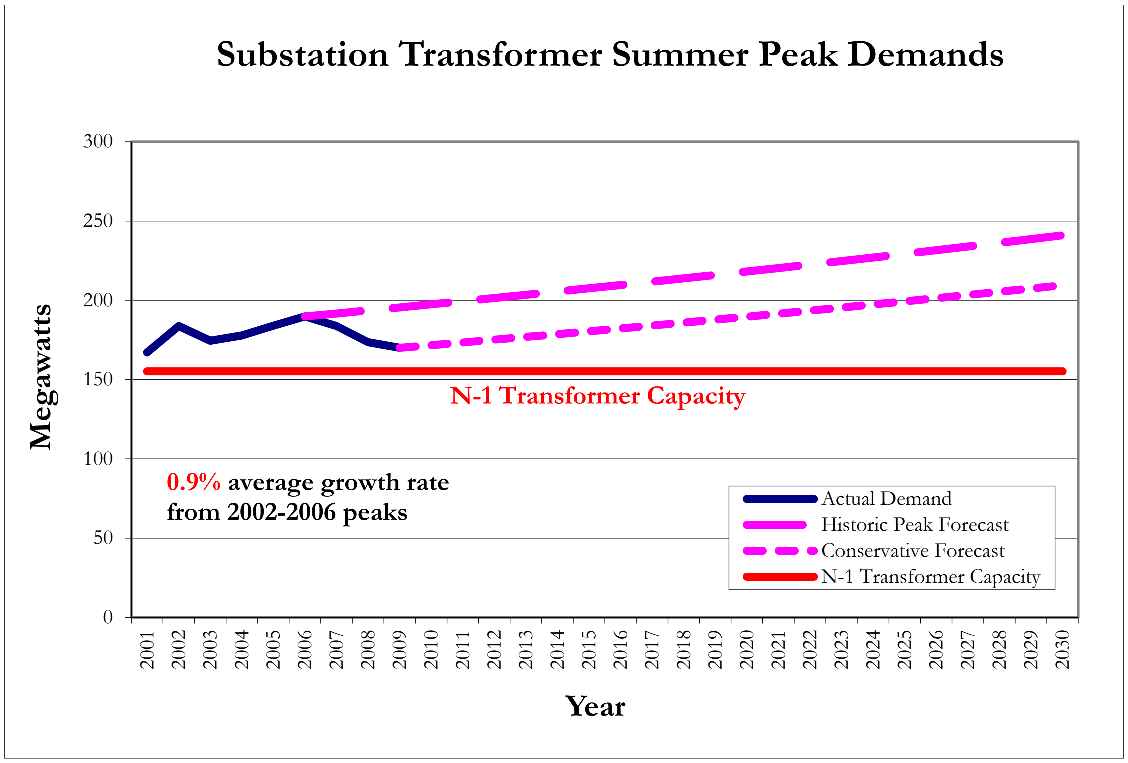
To ensure maximum life and the ability to reliably serve customers, our loading objective for transformers is 75 percent of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75 percent are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization rate, the higher the risk of a transformer outage that interrupts service to customers.

Each distribution substation has a demand meter that is read monthly for each substation transformer. These meters record the transformer's monthly peak. For those distribution substation transformers that have a Supervisory Control and Data Acquisition (SCADA) system connection, we are able to monitor the real-time load on the transformer. We currently have SCADA in about 165 of our distribution substations, which serve over 90 percent of our customers. Similar to distribution feeders, the transformer data feeds into a data warehouse, which can be combined with hourly historic and forecast peak load data in our Distribution Asset Analysis (DAA) system, so we can view the substation transformer's load history.

Each transformer's peak in a multi-transformer substation is non-coincident – meaning the transformers can each individually experience peak load at different times, and potentially on different days. This is a result of the fact that each transformer serves multiple feeder circuits that each serve different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service due to the larger number of customers affected for any event on a transformer than on a feeder.

Figure 18 below is an example of load growth using historical and forecasted peak loads for a set of substation transformers

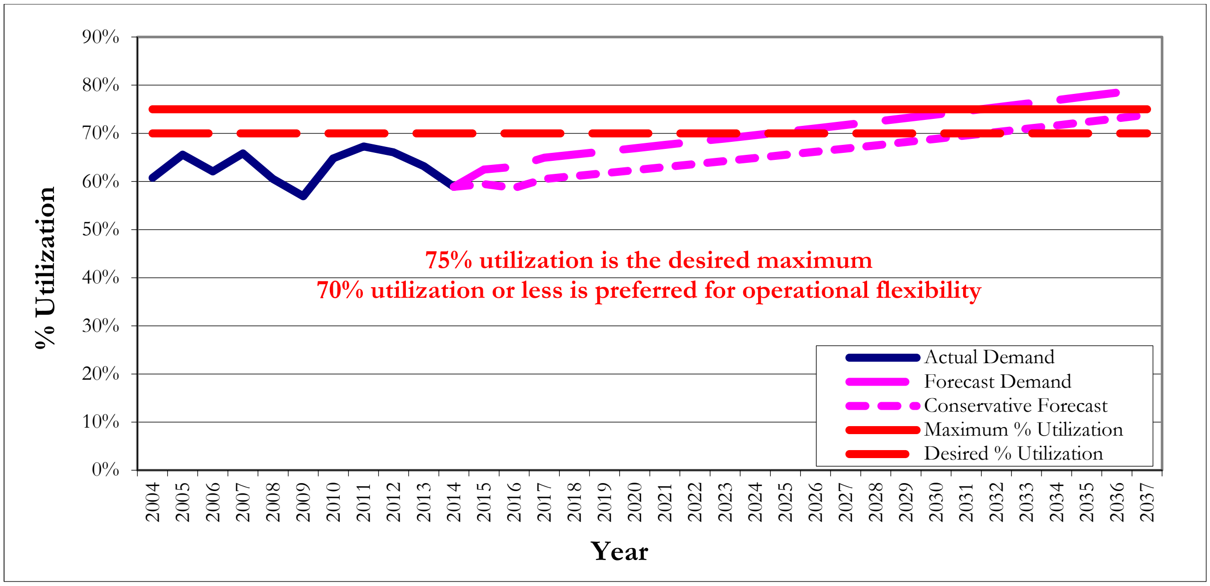
Figure 18: Greater Study Area – Historical and Forecasted Loads



The upper and lower dashed lines provide a bandwidth for growth, forecasted from the conservative peak and historic peak values, respectively.

As part of our analysis, we review the loading and utilization rates of distribution substations. We provide an example of our transformer utilization analysis in Figure 19 below, which illustrates the bandwidth of expected load growth that is forecasted to occur between the upper and lower dashed lines.

Figure 19: Total Transformer Utilization Percentage for Transformers – Focused Study Area



Even when using conservative peak load levels from the lower dashed line, in this circumstance forecasted load levels still exceed desirable loading levels for the substation transformers in the later years of the 20-year forecast in the study. The range of likely transformer utilization falls between the dashed lines of the conservative forecasted demand and the historic peak forecast load levels.

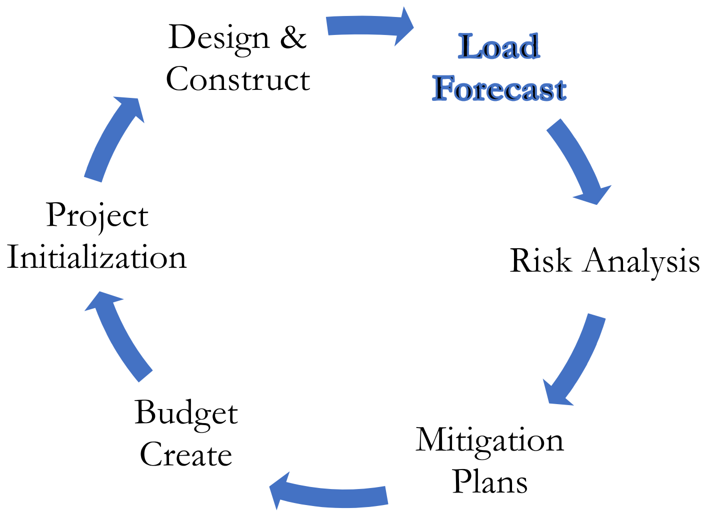
Using the planning criteria such as we have described above, Planning Engineers evaluate the distribution system, and are able to determine transformer and feeder loading and identify risks for normal and contingency operation of the system.

B. Distribution Planning Process

1. *Planning to Meet the Peak Load*

We begin our process by forecasting the load for both feeders and substations.

Figure 20: Annual Distribution Planning Process – Load Forecast



In this step, we run a variety of scenarios that account for all the various drivers of load changes. This includes consideration of historical load growth, weather history, customer planned load additions, circuit reconfigurations, new sources of demand (penetration of central air-conditioning, electric vehicles), DER applications, and any planned development or redevelopment.

Then we generate a five-year forecast, aggregate the results, and compare this analysis with system projections. See the Action Plan Section XIV for the load forecast resulting from this analysis in compliance with IDP Requirement D.2, which requires, in part, that we provide our load growth assumptions and how we plan to meet it in our 5-year action plan. We additionally provide our long-term system load projections in compliance with IDP Requirement D.3 in the Action Plan Section of this IDP.

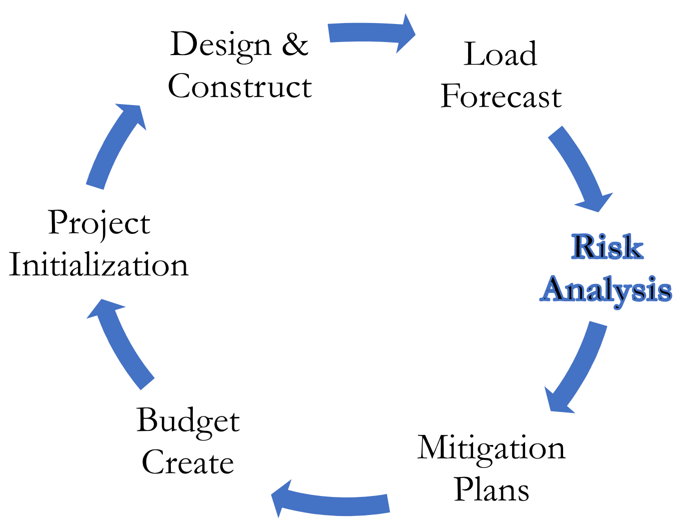
We then provide our distribution forecast to our transmission planning staff, who incorporate the load forecast into their planning efforts. In addition to this load forecast hand-off, we also communicate with transmission regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER at any time of the year, we share that information with transmission. Distribution and transmission personnel also meet twice a year as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system.

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve loads during system peaks.[27] For planning purposes, we define "peak load" as the largest power demand at a given point during the course of one year. Measured peak loads fluctuate from year-to-year due to the impacts of duration and intensity of hot weather and customer air conditioning usage. In examining each distribution feeder and substation transformer for peak loading, we use specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.

2. Risk Analysis

The next step in the planning process is to conduct risk analyses.

Figure 21: Annual Distribution Planning Process



One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload (N-0) is a concern. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability. For example, a 105 percent N-0 for feeder FDR123 means that the peak load on FDR123 exceeds the limit of the feeder's limiting element by 5 percent.

[27] When three phase load data is available, we use the highest recorded phase measurement in our forecast.

Additionally, distribution planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer. For example, a 1.5 MVA N-1 condition for feeder FDR123 means that for loss of FDR123, all but 1.5 MVA of FDR123's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk."

Our 2018 to 2022 annual planning process (initiated in Q4 2017), analyzed forecasted 2018 loads and identified the following total risks across NSPM:

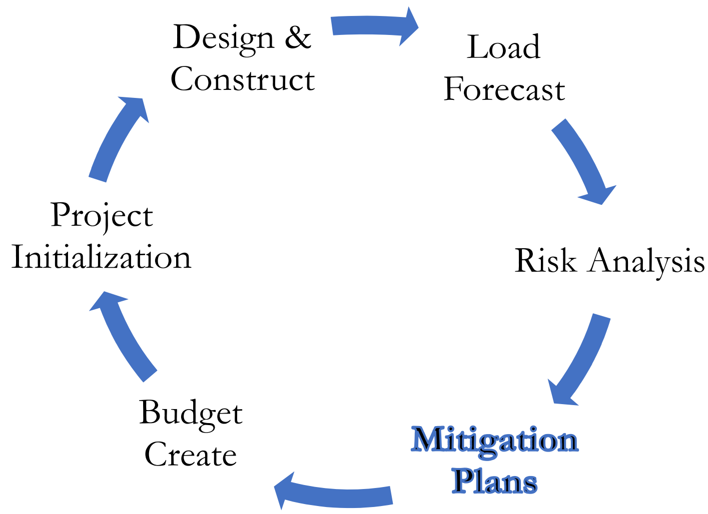
- N-0 normal overloads on 56 feeder circuits
- N-0 normal overloads on 16 substation transformers
- N-1 contingency risks on 408 feeder circuits
- N-1 contingency risks on 122 substation transformers

This process of identifying N-0 overloads and N-1 risks for feeders and substation transformers is referred to as distribution planning's annual "risk analysis." We enter all of these risks into WorkBook, an internal tool used to help rank projects based on levels of risk and estimated costs. The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating risks, planning for new customers, and addressing both the aging of our system – as well as preparing it for the future. We discuss how we strike this balance and prioritize projects below.

3. Mitigation Plans

After identifying system deficiencies, the next step in the planning process is developing mitigation plans.

Figure 22: Annual Distribution Planning Process – Mitigation Plans

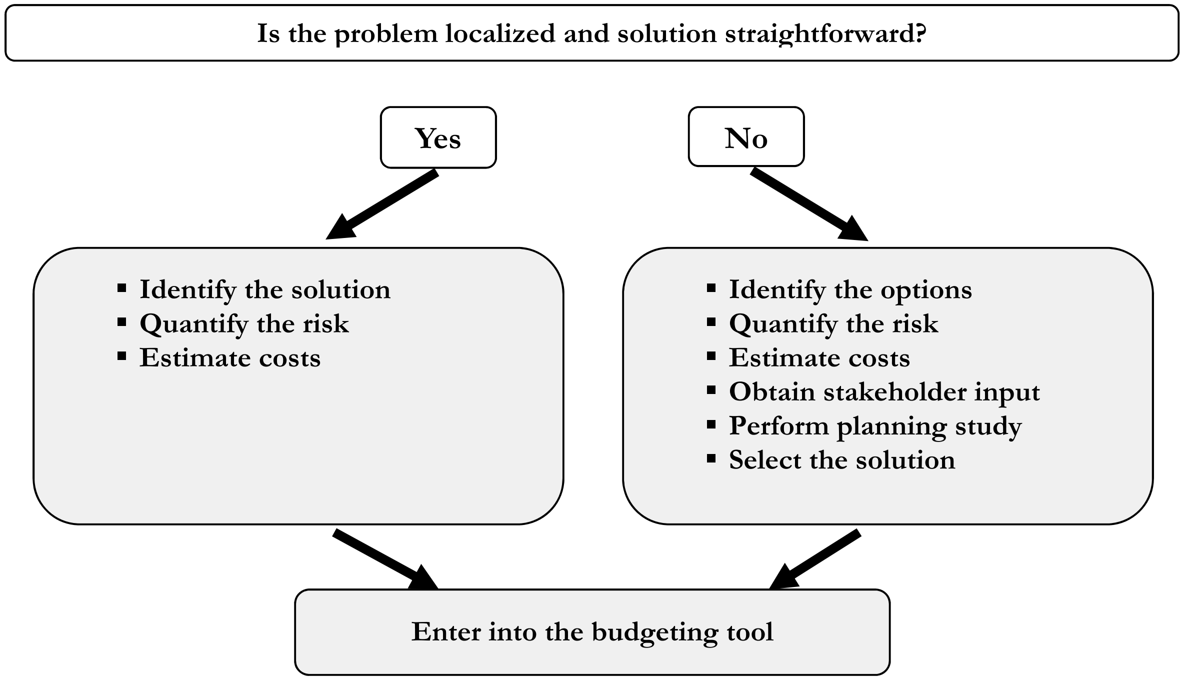


At this step, Planning Engineers identify potential solutions to provide necessary additional capacity to address the identified system deficiencies. We apply thresholds that risks must exceed before we develop a project to mitigate the risk. For N-0 conditions, the overload must exceed 106 percent; for N-1 conditions the load at risk must exceed 3 MVA before we develop a mitigation.

While many of the mitigation solutions are straightforward, others require a detailed analysis. At this point in the process the projects are high level and using indicative unit costs.

Figure 23 below depicts the steps we take to identify potential solutions.

Figure 23: Solution Identification Process



Distribution capacity planning methods address and solve a continuum of distribution equipment overload problems, including isolated feeder overloads, widespread feeder overloads, and substation transformer contingency overloads associated with widespread feeder overloads. Alternatives include reinforcing existing feeder circuits to address isolated feeder circuit overloads, adding or extending new feeder circuits and adding substation transformer capacity up to the ultimate substation design capacity to address more widespread overloads.

Planning Engineers first consider distribution level alternatives including adding feeders, extending feeders and expanding existing substations. If these typical strategies would not meet identified needs because they had already been exhausted or would not be sufficient to address the overloads, the engineers then evaluate alternatives that would bring new distribution sources into the area. DER has not historically been considered a viable alternative for resolving distribution capacity issues due to cost, reliability, capacity, longevity, dispatchability, space constraints and dependability. However, we see these constraints lessening as the technologies mature and operational experience increases.

If we conclude that distribution level additions and improvements would not meet the identified need, we consider the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands. Ideally, new distribution sources should be located as close as possible to the "center-of-mass" for the electric load that they will serve. Installing substation transformers close to the load center-of-mass minimizes line losses, reduces system intact voltage problems, and reduces exposure of longer feeder circuits and outages associated with more feeder circuit exposure.

Once we identify a mitigation solution for the associated risk(s), we enter the mitigation description, indicative estimated costs, and the risks associated into WorkBook, which uses algorithms to develop a ranking score. The result of this entire step, including any necessary planning studies, is a slate of projects for consideration and review as part of the overall Distribution budgeting process.

a. Long-Range Area Studies

If we determine a long-range plan is necessary, we conduct a location-specific study to evaluate various alternatives, which may include DER or DSM. Depending on the scope and scale of the focused study, this process can take weeks or even months, and generally involves the following:

- Identifying the study area (for instance, a single feeder, a substation, or maybe even an entire community or larger).
- Projecting future loads.
- Estimating the saturation of area (limits of development, zoning, etc. on load growth).
- Coordinating with transmission planning to advise them of our work and learn if they have area concerns or projects.
- Generating options.
- Studying and comparing the economics and reliability of the alternatives.

With respect to DSM, we are developing updated methodologies and distribution-avoided costs for energy efficiency.[28] Presently, for assessing distribution impacts, we allocate energy efficiency impacts to each distribution substation and feeder load proportionally based on percentage of system load share. We perform a subsequent summer peak analysis to determine if projects could be deferred. We calculate a deferral value, expressed as $/kW, based on the Xcel Energy corporate cost of capital and using planning level costs for the deferral period. We note that we are also

[28] *See* In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 Conservation Improvement Program Triennial Plans, Docket No. E999/CIP-16-541.

participating in the Minnesota Department of Commerce's Statewide Energy Efficiency Demand-Side and Supply-Side studies, which are examining the future potential for both customers and the Company to reduce peak and energy usage. The Supply-Side study is targeted at utility infrastructure efficiency on the generation, transmission and distribution systems.

These analyses, along with others such as focused long-term area studies, are important complements to our annual planning analysis. We previously provided examples of area studies we have completed, which included non-traditional distribution system solutions.

IDP Requirement 3.A.30 requires that we

> *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.*

We provided examples of public long-term area studies we have completed in the past in our June 21, 2017 Comments in Docket E002/CI-15-556. We provide Attachment D of our June 21, 2017 Comments as Attachment E to this IDP for reference.

b. Plan comparison standards

If Distribution Planning determines a long range plan is needed, we use the following criteria to compare the potential solutions: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which we describe in more detail below. All alternatives must have the ability to meet existing and forecast capacity requirements.

System performance. System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning). We use Synergi system models to examine loading levels and voltage impacts overall and on specific customers under normal and first contingency conditions. We evaluate performance based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

Operability. Operability is how the alternative impacts the Company's distribution equipment, operating crews and construction crews operating the distribution system during normal and contingency operations. We evaluate operability based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

Future Growth. Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure. For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the area.

Cost. For each alternative, we calculate the present value of all anticipated expenditures required for that alternative to serve the forecasted customer loads. The present value calculations are based on indicative estimates for the proposed alternatives,

Electrical Losses. Electrical losses are most often discussed in reference to the additional amount of generation required to compensate for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

c. Capacity Risk Project Prioritization

From this evaluation, projects are assigned a risk score, similar to a cost-benefit ratio. This is useful for comparing the merits of disparate projects. We then select and prioritize the actual solutions for which we intend to move forward.

Based on the analysis of alternatives capable of meeting area customer load requirements, we select the alternative that best satisfies the five distribution planning criteria. For example, locating a new distribution substation closest to the greatest amount of customer load and having the shortest feeder circuits would result in the least amount of customer exposure to outages and the best system performance. It might also use the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered – and be the least expensive to construct and has the lowest electrical losses – making it the most cost-effective and efficient option of the four alternatives.

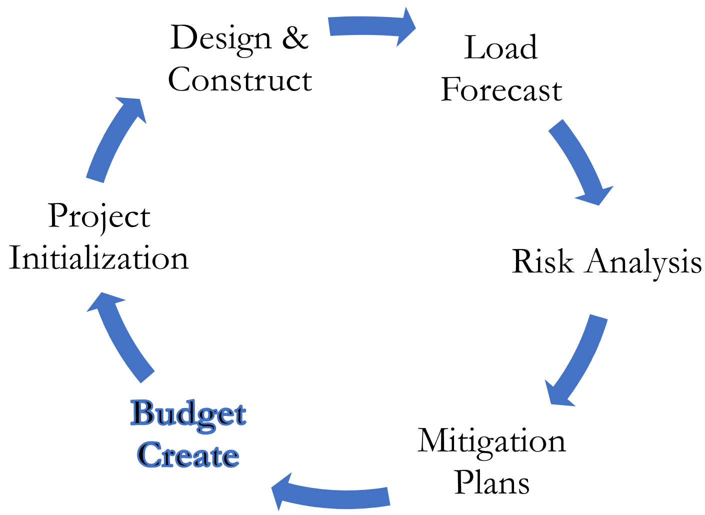
Once we have all the projects identified, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage, and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.).

4. Budget Create

The final step in the planning process before pursuing individual projects is prioritizing the proposed capacity projects into the distribution area's overall budget. At this step, the Company must also provide funding for asset health, new business, and meeting growing customer and policy expectations through support of new technologies and DER.

Figure 24: Annual Distribution Planning Process – Budget Create



The overall budget process recognizes that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. As we replace these key components, we do so with an eye to the future to ensure that the investments we make not only support our customers' needs for reliable service today, but also lay the groundwork for the grid of tomorrow. We must also take steps to implement new systems and technologies that improve our operations and provide customers with more choices related to their energy use. An example of this is investments in our SCADA system, as well as the ADMS we have underway. Together, these systems will provide our engineers and operational staffs significantly improved data from which to monitor and make decisions – all of which benefit our customers in both our planning and response to events occurring on the system.

Given these priorities, we must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by storms, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

As capital spending is determined and, throughout the year as new issues are identified, each operating area brings risks (problems) and mitigations (solutions) forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into a software tool we developed and use to track and rank projects based on the inputs provided – including their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors we use to prioritize investments are as follows:

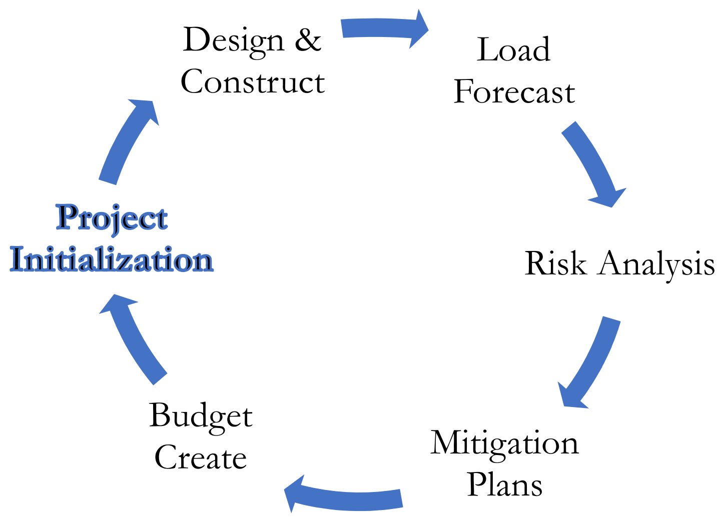
- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities,
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated,
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable,
- *Legal* – Evaluation of compliance before and after the risk is mitigated, and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc. – and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked. We accomplish this by ranking the assessment of each project against each other. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers. We note that we must also apply judgment in the prioritization process. An example of this is two competing new feeder projects – one in the metro area that only involves a short distance, and the other in a rural area that involves installing infrastructure for two miles. The cost of the rural example in this circumstance is higher, and the benefits of the two projects are the same – so the metro project would score higher. However, the rural project is also needed. Our process therefore contemplates some back-and-forth with the planning engineers to validate priorities.

5. Project Initialization

After the capital expenditures budget is finalized, the approved project list becomes the basis for the release, or initiation, of projects during the calendar year.

Figure 25: Annual Distribution Planning Process – Project Initialization



This process must be somewhat flexible to allow for needed additions and deletions within a given year. For example, should an emergency occur during the year, priorities may change and result in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. Through our budget deployment process we are therefore able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Distribution Planning takes the approved capacity projects stemming from this process and communicates them with design and construction. The Planning team continues to participate in the ongoing capital budget processes, as the Distribution business responds to changing circumstances, and interfaces with design and construction to adjust priorities as needed.

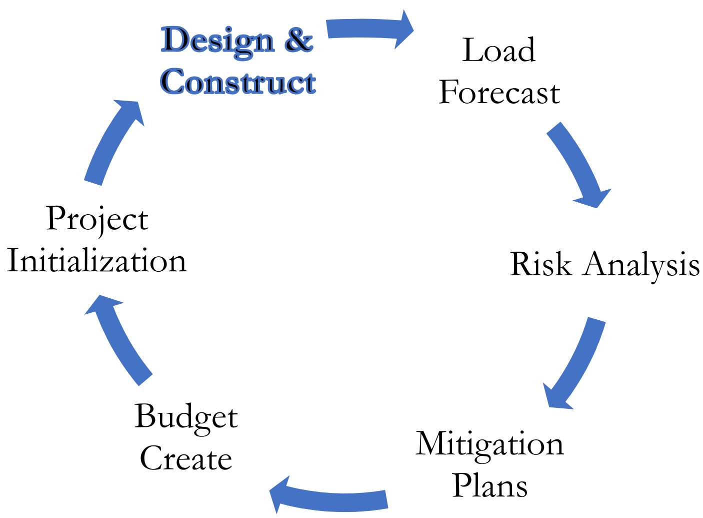
Once the five-year budget is determined, the Planning Engineers write Electric Distribution Planning (EDP) memos for the first two years of approved capacity projects. An EDP memo is a high level step-by-step description of the project that will mitigate an identified risk. The memos describe the problem, the substation design/construction steps to take (if any), and any distribution line design/

construction steps to take. The memos provide maps and text specifying where to place switches, capacitor banks, or where to cut into another feeder to transfer load to a new feeder. These memos initiate the design and construction portion of the project.

6. Design and Construct

Finally, the selected projects are communicated to substation engineering and distribution engineers and designers who bring the projects to life.

Figure 26: Annual Distribution Planning Process – Design and Construct



At this step, these engineers and designers perform detailed design work and initiate their construction. We summarize the groups generally involved and their roles below:

- *Substation Engineering.* If a project requires a new feeder bay at an existing substation or a new substation entirely, this group performs the detailed engineering, design and construction.
- *Distribution Design and Construction.* This area performs the permitting, design, and construction of new feeder circuits or modifications of existing circuits.

Ideally, projects can be implemented precisely as envisioned by Distribution Planning, but often this is an iterative process.

C. Planning Tools

IDP Requirement 3.A.1 requires the following:

Modeling software currently used and planned software deployments.

Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. In response to the fundamental changes occurring on the distribution system affecting how we plan the system, we will need improved tools to aid in developing load forecasts and planning the system. We discuss both current and future distribution planning tools in this section.

1. Current Planning Tools

Table 9 below summarizes the tools and how we use them in our planning process. We then discuss in more detail how we use each of the tools.

Table 9: Planning Tool Summary

Tool	Process	Description
DNV-GL Synergi Electric	Power flow	Contains a geospatially accurate model of the electric distribution Feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system
ITRON Distribution Asset Analysis (DAA)	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	System of record for historical peak feeder and substation transformer load information that we use to evaluate historical load growth and weather adjustments to match prior peaks and identified known load growth to establish a forecast for 1+ years out
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years
CYMCAP	Determines normal and emergency ampacity for Feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as Feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution Supervisory Control and Data Acquisition (SCADA)	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers
WorkBook	Project Prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs

We additionally outline our hosting capacity tool that is not currently part of the planning process.

Tool	Process	Description
Electric Power Research Institute Distribution Resource Integration and Value Estimation (DRIVE)	Hosting capacity	Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine an indicative range of minimum and maximum hosting capacity by screening for voltage, thermal, and protection impacts.

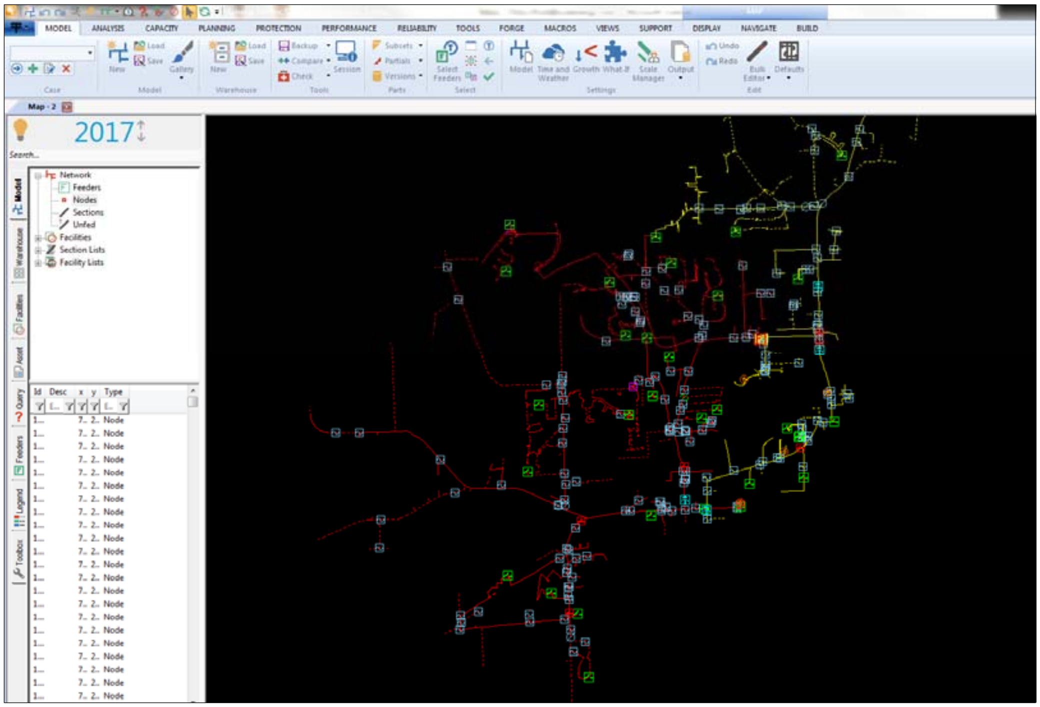
Figure 27: Tool Summary by Distribution Planning Process

Tool	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity
	Planning Process Component						
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
DRIVE							X

DNV-GL Synergi Electric. Synergi is the Company's distribution power flow tool, which we use to model the distribution system in order to identify capacity constraints, both thermal and voltage, that may be present or forecasted. It provides a geospatially accurate model of the electric distribution feeder system with known conductor, electrical equipment, and facility attributes such as material type, which contains ampacity and impedance values. We use it to model different scenarios that occur on the distribution system and to create feeder models that are an input to the DRIVE tool used for hosting capacity analysis; it can also be used to explore and analyze feeder circuit reconfigurations. As load is manually allocated to a feeder and we run a power flow process, exceptions such as voltage or thermal violations may occur. Areas of the feeder are then highlighted due to those exceptions to bring these issues to the engineer's attention.

Synergi can generate geographically correct pictures of tabular feeder circuit loading data, which is achieved through the implementation of a GIS extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. We provide a screenshot from Synergi as Figure 28 below.

Figure 28: Synergi Electric Application Example



To calibrate the model, we import peak day customer usage data into the system, and allocate it to service transformers or primary customer service points. The Customer Management Module within this software takes monthly customer energy usage data and assigns demand values based on the customer class (i.e. residential, commercial, etc.), the assigned "load curves" for that class, and the desired time period. This is done feeder-wide, so that all customers are accounted for. When historical or forecasted peak load data is added from the DAA software package, Synergi is capable of providing power flow solutions for the given condition. At that point, we can also scale the loads up or down across the entire feeder depending upon the estimated demand and scenario need.

The "load curves" that are being utilized come from our load research department and represent different customer classes on a state by state basis. They are not used to analyze different loading scenarios throughout the day, but rather to attribute more accurate peak demands at locations across a given feeder.[29]

[29] For example, it ensures a potential residential customer receives more load at peak than a potential industrial customer with the same energy usage. This is because industrial customers typically have a flatter load profile curve. Accordingly, when industrial customers are compared to residential customers they have more consistent loading throughout the day and have less influence on the peak than the residential customer.

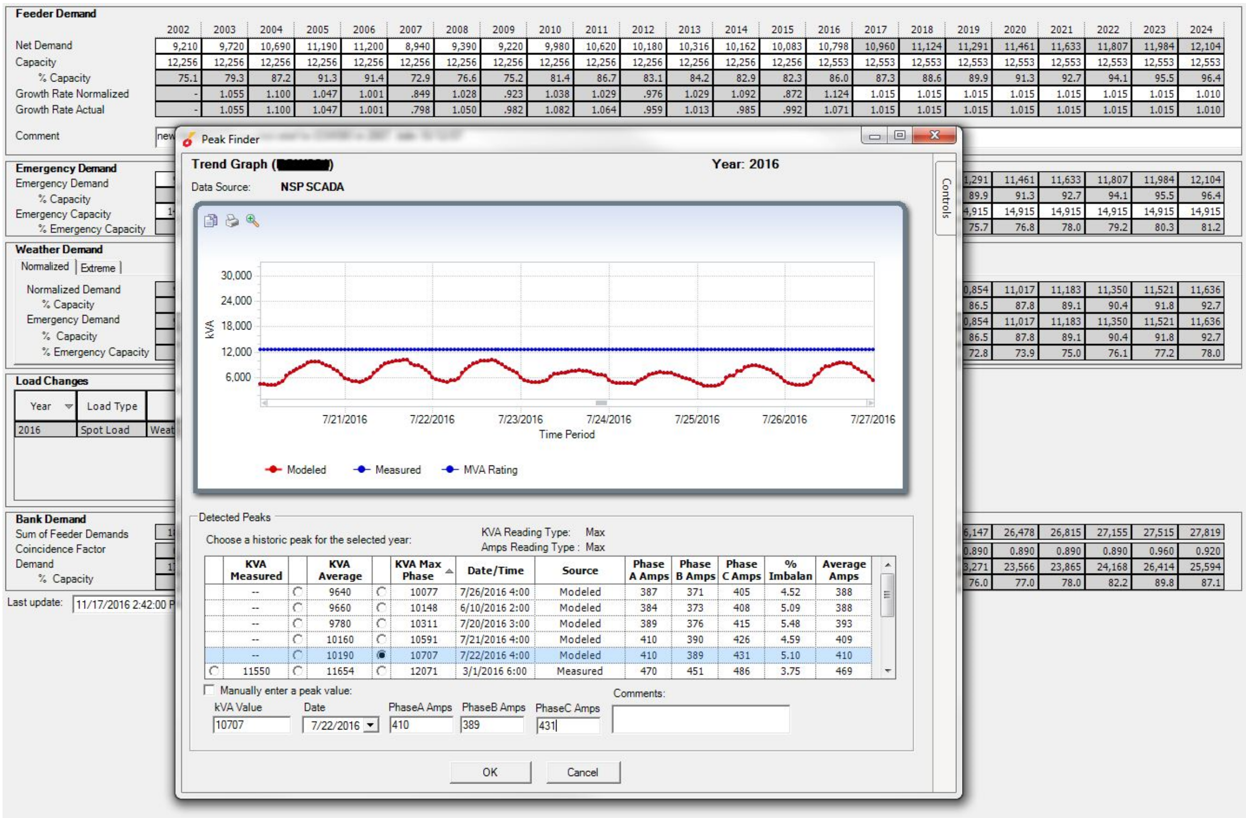
Ultimately, Synergi helps engineers plan the distribution system through modeling. It allows the ability to shift customers and load around, as well as add new infrastructure to simulate future additions to the system. It also can model distributed generation sources, such as solar or wind, so that those affects can be better accommodated.

ITRON Distribution Asset Analysis (DAA). We use DAA for medium to long-range load forecasting of distribution feeders and substation transformers. The DAA system is the historical peak system of record for those distribution elements. By having this collection of historical peaks we are better able to forecast future peaks by trending while taking into account other factors such as weather or known load growth. From this, we develop an annual load projection for future years.

Once our forecasted loads are updated every year we use DAA to create a peak substation load report for Transmission Planning and Transmission Real Time Planning. We also use these forecasts in our risk analysis evaluation, long range plans, and to populate models in Synergi for various purposes.

DAA is also a repository for feeder and substation transformer capacity limits that we use to identify areas of the system where there are capacity constraints. These limits are also passed on to Distribution Operations to ensure the correct notifications occur in the Control Center for any potential overloads.

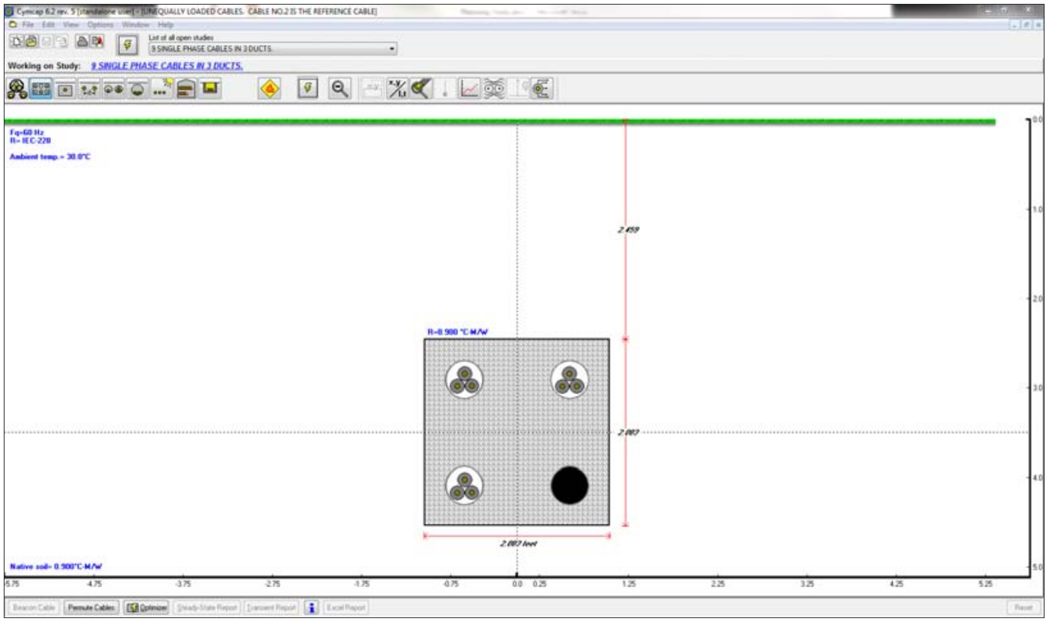
Figure 29: Distribution Asset Analysis Application Example



Microsoft Excel Spreadsheets. We use Microsoft Excel spreadsheets to perform feeder and substation transformer contingency planning. A key part of distribution planning is identifying risks, not only for normal operating situations, but also for situations where the system is in a contingency state; that is not whole. This helps in creating a system with flexibility. To do this we use a series of spreadsheets that include the tie points to other feeders and the capacity that is available at peak times through those tie points. While this is fairly simplistic tool, these spreadsheets provide valuable information about our system that we call "Load at Risk" that we use to justify projects that keep our system reliably robust.

CYME CYMCAP. Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amount of amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP takes into account appropriate factors in determining these values, such as duct line configuration, soil conditions, and cable properties. Unlike overhead conductors that are exposed to the air and wind, underground cables have a tougher time dissipating heat. To ensure the cables are not overloaded, we model the true ampacity of them with the help of this program.

Figure 30: CYMCAP Application Example



General Electric Smallworld Geospacial Information System. Our GIS contains location-specific information about system assets and provides the connectivity model source data and feeder topology to Synergi, as well as other data to many other applications within Xcel Energy. The GIS allows us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.

GIS is also very helpful in capturing changes to the distribution system that may not always be visible to all. For example, we rely on GIS to show changes that would occur as the result of a new Community Solar Garden (CSG) installation. Any upgrades to the feeder that occurred as a result of that addition plus the details of the new CSG itself, would be added in to GIS. This would then be used to update our Synergi models for accurate modeling going forward.

Distribution Supervisory Control and Data Acquisition. Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. For operational purposes, every few seconds it provides system status information, such as operating parameters for our generation and substation facilities. It monitors and collects system performance information for feeders and substations used to ensure the system is safely and efficiently operating within its capabilities. This performance information is also used by planning engineers to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability. As noted previously, we have SCADA in about 165 of our distribution substations, which serve over 90 percent of our customers – leaving approximately 105 substations without remote visibility or control. We have a long-term plan to install SCADA at each of our substations going forward.

For feeders where we have SCADA capabilities, we are able to monitor the real time average or three phase amps on the feeder for operational purposes. For planning purposes, the SCADA system collects enough information throughout the course of a year to determine daytime minimum load and peak demands for all feeders that have this functionality. However, it takes some manual effort beyond collecting the data to adequately decipher those values.[30] The data is maintained in a data warehouse and combined with the historic DAA hourly load data. When three phase load data is available, we use the highest recorded phase measurement to determine facility loading.

Access Database WorkBook. To help rank projects and perform cost-benefit analyses, we use an internally-developed Microsoft Access Database tool called WorkBook. This tool allows us to input our distribution system risks along with the proposed mitigations and their indicative costs that are intended to solve those risks. Algorithms in the tool result in a ranking score that helps to incorporate these projects in the budgeting process. The primary risk inputs that planning engineers develop for entry into WorkBook includes N-0 and N-1 risks for feeders and substation transformers. However, other inputs such as asset age and historic failures are also considered, which further aids prioritization of the projects as part of the budget process.

2. *Future Planning Tools*

As we have discussed, we will need to advance our planning tools and capabilities to facilitate greater capabilities to factor-in DER and to more systematically be able to evaluate NWA. Enhanced planning tools have started to emerge in the industry, but will take some time to mature. Toward that end, we have been participating with others in the industry to examine the types of capabilities that may be needed. We also are in the process of evaluating and procuring the next generation of distribution

[30] This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults or other disturbances on the feeder.

planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes. We discuss the industry efforts below, then summarize the planning and forecasting advancements that we believe are necessary.

a. Industry Efforts

It has been helpful to be involved with various distribution grid research efforts throughout the industry. Our membership with the Electric Power Research Institute (EPRI) has played an important role in helping us keep abreast of innovations in technology in the areas of grid modernization, reliability, integrated planning, solar integration, battery storage and DER interconnection. We participate in several research programs in these areas and are able to learn and share the latest developments with other industry members.

EPRI was key in working with the industry to develop PV hosting capacity tools and we are also excited about their interest in in developing advanced planning tools. EPRI's objective is to develop a more automated and comprehensive platform that performs more robust scenario analysis for various grid investment decisions including non-wires alternatives. EPRI's long-term vision is to develop processes and prototypes that are incorporated and adopted into commercial planning tools.

The National Renewable Energy Lab is also conducting research in similar areas and we have had the opportunity to collaborate with them on various research projects. Some of the efforts with both NREL and EPRI include:

Xcel Energy is partnering with NREL and a set of Colorado customers to examine energy efficient and high renewable energy options for a new development focused on sustainable design. One aspect of the project will involve modeling the distribution system to assess the feasibility and costs of the design.

Xcel Energy is participating with NREL in ARPA-E's *Network Optimized Distributed Energy Systems (NODES)* project with the vision to enable 50% renewables penetration at a feeder level through the use of innovative aggregation control methods. Both the University of Minnesota and MISO are participating in this project.

Xcel Energy is partnering with the NREL to understand how data accuracy can influence the design of the Advanced Distribution Management System model. Through this research project, NREL is modeling six different feeders and three substations to help assess the value and trade-offs with various levels of data available on the system.

We are partnering with EPRI on a research project designed to develop a model that helps identify where energy storage can play a role in addressing various grid issues such as system constraints, high renewable energy penetration and grid deferral. The tool helps evaluate more scenarios in a more efficient fashion and helps perform cost benefit analysis.

Through EPRI, we are participating in an industry working group associated with DER interconnection standards and practices. A primary area of focus is discussing challenges with new options, technical requirements and responsibilities associated with adoption and application of the new IEEE std 1547-2018.

b. Enhanced Planning Capabilities

In response to the fundamental changes occurring on the distribution system, Distribution Planning has recognized a need for a new tool to aid in developing a load forecast and distribution plans. Current tools used for developing the load forecast only analyze specific elements on the distribution system, such as feeders and substation transformers. Additionally, the data that is collected, recorded, and forecasted is limited to the annual peak load for those specific elements. Increasing penetrations of DER on the distribution system require Distribution Planning to better understand the conditions of the distribution system at a more detailed level – this could include hourly profiles in some cases for both feeders and substation transformers.

Looking forward, load forecasts in the future will need to enable four key features:

More granular load forecasts that include the impact of DER. In some cases, load forecasts may include hourly granularity into the loading on analyzed elements of the distribution system.A more granular load forecast can identify the coincidence between native load and typical intermittent DER generation shapes to help understand the impact of DER on the distribution system in higher adoption scenarios.

Forecast aggregation. Forecast aggregation will help ensure that distribution load forecasts align with high-level corporate load forecasts, economic forecasts, and include the impact of DER forecasts (such as forecasts of EV adoption solar adoption, etc). Current distribution load forecasts do not intrinsically roll up to meet high level forecasts – this has to be done manually after the forecast is complete. Furthermore, there is currently no way to incorporate forecasted DER adoption trends or year-over-year economic forecasts into distribution load forecasts; planners are only able to apply a nominal, continuous growth rate to peak loads into the forecast years.

Forecast scenarios. Forecast scenarios will bracket the forecast across multiple possible outcomes to determine a range in which the actual loads are expected to fall. For example, one scenario could be identified as a case with a low load growth rate and a high penetration rate of DER. While the number of possible scenarios is theoretically infinite, a reasonable set of scenarios can aid Distribution Planning in developing plans to mitigate the most likely issues that are expected to occur on the distribution system.

Easier identification of possible Non-Wires Alternatives (NWAs). As we discuss, at present NWA analysis is very manually intensive. This may be aided by improved system planning tools that facilitate easier integration and facilitation of DER forecasts. As we have also discussed, these tools are still evolving and we will learn more as we continue our evaluation.

Recognizing that current tools are inadequate for providing these four key features, the Company has begun the process of searching for a new tool to aid in load forecasting. In addition to enabling the load forecast of the future, a new tool will come with some additional benefits as well. Some of the additional benefits include improving the Company's ability to comply with the forecasting scenarios required in the IDP, and limiting the growth in Distribution Planning resources needed to properly plan the system in the future.

VI. NON-WIRES ALTERNATIVES ANALYSIS

The discussion in this section responds to IDP Requirement 3.E.2, which requires the following:

E. Non-Wires (Non-Traditional) Alternatives Analysis

1. Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than 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.

2. Xcel shall provide information on the following:

- *Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)*

- *A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)*
- *Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed*
- *A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.*

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects proposed and being implemented. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and non-traditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. Recent analysis performed by Xcel Energy has determined that the cost of incorporating DERs as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DERs have the potential to quickly become a cost competitive option. As such, Xcel Energy is working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

Part A of this Section discusses the viability of NWAs for three different project types; Part B discusses the Company's timeline to consider and incorporate any NWA projects; Part C discusses the Company's screening process for NWA projects; Part D provides a detailed analysis of the New Viking Feeder project; and Part E discusses the Company's involvement with Center for Energy and Environment's (CEE) in the Geotargeted Distributed Clean Energy Initiative.[31]

A. Viability of NWAs by Project Type

IDP Requirement E.2 requires, in part, that the Company provide

> *…information on …Project types that would lend themselves to non-traditional solutions (ie. Load relief or reliability)*

In this section we discuss three project types (mandates, asset health and capacity) and discuss why capacity project best lend themselves to a non-traditional solution.

1. Mandated Projects

Mandated projects are projects where Xcel Energy is required to relocate infrastructure in public rights-of-way in order to accommodate public projects such as road widenings or realignments. For technical reasons NWAs would not work well for mandated projects. It is a priority to keep customers connected to the grid. If we chose not to replace distribution infrastructure due to a mandated project we would leave a segment of customers electrically unserved due to having no physical connection to the Xcel system. Those customers would then need to be served via some other local means, like distributed generation. However, if they were served by some other means, that would take away from the interconnectedness of the distribution system. This is necessary to continue reliable service because it allows Xcel the ability to switch customers to other feeders during periods of planned maintenance or unplanned outages. Removing that interconnectedness takes away added flexibility and redundancy that has been intentionally designed into the system and makes operating it more difficult and less reliable. The grid offers many benefits, such as affordable reliability, and removing customers from it is not a viable solution for either Xcel or our customers.

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[31] *See* https://www.mncee.org/resources/projects/geotargeted-distributed-clean-energy-initiative/

Beyond the technical reasoning, these projects generally follow municipal and state funding availability and consequently, are not always specifically represented in our five year budget, especially beyond one to two years. What makes these projects even more time prohibitive is the fact that they must occur prior to the actual public project taking place. A typical example would include a project that was formally funded by a municipality two years in advance of the start of construction. This means that the municipal project design will be completed within the first year after funding was allocated, giving Xcel Energy less than one year to design its project, allocate the necessary funds, and relocate facilities in the affected areas before construction on the municipal project can begin. Implementing a detailed NWA for such a situation would be extremely difficult, if not impossible, to accomplish within such a short period of time given the complexities inherent to a totally unique and new solution that an NWA would offer.

2. *Asset Health Projects*

Asset Health projects are projects required to replace equipment which are reaching the end of life or have failed. This is a broad category that covers pole replacements, underground cables, storms, public damage repair, conversions, , etc. To maintain the existing reliability of the distribution system we must spend money annually to replace our assets.

Keeping customers connected to the grid is the major reason Asset Health projects are not suitable for NWAs. If we chose not to replace distribution infrastructure due to aging assets, there is a high level of risk that certain assets would fail and customers would experience an outage. To avoid or prevent the outage the customers would need to be served via some other local islanded generation. From a reliability perspective at some point our customers need to be hooked back up to the distribution grid rather than staying in a permanent microgrid. So money is spent on infrastructure renewal regardless, it's just a matter of if it's reactive or proactive replacements.

Unlike the mandated projects, with asset health projects there is more potential for ongoing costs. A mandated project requires the movement of a particular piece of the system one time. An asset health project, because it is based on condition, can occur at many points on the system. One project could first be needed to replace deteriorating poles, then another needed to address underground cable that is going bad near the customer, then another to replace breakers inside the substation. Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA doesn't make sense.

3. *Capacity Projects*

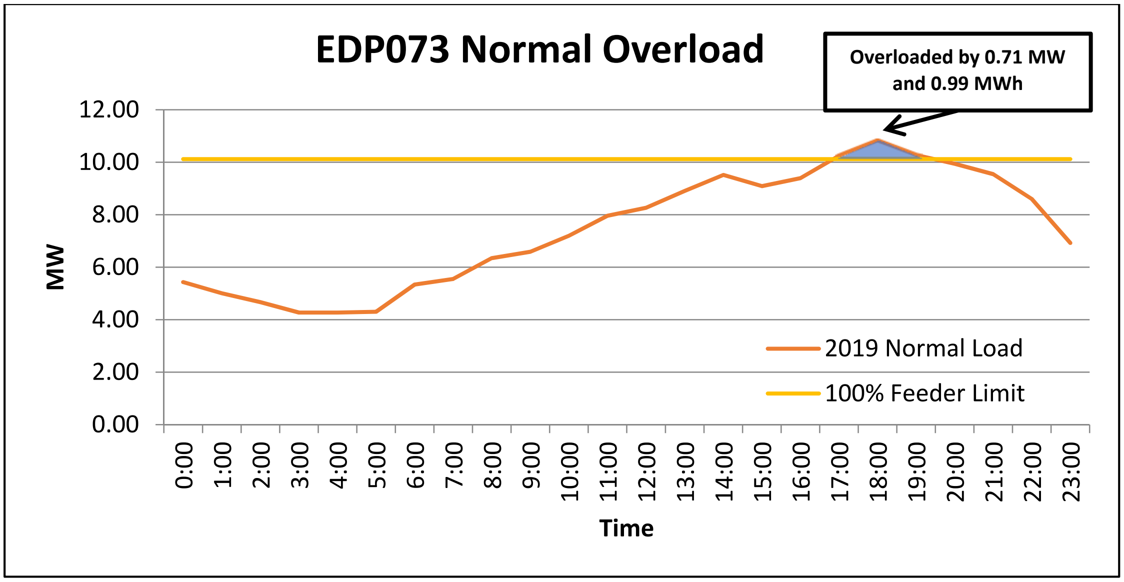
Capacity projects are better suited for NWAs as they are driven by a capacity deficiency that can be offset or otherwise deferred by strategically-sited DER. DER that can generate, discharge, or reduce the consumption of electricity downstream on a feeder can decrease the amount of load that is drawn through the substation and relieve overloads.

Because capacity projects do not have external requirements to build capacity, each project is scored on a cost/benefit basis, and that score is one of the key drivers for prioritizing projects for selection in the budget. Therefore, without some additional driving need, an NWA must be cost-competitive with a traditional solution to be viable in the budget create process.

Capacity risks are identified in two different categories: N-0 (system intact), and N-1 (first contingency). Existing Distribution Planning Criteria dictate that a project needs to be identified to resolve all N-0 risks greater than 106 percent loaded, and all N-1 risks with more than 3 MVA at risk. The viability of NWAs varies between N-0 and N-1 risks due to the nature of the risk types.

N-0 risks are normal overloads that occur under system intact conditions. These typically are manifested as substation transformers or distribution feeders that have just crossed their 100% loading capacity threshold. An illustrative example is the N-0 overload for the Eden Prairie EDP073 feeder – this overload is tied to the new Viking feeder project, discussed later.

Figure 31: 2019 Peak Day Load Profile for EDP073 Reflecting a N-0 Overload

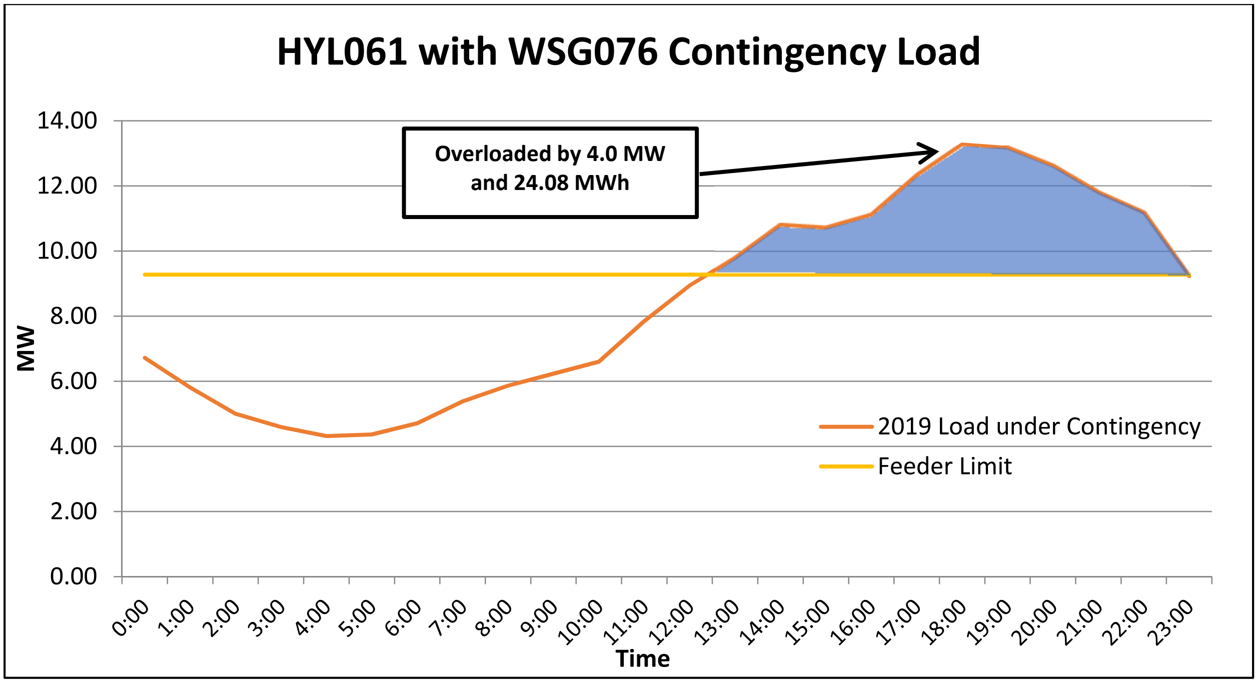


The overload for EDP073 is relatively small with a peak magnitude of 0.71 MW. Additionally, due to the small magnitude the total duration of the overload is brief as well, yielding a total of approximately 1 MWh overloaded. With a unit cost estimate of approximately $600,000/MWh for battery storage, this indicates that the overload could be mitigated with DER for $600,000. This cost estimate is cost-competitive with a typical traditional project to mitigate a comparable overload, which would consist of upgrading feeder cables or conductors, extending a feeder and transferring load, or installing a new feeder.

N-1 overload risks, on the other hand, are significantly less viable for NWAs. N-1 overloads occur when, for loss of a feeder, feeder load is transferred away to adjacent feeders, causing an overload. Per Distribution Planning criteria, projects are not required for N-1 risks until they exceed 3 MVA at risk – this means that total magnitude of the overload on the adjacent feeder(s) exceeds 3 MVA. At this level of overload magnitude, the duration of the overload extends by several hours. This excessive duration accumulates significant amounts of MWh overloaded, and in turn inflates the cost to mitigate the risk.

An illustrative example is the N-1 overload that occurs on the Hyland Lake HYL061 feeder for loss of the Westgate WSG076 feeder. This risk is also tied to the new Viking feeder project discussed later. If an outage were to occur for the WSG076 feeder, the feeder's load would be broken up into sections and transferred to adjacent feeders. In the case of the WSG076 feeder, the load would be broken up into three sections. The first section can be transferred away to an adjacent feeder without causing any overloads. However, when the second section is transferred away to the Hyland Lake HYL061 feeder, it causes an approximate 4 MW overload. The resulting peak day load curve for HYL061 after the WSG076 second section load has been transferred is shown below in Figure 32.

Figure 32: Peak Day Load Curve for HYL061 After the WSG076 Second Section Load has been Transferred



The magnitude of the N-1 overload is relatively normal for N-1 risks tied to a project at 4.0 MW at risk. However, just 4 MW of load at risks causes the duration of the overload to extend to 10 hours. Therefore, the accumulated MWh during the overload totals to 24.08 MWh. With a unit cost estimate of $600,000/MWh for battery storage, the cost to mitigate this risk rises to $14,448,000. This cost estimate is multiple orders of magnitude higher than a typical traditional project to mitigate a comparable risk. A typical traditional project could consist of upgrading feeder cables or conductors, extending a feeder for a new tie, or installing a new feeder.

The load profile shown above is of similar shape to most feeders that comprise a mix of residential and commercial customers. Because of this the cost estimate for the NWA can be considered representative of a typical NWA for N-1 risks of this magnitude. However, even if a 4 MW overload were to occur for only a one hour duration (totaling to 4 MWh), it would still require $2,400,000 of battery storage to mitigate the overload. While this overload duration is unrealistically short, it indicates that the cost to mitigate a 4 MW N-1 overload for even the minimum possible duration would not be cost-competitive with a comparable traditional solution. Therefore, it is not recommended that N-1 risk-driven projects are considered viable for NWAs.

B. Timeline

IDP Requirement E.2 requires in part that the Company:

> *…provide information on . . 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).*

With regard to the timeline that is needed to consider alternatives to any traditional projects, for purposes of this IDP we have assumed we need about three years to appropriately consider and incorporate a NWA solution. This timeline incorporates our internal time for analysis as well as all the steps surrounding a request for proposals (RFP) to actually procure a NWA solution. This includes issuing an RFP, obtaining response, screening the responses, technical and sourcing reviews, and then contract negotiations, and construction. It is our understanding that this timeline is consistent with the approach other utilities have used in similar analyses as well.

Perhaps as we get more experience in this process, the timeline could shrink a bit, however, these projects necessarily take a significant amount of lead time, even when we are addressing them entirely in-house.

C. Screening Process

IDP Requirement E.2. requires in part that the Company:

> *… provide information on the…Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed. And, 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*

NWA Analysis, from a holistic standpoint, is an emerging analysis that many utilities across the U.S. are just beginning to tackle. Not only do these alternatives use some non-traditional solutions but they also use traditional ones in new ways and may combine solutions to fully mitigate an issue. These complexities along with differing implementation and operational strategies will take time and considerable effort to build and maintain.

We note that we are just at the beginning of the future NWA process. Xcel Energy, and the industry as a whole, is trying to create a comprehensive method that will focus on the projects that have the most potential and then evaluate them in an efficient manner against traditional alternatives. We believe much work needs to take place both from Xcel and the industry before success can happen. At present, the effort needed to analyze one project for potential NWA is substantial and increases greatly according to the number of risks associated with it.

Recognizing the current IDP requirement to provide an analysis on how NWAs compare in terms of viability, price, and long-term value for projects with a total cost of $2 million or greater is an interim step, we believe long-term that the right approach to identify candidate projects will involve more than a financial threshold.

We used several filters in our screening process including project type, cost, timeline and number of risks for the 2018 IDP process. However, we expect to continue to refine our process to identify projects for NWAs for future reports. The project filters were applied as follows:

- *Project types*— Project types includes mandates, asset health and capacity projects. As discussed above, mandates and asset health projects were filtered out.
- *Costs*— Per the Commission's order, we evaluated projects with costs greater than $2 Million. However, we believe there's additional work to be done to best identify the range of projects costs for this filter.
- *Timeline*— The timeline included in this screening process includes projects that fall in the 2021-2023 timeframe due to the timing considerations discussed above.
- *Risks*— The number of project risks includes both N-0 and N-1 risks. We did not use a hard cutoff for this filter but factored it in as we determined which project would be best for a NWA analysis.

IDP Requirement E.1 requires the following:

> *Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than 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.*

Using the above screening process, Table 10 below provides the list of projects over $2 million. Applying basic criteria such as project type, cost and timeline, the list reduces to 11 projects.

Table 10: Total Projects Exceeding $2 Million

Project	TOTAL	2019	2020	2021	2022	2023	Project type	Total # of risks	N-0 Risks	N-1 Risks
Install new VKG feeder	$2,500,000	$0	$0	$0	$1,000,000	$1,500,000	Capacity	4	2	2
Install La Crescent TR2 13.8kV 14 MVA	$2,210,000	$0	$0	$0	$300,000	$1,910,000	Capacity	3	0	3
Install 2nd transformer at Albany	$2,150,000	$0	$0	$0	$100,000	$2,050,000	Capacity	3	0	3
Blue Lake reinforce banks to 50MVA and add feeder	$3,200,000	$0	$0	$0	$100,000	$3,100,000	Capacity	4	0	4
Install TR3 70 MVA GLK Sub	$3,600,000	$0	$0	$0	$1,800,000	$1,800,000	Capacity	9	0	9
Add EWITR2 and one feeder	$3,000,000	$0	$0	$0	$100,000	$2,900,000	Capacity	11	2	9
Expand AHI substation	$7,100,000	$0	$0	$100,000	$3,500,000	$3,500,000	Capacity	9	0	9
Install 13.8kV 50 MVA Midtown TR2	$2,000,000	$0	$0	$100,000	$1,900,000	$0	Capacity	1	0	1
Install 2nd transformer at Orono	$3,000,000	$0	$0	$100,000	$2,900,000	$0	Capacity	3	0	3
Reinforce Burnside TR2 to 28MVA	$2,700,000	$0	$0	$100,000	$2,600,000	$0	Capacity	5	0	5
Add TR3 and feeders at WES	$5,250,000	$0	$0	$2,200,000	$3,050,000	$0	Capacity	18	2	16
Upgrade VESTR1 and add VES022	$2,750,000	$0	$100,000	$2,650,000	$0	$0	Capacity	3	1	2
Install 12.47kV Zumbrota #2	$2,270,000	$0	$100,000	$2,170,000	$0	$0	Capacity	5	2	3
Reinforce Kasson TR1 and Fdrs	$2,150,000	$0	$100,000	$2,050,000	$0	$0	Capacity	9	2	7
Add 70MVA 115/34.5kV Rosemount TR2	$3,400,000	$100,000	$1,100,000	$2,200,000	$0	$0	Capacity	4	0	4
Crosstown new 13.8kv sub 2 fdrs	$9,800,000	$600,000	$4,550,000	$4,650,000	$0	$0	Capacity	15	4	11
Add STY TR3 and two new feeders	$6,900,000	$100,000	$2,800,000	$4,000,000	$0	$0	Capacity	16	2	14
Convert Hollydale Sub to 115kV	$16,800,000	$3,000,000	$8,000,000	$5,800,000	$0	$0	Capacity	17	3	14
Upgrade Medford Junction TR1 to 14MVA	$2,300,000	$100,000	$2,200,000	$0	$0	$0	Capacity	2	1	1
New South Afton Substation and feeders	$4,900,000	$500,000	$4,400,000	$0	$0	$0	Capacity	9	1	8
Reinforce SCL TR2 to 70MVA	$2,000,000	$2,000,000	$0	$0	$0	$0	Capacity	1	0	1
Install 35KV transformer at Salida Crossing	$2,600,000	$2,600,000	$0	$0	$0	$0	Capacity	8	4	4
SSI: Convert Hector 4kV to 13.8kV	$2,800,000	$0	$0	$0	$100,000	$2,700,000	AHR			
SSI: Upgrade Clark's Grove to 23.9kV	$2,100,000	$0	$0	$0	$100,000	$2,000,000	AHR			
SSI: Convert Butterfield from 4kV to 13.8kV	$2,800,000	$0	$0	$100,000	$2,700,000	$0	AHR			
SSI: Convert Belgrade 4kV to 13.8kV	$2,700,000	$0	$0	$100,000	$2,600,000	$0	AHR			
SSI: Convert Lafayette 4kV	$2,050,000	$0	$0	$100,000	$1,950,000	$0	AHR			
SSI: Convert Bird Island 4kV to 13.8kV	$2,550,000	$0	$100,000	$2,450,000	$0	$0	AHR			
YLM211 and YLM212 Reinf OH lines	$4,800,000	$500,000	$1,450,000	$1,450,000	$1,400,000	$0	AHR			
ALD Sub, Transfer controls to Transm house	$6,500,000	$1,500,000	$2,500,000	$2,500,000	$0	$0	AHR			
Install Fifth Street switchgear	$5,139,000	$3,399,000	$1,740,000	$0	$0	$0	AHR			
Replace Linde TR1	$3,100,000	$3,100,000	$0	$0	$0	$0	AHR			
Relocate UG and OH Facilities for SWLRT	$12,750,000	$7,800,000	$5,400,000	($450,000)	$0	$0	Mandate			
Relocate UG and OH Facilities for Bottineau LRT - Maple Grove	$9,000,000	$500,000	$4,500,000	$4,000,000	$0	$0	Mandate			
Relocate UG and OH Facilities for Bottineau LRT - Minneapolis	$9,000,000	$500,000	$4,500,000	$4,000,000	$0	$0	Mandate			
Relocate UG and OH Facilities for SWLRT - Minneapolis	$4,250,000	$2,600,000	$1,800,000	($150,000)	$0	$0	Mandate			
4th St Reloc 2nd Ave N to 4th St S	$10,000,000	$5,000,000	$5,000,000	$0	$0	$0	Mandate			
8th Street Relocation Hennepin to Chicago	$11,436,000	$11,436,000	$0	$0	$0	$0	Mandate			

And, while we put significant time and effort into the screening process and determined the final list of projects, given the very compressed timeline for the 2018 IDP, it was not feasible to complete a NWA analysis for all of above projects. While we began work in earnest on many components of the IDP requirements in advance of the Commission's hearing and Order, this was one area that changed throughout the proceeding and was not finalized until just 12 weeks before this IDP was due.

NWA analysis is incredibly time consuming and manual – especially as the risks associated with a project increase and several of the above projects have over 15 risks.

Most capacity projects that are budgeted greater than $2 million are intended to solve larger numbers of risks – this vastly increases the complexity of the problems to solve with a NWA and in turn increases the amount of resources required to conduct the analysis. Projects with fewer capacity risks to solve are more localized and therefore more straightforward.

Accordingly, due to the timeline for this first IDP, we focused on establishing an overall screening process and then performed analysis on the "Install new VKG feeder" project. This is a capacity project to install a new feeder at the Viking substation and is currently budgeted in 2022- 2023. We discuss our analysis below.

With regard to future reports and NWA analysis, we will continue to refine the criteria to identify projects where NWAs have the most potential and will provide the required discussion for those projects. This was a time and resource issue that we were unable to overcome due to the timeline for this initial report.

D. Non-Wire Alternative Analysis for the New Viking Feeder Project

The project to install a new feeder from the Viking substation is currently budgeted in years 2022 and 2023 of the 5-year budget. This project was selected as an example NWA analysis because it is one of the simpler projects in the 5-year budget greater than $2 million. The main driver for this project is to relieve identified capacity issues in the distribution system in Eden Prairie, Minnesota. The fact that the project is driven by capacity deficiencies makes it more viable for a NWA, and the relatively fewer number of risks associated with the project simplifies the analysis.

The project is funded to solve the following four capacity risks:

Table 11: Viking Project Capacity Risks

Feeder	Capacity Risk
EDP073	N-0 overload, 107%
EDP073	N-1 overload on WSG065 for loss of EDP073, 2.3 MVA at risk
HYL061	N-0 overload, 101%
WSG076	N-1 overload on HYL061 for loss of WSG076, 4.2 MVA at risk

For the purposes of this filing, these four risks were analyzed to determine if a NWA could be viable for this project. For each risk, the feeder loading was analyzed to identify the amount of MWh and MW needed to be relieved with DER to mitigate the risk. For the two contingency risks, the normal load curve of the adjacent feeder was added to the section load curve of the outaged feeder to model the contingency overload. For the two N-0 overloads this step is not necessary; the normal load curve of the overloaded feeder is sufficient to represent the overload under system intact conditions.

These results were then used to estimate the cost to mitigate each risk using the optimal combination of batteries and solar. Table 1212 shows the results for each capacity risk, including the amount of DER required and the estimated cost, which totals approximately $22 million.

Table 12: Summary of DER Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution		Estimated Cost
	MW Overload	MWh Overload	Solar PV (MW)	Battery Storage (MWh)	
EDP073 N-0 overload, 107%	0.71	0.99	0	0.99	$595,000
N-1 overload on WSG065 for loss of EDP073, 2.3 MVA at risk	2.04	11.50	0	11.50	$6,900,000
HYL061 N-0 overload, 101%	0.04	0.04	0	0.04	$26,000
N-1 overload on HYL061 for loss of WSG076, 4.2 MVA at risk	4.00	24.08	0	24.08	$14,450,000
Total			0	36.61	$21,971,000

One additional factor for consideration when developing a NWA for this project is DR. Targeted marketing of a DR program in the affected area could potentially reduce the overall loading on the affected feeders by modifying the load consumption of customers. Typical DR programs, such as the Saver's Switch, have historically been applied to limit the loading on a system-wide level. Such a program could be deployed on a smaller scale but it would have to be integrated with the devices controlling other DER as well as the load management system.. Regardless, a targeted DR program could potentially reduce peak loading sufficiently to reduce the overall cost for other DER needed to complete the NWA.

DSM and assorted energy efficiency programs are already considered in the load forecast used to identify the capacity risks associated with the project. The impacts of these programs have been identified as tapering load growth across historical peak loads, and have been applied to future forecasts as reduced load growth rates. However, additional marketing of DSM and energy efficiency programs could potentially further reduce the load growth rate beyond expected levels.

By comparison to the NWA solution which is approximately $22 million, the traditional project that is currently funded in the budget is estimated at $2.5 million. The traditional project will install a new feeder from the Viking substation into the affected area, and will pick up load off of the two N-0 overloaded feeders. By relieving these loads, the new feeder will also provide a stronger tie for the two N-1 overloaded feeders, thus mitigating all four risks tied to this project and providing additional capacity for new growth. By contrast, an NWA solution would not provide additional capacity for new growth, but rather defer the need until new growth did occur. So, an NWA solution would likely need to be less expensive than a traditional capacity solution in order to provide similar value in areas of load growth.

E. Geo-Targeting

Another issue relevant to the NWA analysis is our participation in the Center for Energy and Environment's (CEE) Geo-targeted Distributed Clean Energy Initiative. The objective of this pilot is to provide Minnesota utilities with the opportunity to serve customers by using DER to limit needed transmission and distribution infrastructure upgrades

This project will conduct planning for distributed energy projects in two communities within our Minnesota service territory, and select at least one area to implement a pilot program. The goal is to test the viability of a geo-targeting strategy to provide a reliable alternative to traditional capacity upgrades. Xcel Energy's existing energy efficiency and demand response programs will provide the base for these efforts and will be enhanced with strategies to achieve the high participation necessary for success.

This geo-targeting pilot is relevant to the NWA discussion because it highlights some of the issues that still need to be identified and tested before NWAs can be deployed cost effectively and reliably at a larger scale. This pilot will help explore cost, effectiveness, customer willingness to participate, and the best marketing solutions for this type of application. Second, there are many important issues related to the use of DERs to strategically reduce load on the distribution system that need to be tested and developed. For example, DR is traditionally relied upon for system-wide purposes. Calling these resources for distribution purposes requires updated processes to identify when to dispatch it, how to prioritize dispatch between two different applications (distribution vs. system-wide DR), and to ensure that software and equipment in the field function correctly. Third, we do not yet know how well the targeted, distributed solutions will interact with control systems (i.e., ADMS) and with each other. These integrated solutions across different DER technologies and operating scenarios do not yet exist on a broad scale. Fourth, we will be able to see if there are cost-savings.

The timeline for the geo-targeting pilot is June 2017 – June 2020. We will incorporate our learnings along the way into future IDPs and NWA analyses.

VII. ASSET HEALTH AND RELIABILITY MANAGEMENT

In this Section we describe several analyses and functions that support distribution system reliability and resilience.

A. Electric Distribution Standards

Utility distribution systems are complex and dynamic, in that they involve thousands of pieces of equipment, must be resilient from outside forces over vast areas of geography, and must be able to respond to changes in customer loads and operational realities. Traditionally, distribution systems have been designed for the efficient distribution of power to provide customers with safe, reliable and adequate electric service – with geography playing a significant role in the design of the system. Our Minnesota service area has diverse geography and therefore diverse planning criteria and considerations.

One of the ways we plan the system is through a set of materials and work practice standards that apply to the construction, repair and maintenance of the electric overhead distribution, underground distribution, and outdoor lighting systems. The purpose of Electric Distribution Standards at Xcel Energy is to develop and maintain a broadly-accepted set of material and construction standards that meet the needs of each of the operating companies and stakeholders, while meeting all applicable regulatory and code requirements. The Standards function acts as an expert consultant to operations and engineering, collaborates to enhance public and employee safety, drives cost-effectiveness, and improves system reliability through defining electric distribution standard materials, methods, and applications.

Standards updates may stem from a number of circumstances including regulatory or code changes, company analysis, input or an issue raised by field personnel, and industry guidance, among others.

Xcel Energy's Design standard books consist of Overhead, Underground, and Outdoor Lighting Manuals. Each of these Manuals detail equipment and designs that have been previously reviewed against industry standards and best practices to ensure installation of facilities results in safe and reliable service. Documenting approved materials and equipment configurations allows for efficient design of construction projects. The Standards Manuals simplify electrical distribution projects and optimize a Designer's work because the engineering and code compliance is built-in – and typically only requires engineering input for special circumstances. Reference material on transformer sizing and conductor lengths, which already accounts for voltage and thermal limits, is also part of the Standards Manuals.

We are providing a couple of examples of the work that Standards does, to further help put the Standards function into context:

Porcelain Cutout to Polymer Cutout Transition (2010-present day). Xcel Energy has a process to identify and analyze faulty material. In this case, material submitted from field crews and engineering identified an issue where porcelain cutouts stood out from other materials as having issues requiring further analysis. We had been using polymer cutouts in specialized applications, however not broadly, because industry standards had not yet been developed for the polymer material. We validated our observations on the porcelain cutouts and the potential viability of polymer as an alternative through peer group consultation with other utilities through Midwest Electrical Distribution Exchange and Western Underground Committee.

Electric Distribution Standards worked with local jurisdictional teams with an objective to identify and vet a polymer cutout to be used company-wide, and discontinue the use of porcelain cutouts. We additionally participated in the IEEE C37.41 and C37.42 revision to create testing requirements for polymer cutouts. Recently, we further improved this Standard by consolidating 125kV BIL to 150kV BIL cutouts –allowing a transition from three cutout types to two cutout types, and increasing the number of manufacturing sources from which we can procure polymer cutouts that meet our standards requirements. As we systematically replace remaining porcelain cutouts on our system with polymer, we are improving reliability for customers and the resilience of our system. This change also expanded material availability and resulted in cost savings.

Wood to Fiberglass Crossarm Transition (2010-present day). In 2011, the National Electrical Safety Code (NESC) changed the loading requirements for deadend crossarms. We conducted research with our industry peer groups and found that fiberglass was identified as being the best material for longevity and strength. We evaluated alternatives, and available fiberglass deadend crossarms met the NESC requirements and resulted in an approximate 17 percent cost savings. After our success implementing deadend fiberglass crossarms, we evaluated and ended-up implementing fiberglass tangent crossarms as a cost-neutral option – improving the resilience of our system in a cost-conscious way for our customers.

We have since made further improvements to the fiberglass crossarms after participating in an EPRI initiative to evaluate system materials in terms of system hardening. After conducting further internal research, to develop testing criteria based on galloping and ice loading witnessed by Xcel Energy line crews and Electric Distribution Standards, we updated Xcel Energy standards to obtain a better and longer life product – and are additionally working with the fiberglass crossarm industry to revise the national standards to better take these conditions into account.

For additional context, Table 13 below shows a list of some of the most common industry standard documents applied in distribution engineering. The list is not intended to be inclusive of all standards that may be applied to medium and low voltage systems, but rather is intended to provide insight into standards that are frequently used. Included are primarily documents from the Institute of Electrical and Electronics Engineers (IEEE) which are classified as Standards, Recommended Practice, and Guides. Standards carry more weight when compared to Recommended Practices. Guides often show a number of ways to achieve a technical objective and are the least prescriptive.

Table 13: Common Engineering Standards Summary

Condition	Standard
Safety	National Electric Safety Code (NESC)
	Xcel Energy Safety Manual
Voltage Limits	ANSI C84.1 – minimum and maximum voltage limits, voltage imbalance limits
	Xcel Energy Standard for Installation and Use – voltage limits and imbalance (same as ANSI C84.1)
Thermal limits	Xcel Energy Design Manuals (Distribution Standards Engineering)
	Substation Field Engineering (SFE) transformer loading database – based off of IEEE standards
	IEEE 738 – Overhead conductor ampacity rating IEC 287 and IEC 853 – Cable ampacity rating methodology in CYMCAP program
	IEEE C57.91 – transformer and regulator loading guide IEEE C57.92– power transformer loading guide
Distribution Interconnection	IEEE 1547 – Interconnection of Distributed Resources
Harmonics	IEEE 519 – total harmonic distortion and individual harmonic limits
Voltage Fluctuation	IEEE 1453 – rapid voltage change and flicker limits

Additionally, North American Electric Reliability Corporation (NERC) standard FAC-002-2 applies to studying the impact of interconnecting facilities to the Bulk Electric System, which comes into play with distribution substations. Specifically, Requirement R3 applies when we seek to interconnect new "end-user facilities" or materially modify existing interconnections to the transmission system. It states we shall coordinate and cooperate on studies with our Transmission Planner or Planning Coordinator as specified in Requirement R1. This includes many requirements such as reliability impact, adherence to planning criteria and interconnection requirements, conducting power flow studies, alternatives considered and coordinated recommendations.

B. Asset Health

The NSPM distribution system is composed of nearly 27,000 miles of distribution lines and 1,200 feeders that provide the path for delivering electricity from the distribution substation to the distribution customer transformer and then to customers. This vast system is key to ensuring customers receive safe, reliable and cost effective energy. We continually invest in our infrastructure through established reliability and asset health programs to ensure that we deliver the most reliable and efficient energy to our customers. While we have been able to historically deliver excellent value for customers, the utility industry is changing rapidly and customer expectations for power availability are also changing.

We believe an incremental customer investment (ICI) initiative is necessary to continue to meet the needs of our customers, and shifting funding closer to the customer will be a foundational requirement for the grid of the future. Our ICI initiative has core goals of enhancing the safety, reliability, and resiliency of the system that continues to enable customer choice and the adoption of DER, such as electric vehicles. We are in the process of designing programs for this initiative, which we view generally in two categories: expansion of existing programs, and new programs.

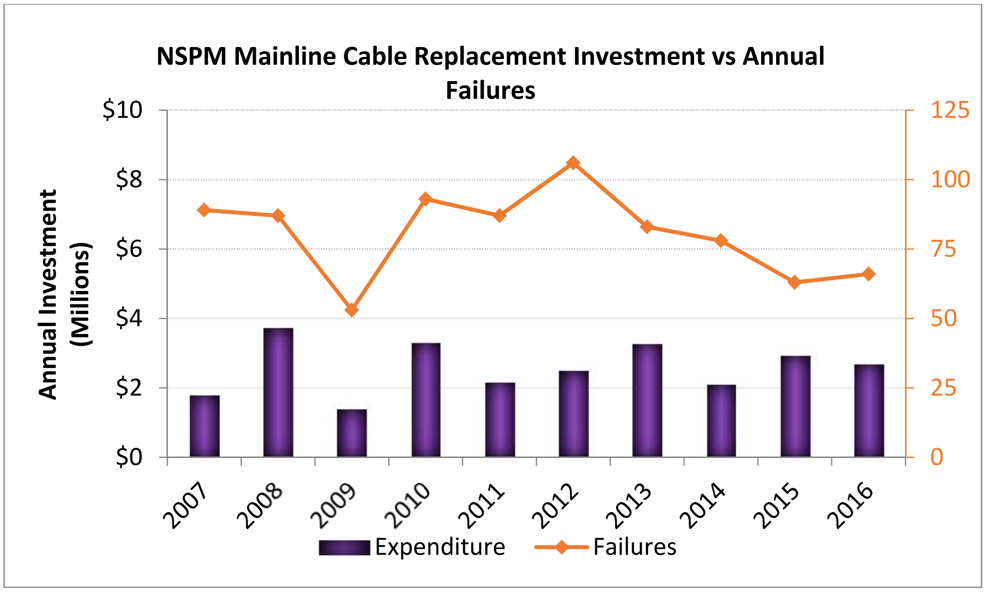
The expansion of existing programs would be focused on improving system reliability and mitigating the underlying common cause of outages such as cable failures and pole fires. New programs would be targeted at expanding investments closer to the customer on the portion of the system that is commonly referred to as the taps and the secondary system. These investments would provide several benefits to customers including replacing older infrastructure, reducing O&M, improving reliability, and enabling increased adoption of DER including EVs. Because these portions of the system are more susceptible to weather-related outages including storms, its performance is a major contributor to the customer experience. The majority of the placeholders in the present 5-year budget are in years 2021-2023 and are being considered and targeted at this portion of this system. One specific initiative we are considering and will potentially include targeted deployment of reclosers (to reduce impact from temporary faults), rebuilding and renewing areas, and targeted undergrounding.

We will identify and prioritize areas based on reliability history, age and condition, storm-related outages and total restoration time, numbers of customers, potential for O&M cost savings, and DER adoption potential; our primary goal will be to create multiple benefits for customers that includes a more reliable, safe, cost-effective and resilient system that enables integration of DER. While we have been able to deliver excellent results for customers, as the industry changes and customer expectations change, shifting funding closer to the customer will be critical to continuing to meet the needs of our customers.

In terms of other ways we currently monitor and address the health of our distribution assets, we track the fleet age of each of our major distribution assets, for example, and use age as a partial proxy for asset health. We also analyze reliability data and work to tie that data to asset health to create and refine programs to manage reliability. We discuss these aspects of our current efforts in terms of examples, in more detail below.

To use underground distribution assets as an example, reliability performance is heavily influenced by the performance of mainline and tap cable. We analyze cable failure rates for both types of cable, and budgets to manage the reliability. Analysis has shown us the era of the cable projects its failure rate which allows us to focus efforts on the cable most likely to fail. Historical performance of cable has also influenced our standards for future purchases for new construction and replacement work. Figure 33 below is one of the ways that we analyze asset performance in terms of maximizing customer value.

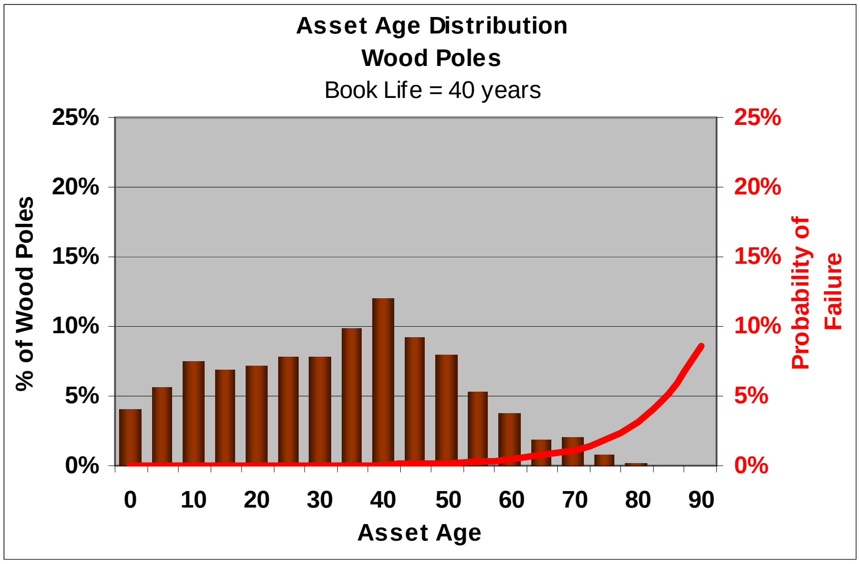
Figure 33: Example – NSPM Mainline Cable Replacement Investment Compared to Annual Failures



The overhead distribution reliability performance is dependent on many factors including vegetation, weather, and the health of the many pieces of the overhead system. The vegetation program is a key program to maintaining good reliability. The vegetation program includes quality checks by visiting outage locations associated with vegetation that impacted 100 or more customers. The check determines if the outage would have occurred if a vegetation crew had worked the line the day before. These checks are showing the value of our vegetation program in mitigating outages. Unfortunately vegetation events can cause damage to our asset health, especially to older assets, so minimizing events is a key factor in maintaining asset health.

Another key program is checking the health of our poles. Pole rot at the base of the pole can be a cause of pole failure, especially in stormy weather. We work to inspect poles on a 12-year cycle to mitigate risk of pole failures. Figure 34 below portrays wood pole failure rates by their age.

Figure 34: Example – NSPM Mainline Cable Replacement Investment Compared to Annual Failures



We have also changed the standards for all new construction and replacement poles to larger poles as part of system hardening. Other programs include:

- Identification of the poorest performing feeders each year and doing an in-depth analysis to identify opportunities for improvement.
- Identification of a protective device that operates frequently and performing a study to identify opportunities for improvement.
- Identification of customers experiencing multiple interruptions, performing a study to identify opportunities for improvement.

Analysis of these outages commonly includes site visits that allow the engineer to see firsthand the condition of the equipment. Mitigations for these programs frequently include updating deteriorating infrastructure and may overlap with other programs.

C. Reliability Management

1. Approach

Each year, Xcel Energy develops and manages programs to maintain and improve the performance of its distribution assets. We identify and implement these programs in an effort to assure reliability, enable proactive management of the system as a whole, and effectively respond when outages occur.

In this section, we provide a snapshot of our 2017 reliability results. We additionally outline our process for developing and implementing programs to maintain and improve our system, detail key indicators of the highest impact programs, and graphically chart current year outages by cause codes. We have also included three tables to illustrate our reliability performance trending as well as a discussion around CEMI (Customers Experiencing Multiple Interruptions) tools to better reflect the customer experience.

In 2017, we achieved a SAIDI result of 73.80 minutes, which exceeds our Quality of Service Plan (QSP) tariff goal of 133.23 minutes.[32] Our 2017 SAIFI result of 0.72 outage events also exceeds the QSP tariff goal of 1.21 outage events.[33] The below graphs show overall system performance for the years 2014 through 2017, with storm days excluded, per the QSP tariff calculation method.

2. *Reliability Indices*

In this section, we demonstrate our 2017 SAIDI and SAIFI reliability performance, and provide a tabular view of our performance over time.

[32] Minnesota Electric Rate Book MPUC. No. 2 Section 6, Sheets 7.1 through 7.11, approved by the Commission's August 12, 2013 Order in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383

[33] In this context, "exceeding" the goals is a positive result, reflecting good system performance.

Figure 35: 2017 Minnesota SAIDI – QSP Method

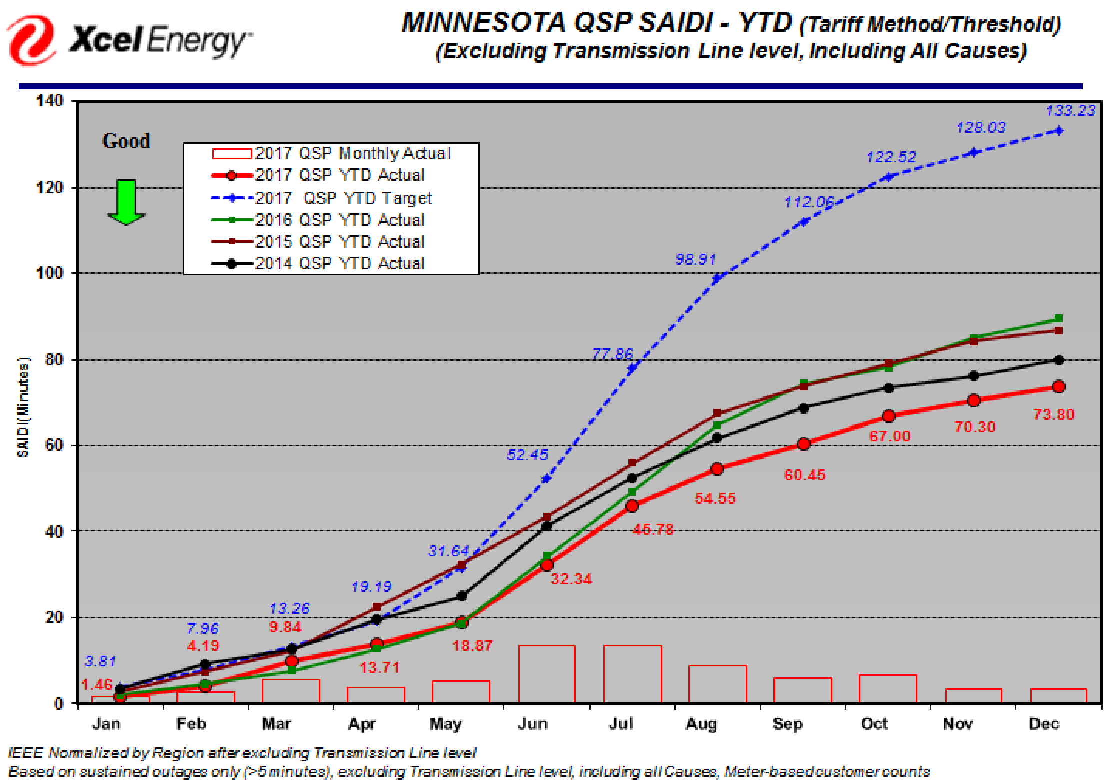
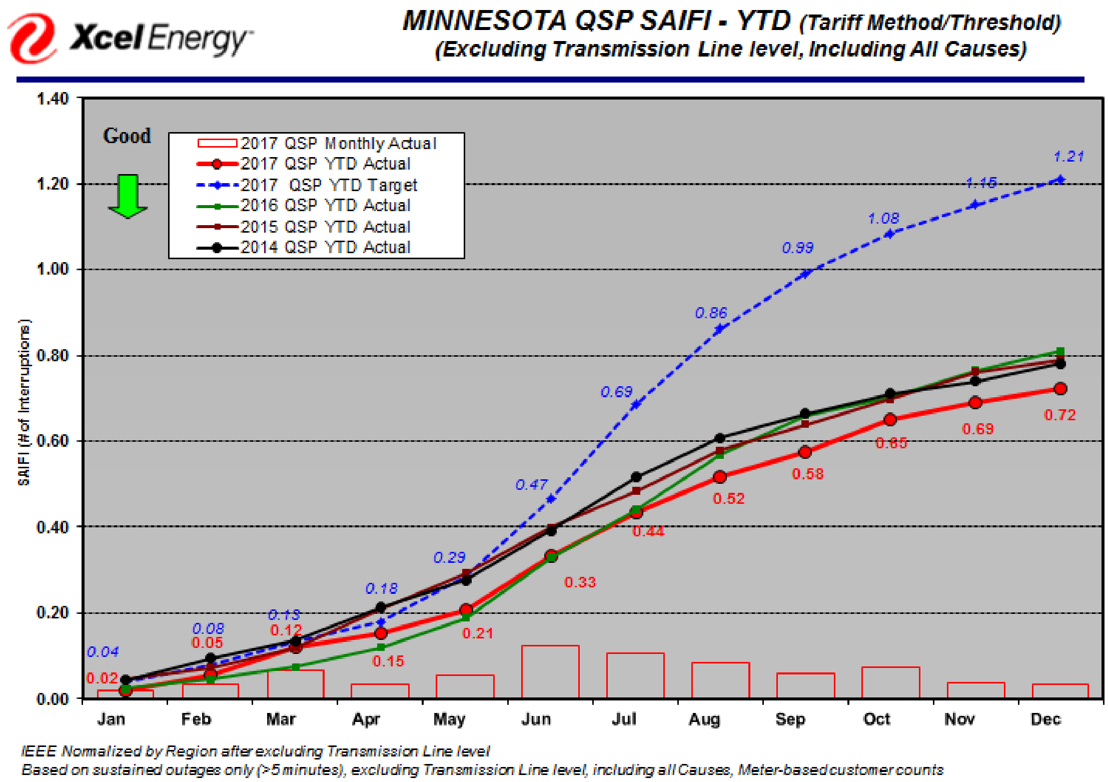


Figure 36: Minnesota SAIFI – QSP Method



In an effort to provide the Commission a better idea of our reliability performance trending, we have provided three tables showing the historical performance, storm days and the current targets under three methodologies (including storms, our QSP Tariff, and the Minnesota Rules) as shown in Table 14 below.

Table 14: Historical Reliability Performance and Storm Day Exclusions – Non-Normalized and QSP Performance & Annual Rules Performance

Historical Reliability Indices & Storm Day Exclusions

With Storms[1]		2009	2010	2011	2012	2013	2014	2015	2016	2017
Minnesota	SAIDI	79.66	274.42	207.77	149.15	562.11	116.43	184.50	214.39	141.70
	SAIFI	0.76	1.50	1.11	1.07	1.39	0.92	0.96	1.05	0.90
	CAIDI	104.58	183.43	187.11	139.51	404.36	126.00	192.32	204.84	158.10
Metro East	SAIDI	76.66	270.43	113.90	190.95	352.30	123.54	177.19	223.67	136.51
	SAIFI	0.76	1.59	0.96	1.20	1.27	0.98	1.04	1.08	0.95
	CAIDI	101.50	170.23	118.95	159.23	278.46	125.93	169.86	206.85	144.37
Metro West	SAIDI	86.77	301.09	238.03	139.19	810.01	105.98	229.78	198.25	148.58
	SAIFI	0.81	1.54	1.19	1.10	1.55	0.89	1.00	1.00	0.86
	CAIDI	106.87	196.10	199.66	126.85	523.66	118.70	229.92	198.86	173.27
Northwest[4]	SAIDI	62.08	181.38	470.05	109.75	468.22	82.82	75.61	225.74	173.71
	SAIFI	0.65	1.26	1.40	0.87	1.40	0.82	0.66	1.07	0.98
	CAIDI	96.21	143.66	334.78	126.17	335.53	101.00	115.40	211.50	177.46
Southeast[5]	SAIDI	73.10	251.24	125.28	97.25	179.29	173.45	98.23	249.05	96.37
	SAIFI	0.66	1.24	0.95	0.71	1.06	0.98	0.79	1.15	0.84
	CAIDI	110.52	203.04	131.69	137.84	168.93	176.51	125.07	217.15	114.75

MN Tariff[2]		2009	2010	2011	2012	2013	2014	2015	2016	2017	'17 Target
Minnesota	SAIDI	74.48	110.83	83.87	96.20	91.12	79.85	86.83	89.49	73.80	133.23
	SAIFI	0.71	1.12	0.82	0.88	0.86	0.78	0.79	0.81	0.72	1.21
	CAIDI	104.90	99.24	102.08	109.60	106.51	102.07	109.90	110.54	102.10	NA
Metro East	SAIDI	69.43	102.03	79.34	90.70	83.56	77.58	93.71	95.49	75.70	
	SAIFI	0.70	1.20	0.83	0.88	0.83	0.82	0.90	0.87	0.75	
	CAIDI	98.60	85.09	96.00	103.35	100.72	94.81	104.58	110.07	100.79	
	MED	0	4	2	5	3	3	2	3	3	
	Days	None	6/25,7/17, 10/26,11/13	7/1,7/10	6/10,6/19,7/3 , 8/3,11/10	6/21,6/22, 6/23	2/20,6/14,6/16	7/12, 7/18	7/5,7/6,7/21	6/11, 6/14, 7/12	
Metro West	SAIDI	85.69	123.25	88.20	103.42	101.24	81.85	88.98	82.90	69.28	
	SAIFI	0.80	1.22	0.87	0.97	0.96	0.82	0.82	0.82	0.70	
	CAIDI	107.03	101.10	101.09	106.83	105.85	100.15	108.90	101.51	98.40	
	MED	0	4	5	3	5	1	1	3	2	
	Days	None	6/25,7/17, 10/26,11/13	5/22,7/1,7/10, 7/18,8/1	2/29,6/19,8/3	6/21,6/22, 6/23,6/24,8/6	6/14	7/18	7/5,7/6,7/21	6/11, 6/14	
Northwest[4]	SAIDI	52.61	102.79	79.42	94.20	85.78	62.16	69.39	80.19	69.41	
	SAIFI	0.45	0.80	0.69	0.73	0.75	0.61	0.57	0.56	0.64	
	CAIDI	116.70	129.28	115.38	128.31	113.87	102.05	121.05	143.58	107.70	
	MED	0	2	6	0	2	0	0	4	1	
	Days	None	8/13,10/26	2/20,5/30,7/1, 7/10,8/1,8/2	None	6/21,6/22	None	None	5/19,6/19,7/5 ,11/18	6/11	
Southeast[5]	SAIDI	59.71	89.58	82.70	82.40	73.58	94.45	70.78	109.59	92.84	
	SAIFI	0.56	0.69	0.70	0.59	0.57	0.67	0.52	0.82	0.79	
	CAIDI	107.39	130.66	118.72	138.48	129.93	141.93	135.23	133.06	117.19	
	MED	0	5	2	1	4	4	1	3	0	
	Days	None	6/25,6/26,7/24, 8/13,11/13	7/1,7/23	8/4	4/9,5/2,5/26, 6/21	2/20,6/16,8/4, 12/15	7/18	6/10,7/5,7/6	None	

Annual Rules[3]		2009	2010	2011	2012	2013	2014	2015	2016	2017	'17 Target
Minnesota	SAIDI	77.36	101.99	81.10	99.00	93.73	86.63	92.08	89.43	70.85	NA
	SAIFI	0.74	1.10	0.82	0.90	0.88	0.84	0.84	0.82	0.72	NA
	CAIDI	104.49	92.54	98.75	109.47	106.06	102.63	110.02	108.92	98.63	NA
Metro East	SAIDI	74.21	88.30	69.89	98.35	81.28	79.73	101.38	84.89	66.17	89.13
	SAIFI	0.73	1.15	0.78	0.91	0.83	0.86	0.92	0.82	0.69	0.87
	CAIDI	101.87	76.87	89.61	108.36	97.75	92.46	109.67	102.91	95.33	102.42
	Storm	1	7	5	5	5	3	1	5	6	
	Days	5/20	6/25,7/17,8/10, 9/21,10/26, 10/27,11/13	7/1,7/10,7/18, 8/1,8/2	2/29,6/10, 6/19,7/3,8/3	4/23,6/21, 6/22,6/23,6/24	2/20,6/14,6/16	7/18	6/25,7/5,7/6, 7/21,11/18	3/7,6/10,6/11 ,6/14,7/12,7/ 26	
Metro West	SAIDI	84.43	114.85	85.07	103.98	98.71	83.02	90.95	83.64	69.51	92.06
	SAIFI	0.79	1.19	0.87	0.98	0.94	0.84	0.84	0.82	0.71	0.89
	CAIDI	106.58	96.49	98.20	105.93	105.09	98.50	108.44	101.43	97.84	103.98
	Storm	1	5	7	3	7	1	1	3	2	
	Days	5/20	6/25,7/17,10/2 6 10/27,11/13	5/22,6/21,7/1, 7/10,7/18,8/1, 9/29	2/29,6/19,8/3	6/21,6/22, 6/23,6/24, 6/25,6/26,8/6	6/14	7/18	7/5,7/6,7/21	6/11,6/14	
Northwest[4]	SAIDI	62.07	84.02	103.27	106.07	95.90	82.80	75.27	119.36	75.77	95.88
	SAIFI	0.65	0.77	0.85	0.84	0.93	0.82	0.65	0.80	0.76	0.81
	CAIDI	96.21	108.70	122.13	125.62	102.86	101.02	115.32	149.53	100.28	118.45
	Storm	0	8	8	1	3	0	1	3	1	
	Days	None	5/22,6/11,7/17, 8/12,8/13,10/2 6,10/27,11/13	5/30,6/21,7/1, 7/5,7/10,7/15, 8/1,8/2	6/19	6/21,6/22,6/23	None	7/28	6/17,7/5,11/1 8	6/11	
Southeast[5]	SAIDI	69.37	103.67	78.15	71.54	108.83	129.20	82.96	103.28	87.67	99.16
	SAIFI	0.63	0.86	0.72	0.59	0.75	0.81	0.72	0.81	0.80	0.74
	CAIDI	110.06	121.07	107.92	120.50	145.11	158.78	115.64	126.85	109.73	134.40
	Storm	1	10	7	5	4	7	2	4	2	
	Days	5/20	6/11,6/17,6/25, 6/26,6/27,7/24, 8/10,8/13,10/2 6,11/13	6/14,7/1,7/11, 7/15,7/18,7/23 ,7/27	6/14,6/19,6/2 0 8/4,9/5	5/2,6/21,7/13, 10/3	2/20,4/27, 6/15,6/16,6/17 ,6/18,8/21	6/22,7/18	6/10,6/14,7/5 ,7/6	6/12,7/19	

Legend for Table 14 above:

1) With Storms - Includes All Days, Levels and Causes, Meter-based customer counts
2) MN Tariff - Normalized using IEEE 1366 at the Regional level after removing Transmission Line level. All Causes, Meter-based customer counts
3) Annual Rules - Normalized using 3 sigma of rolling 5 year count of sustained outages at the Regional level.
All Levels, All Causes, Meter-based customer counts
4) Northwest - Includes customers counts and outages in the North Dakota work region that impact Minnesota customers
5) Southeast - Includes customers counts and outages in the South Dakota work region that impact Minnesota customers

In addition to SAIDI and SAIFI, we have developed tools that allow us to better track the causes of our outages from a customer's perspective – or CEMI. In conjunction with a mapping tool, we can look at our customers' experience as it identifies customers with multiple outages over a revolving 12 months and then provide a visual representation of those outages in our service territory. Although, the metric measures customers who have experienced at least six sustained outages during non-storm days, we can study customers' experience earlier. This customer centric tool helps highlight customers that have had outages from different causes rather than a single root cause. In other words, this tool does not look at the device that caused the outage, it examines how many times a customer was out of service regardless of the reason.

The Outage Exception Reporting Tool (OERT) combines the CEMI tool with an earlier tool that helped us identify specific equipment issues (for example, the same device tripping multiple times). The OERT tool provides the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this new tool really rounds out our reliability planning by helping focus on the customers' experience.

There are many reasons a customer could have an outage. These causes include downed trees, animal contact, a car hitting a pole, or even a lightning strike. Each one of these causes could show up on a different report for a different piece of equipment that all flow down to the same customer. These tools allow us to analyze customer experience *truly* from a customers' experience. These tools help our efforts in the long term to reduce repeated outages for customers. We illustrate the results of these tools in conjunction with our annual service quality reports every April 1.

3. *Cause Analysis*

Our annual reliability planning process begins with an analysis of the causes for historical outages. We use pareto charts in our analysis, as provided below, which show outage cause codes for a multi-year time period, ranked in descending order by the number of Sustained Customer Interruptions (SCI).[34]

[34] Electric service interruptions greater than five minutes in length.

The following pareto charts show feeder, tap, substation and transmission level customer interruptions by primary cause code for the years 2013 through 2017. The "balloons" highlight areas our plans are currently focusing on. These charts are based on Minnesota only using our QSP Tariff methodology. We note that programs typically require multiple years before their full impact is realized. At first, the programs may only halt SCI increases, but continuing investment eventually reverses adverse trends.

Our current reliability management program (RMP) investments are maintaining appropriate levels of overhead (OH) and underground (UG) system performance. Programs such as our Feeder Performance Improvement Program (FPIP) OERT have realized significant contributions in system performance, and are helping to eliminate or mitigate the failures that would be otherwise typical of aging equipment. We recognize that it is critical to combine our RMP process with a longer-term view of the aging distribution system in order to provide our customers with reliable electric service, and are taking actions to that end as we have discussed.

Figure 37: Minnesota Customer by Primary Cause

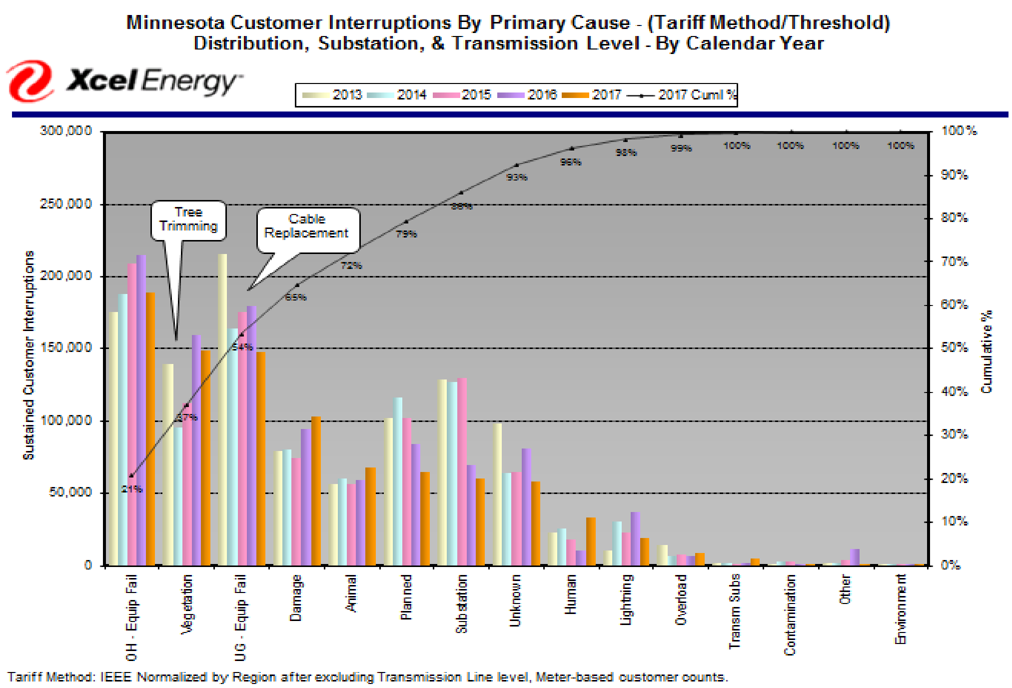


Figure 38: Minnesota Customer Interruptions by Failed Device – Overhead Mainline

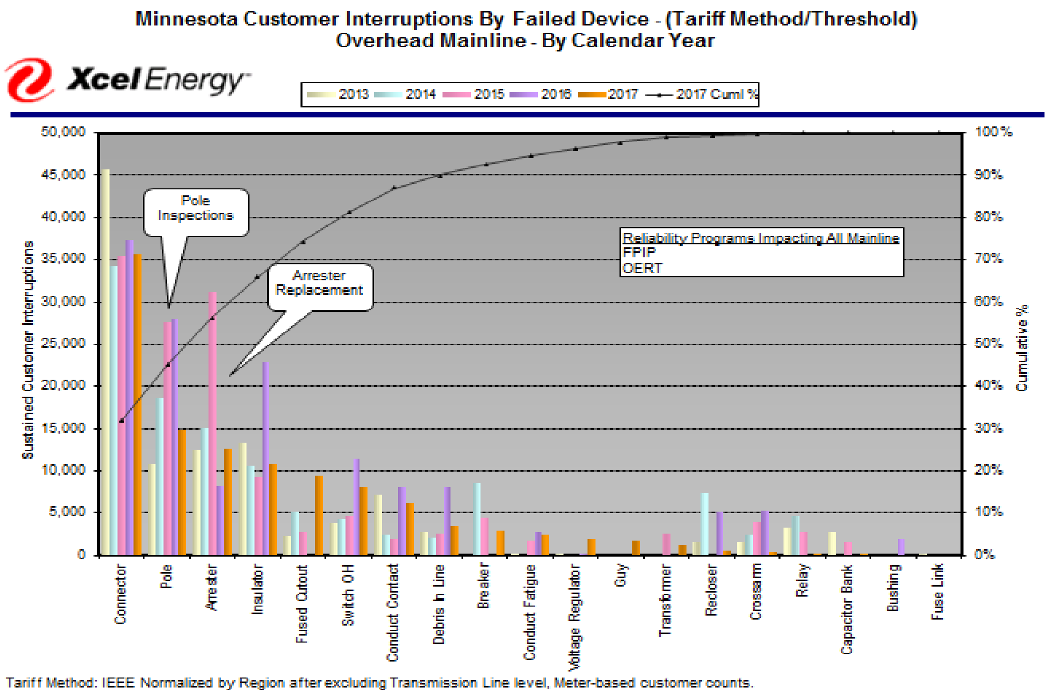


Figure 39: Minnesota Customer Interruptions by Failed Device–Overhead Tap

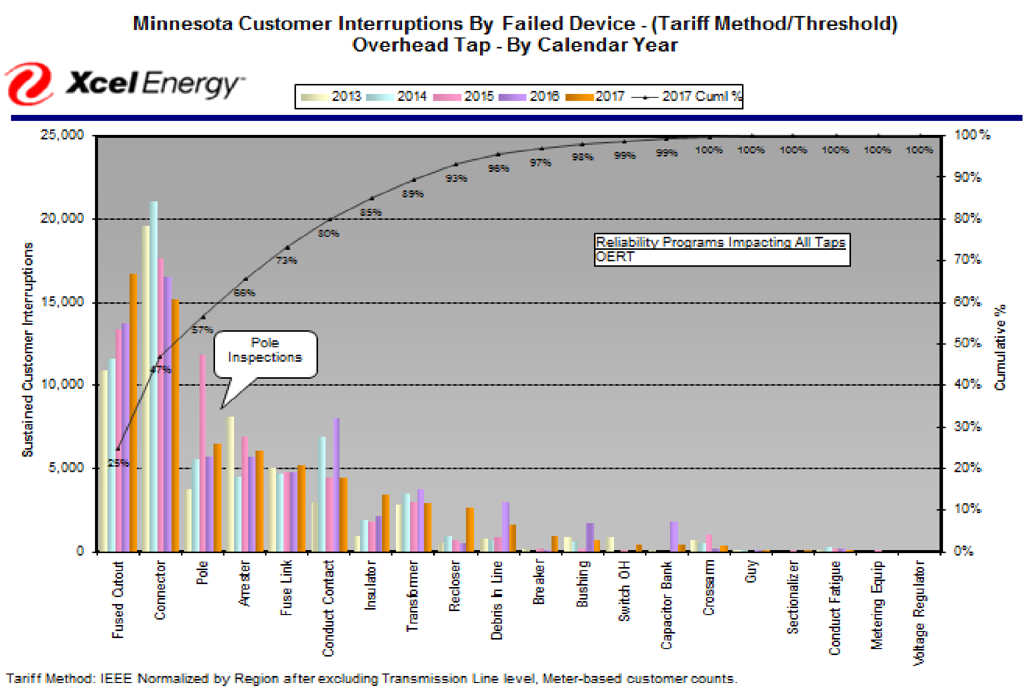
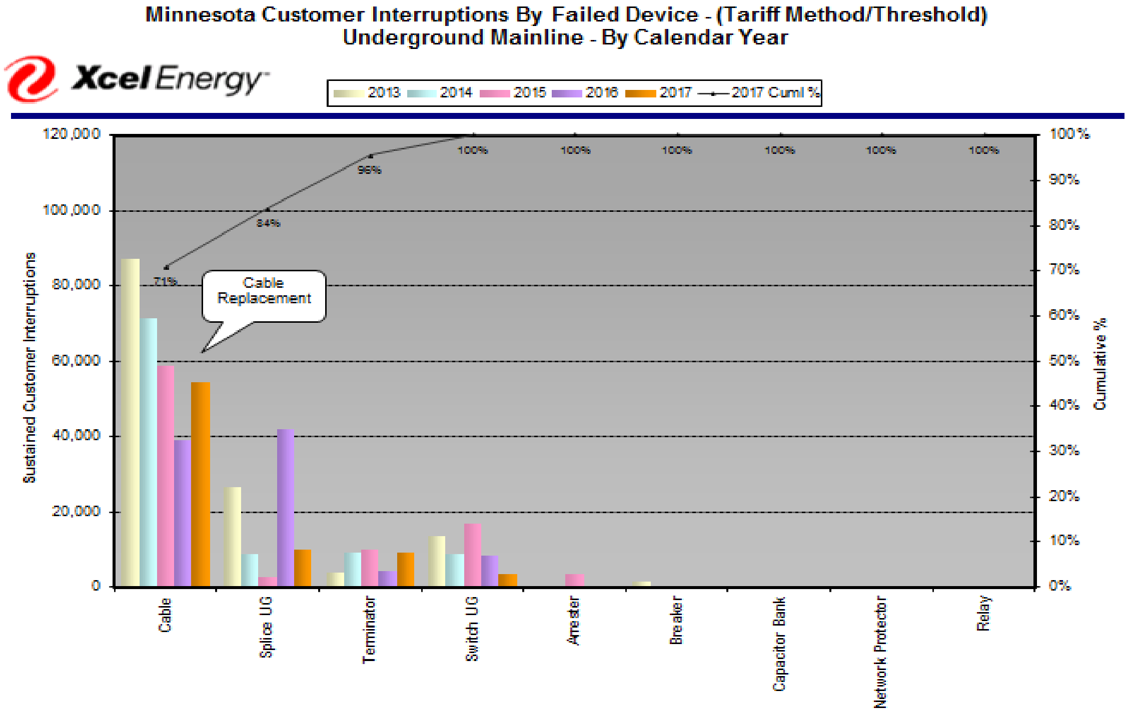
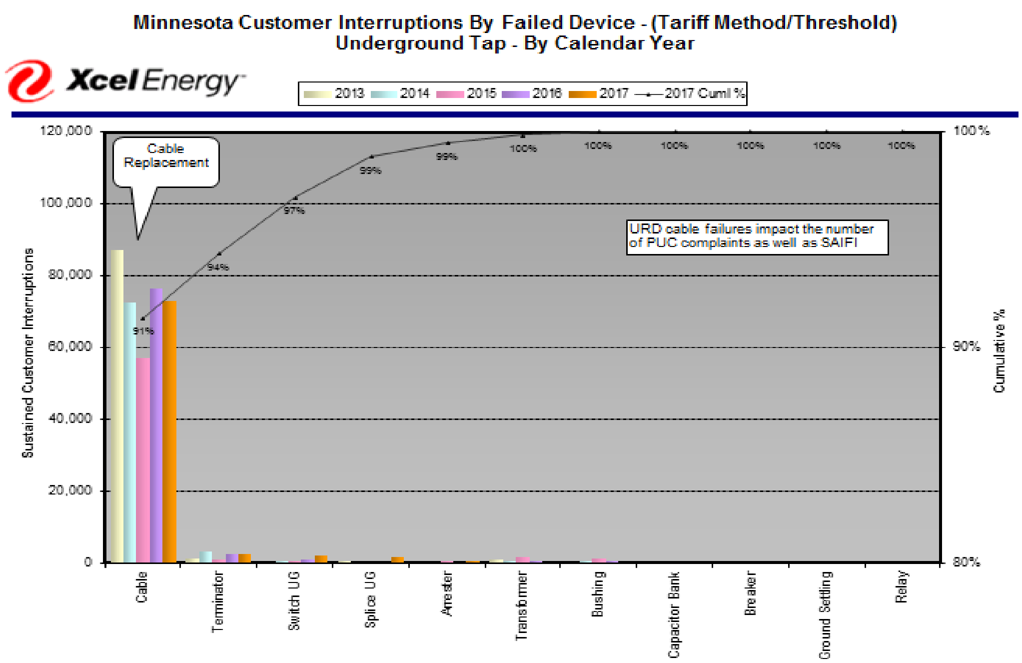


Figure 40: Minnesota Customer Interruptions by Failed Device – Underground Mainline



Tariff Method: IEEE Normalized by Region after excluding Transmission Line level, Meter-based customer counts.

Figure 41: Minnesota Customer Interruptions by Failed Device – Underground Tap



Tariff Method: IEEE Normalized by Region after excluding Transmission Line level, Meter-based customer counts.

After considering the most common failures and their causes, as well as at-risk equipment, we develop work plans, or programs, to target our investments. These programs represent those proactive investments in our distribution systems that we believe are most likely to improve overall reliability, asset health, and meet various contingency planning requirements. We describe the primary programs in Table 15 below.

Table 15: Reliability Management Program Summary

	Programs	Description
Reliability	Feeder Perf. Improvement Program (OH & UG)	FPIP evaluates and implements improvements for feeders experiencing an increased number of outages based on prior year information.
	Reliability Exception Monitoring System (OH & UG) – MN	REMS process provides automatic notification to area engineers when protective devices (e.g., breaker, fuse, etc) operate 2 or more times in a rolling 12 months and engineering solutions are implemented to eliminate recurring problems.
	Mainline Cable Replacement (UG)	Deteriorating non-jacketed cable is failing and causing repeat outages. Proactive and reactive replacement of this cable reduces the outages.
	Tap (URD) Cable (UG)	
	Install Automated Switches	These automation solutions reduce restoration times for long lines with long drive times to bring CAIDI in-line with other distribution lines.
	Feeder Infrared Evaluation (OH)	Many pieces of equipment show excess heating prior to failure. The FIRE program provides infrared scans of overhead mainline which reveal specific equipment that is likely to fail so it can repaired prior to causing an outage.
	Vegetation Management	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.
Integrity	Pole Inspection & Replacement (Distribution)	Pole Inspections include an above groundline visual inspection. Groundline inspections are based on age and environment and may include visual, sound and bore and excavation. Treatment of poles may be included. Based on results poles may be tagged for replacement.

Note: The above table reflects multi-year initiatives that are part of the Reliability Management Program(RMP). Information is based on current RMP, and is subject to change.

We have indicated the primary performance impacts of these programs with a red star, where applicable; possible performance impacts include SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration Index), CEMI and Customer Complaints.

These programs become part of the annual RMP. A Reliability Core Team (RCT), consisting of both Field and Planning functions monitors system performance and progress against the RMP on a monthly basis, taking actions as necessary to ensure the best possible system performance.

In addition to programs, we also implement work practices to improve reliability, which are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur, or to reduce the *frequency* of outages.

As noted in Table 16 below, we assess and prioritize the actions based on a balance of their ability to positively impact reliability, as well our ability to incorporate into standard work practices – with most occurring concurrently. Many of these actions do not require additional funding to implement, and are achieved via ongoing employee training and/or incorporation into standard work procedures. We continuously monitor all actions, and update our plan as appropriate.

Table 16: Reliability Management Work Practices Chart

Areas of Opportunity	Objective	Action/ Program	Description
Resource Management	**Duration**	**Contractor staffing**	Use contractors for appointments, freeing up Xcel Energy crews to respond to outages
Feeders	**Duration**	**Restore before repair**	During a feeder event Control Center personal restore service to as many customers before making temporary/permanent repairs.
	Frequency	**Intentional Outages**	Reduce Impact of Intentional Outage to ensure all steps are being taken to keep the maximum number of customers on Verify switching to reduce customer counts. Repair while hot instead of taking the outage.
	Frequency & Duration	**VM Partnership**	Partner with Vegetation Management leadership to prioritize trimming of circuits that are scheduled to be trimmed. Substations to be trimmed with associated Feeders
Feeders Control Center COM	**Frequency & Duration**	**Feeder Patrol Program**	Looking for unfused taps and animal protection. Identify 336 auto splices. Continued use of IR/thermo imaging to identify problems.
	Duration	**Model 1/0 Switching**	This is a pilot project to model 1/0 URD as close to real time so the OMS model will reflect the configuration of the URD circuit after it has been switched
	Duration	**Validate Restoration Times**	Tighten up existing process on actual restoration times, utilize approver process to ensure outage times are correct
	Duration	**COM Saturday Crews**	6 Metro COM Saturday Crews. 3 Metro East and 3 Metro West
Control Center	**Frequency & Duration**	**Underground cable repair**	Repair and/or replace cables as directed by engineering
	Frequency	**OERT/CEMI work**	Complete work referred by engineering in a timely manner
Reliability Team/ Communications	**Frequency & Duration**	**On-going regular reliability meetings**	Meet regularly to review reliability, and share ideas to improve reliability performance
	Duration	**Outage Review**	Root Cause Investigation of outages greater than 90 minutes of 0.1 SAIDI

VIII. DISTRIBUTION OPERATIONS

In this section, we discuss key aspects of our distribution operations. First, we discuss escalated operations – or how we plan for, approach, and respond to unplanned events impacting our system and customers – most frequently these are storm or weather-related. Part B of this section discusses other major components of our day-to-day work to provide our customers with reliable electric service. These activities include Vegetation Management, Damage Prevention, and Fleet and Equipment Management.

A. Reactive Trouble and Escalated Operations

We have discussed the many ways that we plan the system to ensure reliable service for our customers. However, sometimes we must quickly rally and respond to customer outages and infrastructure damage caused by outside forces, such as severe weather. In this section, we discuss our pre-event planning, outage restoration, and outline storm-related costs.

1. Escalated Operations Pre-Planning

To ensure we are prepared, we maintain a playbook that guides our planning, execution, and communications – and we regularly assess and drill our readiness and response. Our planning and preparations start well in advance of an actual weather event with foundational elements such as agreements with contractors to supplement our field forces when needed – and mutual aid agreements with other utilities for the same purpose.

We also maintain lists of hotel accommodations and conference facilities across our service area for when they are needed to house crews aiding in restoration activities, or serve as dispatch centers or areas to conduct tailgate or safety briefings. We also maintain lists of available transportation options such as for buses and vans, to move crews and support staff between locations. Finally, we also pre-identify staging sites across our service area so we are able to quickly implement plans that involve staging equipment or non-local crews – and ensure we have street and feeder maps readily available for them to use. Our planning also incorporates details are not top-of-mind when thinking about what might be needed for an effective storm response – such as ensuring we have ready access to catering to feed crews, adequate restroom availability, laundry facilities, garbage and debris containers, and security.

In terms of planning and preparations in the immediate timeframe before a weather event, we are continuously assessing the weather, system status and customer call volumes to recognize "early warning signs." As the storm picture becomes more clear, we inform office staff, field workforces, and strategic communications stakeholders, which includes the call centers, external communications, community relations, and regulatory affairs, among others. We begin to send regular weather and staffing updates to pre-defined internal distribution lists, and inform employees in identified storm support roles to prepare for an extended time at work. At this point, we are also informing support functions such as supply chain, fleet, safety, security operations, and workforce relations of our assessment of the impending weather. We also inform our local unions of our assessment and planning criteria. We may also begin to strategically move and stage field crews and equipment to areas expected to be significantly impacted – especially if we expect access to those areas to be limited or hampered as a result of the weather event.

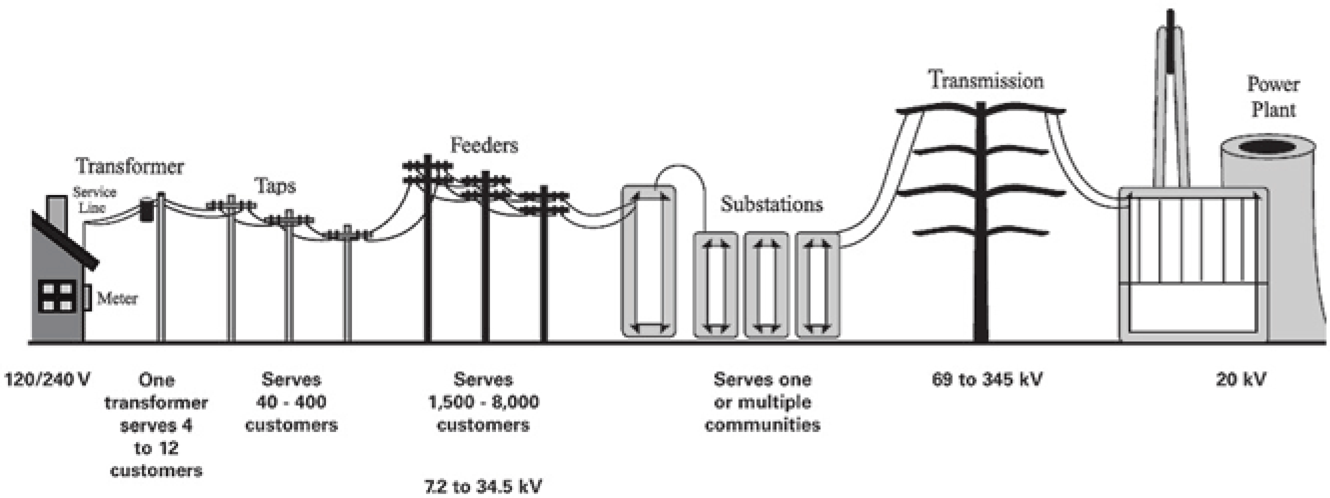
At the point operations leadership believes the forecast presents risk to the distribution system, we hold an operational call where we review our assessment of conditions, staffing, and other preparations. When system impact is confirmed, we initiate "Mission Mode," which alerts pre-defined lists of individuals representing key functions across the organization. A regular cadence of escalated operations calls that follow a standardized agenda that both communicates key facts about the event including customer and infrastructure impacts and restoration staffing – and gathers information from support functions and external facing groups such as from the call center, community relations, and large managed accounts.

As soon as Xcel Energy knows there is an outage, a crew is dispatched to investigate. When the crew arrives on the scene, it assesses the problem and proceeds with the repair. Due to the complexity of the Xcel Energy electric system and the variety of probable causes, this process can take several minutes or, in extreme circumstances, hours. Time estimates can vary based on the extent of the outage, public safety issues that take priority, etc.

The Xcel Energy restoration process gives top priority to situations that threaten public safety, such as live, downed wires. Repairs are then prioritized based on what will restore power to the largest number of customers most quickly. Crews work around the clock until power is restored to all customers.

The number of customers affected by an outage will depend on where the cause of the outage occurred. Figure 42 provides a high level view of the major electric grid components involved in restoring power to customers, whether the outages are part of an escalated operations event or a more isolated outage event.

Figure 42: Major Grid Components



2. *Outage Restoration*

Outage restoration prioritization generally follows the system components that will restore power to the greatest numbers of customers, which we describe below. We note however, that we also take into consideration critical infrastructure such as schools, hospitals, and municipal pumping operations.

Restoration of transmission lines and substations are a top priority, because they may serve one or several communities. Generally, damaged or failed transmission facilities do not cause customer outages due to the interconnected nature of the transmission grid. Regardless, they are a top priority because a failed or damaged component reduces our resilience by creating a vulnerability on the grid. Transmission lines and substations have a dedicated workforce, which allows Distribution to focus on restoring portions of the system that more directly impact customers.

Substations can be either transmission or distribution. Distribution substations distribute power to feeders. One feeder might serve between 1,500 to 8,000 customers. Feeders distribute power to power lines called taps. One tap line might serve between 40 to 400 customers. Tap lines distribute power to transformers. Transformers may serve a single building or home, or serve multiple customers (generally 4 to 12 customers). Service wires connect transformers to individual residences and businesses.

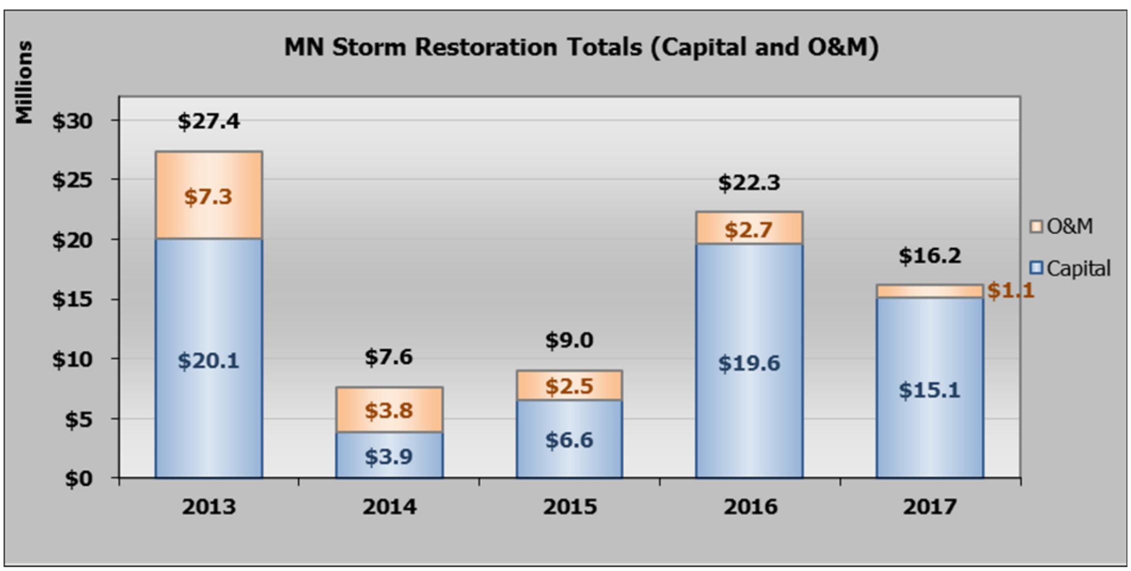
Sometimes, a tap, feeder or substation outage will be restored while a transformer or an individual customer (service) may remain without power. This type of outage may go undetected at first until the customer notices that their neighbors have power, or they receive a notification that their electricity has been restored, when in fact, it has not been. AMI will significantly improve our ability to initially "sense" and thus record individual customer outages – and track them all the way through to restoration. Similarly, with this detailed information enabled by AMI, we will have increased capabilities to avoid "okay on arrival" truck rolls, because we will have better data at an individual customer level than we do today.

3. *Costs Summary*

Our annual capital and O&M expenditures are influenced by the magnitude and frequency of significant storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a typical year for severe weather.

Figure 43 below portrays our capital- and O&M-related Escalated Operations costs for the recent past, demonstrating how variable this aspect of our operations can be.[35]

Figure 43: Escalated Operations – State of Minnesota Electric Jurisdiction Capital and O&M Expenditures (2013 to 2017)



In terms of budgeting for storm restoration, due its significant variability from year-to-year, we budget dollars in a working capital fund that are not assigned to a specific project or program. When emergent circumstances, such as storm restoration arise,

[35] Represents escalated operations events significant enough for a workorder to be established.

we reallocate budgeted dollars to address the circumstance while remaining in balance with our annual budget. For O&M, we do something similar – we factor-in a base level of funding within key labor accounts, such as productive labor and overtime.

B. Distribution Operations – Functional Work View

In this section, we highlight a few key aspects of the distribution function that contribute to providing customers with safe and reliable service – but that are not as prominent as storm response or constructing new feeders and substations. These include:

- Our *vegetation management* program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our *damage prevention* program that helps the public identify and avoid underground electric infrastructure, and
- The fleet, tools, and equipment that support everything the Distribution function does every day.

1. Vegetation Management

The Vegetation Management activity includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages. It includes the activity associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on and adjacent to the Company's rights-of-way to limit preventable vegetation-related interruptions. An effective Vegetation Management program is essential to providing reliable service to our customers. We have established a five-year routine maintenance cycle for our distribution facilities, generally meaning that vegetation around our electric facilities will be maintained every five years.

Tree-related incidents are among the top two causes for electrical outages on the Company's distribution system. Being as close as practicable to 100 percent on a five-year cycle will better ensure that preventable tree-related interruptions are minimized, public and employee safety is addressed, and various regulatory compliance requirements are met. This category also includes the pole inspection program, because we use the same workforce to perform both of these activities.

We budget for Vegetation Management annually based primarily on the number of line-miles of transmission and distribution circuits needing to be maintained on an annual basis. To maintain on-cycle performance, varying miles of circuits come due each year that were last maintained five years previous, and need to be maintained again. Annual budgets are prepared based on the line-miles coming due in the given year. In addition to line-miles, key cost drivers are the number of line-miles due in a given year to maintain on-cycle performance, degree of difficulty (forestation) associated with scope of annual circuits due, and finally, the contract labor rates of our primary contractors.

2. *Damage Prevention/Locating*

The Damage Prevention category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements. This program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. We summarize in Table 17 below the volume of requests for electric facilities locates over the recent past:

Table 17: Electric Locates Volumes (2013-2017)

	2013	2014	2015	2016	2017
State of Minnesota	336,871	361,966	393,111	383,442	400,296
NSPM Total	393,213	413,469	446,838	440,515	460,483

The budget for Damage Prevention is based on several factors, including our most recent historical annual locate request volume trends, regional economic growth factors including new housing starts, and the contract pricing of our Damage Prevention service providers.

3. *Fleet and Equipment Management*

From a functional perspective, this category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently, which includes the necessary replacement of vehicles and equipment that have reached their end of life. The O&M component of fleet is those expenditures necessary to maintain our existing fleet, which includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the Distribution fleet utilized for O&M activities as compared to capital projects.

The largest cost driver for this category is for fleet vehicles. Our fleet managers maintain accurate records on vehicles and have performed analysis to determine the optimal investments to ensure a reliable, yet cost-effective fleet. Through our rigorous tracking of vehicle maintenance expenses, we are able to select vehicles to replace in order to achieve the lowest cost of ownership. We analyze which units have met their candidate age for replacement, quantitatively prioritize which assets will return the largest reduction in maintenance and repair as a proportion to their capital investment, qualitatively review condition assessments with the mechanics, and review work priorities and gather non-replacement fleet needs with users. The annual fleet budget can then be derived based on the proposed number of fleet replacements (by type of vehicle) coupled with the latest known pricing for each type and quantity of vehicle being proposed for replacement.

IX. GRID MODERNIZATION

In this Section we describe the Company's overall grid modernization strategy and short- and long-term plans for specific grid modernization initiatives. We also discuss our current and planned investments in grid modernization in relation to the U.S. DOE's Next Generation Distribution System Platform (DSPx).

A. Overview and Grid Architecture

While incremental modernization efforts have taken place on the distribution system over many years, and we have used these investments to provide reliable power for decades, we believe the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems.

In response to changing customer demands and technological advances, the Company developed the advanced grid intelligence and security initiative (AGIS). The foundational investments in our AGIS initiative, described in our 2015 and 2017 Grid Modernization reports[36] and in this report, include:

- Advanced Distribution Management System (ADMS)
- Advanced Metering Infrastructure (AMI)
- Field Area Network (FAN)

[36] *See* Docket Nos. E999/M-15-439 and E002/M-17-776

- Fault Location, Isolation, and Service Restoration (FLISR)

These foundational elements, in concert with other future investments, will provide cumulative benefits over time and transform the customer experience by providing new, innovative customer programs and service offerings, developed internally and in concert with partners. For instance, more refined customer usage data, captured by AMI meters and communicated to utility systems through the FAN, enables new rate, billing, and program options that allow customers to adjust their usage to save money or participate in cost saving programs, using their devices.

AMI and FAN will also improve existing MyAccount information to provide more personalized insights to help customers understand how and where energy is being used and provide ways to help them save money. These foundational investments will also allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value and depend upon. As an example, FLISR and ADMS combine to automatically reconfigure the grid to reduce the numbers of customers affected by an outage and provide better information to outage restoration crews to speed up their response or avoid those outages in the first place.

The benefits and offerings described above, in addition to many others, will become available as these advanced technologies are deployed. As foundational investments, they also lay the groundwork for later years. For example, the secure, resilient communication networks and controllable field devices deployed today through these investments become more valuable in the future as additional grid sensors and customer technologies are integrated and coordinated.

As we deploy infrastructure and advanced technologies we expect three, primary outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. This information will be utilized to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communication. These options will give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. Early initiatives will focus on the execution of services that benefit all customers. Other customer choice programs enabled or enhanced by AGIS initiatives may include smart thermostats, home area networks, rooftop solar, community solar gardens, optimized EV charging, and other DER offerings.

Improved core operations and capabilities. We will also improve our core operations, making investments to more efficiently and effectively deliver the safe and reliable electricity that our customers expect. While NPSM has historically provided reliable service, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve.[37] Our advanced grid investments provide technologies to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation. This will benefit customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. Designing for interoperability enables a cost-effective approach to technology investments and means we are able to extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our AGIS investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks (such as the DOE's DSPx framework).[38] By doing so, we sequence the investments to yield the greatest near- and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

Adherence to industry standards also allows us to better secure the grid and the devices we have connected to it. However, the increasing number of interfaces also increases our cybersecurity exposure. As we move forward into the next generation of intelligent, interactive electric distribution, every facet of the electric network must be evaluated for cybersecurity risk. Therefore, all aspects of the advanced grid must be inventoried, securely configured, and monitored regularly and thoroughly.
These investments will also produce a wealth of customer and grid data, which will in turn enable us to provide the new services described here and enhance existing services. These data-related efforts have begun, and next steps will include identifying the analytics capabilities needed to add additional value to customer offerings or improve utility operations. Data analytics in the utility industry continues to mature,

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37 See Leading the Energy Future 2017 Corporate Responsibility Report, Page 85, Xcel Energy (May 2018).
38 *See Modern Distribution Grid, Volume III: Decision Guide*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

so as grid modernization investments are deployed, these capabilities will evolve as well.

While the amount of DER in Minnesota is relatively low in comparison to states like California and Hawaii, our customers are increasingly looking to DER to help manage their energy usage and expect NSPM to have the technology and processes in place to integrate these resources. In our future, we will need to enhance our forecasting and planning capabilities to continue to design and operate the grid in a safe and reliable manner. The ability to better understand the current state of the grid provided by AMI and ADMS will facilitate more advanced planning capabilities. This advanced planning will help us identify opportunities where DER can provide a more efficient solution to distribution system needs. Through these more advanced capabilities we will also enhance the DER interconnection process, leading to more timely, efficient, and accurate integration of DER.

The time is now to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and the flexibility to adapt to an uncertain future.

B. Advanced Grid Efforts to Date

The Company has already taken important steps to further our AGIS efforts. Thus far, two advanced grid investments have been submitted for certification in prior biennial grid modernization reports and approved by the Commission. In the 2015 Biennial Grid Modernization Report, the Company outlined the ADMS initiative, which was submitted for certification and subsequently approved on June 28, 2016. In the 2017 Biennial Grid Modernization Report, the Company outlined its Time of Use (TOU) pilot program and certification was approved in the Commission's August 7, 2018 Order, and maintained in its October 15, 2018 Order Denying Reconsideration.

1. ADMS

ADMS is a collection of core functions and applications designed to monitor and control the entire electric distribution network efficiently and reliably. ADMS will provide an integrated operating and decision support system to assist control center operators, field personnel, and engineers. ADMS will allow the Company to monitor, control, and optimize the electric distribution system. The core software functions will include:

- *Distributed Network Modeling.* This provides a single, network model that represents the entire distribution network from the high side of substation transformers down to the secondary side of service transformers, including DER
- *Distribution Supervisory Control and Data Acquisition (SCADA) Monitoring and Control.* This will provide monitoring and control capabilities for all devices providing telemetry and capable of being controlled remotely. This includes, but is not limited to substation devices, intelligent field devices, and emerging devices that will integrate with the distribution grid
- *Unbalanced Load Flow and Network Topology Processing.* An unbalanced load flow considers the individual phase currents and voltages, in contrast to a balanced load flow which uses average phase data. The unbalanced flow is more complex, but necessary for our purposes. The network topology processor adjusts the model to reflect changes in the distribution grid due to switching activity. This updates the model so that it is accurate as the distribution grid changes and will provide near-real time load flow calculations for all segments of the distribution network

These functions meet the core objectives of integrated grid preparedness, improved reliability, and increased grid efficiency.

Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, and FLISR in the near-term, while preparing the Company to implement advanced applications like Distributed Energy Resource Management System (DERMS). Through an initial rollout by 2020, ADMS will serve as a foundational investment, providing situational awareness and automated capabilities that sustain and improve the performance of the increasingly complex grid. ADMS will enable more efficient and effective management of the grid and more reliable service to our customers. By implementing an ADMS, we are better positioned to fully realize the benefits of technologies deployed on the distribution grid.

2. *TOU Pilot*

In the 2017 Distribution Grid Modernization report, the Company sought and received certification for its residential TOU rate. The Commission took action in May 2018, and thus, the early-stages of the implementation began. The TOU pilot implements new residential TOU rates in two communities in the Twin Cities metropolitan area, providing select customers with pricing specific to the time of day energy is consumed. This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions. This pilot relies on AMI to measure and record customer energy usage in detailed, time-based formats for frequent transmittal and provision of such information to the utilities and customers. The communication function embedded within the advanced meters is a component of the Company's FAN.

To support the TOU pilot, we will deploy advanced meters to approximately 17,500 residential customers in Minneapolis and Eden Prairie. We will also deploy FAN communications. AMI and FAN operations will require a head-end system, which we aim to complete by early 2019. With customer engagement efforts underway, installation of both FAN and AMI, in connection with the TOU pilot, will begin in 2019. Baseline information will be collected, and the pilot will launch in 2020. We intend to operate this pilot for two years, sharing learnings about the effectiveness of these techniques to generate peak demand savings. We will also explore the performance of selected technologies, the impact of the price signals, and the effectiveness of customer engagement strategies. Ultimately, this pilot will inform future consideration of a broader TOU rate deployment in Minnesota.

The limited deployment of FAN and AMI through the TOU pilot will allow the Company an opportunity to measure and verify key assumptions regarding customer behavior in advance of the planned wider rollout of both initiatives. Customer response will be measured and the infrastructure will be tested.

C. Roadmap and Planned Investments

Our advanced grid roadmap is the continuation of efforts that have been underway for several years. The early steps of this transition are focused on building the foundational elements needed to enable more advanced applications at the "pace of value." This means that investments are logically sequenced to build capabilities as they are needed and incrementally upon each other.

These advanced grid plans align with Xcel Energy's corporate strategic priorities to create a better customer experience, provide more ways for customers to save money, and deliver cleaner, more reliable energy, as well as the Commission's Staff Report on

Grid Modernization.[39] Principles for grid modernization developed by Commission Staff include:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies,
- Enable greater customer engagement, empowerment, and options for energy services,
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies, and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

Accounting for this foundational approach and grid modernization principles and goals, our current near-term plans involve three AGIS projects: (1) AMI, (2) FAN and (3) FLISR. Below, we describe each of these three projects including an overview of the technology, components of the investment, benefits associated with the investment, the implementation schedule and plans, interoperability and interdependency considerations, alternatives considered, and finally, costs. We also have additional investments either already under way or under consideration for the long-term that we discuss later in this section of the IDP.

As we are still determining the details of our customer strategy and a variety of investment decision points impact that, we are not yet seeking certification of these three investments but rather we provide a detailed discussion of our current internal plans, budgets, and considerations in the interest of transparency into our AGIS initiative and grid modernization strategy. All costs contained herein are intended to be directional and used as a point of context and are thus subject to change as we continue to refine our strategy and investment plans. We will bring the costs associated with these projects to the Commission for approval through a future certification request in the grid modernization/IDP filings or through a general rate case.

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[39] *Staff Report on Grid Modernization*, Minnesota Public Utilities Commission (March 2016). https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E04F7495-01E6-49EA-965E-21E8F0DD2D2A}&documentTitle=20163-119406-01

D. Near-Term Investment: ***Advanced Metering Infrastructure***

1. Overview

As we have discussed, fundamentally, we must replace our current AMR system and now is an opportune time to move to AMI. AMI is an integrated system of advanced meters, communications networks, and data management systems that enables two-way communication between utilities' business and operational data systems and customer meters. AMI is a foundational element of the Company's AGIS plan because it provides a central source of information with which many components of an intelligent grid design interact. The system visibility and data delivered by AMI provides customer benefits for reliability and remote connection, and enables greater customer offerings for rates, programs, and services, and enhances utility planning and operational capabilities.

The Company plans to deploy approximately 1.3 million advanced meters in Minnesota, between 2020 and 2023. This deployment of AMI builds off the limited installation of AMI meters planned for installation in late 2019 as part of the TOU pilot certified by the Commission as part of the Company's 2017 Grid Modernization.

2. Initiative Components

Advanced metering infrastructure consists of several components – advanced meters, communication networks, and data management systems.

The advanced meter itself is made up of several components – a metrology component (responsible for measurements and storage of interval energy consumption and demand data), a two-way communication module (responsible for transmitting measured data and event data available to external applications), and an internal service switch (to support remote connect and disconnect of residential type service). AMI meters can also measure values such as voltage, current, real and reactive power, and certain power quality events such as sags and swells.

These meters detect outage and restoration events; detect tampering events; and perform meter diagnostics. This information is transmitted through the radio frequency communication module, through the FAN (described below), and received by the AMI head-end application – the operating software system that is used to send data requests and commands to an advanced meter, and receive data from an AMI-capable meter.

3. *Benefits*

Our proposed deployment of AMI is well aligned to the aspirations of transforming the customer experience and creating customer value through advanced capabilities achieved by deploying utility systems and technology.

There are several capabilities provided through AMI and FAN directly, and additional capabilities can be enabled or enhanced through the combination of AMI data and existing or planned investments; including ADMS, an enhanced customer platform, Home Are Network (HAN), or distribution planning tools in the near term, as well as longer term investments like data analytics applications.

The collection of interval meter data is the primary capability delivered by AMI. This interval data can be used in conjunction with our other AGIS investments and offerings to deliver new benefits. Furthermore, these benefits are often interrelated. For instance, the energy usage insights developed using AMI and presented through the customer portal enables the customer to better manage their energy usage; however, without utility offerings for time of use rates or new DSM programs, our customers' options to act on these insights are limited. Similarly, the disaggregation and analysis of usage data may be interesting, but the offerings are made actionable when combined with a customer's HAN and two-way communication between and among utility systems.

From a customer's perspective, AMI data will be used to provide:

- *Energy usage insights.* By presenting the customer's detailed energy usage information through the customer platform (web portals and smartphone applications), we will empower customers with the information and options to make more informed decisions on their energy usage. The customer platform may be combined with an analytics engine to provide the customer with insights and energy savings tips. These analytics may predict disaggregation of the customer's usage to determine specifically what drives their usage (e.g., A/C load, laundry machines) to provide customer's actionable options to change their energy consumption behavior. Proactive messaging and education can help customers save money by adjusting their energy usage or tailoring it with programs and offerings. An option that we have previously adopted and are looking to improve through more granular and actionable insights is energy usage comparisons relative to neighbors, which has been shown to influence customer behavior

- *Enhanced rate offerings*. As discussed in our certification request for the TOU pilot,[40] AMI enables the development of additional rates to meet our customers' particular usage profiles and needs. When Oklahoma Gas and Electric offered pricing programs as part of their AMI rollout, 99 percent of participating customers saved money through their program.[41] The design of these rates may be facilitated using analytics applications. Looking ahead, as EV adoption increases we expect to offer new EV and 'Whole Home' rates.

- *Targeted DSM program offerings*. As more granular customer usage profiles are developed using the interval meter data produced by AMI, we can offer more targeted participation offerings in energy efficiency and DR programs. Programs that have been implemented as part of AMI rollouts for other utilities include Commonwealth Edison's Peak Time Savings[42] program or Baltimore Gas & Electric's Smart Energy Awards offering day ahead notice and bill credits for lowering consumption during the peak hours of peak days.[43] Specific offerings under consideration include energy efficiency upgrade impacts, that would help show customers the direct benefits of their energy efficient choices by showing the corresponding reduction in their usage and bill, or reward gamification to engage customers in managing energy usage in ways that are mutually beneficial to the customer and the grid

- *In home-interfaces*. If deployed with a HAN, the two-way communication from utility systems to customer premises enables greater interaction with customer in-home devices, ranging from thermostats to distributed generation, and the utility meter

- *Improved billing features*. The bill, one of the primary and constant means of communicating with customers, can also be improved. Interval meter data, collected on a more frequent basis enables us to provide customers usage or high bill alerts, like how mobile phones warn about data usage overages. It also improves budget billing, letting a customer budget their energy usage through the year. AMI enhances the offering that allows customers to pick a bill due date that meets their monthly cash flow needs

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[40] *See* 2017 Biennial Report - Distribution Grid Modernization, Docket No. E002/M-17-776 (November 1, 2017).

[41] See AMI and Customer Systems: Results from the SGIG Program, Page 32, U.S. Department of Energy (September 2016).

[42] Peak Time Savings, ComEd - An Exelon Company. *See* https://www.comed.com/WaysToSave/ForYourHome/Pages/PeakTimeSavings.aspx

[43] Smart Energy Rewards, BGE - An Exelon Company. *See* https://www.bge.com/SmartEnergy/ProgramsServices/Pages/SmartEnergyRewards.aspx

From a grid perspective, the meter data provided by AMI is used:

- *To maintain greater awareness of customer outages and aid in more expedient restoration.* Advanced meters report power-out or "last gasp" events to the AMI head-end application and report a power-on event when power is restored. "Last gasp" is the final message transmitted by the meter upon detection of an outage. This information will flow from the head-end application into ADMS, improving the calculations for the fault location and restoration applications. These power-on and power-off notifications will provide us with a more timely and accurate scope of the outage without relying on customers to report an outage. The restoration confirmation also enables us to focus and optimize our restoration efforts on active outages, minimizing field trips where outages do not exist, also known as "Okay on Arrival" calls.

  While not quantified in the benefits described below, we anticipate some reduction in outage frequency attributed to more granular awareness of local power conditions. This could include momentary outages, which are often a precursor of more significant grid events. Additionally, the smart meters produce a wealth of data that could be analyzed to determine where to target vegetation management or correlating customer usage with equipment data to predictively maintain equipment and avoid failures.
- *As an input for more granular distribution planning analysis, inclusive of DER.* Described in greater detail in the Distribution Planning Tools section

The AMI meter also has the capability to remotely connect or disconnect service, which provides customers more on-demand service for move-in or move-out while also reducing costs associated with these transactions.

While some of these capabilities are possible with the current fixed-network AMR technology, all capabilities above are enhanced and more efficiently attained with AMI and more timely and granular data. The fixed network AMR system in place in Minnesota is a one-way communication technology with limited two-way communication capability in the collection of meter data and events for subsequent download to the Company's business and customer billing systems. The limitations of the AMR system currently in place include:

- The limited ability to record interval (load profile) data
  - As described in our TOU Pilot Petition, the lack of billing quality interval data limits the ability to support TOU rates for residential

customers.[44] The currently installed meters do not have any register level interval data or multiple "bin" TOU functionality. The existing vendor could extend their network with new meters and communications assets to enable TOU in some areas, for slightly lower pilot costs ($9.8M vs. $11M). However, as noted in our petition, and agreed to by the Commission, the AMI/FAN technologies offer greater benefits and do not have the end of life concerns present with enhancing the AMR solution. Our present AMR system, provided by Landis+Gyr through a service agreement, will no longer be supported after the early-2020s – and they plan to discontinue support for AMR technology entirely in the mid-2020s, around the time our current service agreement will end. .

- AMR meters do not measure important characteristics of electricity delivery such as voltage, current, power quality data
- AMR meters provide meter energy and demand readings once per day collected by a proprietary fixed communications network
- The daily collection of data available from existing AMR meters limits the usefulness of meter data to operational systems such as ADMS, which require more near real-time energy and voltage system information
- AMR meters cannot be reprogrammed remotely to support different metering configurations and firmware cannot be upgraded remotely, requiring a truck roll to perform these tasks when necessary
- AMR meters readings are transmitted in a single path in a point-to-multiple point proprietary communication system and reliant on a clear radio signal to a network collection device. The proposed AMI technology provides for the meters' data to be communicated over mesh communications technology. The mesh style network enables multiple communication pathways to the utility if there is an obstruction of the radio frequency in the primary established communication path. This provides more robust communications with the meter and minimizes customers receiving estimated monthly bills

Many of the alternatives to AMI are essentially antiquated approaches that will not move the Company forward in terms of grid modernization. As the AMR system is retired, the Company could leave those meters in place and perform manual meter reading. While this approach is possible, and reduces the costs of the meters

[44] *See* PETITION FOR APPROVAL OF A TIME OF USE RATE DESIGN PILOT PROGRAM, Docket No. E002/M-17-775, Page 30, Xcel Energy (November 2017).

themselves, the level of information provided to customers regarding their energy use would be greatly diminished and there would be significant cost in staffing meter reading personnel to cover the vast geographic area of our service territory.

In addition to the enhanced capabilities and new offerings described above, AMI will deliver quantifiable savings or benefits in terms of capital, O&M, and operations. The capital savings include distribution system management, outage management efficiency, and avoided meter purchases associated with fewer meter replacements. The O&M savings relate to meter reading costs, field and meter service costs, improvements in customer care, and distribution management and outage management savings. Additionally, we anticipate savings related to reduced customer outages, revenue protection, reduced consumption on inactive premises, reduced uncollectible and bad debt expense above and beyond what we can achieve with AMR today. The summary of these quantifiable benefits is included in Table 18 below:

Table 18: AMI Benefits

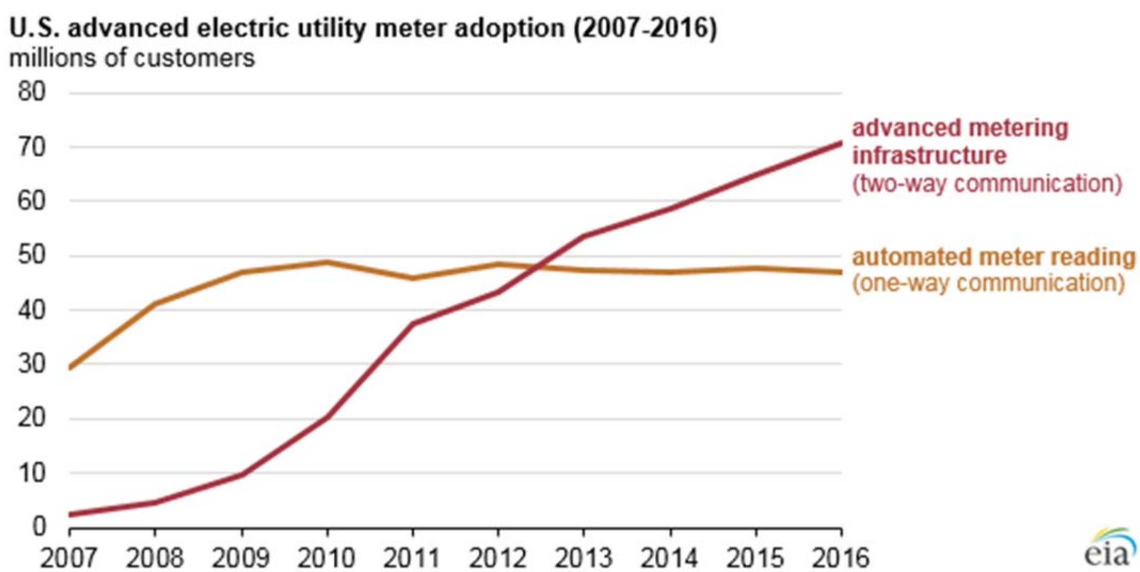
Benefit	Description
Distribution System Management Efficiency	More efficient use of capital dollars to plan and design the system
Outage Management Efficiency	More timely and accurate scope of outage and reducing "Okay on Arrival" outage calls
Avoided Meter Purchase	Lower meter retirement rate associated with lower meter failures
Reduction in Meter Reading	Elimination of costs (fixed and variable fees) associated with AMR Cell Net meter reading
Reduction in Field & Meter Services	Less labor required to address meter and outage complaints
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft
Distribution System Management Efficiency	Increased efficiency of distribution maintenance costs
Outage Management Efficiency	Improved O&M spending efficiency during storm events
Critical Peak Pricing	Closer alignment of rates with the real time cost of energy to incentivize load reductions
Customer Outage Reduction	Reduction in customer outage minutes due to faster response capability
Reduced Consumption on Inactive Premises	Expedited ability to turn off power when the premise has been determined to be vacated
Reduced Uncollectible Bad Debt	Decreased loss due to uncollectible accounts
Carbon Reduction	Reduced natural gas generation by shifting consumption to time periods when renewables are producing more

4. *Implementation*

Our present AMR system has delivered substantial value for customers since it was implemented in the mid-1990s. However, fundamentally, we must replace our legacy AMR system and it is an opportune time to replace it with AMI due to the pending sunset of AMR technology by our vendor, and the maturity of AMI market solutions. Our current AMR system is owned and operated by Landis+Gyr under a service agreement. Landis+Gyr has announced that the technology will no longer be supported after the early-2020s – and they plan to discontinue support for AMR technology entirely in the mid-2020s, around the time our current service agreement will end. Our present plans are to complete our AMI implementation in Minnesota no later than the end of 2023.

Many other vendors are also discontinuing support of AMR technology, which is being driven by the maturity of AMI. According to the United States Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollout has flattened.[45] See Figure 44 below.

Figure 44: AMI vs. AMR Penetration



Beyond industry maturity, we also have the opportunity for first-hand experience with the design and implementation of AMI on a limited basis through the TOU pilot in

[45] "Nearly half of all U.S. electricity customers have smart meters", U.S. Energy Information Administration (December 6, 2017). https://www.eia.gov/todayinenergy/detail.php?id=34012

Minnesota and on a wide-scale deployment in Colorado. Our operating company affiliate Public Service Company of Colorado (PSCo) has begun the design phase, has selected an AMI solution provider, and is currently selecting a meter manufacturing vendor for the meters and installation.

5. *Interdependencies*

As noted in our 2017 grid modernization report, the AMI plan is dependent on the parallel deployment of the FAN for communication:[46]

> *By leveraging the FAN, AMI creates a network among the advanced meters, our business systems, distribution automation field devices, and control centers, facilitating near real-time collection and dissemination of energy usage, customer service status, and service quality information to customers and the Company.*

There are several systems that are dependent on or enhanced by AMI data. AMI provides data to its head-end system which will interface with the ADMS. AMI data also enhances outage management capabilities through its last-gasp functionality. The interface between AMI and the HAN offers the two-way communication channel between the utility and customers' home devices. AMI data, combined with DRMS and DERMS, will provide greater insight into DER and Electric Vehicle system impacts.

6. *Alternatives Considered*

The alternatives to AMI meters are to continue with the existing AMR meters or return to non-AMR, manually read meters. As part of the alternative of continuing with existing AMR meters, we considered the adoption of the AMR meter that would provide TOU and load profiling functionality described earlier. Although we may be able to provide customers more choice of time based rates with these meters, it is not viable to continue to utilize AMR technology long-term because it does not provide the timely two-way communication of data and other associated customer and Company benefits of AMI. Additionally, as referenced earlier, our vendor has announced they plan to discontinue support for AMR technology entirely in the mid-2020s. Meanwhile, utilities have continued to replace AMR with AMI technology as the predominant standard in the industry. Finally, reverting to manual meters is not viable because they also lack the ability to provide timely two-way communication and

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[46] *See* 2017 Biennial Report – Distribution Grid Modernization at pages 38-39, Docket No. E002/M-17-776, (November 1, 2017).

the other benefits of AMI meters as described above.

We believe the time is now to implement AMI as it (1) provides operators with more visibility into the system; (2) enables customers access to more information; and (3) enables future products and services. Delaying AMI would leave the Company with less insight into the functioning of the distribution system, less up-to-date system data, and more limited customer services into the future. Additionally, AMR technology is stagnant and will not be supported in the long term. Finally, as more utilities adopt AMI technology the Company will fall behind industry standards.

7. Costs

Our current projected capital costs for implementation of AMI and FAN are expected to be in the range of $450 to $600 million. Our current projected O&M costs for implementation of AMI and FAN are expected to be in the range of $110 to $150 million. However as we have discussed, final costs will depend on the final customer and data management strategy and related investment decision points, which are currently pending.

E. Near-Term Investment: ***Field Area Network***

1. Overview

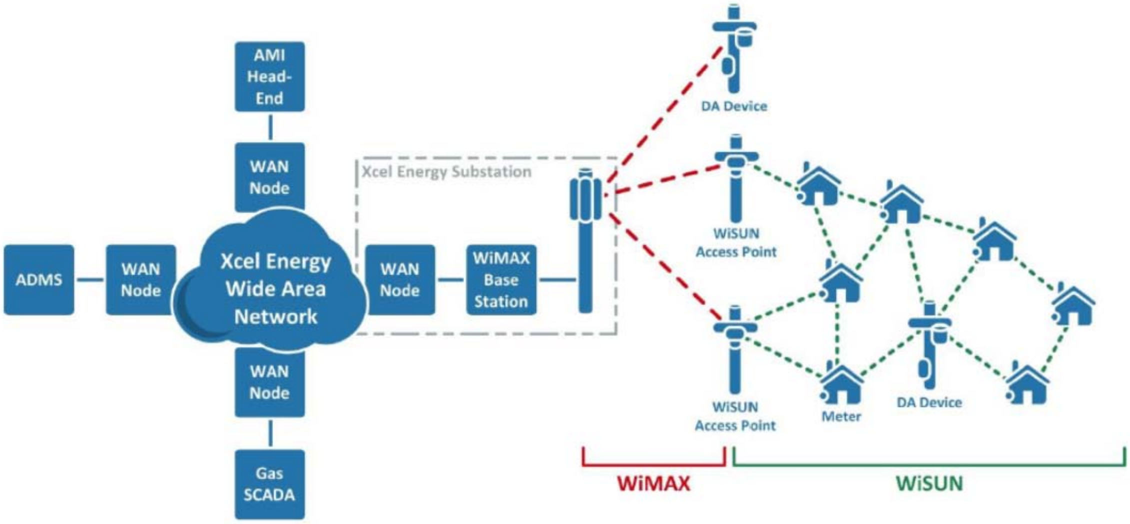
The FAN is a foundational component of our intelligent grid initiative and will be capable of simultaneously accessing diverse types of endpoints on the electric system - each with their own performance requirements. Our FAN strategy provides a two-way communication network that serves multiple "tenants" that include, but are not limited to ADMS, FLISR, and AMI – with potential for future applications such as natural gas regulators that are installed or upgraded with communications modules, streetlight monitoring and control, and eventually smart inverter monitoring and control. Collectively, these potential unknown future applications are termed "Edge Device FAN Integration" and positioned as a more distant potential application in our roadmap.

The FAN is a private, Company-owned wireless communications network that will leverage our existing Wide Area Network (WAN) and substation infrastructure to securely and reliably address the need for increased communication capacity that arises from grid advancements.[47] Its primary function will be to enable secure and efficient two-way communication of information and data between our existing substation infrastructure and new or planned intelligent field devices - up to and including meters at customers' homes and businesses.[48] It is consistent with developments within the electric utility industry, and is premised on current industry standards that have been adopted by vendors, organizations, and other electric utility companies.

A comprehensive, modern communications network improves efficiency through increased standardization, monitoring, and remote control of the system in a secure manner. By transporting data from meters and field devices to utility collection points and systems, the proposed Company-owned FAN design best positions us to operate in an increasingly more decentralized manner, in a way that is not possible with a commercial solution. In the long term, the decentralization of communications with Company assets, and potentially third parties (i.e., energy storage, microgrids, etc.), could help address future bandwidth issues, increase timeliness, and provide more resiliency to the communications network. The FAN will use two wireless IEEE technology standards: (1) a WiMAX network; and (2) a WiSUN mesh network.[49] The use of these standards aligns with the design of our grid systems and architecture for interoperability. The interaction between and among the WiMAX and WiSUN equipment provide reliable and secure communication capabilities between field devices and substations and is shown in Figure 45 below.

[47] The current WAN is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications that are supplemented by leased circuits from a variety of carriers as well as satellite backup facilities.
[48] These endpoints will include a variety of field devices including reclosers, feeders, electric meters, capacitor banks, and virtually any other field device capable of communications now and in the future.
[49] The term "mesh" refers to the network's topology, which resembles the interlaced design of mesh material, as shown in Figure 10. All nodes on the network will relay data and cooperate in the distribution of that data in the network. The mesh design provides redundancy benefits.

Figure 45: FAN Overview



2. *Initiative Components*

Our implementation of FAN consists of layers of secure wireless radio networks and supporting IT infrastructure designed to provide access to utility endpoints, and to serve as a reliable communication medium for the wide variety of legacy, current-, and future-state monitoring and control applications. The principal technologies used are a lower speed WiSUN mesh network and a high-speed point-to-multi-point (PTMP) WiMAX network.

The WiSUN mesh network will communicate directly with the AMI infrastructure and the Distribution Automation (DA) field devices. WiSUN is the common name for the IEEE 802.15.4g standard for local and metropolitan area mesh networks. It operates on the unlicensed 900 MHz spectrum, and is well-accepted in the utility and communications industries. Communications flow between field devices, meters, and WiSUN access points through a mesh-styled network, portrayed with the green dashed lines in Figure 10 above.

The core mesh infrastructure will consist of two main device types: (1) access points, and (2) repeaters, which will principally be located on distribution poles or other similar structures.

An access point is a device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network – WiMAX, in this case) to pass traffic between the mesh network and the WAN. The term "traffic" refers to the actual digits and bytes of data that flow over the wired and wireless networks. Access points will extend the reach of our communications network and will define the boundary of the mesh itself.

Repeaters are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provides devices more options to communicate with their access point. For example, adding a new capacitor bank could mean that meters nearby would have a more reliable and efficient way to reach their communications destination through the network. Further if other devices are added, such as streetlights, there would be additional nodes located at greater heights, which could mean a meter may only be two communications "hops" away from an access point rather than three – increasing the speed of that communication.

In addition, the mesh network will be able to reconfigure itself to respond to any ongoing environmental change, such as radio frequency interference, outages, and traffic congestion on the network itself. In short, the network improves as more devices are brought online and within the FAN. The meters we deploy as part of our AMI implementation will become an essential and important part of the WiSUN network – providing important data from these points across our system, including voltage and power quality.

WiMAX is the commercialized name for IEEE's 802.16 series of standards. The WiMAX Point to Multi-Point network will be based in Northern States Power's substations and will enable high-speed connectivity at locations across the distribution system. The WiMAX network will wirelessly connect directly to devices on the Company's distribution feeder lines as well as provide the secure, reliable connectivity between the Company's WAN and WiSUN networks.

Figure 46: WiMAX Portion of the FAN on a Distribution Pole

The WiMAX network will consist of two main components: (1) base stations, and (2) customer premise equipment (CPE).[50] In this case, NSPM is the customer, as we are a customer of the equipment manufacturer. It does not refer to any specific customer of the Company, or to our customers generally.

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station which communicates with the WAN via private fiber or alternate cabling and multi-directionally with CPEs out in the field of operations. The CPEs will communicate wirelessly with the WiSUN mesh access points.

3. Benefits

The FAN, in and of itself, does not provide direct benefits to customers or the Company. Benefits to customers and the distribution system will be realized through FAN's support of, and interaction with, other programs and technologies.
The FAN strategy proposed is tightly coupled with the proposed AMI implementation and similarly enables other technologies that transform the customer experience and create customer value. The reliable, private, secure network capabilities provided by the FAN also enable the end-to-end transport of interval meter data to provide the customer and grid benefits described above in the AMI section. FAN also enables the communication for FLISR and thus contributes to the outage restoration capabilities. The automated functionality of these advanced applications cannot be supported with the current communication networks which

50 We may use alternate means of communication, such as cellular or satellite, in situations where WiMAX does not prove viable either practically or financially.

bypass the substations and high-speed WAN interface.

Currently, our internal communications networks serving field devices and all external network providers bypass the substations, which adds delays that can make the data unusable for automated operations. By bringing more of the communications network in-house, we can improve security against cyber threats by reducing third party networks, reducing the use of public networks (i.e., cellular) and reducing the reliance on external entities for communications support. The FAN will also enable the use of Quality of Service (QoS) to separate communication channels that might be more important in an emergency, which is not widely available today with many public communications options.

Our proposed implementation of FAN offers interoperability and future flexibility relative to other options considered for meter and field device communications. Prior generations of AMI included vendor specific proprietary communications. While these older proprietary AMI systems may be available at a slightly lower cost, this creates vendor lock in for both meter purchases as well as dependencies for vendor life cycles as being experienced with the scheduled AMR system retirement (described in greater detail in the AMI section). A FAN design based on Internet Protocol (IP) standards enables both meter and distribution field devices from multiple vendors to be connected to the FAN and utilized over time.[51]

This avoids vendor lock-in which provides flexibility in terms of future technology and vendor selection. The FAN design is a better option than the use of cellular carrier solutions, which would require the deployment of a cellular modem at every device or meter requiring communication and monthly service fees. Considerations for reliability, resiliency, security, latency and support costs all support the decision for a FAN design relative to public cellular services.

Our strategy for FAN offers reliability and resiliency benefits relative to other available communication solutions. The design of FAN for redundancy will facilitate the overall dependability of the communication network. If a device fails on the WiSUN network, the mesh configuration of the system will allow that node to be bypassed so other nodes will be unaffected and network communications will continue. Furthermore, access points will be served by multiple WiMAX base stations, so communications can be re-routed if a base station goes offline.

The core infrastructure on both WiSUN and WiMAX are backed up by batteries to

[51] Meter specific head-ends are still required in the case of multi-vendor meter deployment.

enable continued functionality and operations in the case of a power failure to that device – when continued functionality of those devices is most critical. Continued operation during power failure ensures the last gasp messages from AMI meters reach the back-end systems and enable operators to more quickly identify and restore outages.

Protecting the integrity of the communication devices and channels is paramount to avoiding disruptions of service and allowing the advanced grid to perform at expected levels. Developing the FAN as an internal private network allows us to implement our cybersecurity measures into the design at all levels. FAN will utilize a layered defense model, which includes defenses at each endpoint and throughout the communication network. These cybersecurity defense measures contribute to the reliability and redundancy of the communication network, and as a result, the reliability of the electric service we provide to our customers.

Our proposed FAN, composed of WiMAX and Wi-SUN components, is also consistent with developments within the electric utility industry, and current industry standards that have been adopted by vendors, organizations, and other electric utility companies. We actively participate with industry standards organizations and alliances – such as EPRI and IEEE – to ensure that our requirements and assumptions are aligned with the standards and products being deployed throughout the industry. In choosing our FAN technology, we have relied on information from industry experts and systems integrators on actual installations of the FAN technology, public records on other utility implementations, and information through participation in industry research programs such as EPRI. The Wi-SUN and WiMAX networks are standards-based network solutions that conform to IEEE standards.

The Wi-SUN mesh system, in particular, benefits from the availability of additional devices. In the case of our AGIS initiative, once we deploy AMI, we expect to have a high density of devices that will need to communicate data to our data centers. For most traditional point to multipoint (PTMP) communication systems, like cellular carriers (or the WiMAX system if it were deployed independently), adding more devices results in splitting resources between those devices.

However, since Wi-SUN is a "mesh" network, adding more nodes to the network means the devices have more options to communicate with their access point. For example, adding a new capacitor bank could mean that meters nearby would have a more reliable and efficient way to reach their communications destination through the network. Further, if other "smart" devices are added, such as streetlights, there would be additional nodes located at greater heights (which can "see" more physical space) to the system, which could mean a meter may only be two communication "hops" (that is, one portion of a communication signal's journey from one device to the next—here, between two devices in the mesh network) away from an access point rather than three—reducing the latency of that communication.

In addition, the Wi-SUN mesh network will be able to reconfigure itself to respond to any ongoing environmental change, such as radio frequency interference, outages, and traffic congestion on the network itself. In short, the network improves as more devices are brought online and within the FAN.

The IEEE 802.15.4g standard forms the foundation of Wi-SUN and is incorporated into the latest revision of the parent standard, IEEE 802.15.4-2015. While this means that IEEE 802.15.4g is administratively superseded, its features and functions are wholly included in IEEE 802.15.4-2015. We additionally note that the industry continues to refer to IEEE 802.15.4g as the component of 802.15.4 that is specific to wireless smart utility networks.

4. *Implementation*

FAN technologies are being deployed on a limited basis through our TOU pilot. FAN components are deployed approximately six months in advance of the deployment of AMI meters, which is important because the communication network is necessary for the successful operation of other technology components. If meters were installed prior to the FAN, the meters would need to be read manually until the FAN became operational. When FAN is installed prior to AMI, the back-office systems can verify meters are installed correctly, associated with the correct customer, and reporting to the back office appropriately as the meters are deployed. The FAN will be deployed between 2018 and 2023.

5. *Interdependencies*

The FAN supports the AGIS and grid modernization infrastructure and technologies which require secure, reliable communication capabilities, including AMI and the FLISR application of the ADMS.

The communication modules of the AMI meters will be used as part of the WiSUN network. The WiSUN mesh network of FAN will provide the transport for the data transfer between the meters and the AMI head-end application, including interval reads, register reads, voltage information, and power quality data. It will also provide the sending and receiving of commands like power outage notifications and remote connect/disconnect commands.

FAN supports the distribution equipment deployed as part of FLISR by providing transport between the FAN radios in FLISR switching devices and ADMS. FLISR is managed by our ADMS. The FAN infrastructure supports the ADMS by providing two-way data from field devices to a common Enterprise Service Bus (ESB) via the WAN, which will then deliver data to the ADMS.

6. Alternatives Considered

The principal alternative to the FAN for supporting AMI is the use of cellular carrier solutions. This would require the Company to deploy a cellular modem in every meter and pay monthly fees for usage and for the private internet protocol service for every device. This alternative would cause the Company to incur substantial monthly and annual expenses. In particular, when comparing cellular carrier solutions and the FAN, the Company determined that device costs were fairly similar but monthly and annual expenses were considerably higher with the use of public cellular. Other key decision criteria such as security, reliability, latency, and support costs all weighed into the decision to choose the FAN which are discussed below.

The most significant advantage of a Company-owned FAN is security. A private network allows the Company to better control the integrity of the devices on its network and the data exchanged with those devices. The alternative—a public network—would expose the devices and the Company to increased risk because the Company would not be in control of the network.

In addition, the private network solution allows NSPM to utilize the network's full bandwidth and all capacity is dedicated to the Company's use, which is particularly critical during emergency and outage situations.

Another advantage to having a private network is flexibility; replacing a meter or adding a new meter to the Company's WiSUN network will be a straightforward process that will be handled internally by company personnel, whereas provisioning a meter on a third party or public network could take as long as days or weeks.

A private mesh network will also afford the AMI meters the ability to communicate directly with one another on the WiSUN network. This will enable future distributed intelligence and computing capabilities so that applications running on the system will be able to respond quickly to changing load conditions that occur behind a transformer. This is becoming increasingly critical to energy operations as a larger number of distributed energy resources connect to the distribution grid. Public networks and cellular communication alternatives would prevent or hinder this capability.

7. *Costs*

The costs for FAN are wholly attributed to the AMI implementation and as such are included above in the AMI section.

F. Near-Term Investment: *Fault Location Isolation and Service Restoration*

1. *Overview*

FLISR is a core application within ADMS with the primary function of improving distribution system reliability by isolating a faulted segment of a feeder and automatically restoring power to available un-faulted segments. The FLISR application relies on three primary components to operate: (1) ADMS, for the central control and logic; (2) the FAN, for wireless communications to each device; and (3) intelligent field devices (reclosers, overhead switches and padmount switchgear), to detect faults, isolate where possible and operate when commanded by ADMS. Fault Location Prediction (FLP) is a subset application of FLISR that considers sensor data from field devices (such as sensors and relays), status signals from field devices (such as a remote fault indicator) and leverages the ADMS impedance model to locate a faulted section of a feeder line and reduce field response patrol times needed to locate the fault.

The FLISR system is expected to reduce outage durations for customers and improve key overall system reliability performance metrics of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). FLISR is also expected to decrease CEMI, which is the metric of how many customers experience multiple interruptions *n* or more times. This metric is used to track pockets of customers whose reliability is poorer than average and may not improve while the system reliability is improving.

For a number of years, we have been installing an intelligent feeder automation system across our service area. The majority of these automated feeders are on our South Dakota system and our 35kV system in Minnesota. These feeders are automated as a standard due to the length of the feeders and high customer counts that are enabled by the higher distribution voltage. This intelligent feeder automation system does have limitations however, and we feel strongly that in order to automate the number of feeders planned in Minnesota, a centralized FLISR solution is the safest, most reliable approach to achieve our reliability goals in a cost-effective way. ADMS FLISR will bring a number of benefits to our feeder automation program, including:

- Real-time situational awareness – ADMS, through its awareness of the state of the distribution system, has the ability to execute FLISR in any number of feeder configurations resulting in a system that will work even when parts of the distribution system are abnormal
- Limited need to manage software on each individual device – With ADMS FLISR, each field device only needs to have two-way communications and the ability to be remotely operated to work with FLISR
- Forecasting – ADMS has a weather integration as well as a historian which allows the system to predict loading into the future up to seven days in advance. This forecasting enables FLISR to make the best decision in the moment for the future loading of the distribution system
- Complex Switching – As more feeders are automated and more devices are remotely controllable, FLISR will have the ability to perform complex switching to restore as many customers as possible and in addition, the system can propose additional switching steps which can be done manually to restore more customers while the cause of the outage is being addressed

Existing intelligent, remotely controllable switching devices that exist on our feeders will all be transitioned to ADMS control over time for use with FLISR.

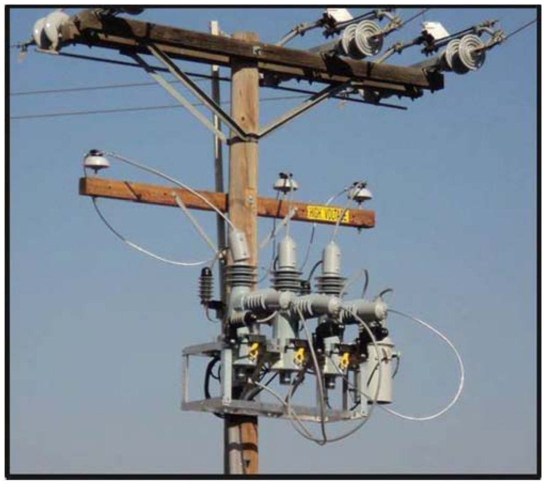
2. *Initiative Components*

Over time, as we have needed to replace distribution equipment, we have done so with updated technology as it becomes available and that is compatible with our current system. FLISR will involve implementing four principal components: (1) Reclosers, (2) Automated Overhead Switches, (3) Automated Switch Cabinets, and (4) Substation Relaying.

a. Reclosers

A recloser is a breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. Reclosers can be installed on the distribution line or inside the substation, acting as a circuit breaker. Reclosers have evolved from hydraulic operation, which were limited in their ability to sense faults and to coordinate with other devices, to today's reclosers that are equipped with vacuum or SF6 gas interrupting technology and digital electronic controls. Modern reclosers require less maintenance, provide enhanced operator safety, and add application flexibility that allows them to be used in numerous ways. The programmable electronic controls allow close coordination with other devices, and their enhanced sensing capabilities ensure more accurate operation and provide information that helps evaluate system performance. When connected with a communication network, the recloser can communicate the operating information and a field crew can be dispatched to fix a fault when the reclosing operation doesn't eliminate the problem.

Figure 47: Recloser on a Distribution Pole



FLISR reclosers will be pole-mounted remote supervisory reclosing and switching devices. We currently have reclosers on the distribution system; the new devices FLISR reclosers will be pole-mounted remote supervisory reclosing and switching devices. We currently have reclosers on the distribution system; the new devices will perform the functions of existing reclosers, will "re-close" after a fault event to determine if a fault still exists and restore service if possible. They will also be able to report fault current to ADMS, which provides the ability to use FLP to identify the possible location of the fault. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will open and remain open, then communicate information about the fault event to ADMS.

b. Automated Overhead Switches

When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on these switches sense the fault and the loss of voltage and open, isolating the fault allowing the feeder breaker to close and restore all customers up to the newly opened switch. This function is called sectionalizing. Unlike a recloser, the overhead switches will not be able to re-close to determine whether there is a permanent fault. Instead, overhead switches rely on the feeder breakers for the reclosing functionality.

Although automated overhead switches lack the reclosing capability, they are compact - making them a better choice for space-constrained locations compared to reclosers. They are also a good choice when protection coordination is difficult from multiple reclosers in series. The use of these switches as sectionalizers is dependent on the location of the switch and the design of the FLISR scheme on that particular feeder. Many overhead switches will only be controlled by ADMS, taking any open or close command from the system during the steps of FLISR.

c. Automated switch cabinets

These pad-mounted sectionalizing and switching devices are motor-operated, remote-controlled devices used for underground feeder installations - performing functions similar to the automated overhead switches, but for underground feeders. These cabinets have multiple switches inside each unit providing versatility which is unique to the underground system.

d. Substation Relays and Breakers

Substation relays provide the logic inside a substation for when and why a breaker opens. Modern relays are multi-functional and have multiple protection functions programmed into them. The primary use-case for a relay on a feeder breaker is to monitor the status of the distribution system and trigger an open command to the breaker in the event of a fault on the system. These relays can also capture important fault information which will be sent to ADMS for the Fault Location application.

3. Alignment with Advanced Grid Aspirations

FLISR supports our AGIS aspirations of maximizing value for customers and optimizing planning and operations. Customer satisfaction greatly depends on whether a product or service meets a customer's expectations. Virtually every sector of the modern economy depends on electricity, and with the rise of personal electronic devices, reliable electric service has become even more important to our customers. We regularly survey our customers to understand their satisfaction with our service, and to learn about what they value regarding our products, services, and performance. We also glean insights from sources such as J.D. Power and broader industry studies, which clearly indicate that power quality and reliability are the most significant contributors to customer satisfaction.

While our current reliability performance, as measured by SAIDI and SAIFI, has been strong, we believe that simply being "good enough" with respect to certain reliability metrics is not the ultimate goal. Rather, we should be consistently working to improve customer satisfaction overall, and improving reliability is a key part of this goal. One of the primary benefits of FLISR is that it will reduce the numbers of customers who experience a sustained outage and will shorten the duration of certain sustained outages. FLISR will also provide increased visibility into outage events occurring on the system for our engineering and operations personnel, which will inform our operations and future investments in the system.

We plan to target implementation of FLISR in areas where we expect to achieve the greatest reliability improvements – overhead areas with high customer density, and areas with a history of more frequent outages as compared to the rest of the system. As a result, it is our expectation that FLISR will provide marked improvement in reliability to many of our customers who previously have had poorer reliability than average. It will also enhance our ability to keep customers informed, which will translate into greater customer satisfaction.

Furthermore, we must continue to improve reliability performance to maintain its position relative to industry standards and expectations. As electric utilities across the country implement grid modernization projects, existing IEEE SAIDI and SAIFI benchmarks will improve with peer utilities' improved performance. While SAIDI varies from year to year by company and the industry in general, by 2020, it is expected that first quartile SAIDI benchmarks will trend to 79 minutes and below, and second quartile rankings will be between 98 and 79 minutes.[52] This compares to 2008 industry results of 99 minutes for the first quartile threshold with the 2nd quartile rankings between 126 and 99 minutes. Simply put, without implementation of FLISR and other reliability-focused efforts, we will not be able to keep pace with the improving industry reliability benchmarks and will fall behind relative to our peers.

While benchmarking the Company to the industry is important, benchmarking does not include storm day performance, and does not include the individual customer experience. We look at various reliability programs' ability to improve performance during a typical day and storm days, while also viewing how a reliability program can improve pockets of poor performance using the CEMI metric. We have evaluated a number of ways to improve reliability performance in terms of these measures – including pole fire mitigation, lightning arrester replacement, pole top reinforcement, mainline cable replacement, tap cable replacement, and overhead to underground conversion. The FLISR program compares well to other ways to improve reliability

[52] These benchmarks represent storm-normalized results.

performance based on SAIDI improvement to dollars spent and also CEMI improvement per dollar spent. While some of these alternatives are promising and we will continue to evaluate all options, we believe that FLISR is one of the most cost-effective ways to improve reliability and is likely to yield substantial results.

4. *Benefits*

As noted above, we expect the most significant benefits of FLISR to be in reliability, but we also expect to achieve operational efficiencies with this initiative.

Reliability Benefits. Overall, implementing FLISR allows the Company to more efficiently restore power and will improve the customer reliability experience. Specifically, in an event on a feeder that is automated with FLISR, we will be able reduce the number of customers who experience a sustained outage by two-thirds and will shorten the duration of certain sustained outages that affect a substantive portion of our customers.

The primary reliability benefit of FLISR is that it will allow us to restore service to two-thirds of customers affected by an outage within minutes of a fault. In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will then step through the FLISR sequence. The first step is fault location, identifying the location of the fault to, at minimum, between two telemetered devices. Next, FLISR will proceed to isolation, in which ADMS will send open commands to any additional devices necessary to isolate the faulted section of feeder. Last, FLISR will execute supply restoration, which will generate a switching plan to restore load to all possible customers.

Supply restoration can be done manually or automatically within the system. Supply restoration considers not only device and feeder loading - but surrounding feeder and substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to investigate the fault event. This process is expected to take from 15-45 seconds from start to finish and by design, restore power to approximately two-thirds of the customers on that feeder (see the Implementation section for additional detail on the system design that will enable this outcome). After the supply restoration step, system operators will send a crew to the isolated section to investigate the fault event, make repairs and restore service to the remaining customers.

The second reliability benefit of FLISR is better fault location through the FLP application. ADMS will run the FLP algorithm and predict where within a FLISR section the fault exists, which will reduce expected patrol times by crews. FLP can also be run on its own, with only information about the fault, providing value to feeders that do not have any two-way monitored devices. For FLP to work on a given feeder as a stand-alone function, it requires either a digital relay within the substation capable of measuring and reporting the fault magnitude or an intelligent distribution device capable of capturing this data, such as a recloser or an advanced power-line sensor. FLP also requires that the model of the feeder be highly accurate so that prediction of the fault location is accurate. This requires field data collection to update the Geographic Information System (GIS) model, which is the data source for ADMS. Without an accurate impedance model, FLP will not produce accurate results, thus it is necessary to collect the feeder data up-front and maintain model accuracy as the system evolves over time.

We also expect that the improvements above will improve our overall response time, primarily through reduced drive time, which should allow crews to move on to subsequent outages more quickly. While difficult to quantify, we have estimated these benefits in terms of impact on SAIDI and included them in our cost benefit analysis. While drive time will be reduced, we do not expect a significant benefit in terms of fuel savings or number of crews required in response to outages.
One additional benefit we may see from FLISR could come in the form of economic development. When large commercial and industrial customers are exploring options for siting new business, the majority inquire about reliability measures in potential areas for development. Targeted improvement in reliability on our worst performing feeders through FLISR could translate to greater economic development in those areas.

Operational Benefits. We also expect to realize operational efficiencies that will translate to customer benefits in the areas of: (1) equipment interoperability and cost, (2) increased visibility into the system that improves crew efficiency and our management of the system, and (3) improved data for system planning.

Equipment Interoperability and Cost. Implementing FLISR rather than continuing to rollout the existing automated devices is consistent with our strategy of selecting and implementing devices, communications systems, and control systems that are vendor-neutral, non-proprietary, standards-based, and interoperable. With ADMS-based FLISR, we have the ability to install devices for a lower cost per device than the equipment that includes vendor proprietary software - and we will have the ability to switch equipment vendors at any time, knowing that the new devices will also operate in the FLISR system with minimal effort to integrate them into the system. With our intent to automate hundreds of feeders across our operating footprint, a standards-based approach is financially responsible, provides important long-term flexibility, and helps to mitigate the risk of obsolescence in equipment technologies.

Increased Visibility into the System. A primary benefit of FLISR is the ability to see the real-time load across many critical points on the distribution system and the ability to operate devices remotely. During the summer peak season and during normal switching operations for construction, the control center must dispatch crews to open and close switches, moving load from one feeder to the next either to offload a piece of equipment or de-energize a section of line for planned work. The remotely controlled devices from this initiative allow much of that work to be done remotely, which is faster, safer, and allows the efforts of our crews to be more focused and thus productive. The improved speed comes from both the ability to remotely operate the system but also from the ability to make the switching efficient through load visibility. Additionally, because FLISR and other remotely- controlled devices will allow us to identify and thus restore the root cause of an outage faster, our crews will be able to get to the next outage faster - increasing crew productivity and reducing the duration of each subsequent outage event from what it would have been without the increased system visibility. Once our system is widely automated, the cascading benefits from this will have a meaningful impact on reliability for all customers, whether they are on a FLISR feeder or not, or experiencing a mainline outage or a tap level or below outage.

This increased visibility and remote-control capabilities also allow distribution system operators to better manage, in real-time, the flow of electricity on the grid. In many instances during the summer peak season, operators send trouble crews to manually close and open switches to move electric load from one circuit or substation to another. This action helps us reduce the risk of overload on the system and maintain system integrity. With the FLISR program, much of this work will be done quickly and easily from the control center, with ADMS providing a high level of detail around the real-time load and capacity of the system.

Improved Data for System Planning and Reliability. FLISR provides key data at critical points along the system, which is fed into historical systems and can be leveraged by engineering to make decisions about how to plan and design the future system. System planning uses historic measured load at a single point on the feeder to allocate that load across the feeder. With multiple FLISR devices on each feeder, the granularity of these data measurements will be much finer across the feeder. The increased system visibility will also improve our reliability management efforts by increasing the richness of the information we are able to analyze. In addition, some of these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

5. *Implementation*

In general, we plan to target areas for FLISR where the electric system is predominately overhead, has high customer density, and has a history of more frequent outages than the rest of the distribution system. There are two key criteria that drive feeder selection, both of which are based on actual historical reliability information: (1) feeder SAIDI performance, and (2) the combination of the number of feeder mainline outages and customers impacted over time.

As discussed previously, FLISR, like other advanced grid applications requires communications capabilities to each sensor and switching device. For Xcel Energy, this communications platform is the FAN. So, this implementation must be in concert with the FAN deployment.

FLISR devices in general are among the most critical devices that will communicate via the FAN. These devices must respond quickly and reliably in an outage - and must be available when there are wide-spread power outages, in order for FLISR to respond and restore the system to the fullest extent possible.[53] We are designing our FLISR implementation to divide the distribution feeders approximately into thirds with each section having less than 1,000 customers – and with intelligent switches in place to tie the automated feeder to another feeder.[54] This approach is consistent with the way we plan and design our overall distribution system. We are also integrating existing reclosers and other intelligent devices into the FLISR scheme to further enhance the capabilities and customer benefits of that existing automation.[55]

The FLISR application is most effective and can have the largest impact on reliability and operations when deployed on multiple distribution feeders in a geographic area. Doing so allows for normally open tie switches to be shared between two automated feeders, reducing the cost of deployment and increasing operational flexibility. The deployment plan we therefore propose for Minnesota is focused around deploying in this geographic approach - first identifying areas where a number of feeders have experienced the lowest levels of reliability over the past several years and building out

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[53] Part of the engineering and design of FAN is to ensure that FLISR devices have Quality of Service (QoS) over other devices on the network, to ensure that the critical FLISR data can get through the network to ADMS as well as a requirement that the communications route from the FLISR device to the head-end be battery-backed.

[54] More heavily populated feeders with greater than 4,000 customers will end up with four or five feeder sections and multiple tie-points.

[55] If an existing device is in a proper location to employ FLISR functionality, in most cases, we will be able to use that existing device rather than install a new device.

from there. As we have noted previously, our proposed FLISR project is based on a nine-year deployment timeline, but we are open to a more accelerated implementation if the Commission wants to realize the customer benefits more quickly.

We note that for a period of time, we will run FLISR in "manual mode," where ADMS will take all of the inputs from the field devices and propose the optimal switching sequence for isolation and restoration. Our control center operators and grid engineers will review the sequence in real-time to verify the identified steps are accurate. We expect this review will happen very quickly (minutes), and once validated, the operator will allow ADMS to execute the switching sequence. Once we have established high confidence in the system, communications, and devices, we will enable ADMS to execute FLISR automatically. Note we will only automate FLISR if and only if it proves to be extremely reliable.

We are planning a scaled deployment, with investment increasing each year. We believe an incremental approach that starts slow and ramps-up year-over-year is a prudent strategy and is similar to the approach we are taking with our Colorado FLISR project. This approach enables us to evaluate feeders for deployment, to ensure that we are identifying and installing devices where our customers will gain the greatest value. This approach also allows us to tightly integrate with the ADMS schedule; while we will immediately realize benefits from deploying the devices, we will realize full FLISR benefits when it is operational in ADMS.

6. *Alternatives Considered*

The alternative to FLISR is to do nothing. We determined that FLISR is a reasonable means of not only reducing outage minutes and their quantifiable impact on customers, but also improving our reliability standards and customers' satisfaction with their electric service. Absent FLISR, our ability to isolate, locate, and resolve faults is limited due to: (1) a lack of intelligent field devices that interact with the FAN and ADMS to restore service to a majority of customers on the faulted circuit; and (2) a lack of visibility and information regarding where the fault may have occurred and the type of fault occurring. Overall customer satisfaction tends to decline when customers experience frequent outages and when service is not quickly restored after an outage event.

7. *Costs*

As we previously outlined in our November 2017 Grid Modernization Report in Docket No. E002/M-17-776, the projected capital costs for the implementation of FLISR are expected to be approximately $66 million. These estimates include the devices, installation, and system integration. Note that the FLISR initiative will also be supported by FAN infrastructure, including necessary WiMAX and WiSUN equipment, installation, and integration needed to support FLISR. The FAN infrastructure will benefit both AMI and FLISR, as will ultimately other advanced grid initiatives. The only FAN cost included in this estimate is for each radio that goes at the individual FLISR device locations, which otherwise would not have been installed if not for FLISR.

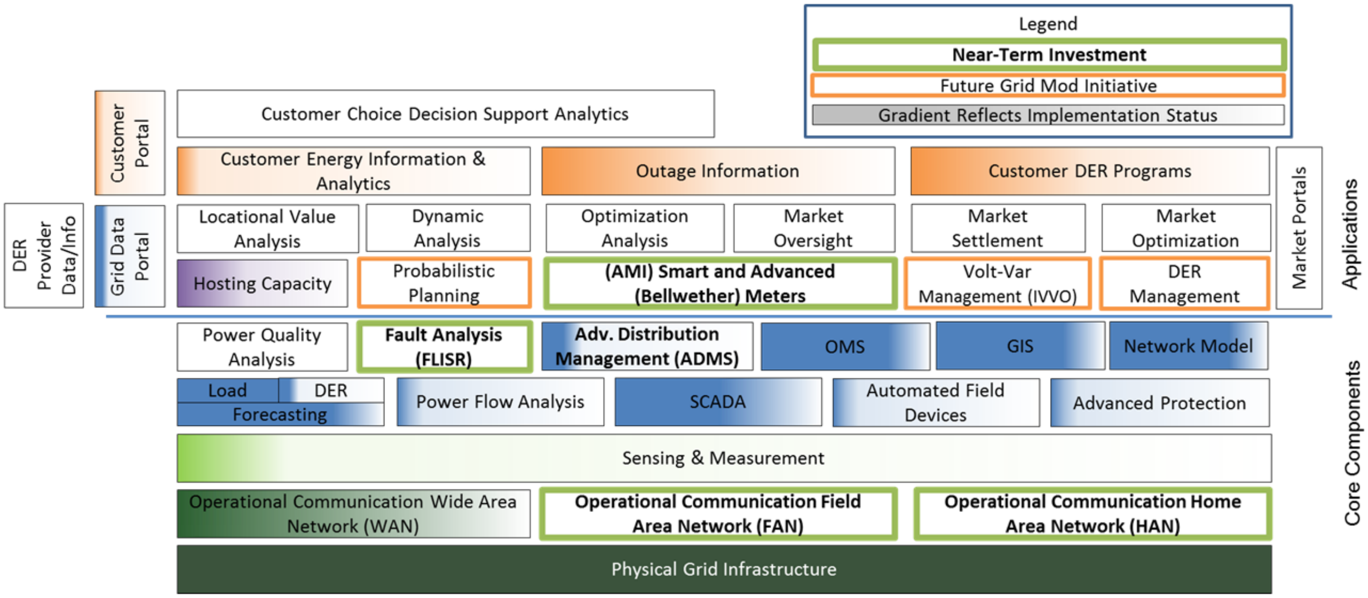
G. Xcel Energy's Plans Compared to DSPx

The U.S. DOE's Next Generation DSPx, Volume III provides a good reference for how to consider both the elements of a modern grid and their costs.[56] The DSPx report was sponsored by the U.S. DOE's Office of Electricity Delivery and Energy Reliability. This report was developed at the request of, and with guidance from, the MPUC among others like the California Public Utilities Commission (CPUC), the New York Public Service Commission (NYPSC), and the Hawaii Public Utilities Commission (HPUC).

We evaluated our current state systems and process against the DSPx framework as shown in Figure 48 below. Developing "core components" as the foundation for our advanced grid roadmap first and subsequently building on that foundation to enable advanced applications is well aligned with the DSPx framework. Many of these core components are already in place, and others we intend to propose in the near-term will build additional core capabilities to support grid modernization applications.

[56] *See Modern Distribution Grid, Volume III: Decision Guide*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

Figure 48: Estimated Status of AGIS Implementation



H. Cost Benefit Analysis

Though we have done a significant amount of development work, we are still in the planning stages of AMI, FAN and FLISR and are not yet seeking cost recovery or certification of these investments, we have conducted a high level cost benefit analysis (CBA) for purposes of this filing. Since we have not yet finalized our customer and data strategy, we have not yet finalized our planned investments or costs, so the estimates used in building this CBA are preliminary. The CBA is intended to provide a point of reference and considerations when evaluating these holistically. Generally, we evaluate investments such as these on a "least-cost best-fit" basis to meet the identified need- meaning that the selected investments are those that provide the highest value to customers and the needs of the distribution system when considering *both* the costs and the value of being offered by the projects in light of the identified needs. In other words, these decisions are not based entirely on CBA results- the benefits of our AGIS investments are not limited to quantifiable items; they will also improve our customers' overall experience and help achieve broader energy goals.

We currently estimate that the total capital and O&M costs for AMI, FAN, and FLISR is between $632 and $822 million. While these projects are in the early phases of planning, these costs were identified on the basis of benchmarking, internal expertise, and appropriate contingency. Further, these costs are offset by benefits, such that we estimate a range of benefit-to-cost ratios of approximately 0.50-0.80 for AMI (of which FAN is a component) and 2.50-3.00 for FLISR, with a total quantitative benefit-to-cost ratio somewhere between .70- 1.10. These analyses only compare quantifiable projected benefits, such as O&M and capital expenditures savings. By definition, these analyses do not capture other benefits that cannot be quantified, such as customer satisfaction, improved power quality, human health and safety, the secondary effects of lost productivity, business, consumables on customers due to electric outages or possible future capabilities like wire-down detection.

Some of the AMI benefits include:

- Reduction in manual meter reading expenses,
- Reduction in bad-debt write-off
- Reduction in okay on arrival trips associated with outages
- Costs savings from remote disconnect capability
- Reduction in labor associated with estimated bills
- Savings from reduction in call volume
- Outage management efficiency
- Reduced outage duration
- Reduced field trips for voltage investigations
- Savings from reduction in theft

Some of the FLISR benefits include:

- Customer Minutes Out- CMO Savings
- Patrol Time Reduction
- Real time grid visibility and control

Certainly balancing the costs and benefits of any given investment is an important consideration, which we do not discount. However, it is not the only consideration. From a policy perspective, the importance of the unquantifiable benefit of advancing the distribution grid are difficult to overstate. Safety, reliability, and customer satisfaction are key to our role as a public utility. A more automated, transparent grid supports greater customer and employee safety. Similarly, without the advanced technologies associated with the AGIS initiative, the Company will not be able to keep up with industry trends regarding reliability, as measured by SAIDI. Nor can utilities keep up with greater customer demand for DER without investing in the advanced grid technologies necessary to support these resources—in particular EVs, as AMI would give us insight to adoption and charging issues allowing us to effectively manage EV integration and potentially extract additional value. In addition, giving customers choice and control over their energy usage by providing greater data to customers; giving customers greater input into the types of energy they use by supporting DER; and empowering customers to make good choices about their impact on the environment are important pieces of both building customer satisfaction and managing electric demand.

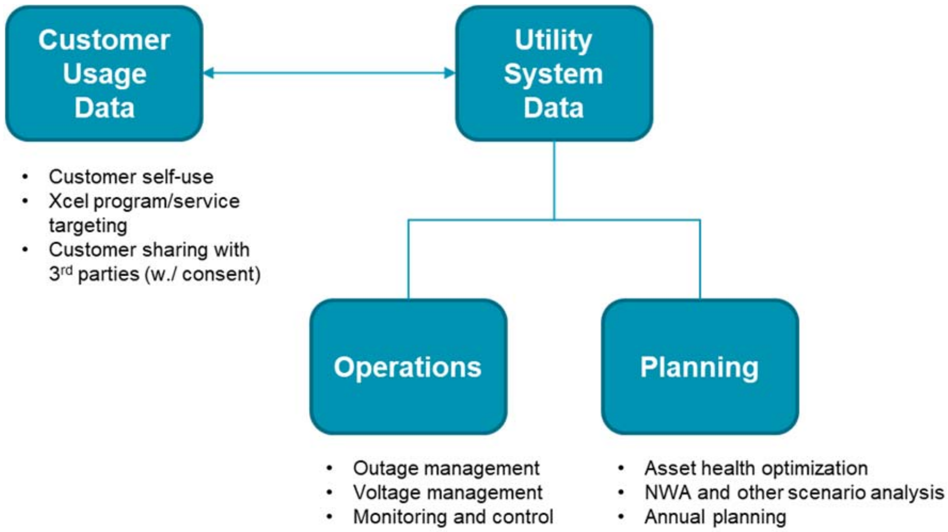
We recognize that it is difficult to put a numeric value on future opportunity and non-monetary benefits, and that evaluating these possibilities can be a challenge. However, the trends in the utility industry and the efforts of other states to advance their distribution grids verify the importance of bringing utilities' distribution grids into the future. Along these lines, our legacy AMR system that was installed in the mid-1990s under a services agreement will no longer be supported by our vendor after the early-2020s. Further, they plan to discontinue support for AMR technology entirely in the mid-2020s, like many other vendors, around the time our current service agreement will end. Without AGIS, we would otherwise be behind in managing to customer standards, supporting DER, employing current technologies, meeting reliability goals and expectations, and fully capturing DSM opportunities.

X. CUSTOMER AND OPERATIONAL DATA MANAGEMENT

The proliferation of sensor technology and AMI is producing new and voluminous data for utilities. As this data becomes more available, utilities are faced with the challenge of leveraging it to improve the customer experience and capture additional value streams, while managing data security and privacy concerns. As discussed above, we are still working through our overall customer and data management strategy as these are critical components of ensuring we optimize these grid modernization investments for our customers. However, our strategy planning is evolving and we have made great progress thus far. Our data strategy work to-date (summarized in Figure 49 below) considers three types of data and their associated uses: a) customer data and two types of system data, b) operational data, and c) planning data.

In this Section, we discuss each of these types of data and what the Company envisions for the future use of data, from both customer and Company perspectives. Among other things, this Section addresses the specific requirement for the five-year Action Plan set forth above related to its customer data and grid data management plan.

Figure 49: Data Strategy Framework



A. Customer Data

1. *Applications*

AMI will provide more granular customer data at more frequent intervals. The Company's data strategy will consider several potential applications of customer data, including personal use, company use, and third-party use with consent.

Personal Use – Company-conducted research revealed that customers want increased transparency from the utility. In the near term, we plan to provide customers access to their detailed usage information. We will also offer notifications and alerts to provide more accurate information to customers about power outages, grid updates, and repair work by field crews, all of which can raise customer satisfaction. In addition, offering customers the ability to connect Home Area Network (HAN) devices enables or enhances the potential for participation in DSM programs that utilize connected technologies.

Company Use – As we continue to build our data management and analytics capabilities, we will develop a better understanding of our customers and their energy usage. We will be better able to create targeted programs and service offerings. These offerings include program recommendations, impactful energy efficiency campaigns, time-varying rates, and gamification to help customers modify their usage to conserve energy or shift to off-peak usage.

Third-party use – Customers will also have the option to share their data with third party vendors. The Company's participation in Green Button Connect My Data allows customers to automate the secure transfer of their own energy usage data to authorized third parties which may offer additional programs. Customers will share this data with affirmative (opt-in) consent and control.

Figure 50: Customer Benefits Realized Over Time

	2018 – 2022 Near-Term	2023-2027 Medium-Term	2028-2032 Long-Term
Benefits Realized	• Avoided and shortened outages through greater system visibility and faster problem location, isolation, and restoration • Timely proactive outage communication with improved restoration estimates • Continued reliable electric service by managing a dynamic environment of two-way power flows • Demonstrate savings potential of non-traditional grid solutions through NWA pilot • Streamlined interconnection processes for customers installing DG, like rooftop solar	• Enhanced power quality • Reduced costs through reduced fraud and theft • Reduced carbon emissions through DER and transportation electrification • Cost effective deferral of traditional grid infrastructure through NWA solutions • Continued interconnection process improvement through increased study automation	• More effective utilization of customers' DERs, for the benefit of all customers • Continued operational efficiency gains through more efficient maintenance and inspections of field devices • Reduced carbon emissions through continued transportation electrification
Potential New Offerings for Customers	• More pricing and rate options • Bill forecasting and goal setting • Customized payment dates and bill pre-pay • Engaging energy insights and benchmarking • Proactive communication on consumption and options to control • Ability to share usage data with other service providers • Expanded Electric Vehicle offerings • Partnerships to support energy services • Customer participation in NWA pilots	• Further pricing and rate offerings that suit customers' lifestyle and budget • Personalized energy saving recommendations and control based on customer behavior • Managing bill with home automation • Improved Smart EV charging • Remote connect/disconnect services	• More sophisticated solutions and revised policy and regulatory mechanisms to integrate DER • Orchestration of home and business devices • Continued evaluation and use of technology and deployment partners that enhance customer experience
Enabling Data	• Interval meter data • Field device sensing • Customer outage data • TOU pilot results • EV pilot results • Storage pilot results	• Grid edge operational awareness • DER performance data • Asset health data • Enhanced system diagnostics • More accurate DER benefits and costs • Disaggregated usage data	• TBD – expect enhancements based on evolving data capabilities and industry maturity related to operational experience

Data Maturity

2. *Customer Platform*

Currently the Company has a customer portal called MyAccount. The customer portal is used by our customers to access their account information, such as billing and meter reading history. It is built on an existing customer platform that is integrated with the Customer Resource System (CRS) and Meter Data Management System (MDMS). Once integrated with AMI, customer usage data and other system data from field devices will be transmitted through the AMI head-end system, to the customer portal, where customers will have the ability to see more granular meter reading data than they see with today's AMR system.

The Company has a developed a customer platform plan for enhancements to the portal once AMI meters are reporting more granular usage data several times per day.

The customer portal will automatically send an "on demand" read request to the meter, obtain the latest readings from the meter, and then combine this new data with the data obtained from the routine reading process for customer viewing. Similar capabilities will be developed for the smartphone application as well.

The current platform technology that supports the customer portal is reaching the end of life, and it is expected that it will not be capable of handling the new data and user information that will become available with the implementation of AMI. To enhance the customer experience, new technologies will be deployed to support the customer portal and other functionality, known as the customer platform.

The customer platform enhancements are primarily aligned with our aspirations to transform the customer experiences and build new grid capabilities. Many of the customer offerings enabled or enhanced by other advanced grid investments will be presented through the enhanced customer portal. From a grid perspective, the enhanced customer portal contributes to greater participation for customer "behind the meter" (BTM) technologies in utility programs, better outage communication with customers during events, and a more streamlined interconnection experience.

The customer platform enhancements will enable an improved customer experience and new product and service offerings. The enhancements ensure our customers are provided the most accurate and up to date usage data. The platform will also be the mechanism for providing customers greater insight into their energy usage, proactive messaging and education, and tailored programs and other offerings. The platform will allow for greater engagement for customers, increased customer satisfaction due to better information being more readily available, and improved customer access to programs and services that facilitate energy efficiency and savings. As benefits from other investments are realized over time, the platform will play a key role in connecting customers with new offerings. The more detailed timing of the new offerings is described in the Implementation section below.

B. Operational Data

Using data from new and existing grid sensors, the Company intends to better monitor and control the distribution system through advanced analytics. These capabilities will enhance existing processes like asset management and DER management.

Field assets require ongoing maintenance and continued calibration to maximize their life cycle and effectiveness. We intend to use operational data and advanced analytics to enhance its asset management capabilities. Enhanced analytics will enable better management and scheduling of predictive maintenance, identification of poorly performing assets to replace or repair, and confirmation that assets are properly calibrated. Assets that are at risk can be identified and repaired/replaced before they fail, preventing outages and minimizing impacts to customers. These capabilities will also include the ability to centrally manage data about field assets.

Lastly, the Company will use operational data to better manage a more dynamic grid as DER adoption increases. Meters can provide more granular historical performance information, which can inform forecasting and troubleshooting. Grid edge sensors will communicate back to central control systems, like the ADMS, information such as voltage fluctuations resulting from variable renewable resources. This situational awareness will allow our operators to better understand and respond to changing conditions on the distribution system.

C. Planning Data

Lastly, we intend to use data from new and existing sensors to improve distribution planning processes including enhanced DER forecasting, strategic siting of Company-owned DER, and identification of NWA opportunities.

For distribution planning, more granular distribution level data will offer visibility of the actual performance of the grid. Analytics will assess trends and load growth to better forecast future needs in different areas within the Company's service territory. As the number of DER deployments increase, software systems will help assess their potential impact. In addition, analytics can identify potential locations for strategic storage deployments to minimize the effects of intermittency.

We are also looking at ways to use planning data to facilitate NWA assessment and development. The deeper knowledge afforded by the more granular distribution planning data will help us identify targeted solutions for areas where forecasted system needs exceed current capabilities. All the data types above are enabled by data management hardware, applications, and use cases. To unlock the value of this data, we will focus on standardizing our data products, defining valuable data analytics use cases, developing the necessary skills, and implementing a data governance and cybersecurity policy.

D. Data Security

The role of cybersecurity within the AGIS plan is to ensure all components of the intelligent grid are identified and protected, both for the protection of customers and for the reliable and safe delivery of energy to customers. Cybersecurity will validate that there are sufficient detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity, while also planning, refining, and exercising the appropriate levels of response to all possible threats to the intelligent grid. Furthermore, as the Company moves forward into the next generation of intelligent, interactive electric distribution, each and every facet of the electric network must be evaluated for cybersecurity risk. Reliable delivery of electricity is of paramount importance and protecting the integrity of our system is part of that responsibility. Therefore, all aspects of the advanced distribution system must be inventoried, securely configured, and monitored regularly and thoroughly.

Though there are various industry standards produced by NERC Critical Infrastructure Protection (CIP) and National Institute of Standards and Technology (NIST), these standards are not fully applicable to the distribution grid at this time.[57] Despite this, the Company is committed to cybersecurity and employs cybersecurity best practices through execution of a four-principle plan. The first of these four principles is "defense in depth." This principle ensures there are multiple layers of protection and detection defined within the AGIS effort. This includes defenses at each endpoint, throughout the communication network, at the entrance to the distribution control centers, and at all authentication and authorization points. It then provides a robust monitoring and alerting system to notify appropriate personnel in the event of anomalous or suspicious activity. Second is the principle of "zero trust," which creates isolation points within the information network in order that only specific hosts are able to communicate with other specific hosts. This requires granular segmentation and tight communication rules so that only valid communication is received and acted upon.

The third principle, "least privilege," builds upon the first two principles; only necessary individuals and services are allowed to interact with devices on the intelligent electric distribution network. Strong authentication must exist to validate administrative users and the concept of "least privilege" is applied to all users and services running on the devices. Least privilege means that users or services only receive permissions to perform the functions necessary for specific duties. This limits the exposure to systems or devices if an account is compromised. The last principle is similar to the third; systems and devices are configured to match "least functionality." Least functionality does not mean minimum service or function overall, but rather only necessary ports and services are open and running on the systems and devices. This minimizes the exposure point of any discovered or undiscovered (zero-day)

[57] *See Guidelines for Smart Grid Cybersecurity,* National Institute of Standards and Technology, Gaithersburg, MD (September 2014).

vulnerabilities, decreases the threat profile of the environment, and reduces potential exposure should a vulnerability be identified for an unnecessary, disabled service.

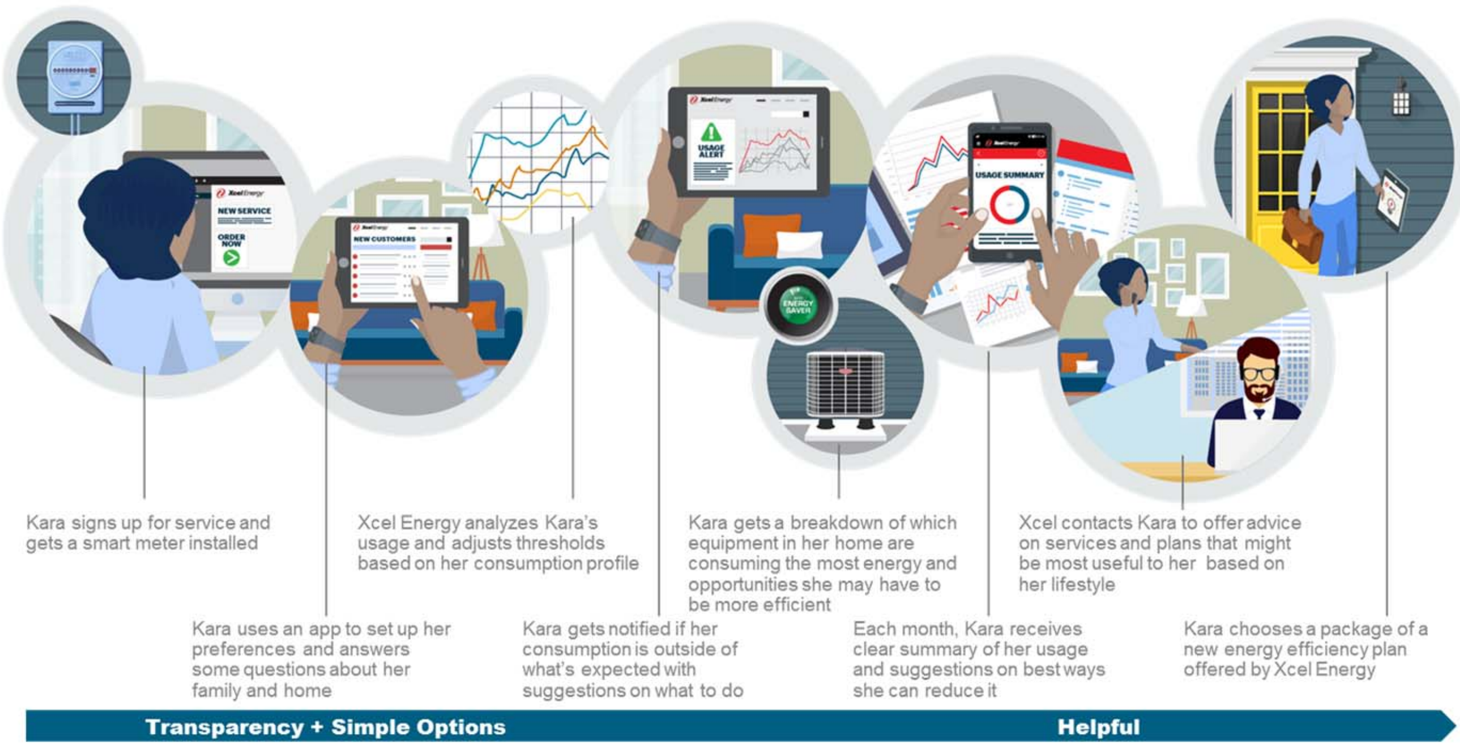
Xcel Energy's security principles and the protection implemented by NSPM will secure customer endpoints and the communications network. Endpoint Protection is the installation and/or enablement of protective and detective cybersecurity controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at a communication endpoint. This includes the AMI meter and head-end, but also includes any communication device such as routers or switches that could be used to exploit the network. Each of these endpoint protections will support the overall security of advanced grid technologies and customer data.

As with the consumer endpoint devices, the communication network, which facilitates data movement from the endpoint at the consumer premise to the utility's control center, must also have a high level of security built into the architecture to ensure confidentiality, integrity, and availability of the intelligent electric distribution network. The equipment that makes up the communication network will adhere to a least-privilege authentication and authorization model.

E. View Into the Future for Customers

Below, we portray some of the types of programs and services that will be available for customers at AMI Day 1 and then Day N – which will be determined at a later date, but is intended to demonstrate some of the longer-term benefits and capabilities we envision. The phased approach allows us to gradually offer customers benefits that come with the implementation of AMI and the analysis of the AMI data collected.

Figure 51: Day 1 in the Life – Residential Energy Usage Information



The collection of interval meter data is the primary capability delivered by AMI through the AGIS system, and offers customers access to their actual usage data in near real-time. The Company's investments in data analytics capabilities to make use of the interval data produced by AMI meters in conjunction with our other advanced grid investments and offerings to deliver new benefits. As illustrated in this Figure, by analyzing AMI data, we can help customers create profiles that enable better energy usage, provide personalized insights, and identify the most appropriate demand side management programs for their personal situation.

In this figure, Xcel Energy customer Kara is receiving a usage or high bill alert, similar to mobile phone alert messages that notify mobile phone service customers of data usage overages. This proactive notification is sent based upon parameters Kara has set such as a monthly forecast or a dollar limit she does not want to surpass. When Xcel Energy sends this notice it can help Kara take immediate actions to manage her energy usage and save money. This notification, other subsequent notifications, provides Kara insight into which appliances or technologies are using energy thereby helping her take more specific action to reduce energy usage. For example, if Kara went on vacation and forgot to set her smart thermostat to an "away" setting, the communication she received could remind her of this and she could, through a mobile application, remotely adjust the temperature in her home. As a result of the initial alert, and any actions Kara may take, Xcel Energy then sends a follow up communication with a personalized package of DSM programs designed to help her reduce energy usage and save money on her monthly bills. This personalized package reduces the time and effort Kara needs to invest in identifying the best energy savings programs to meet her needs. Further, this process creates efficiencies for the Company by recruiting ideal participant's for individual energy efficiency programs, thereby increasing the efficiency and effectiveness of our marketing and administrative costs.

Finally, this new AMI data may help identify and develop new demand side management programs to meet customer needs and expectations. Examples of new programs that may be enabled by AMI data in the future include, additional rate options to meet our customers' particular usage profiles and needs such as electric vehicle (EV) and 'Whole Home' rates; reward gamification to engage customers in managing energy usage in ways that are mutually beneficial to the customer and the grid; and day ahead notice and bill credits for lowering consumption during the peak hours of peak days. These new programs will offer additional opportunities for customers to participate in DSM programs that meet their unique needs, save energy, save money on their monthly electric bills and ultimately reduce system costs for all customers.

Figure 52: Day N in the Life – Residential Advanced Home Control

To fully maximize AMI and supporting FAN technologies, advanced meters will be used to activate energy management systems. An energy management system connects electronic devices, such as smart thermostats, energy display devices, and smart appliances, into a common customer network that allows these devices to communicate with each other and be managed remotely. In the future, advanced rate designs, new DSM programs, wider deployment of DERs, and a cleaner, more reliable grid will enable the Company, in partnership with customers, to directly manage energy usage. This is in contrast to the Day 1 Figure 51 above in which the Company informs, but Kara must act. In the future, the Company will still inform the customer but through a partnership can act on their behalf and reduce the need for customers to actively engage and invest time in managing their energy usage.

As shown in Figure 52 above, Xcel Energy customer Sachin contacts the Company to install an advanced control home package. This package will connect smart devices in Sachin's home and optimize their operation to minimize his energy costs. Later, Sachin decides he would like to purchase an EV and contacts Xcel Energy to understand the potential cost of ownership. AMI data provides insight about Sachin's personal energy usage patterns. Xcel Energy will prepare a personalized report for Sachin that compares his estimated pre and post transportation costs and identify technologies and rate designs that optimize his experience and manage his energy costs. Upon deciding to invest in an new EV, Sachin has a smart charging station installed by Xcel Energy and enrolls in the managed charging program that allows the Company to charge his EV when renewable energy, from his private solar or system resources, are abundant.

Turn-key services like these help set the path for customers like Sachin, to execute on their energy goals in partnership with the energy experts at Xcel Energy. This partnership is intended to reduce the pressures our customers may feel when facing investments in their energy usage and clean transportation options. All customers reap the wider system benefits of reduced emissions because Xcel Energy's management of Sachin's energy goals allows it to manage those in concert with other customers. This holistic management reduces system impacts such as distribution system investments that increase customer bills; and maximizes the usage and integration of renewable energy which reduces fuel costs and emissions.

1. HAN

As described in this document, AMI is integral to the Company's advanced grid roadmap. To fully maximize AMI and supporting FAN technologies, advanced meters will be used to activate a HAN. NIST defines a customer's residential, commercial, or industrial HAN as a "network of energy management devices, digital consumer electronics, signal-controlled or enabled appliances, and applications within a home environment that is on the home side of the electric meter."[58] A HAN connects electronic devices, such as thermostats, security systems, energy display devices, and smart appliances, into a common customer network that allows these devices to communicate with each other. HAN devices can be smart devices which consume energy, evaluate energy consumption of other devices, or display energy consumption data.

a. Initiative Components

A Utility Energy Services Interface is a device responsible for providing gateway and general connectivity between the utility and HAN. For our purposes, this connectivity will be provided by the Network Interface Card (NIC). A NIC is communication hardware containing two software defined radios installed within the AMI meter. One of these radio devices is dedicated to communicating with our

[58] See SG Network System Requirements Specification Interim Release 3, U.S. Department of Energy (May 17, 2010).

WiSUN mesh network, providing energy usage data and other meter data to our management systems. The WiSUN mesh network is part of our FAN, which connects AMI meters, substations, and field devices with the Company's back-office applications. The second radio device within the NIC facilitates direct communication between the AMI meter and customer HAN devices. These direct communications between the AMI meter and HAN devices support customer automation and energy management functions, and the FAN supports the use of HAN device information in our back-office applications.

b. Benefits

HAN supports the Company's advanced grid aspiration to transform the customer experience by enabling interfaces with customers' BTM technologies and by helping to provide customer usage information and insights through preferred channels (e.g., mobile, web). Through the deployment of HAN in combination with AMI, customers will be able to access new ways to coordinate the interaction of their home devices with new utility programs and services.

The benefits of enabling a HAN device will depend both on the type of HAN device as well as the extent to which the customer engages with the device. While a HAN device can enable a customer to obtain near real-time energy usage data, not all HAN devices automatically reduce energy usage. Thus, the customer still must decide how and when to utilize their energy usage data. For example, in the case of an in-home energy display HAN device, a customer may be more informed as to their energy usage; however, they will need to take action or invest in an energy management system or HAN gateway, to reduce their energy usage or shift their usage to a different time (if on TOU rates) to reduce their electric bill.

c. Implementation

As part of the AMI meter hardware, HAN will have the same deployment and implementation timeline as the rollout of AMI and FAN. However, customers will be unable to begin HAN communications until the necessary communications infrastructure and back office capabilities are in place. Implementation of these will begin as part of the TOU pilot and will be rolled out on a widespread basis between 2020-2023, pending certification. Due to high levels of connectivity between customer devices and utility communication networks, the Company will deploy HAN in a manner meeting cybersecurity concerns consistent with industry and best practices.

In accordance with our cybersecurity standards, the customer must register their

HAN device, and the Company will utilize a two-step authentication process to enable activation. The Company is expecting to allow "bring your own device" (BYOD), meaning all HAN devices should be able to connect to the AMI meter if compliant with communications protocol. It is our belief that the BYOD process enhances the customer experience by allowing customers to choose the compliant HAN devices that best meet their needs. In addition, the two-step activation process is a relatively simple and quick process that will increase customer participation and engagement, while still ensuring robust cybersecurity.

To assist customers with HAN device connection, the Company will offer tools and forms on the customer platform or through support channels (e.g., telephone, email, or social media). The education and outreach plan for HAN will be incorporated into the Company's general AMI education and outreach plan; it will include both tactical instructions for using the HAN features as well as information on how to maximize the use of HAN, contextualized into more meaningful concepts, rather than kWh savings.

d. Interdependencies

As the Utility Energy Services Interface, the Itron Generation 5 NIC must be compatible with the Company's FAN. The NIC is also a physical component of the AMI meter. Thus, HAN is dependent on the deployment of both AMI meters and FAN to realize customer benefits. Further, we must enhance the customer platform to communicate with and educate customers on HAN devices and the potential benefits to customers through enhanced utility services and programs.

e. Costs

The capital costs associated with implementing the HAN include two components: (1) the cost of installing a HAN radio in each meter; (2) software licensing, hardware, and associated labor to install and maintain secure connectivity. The O&M costs associated with implementing the HAN include the following components: (1) customer care support; (2) customer education and outreach; and (3) software maintenance, software training, cybersecurity strategy, and a security test. We are still in the process of determining the most cost-effective path for enabling HAN capabilities and will estimate the costs and any potential cost recovery as further decisions are made.

F. Views Into the Future for Company Operations

1. Potential Enhancements to Existing System

The Company currently utilizes the Oracle Network Management System (NMS) as its Outage Management System (OMS). This OMS is utilized in a classic implementation where customers call in when their power goes out, the extent of the outage is determined based on customer calls from different locations, the outage is logged in the OMS, a work order is generated to investigate the outage, and details are added to the outage event record in the OMS as additional information is gathered from both customers and the restoration crews. The OMS also provides information to populate the publicly-available outage map so customers can understand the extent and restoration status of an outage.[59]

The OMS is currently being updated to a new version from Oracle and the AMI outage notifications will assist the OMS in identifying an outage. However, the updated system will not yet be fully integrated with the Schneider ADMS currently being implemented. Therefore, it is envisioned that the OMS will be brought into the ADMS to become fully integrated as a comprehensive distribution grid management solution during a future update. This update will increase the coordination between the ADMS, FLISR, OMS, and AMI capabilities to provide improved outage information for Company operations and customers. The AMI outage alerts and OMS outage tracking data will combine with the system level data and distribution sensing, configuration and control capabilities from ADMS and FLISR to further refine outage identification, evaluation, remediation and service restoration capabilities. The ADMS and FLISR capabilities are likely to evolve over this timeframe as well, providing additional capabilities and insights as the ADMS solution evolves and matures.

The Company has a metering database and billing system that was initially purchased as an off-the-shelf solution but was subsequently customized. This system has supported both the storage of AMR meter data as well as customer billing since and will support the initial rollout of AMI, which will result in transitioning from daily meter reads to 15-minute interval meter data. The 15-minute interval meter data represents 96 times more usage (kWh) data, in addition to other data collected including demand (kW), voltage, outage, and data channels for energy consumption or export. While the current meter database will support this increased volume of data in the near term, the Company may need to upgrade to a commercially available MDMS specifically designed to support AMI in the future. The modern MDMS has built in analytics capabilities such as Validation, Estimation, Editing (VEE), Exception Management, billing determinant calculations, and virtualization capabilities to

[59] See the outage map at https://www.outagemap-xcelenergy.com/.

support new and complex rate structures. These analytics capabilities allow the MDMS to receive/relay data or respond to events such as outage, tampering, and power quality alerts automatically.

2. *Demand Response Management System*

We have been working with AutoGrid for two years in the phased deployment of our Demand Response Management System (DRMS), which enables new capabilities for Demand Response. These capabilities include functionality to support the enrollment, forecasting, scheduling, notification, event execution, and performance report of DR programs.

a. Benefits

The DRMS will position the Company to grow future demand management capabilities to increase customer options and align with changing market requirements. Customer benefits include additional tools and data for more informed energy usage decisions, a wider offering of customer programs, greater environmental engagement, and lower energy bills. In addition to the new capabilities enabled for the operation and planning of DR programs, the implementation of our AutoGrid DRMS product enables the retirement of legacy software applications and associated hardware.

b. Implementations

Historically, DR has been used to reduce peak demand on the bulk generation system. As we complete AutoGrid implementation, the Company will operate this product, while identifying its place in grid modernization efforts. For example, the DRMS could be utilized to automatically dispatch, addressing geography-specific distribution issues, either broadly or at the feeder level, or other applications. Applications could include deferral opportunities, DER integration, and peak demand reduction. Over time, more DER technologies (e.g. home thermostats, air conditioners, water heaters) could be aggregated collectively to meet a distribution system need.

In Colorado, we have integrated the AutoGrid system with our Panasonic Pena Station battery project. With this application, during a demand reduction event, the DRMS sends a signal to the battery to discharge. We are also working with both the battery vendor and AutoGrid to build functionality allowing the battery to discharge during a peak feeder event to reduce constraints at the feeder head.[60] The system would read amperage readings at the substation and respond to high amperage events. Like many software platforms, additional DRMS capabilities will develop over time. As this occurs, we will evaluate how these developments influence our demand response portfolio.

c. Interdependencies

As we complete implementation of the AutoGrid system and gain experience using the new functionalities, there may be an opportunity to use DR as a more operational distribution resource. In order to do this, there may be necessary interfaces with ADMS and/or design considerations with DERMS. These enhancements are beyond those required when DR strictly serves to reduce peak demand.

d. Costs

The implementation of the AutoGrid DRMS is nearly complete. At this time, we do not foresee an immediate need for incremental funding. As DR becomes a more operational tool, we will evaluate the necessary system integrations and/or enhancements.

3. Volt-Var Management (IVVO)

IVVO is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices or VAr control devices that are dispersed across distribution feeders. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile - or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder to the tail-end in concert with capacitors and other voltage regulating devices for voltage support. With IVVO, voltage can be monitored along the feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be lowered to achieve a variety of operational outcomes which are described later.

As penetration of DER grows, enhanced voltage control through IVVO will allow us to better manage the expanded range of distribution system voltage cause by DER.

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[60] More information can be found in the 2018 Semi-Annual Report to the Public Utilities Commission, regarding the Innovative Clean Technology Program, Docket no 15A-0847E.

a. Initiative Components

Xcel Energy has already purchased the IVVO module in ADMS and will test it as part of the initial ADMS deployment. In addition to the operating system and communication network, there are four principal utility field equipment components of IVVO: (a) capacitors, (b) secondary static VAr compensators (SVCs), (c) voltage sensing devices, and (d) Load Tap Changers (LTC).

Voltage sensing devices placed at strategic points on the distribution system enable IVVO systems to operate the most effectively. While these may be unique devices, using AMI meters where available is a cost-effective solution. For this reason, the Company intends to use bellwether AMI meters as its primary voltage sensing device in Minnesota.

To maximize the benefit of an IVVO program, a significant cost of implementation is replacing/upgrading LTCs with the controls to do full Conservation Voltage Reduction (CVR) as existing LTCs on the distribution system are not capable of accepting IVVO commands from an ADMS. This would be a significant cost in Minnesota. Other costs include remote terminal units (RTU) replacements and reprogramming and deploying Varentac ENGO hardware in the field (the Company's standard SVC vendor).

b. Alignment with Advanced Grid Aspirations

IVVO supports our advanced grid aspirations to create value for customers and build new grid capabilities. Specifically, it will allow the Company to manage and optimize voltage to deliver enhanced power quality. It will better prepare the Company to accommodate DER and respond to changing conditions on the grid by dynamically balancing load through automated switching in non-outage situations.

Customers' energy consumption is more dynamic than ever. Residential customers can have on-site solar, batteries, electric vehicles, smart appliances, smart thermostats, and many more electronic devices. Traditionally, the Company has based control settings of devices like capacitors on the peak demand of a feeder and these devices operate with very little awareness of the energy consumption upstream or downstream. The current process has worked well enough in the past, although not as efficiently as possible. ADMS will provide a centralized system that will dynamically react to changes in conditions on the distribution system and IVVO will improve the Company's ability to monitor and control voltage levels based on the actual conditions along a feeder.

c. Benefits

There are several potential operational benefits of IVVO, including:

- *Reduction of Distribution Electrical Losses*. IVVO models in ADMS can turn the capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on the distribution system. This improves the efficiency of the system, reduces system losses, slightly decreases energy generation needs, and reduces carbon emissions. Because of power factor improvements already achieved through our existing SmartVAr program in Minnesota, we expect the incremental benefits of IVVO to be minimal.
- *Reduction of Electrical Demand and Energy Consumption*. Flattening the voltage profile along a feeder and operating in the lower range of 114V to 120V reduces energy consumption for certain devices, like incandescent lighting or motors, such as those found in air conditioners, dryers, and refrigerators. By ensuring these types of devices are operated in the lower voltage range making them more energy efficient. The industry term used to describe operating in the lower voltage range is CVR. Studies have shown that the CVR benefit varies with the load type, climate zone and feeder characteristics. The amount of energy efficiency or demand reduction achievable is highly dependent on a number of factors, including various attributes and configuration of the distribution system, and customer attributes such as customer density, load characteristics, and the mix of residential and commercial customers.
- *Increased Ability to Host DER*. IVVO will increase our ability to host DER. As penetration of DER grows, the Company will need to manage the expanded range of distribution system voltage. Traditionally, with only load on a feeder, the Voltage Control objective was to raise voltage at time of heavy load to manage voltage within the acceptable range. With DER causing reverse power flow and raising voltages during times of light loading, voltage control schemes must now both raise and lower voltage
- *Demand Response*. Lastly, IVVO provides the Company with an additional demand response tool. Using voltage management capabilities enabled by ADMS and IVVO, we will be able to target voltage at certain substations or transformers for 1-2 percent reductions in response to system conditions

d. Implementation

The ADMS that we are in the process of implementing can run the IVVO application in several different operating modes: Voltage Control, Peak Reduction, Var Control, and CVR. We plan to use the capabilities of the IVVO application within the ADMS in Minnesota – however, IVVO can be any combination of the four of the following operating modes.

- *Voltage Control mode* functions to optimize voltage on the feeder around standard operating voltages – maintaining adequate service voltage for all customers. This mode is generally a secondary operating mode of IVVO, and only used to establish the voltage boundaries within which the other operating modes must stay within. As penetration of DER grows, Voltage Control will become more common as a primary control mode to manage the expanded range of distribution system voltage caused by DER.

- *Peak Reduction mode* serves to reduce load only during peak load events. It is a manually triggered mode that reduces system voltage to a targeted value to reduce load on the system for a short duration – typically one or two hours. This peak reduction tool can be used in large operating regions, such as Minnesota as a whole, or tactically by feeder, substation, or other targeted area.

- *VAr Control mode* seeks to reduce system losses and save energy by optimizing power factor on each distribution feeder.

- *CVR mode* seeks energy savings through reduced operating voltages. CVR mode uses the LTC or Voltage Regulator inside the substation to lower voltage on the feeder. This lower operating voltage results in small energy savings for most customers on a feeder.

Since 2010, we have been doing Var control through our SmartVAr program in Minnesota, which has provided benefits to the grid and our customers. SmartVAr is a VAr control system that functions to bring feeder and transformer power factor to as near unity power factor as possible. We have VVMS running on hundreds of feeders that accounts for the majority of our large substations. SmartVAr is presently managed through a specific system and will ultimately be transitioned to the ADMS, where we will have the ability to implement other IVVO objectives on the Minnesota system. However, there are important considerations involved in determining IVVO application on the system – some of which are technical, and others are about maximizing value for customers.

We know that the different types of voltage control are affected by a variety of factors throughout the distribution network. In PSCo, we will be using CVR as the primary operational mode, with Var Control as the secondary mode. The following key differences in feeder design between Minnesota and Colorado have factored into our decision to deploy IVVO differently in these two operating areas:

- *The system design in Colorado uses feeders with larger conductors to support a denser load –*

Larger conductor size has lower impedance, which means that the voltage drop across the wire is reduced – making the system more capable of CVR; higher load density on each feeder means that the net impact from IVVO on a per-feeder basis can be greater. As a result, the PSCo feeder design is more amenable to CVR

- *The standard substation bus voltage is different* – In PSCo, the standard bus voltage is 125V, which is at the very high end of the ANSI C84.1 standard for distribution voltage. This higher starting voltage allows for a greater range of voltage reduction to be done with IVVO, giving more opportunity for energy savings while maintaining adequate service quality to customers. In the NSPM service area, average bus voltage is typically 123.5 volts. This, along with smaller wire size, reduces the potential impact of CVR for Minnesota
- *AMI is a beneficial component of IVVO* – AMI meters used as 'bellwether' meters are the least cost method to provide voltage inputs to ADMS at key locations across the grid. For IVVO to be successfully and safely operated, voltage endpoints are necessary at ten end points on each feeder; without AMI, this data would need to be gathered in other ways. Our preliminary Minnesota analysis shows the use of Voltage Sensors would be approximately ten times the cost per unit of an AMI meter. Thus, our AMI initiative is a critical part of IVVO deployment to minimize costs and provide voltage data
- *Additional considerations* – Our sample set, using a simple average generated from the Wilson Substation pilot, may not be representative of the potentially wide range of CVR Factors existing on the system. This study also did not consider higher anticipated levels of DER. Furthermore, the analysis did not take into consideration the declining use per customer driven by organic and explicit conservation measures; declining customer use diminishes the potential benefits of IVVO

As such, we do not believe that the benefits of CVR are significant enough to justify the cost of implementing IVVO in the near term beyond our existing SmartVAr program. However, we see value in developing its voltage management capabilities – particularly as the level of DER in our service are increases over the period covered by this Roadmap. The current plan is to complete the various projects that will enable IVVO (e.g., ADMS, FAN, AMI) and monitor other indicators (such as the results of the roll-out of IVVO in Colorado and DER penetration levels in Minnesota) to determine the appropriate time to make this investment. We will also test IVVO functions (including CVR) in Minnesota as a part of its in-servicing of the ADMS software.

4. *Data Analytics Capabilities and Tools*

Driven by the proliferation of sensor technology and AMI, utilities are collecting more data than ever. As this trend continues, many utilities are investing in data analytics capabilities to collect and analyze large quantities of data to provide meaningful information to support real-time and predictive decision-making and to provide customers with information to optimize their energy usage.

The Company has begun to develop analytics capabilities by focusing on foundational elements. The Company's first steps are to ensure that existing data capabilities, such as billing, reporting, and warehousing, are well maintained and can manage the impending changes of how and where the data will flow and what data fields will change. The Company is taking a measured approach to ensure that the data is of good quality, is clean and accurate, and is sourced logically before investing in a large-scale data analytics push.

The existing data warehouse is currently used to consolidate data from separate systems of record to facilitate generation of reports and perform data analysis. There is an existing ESB that will connect this new data coming in to existing systems such as SAP applications (e.g., Asset Management, ERP), GIS, and the billing system. Recently, the Company has made some decisions about its data infrastructure that are necessary in order to meet the demands of a modernized grid. These include the introduction of data lake technologies to optimize handling of large data volumes and the addition of a data hub to provide focused support for integrations.

Over the long-term, as we gain familiarity with the data coming in from AMI and other systems, we will further expand our data analytics capabilities by investing in an analytics software tool(s) and deploying specific analytics use cases.

a. Initiative Components

The data analytics initiative will be made up of several components, including: data management hardware and infrastructure, data analytics software, and data integration.

Data Management Hardware. As the Company collects increasing amounts of data from more sources, it is important to invest in the storage and computing capacity necessary to fully utilize it. Data management hardware includes the necessary infrastructure, such as servers and a data warehouse, to store data in a central repository where it can be analyzed for beneficial purposes.

Data Analytics Software. With the roll-out of AMI, the Company will invest in new distribution analytics software, which is expected to receive data from the AMI head-end, MDMS, and the CRS. The software is expected to perform analytics to identify trends for items such as reverse flow, tampering, load side voltage, and temperature. The additional field devices proposed for FLISR will report operational data back to ADMS and potentially enable other data analytics uses.

Once specific data analysis needs are defined, and the new infrastructure is in place, the Company will establish an analytics function, ensure the necessary skillsets are staffed (data experts), develop the analytics software/platform, and integrated the data sources. Looking ahead, we intend to purchase or leverage partnerships for analytics applications. Where feasible and cost effective, these applications will be designed for scalability to integrate additional data sources. As additional data sources are integrated, additional use cases are enabled and will help us to realize further benefits for the Company and our customers.

Data Integration. The analytics capabilities of any software or tool is only as good as the data that feeds it. For that reason, it is important that all the necessary data sources such as AMI and the CRS are connected to the tool. It is also necessary that this data is clean and housed correctly to ensure the results of the analyses are also accurate. The data sources, the data infrastructure, and the data analytics software all need to be integrated to capture all the benefits of the data being collected. Without integration, the data provided from the new field devices cannot be communicated, stored, or analyzed by the analytics applications. In addition, a lack of integration would lead to more manual processes and would not allow for real-time decision-making, all of which will reduce the potential benefits of technologies, like ADMS.

b. Benefits

Data analytics support our advanced grid aspirations of transforming the customer experience and optimizing planning and operations. As noted in the introduction, the benefits and new offerings of our roadmap are underpinned by the collection and intelligent use of the data generated by our advanced technologies. Value will be obtained through these targeted applications, described below.

Key benefits of enhanced data analytics can include enhanced customer engagement, reduced costs, or improved reliability. The specific benefits of the Company's data analytics initiative will depend on which use cases we ultimately decide to implement. Below are some of the common utility industry use cases that we are evaluating and their associated benefits.

Enable Customer Engagement. Data collected through AMI meters offers customers access to their actual usage data in near real-time. To offer customers insights about usage, identify trends, customize and recommend programs, and identify efficiency upgrade impacts, the Company needs to invest in data analytics capabilities to make use of the interval data produced by AMI meters. For instance, by analyzing AMI data, we can identify customer usage profiles that would be well suited to participate in our CIP programs, more efficiently acquire customers for these programs, or develop new programs as common profiles emerge.

Cost Reduction. Analytics can help utilities reduce operations and maintenance expenditures via predicting failures or damage to assets in the field, detecting thefts, and reducing field service times. Potential use cases include:
Asset Health Monitoring: Utility distribution systems are capital intensive businesses with many types of assets. Ensuring proper functioning of those assets is critical to keeping customers supplied with power. Data collected from sensors on the grid can be used to monitor the health of assets and predict, diagnose, and prevent equipment or system failures. Specific examples of asset health use cases that NSPM is evaluating include proactive transformer replacement and predicting underground cable failures. Potential benefits of these initiatives may include avoided O&M through reduced truck rolls and improved reliability
Revenue Recovery/Theft Detection: Advanced analytics can be applied to AMI data to detect anomalies in consumption data and identify fraud. Benefits include safeguarding revenues and reduced time and cost of fraud and theft detection

Improve Reliability. In addition to more effective deployment of capital, predicting asset failure can also increase reliability by preventing outages through real-time identification of issues. Overall performance can also be improved by analyzing trends and making changes based on these observations. Potential use cases include:
Outage Analysis/Categorization: When a customer loses power, they are given an Estimated Time of Restoration (ETR). Advanced analytics can more accurately predict the ETR, which will increase customer satisfaction and improve overall outage management.

Power Quality Analytics. As we continue to install more smart meters we will have the ability to monitor the data feeds and predict when a customer is on the verge of losing power, so we can pre-emptively repair the issues and minimize the number of outages occurred. Advanced analytics may also be developed to proactively dispatch a crew to a job before a customer actually loses their power. Benefits of this use case include: increasing ratio of permanent/temporary repairs and reduce backlog of shunts/bridges; improving SAIFI; increased customer satisfaction with reduced outages

Other potential uses cases under evaluation include: AMI load flow estimation, identifying meter phasing, tracking of transformer load profiles, transformer load management, and system voltage monitoring/exception reporting.

c. Implementation

As noted above, we are currently focusing on foundational elements of data analytics, including data clean-up and governance processes, and starting to build in-house skillsets and capabilities. With the roll-out of AMI, we will purchase an analytics platform that will consolidate various data sources in one place. Over the long-term, we intend to integrate additional data sources and develop applications for specific use cases based on proven concepts and perceived value to our customers.

XI. DISTRIBUTED ENERGY RESOURCES

In this section, we provide the DER-related information specified in the IDP Order. As a point of reference, the IDP Order defines DER as follows:

> *Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.*

Specifically, IDP Requirement Nos. 3.A.6, 3.A.17-25, and 3.A.31-33, which includes explanations regarding how DER is treated in load forecasts, present and forecasted DER levels, and DER scenario analysis.

A. DER Consideration in Load Forecasting

IDP Requirement 3.A.6 requires the following:

> *Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology.*

We discuss how DER is factored into both the corporate load forecast and the distribution system planning forecasts below.

1. DER Treatment in the Corporate Load Forecast

The Company's corporate sales forecast relies on econometric models and other statistical techniques that relate our historical electric sales to demographic, economic and weather variables. We also make adjustments for known and measureable changes by large customers, and to incorporate the effects of our customers' energy efficiency, distributed generation solar PV adoption, and light-duty electric vehicles in the Residential sector. The resulting sales forecasts for each major customer class in each state across the Xcel Energy footprint are summed to derive a total system sales forecast.

The sales forecast is converted into energy requirements at the generator by adding energy losses (See Section 4 for a discussion regarding loss factor percentages). The system peak demand forecast is developed using a regression model that relates historical monthly base (uninterrupted) peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. Distribution Planning compares their summed/bottom-up feeder level forecast to the overall peak demand forecast for reasonableness, as discussed in Section V above.

a. Forecast Adjustments

After determining the base forecast, we develop net forecasts that include adjustments for future demand-side management programs, distributed solar behind-the-meter generation, and electric vehicles. We also account for the effects on the system peak demand forecast of our load management programs by subtracting expected load management amounts to derive a net peak demand forecast.

Demand-Side Management Programs. One important adjustment to the forecasts is the impact from our conservation improvement programs. The sales model implicitly accounts for some portion of changes in customer use due to conservation and other influences by basing projections of future consumption on past customer class energy consumption patterns. In addition, the regression model results for the residential and commercial and industrial classes and for system peak demand are reduced to account for the expected impacts of Company-sponsored DSM programs.

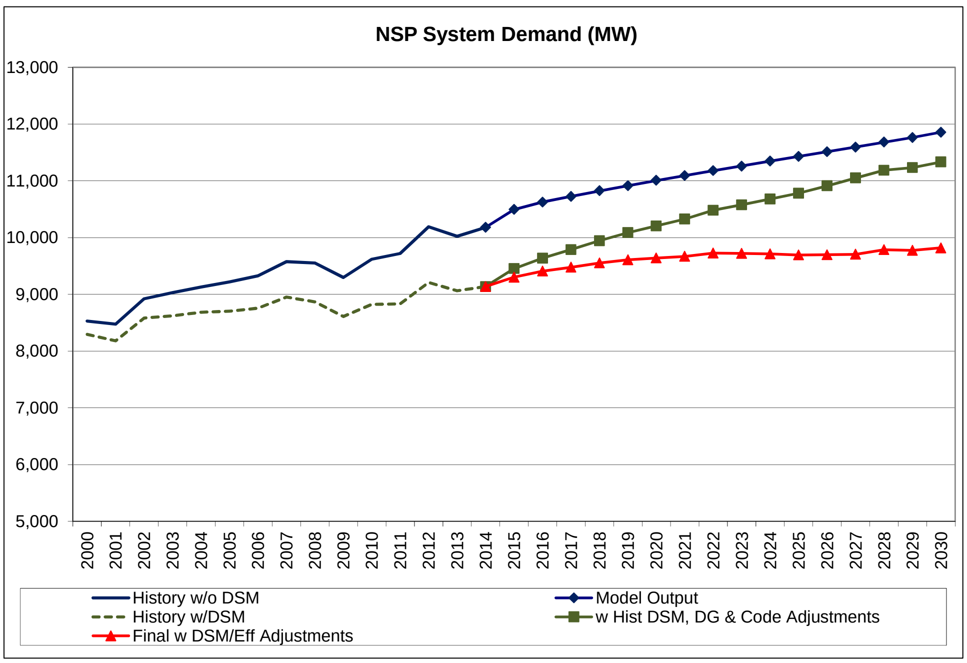
The DSM methodology for the states of Minnesota (and South Dakota) follows these distinct steps:

- Collect and calculate historical and current effects of DSM on observed sales and system peak demand.
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales and peak demand to show hypothetical case without DSM).

- Adjust the forecast to show the impact of all planned DSM in future years.
- Also adjust the forecast to account for codes and standards changes for lighting in the Residential and Business segment resulting in decreased sales that are in addition to company-sponsored DSM.

The Company-sponsored Minnesota DSM adjustments are based on the Company's Triennial Plan goals currently in effect. Figure 53 graphically illustrates the DSM adjustment described above.

Figure 53: Illustrative DSM Adjustment



Distributed Solar PV. For distributed solar, we adjust the Minnesota class-level sales forecasts and the system peak demand forecast to account for the forecasted impacts of customer-sited behind-the-meter solar installations on the NSP System. Specifically, this adjustment is based on solar capacity targets consistent with 2017 solar-related legislative outcomes and program activity that includes but is not limited to the removal of the Made in Minnesota program after 2017, increased Solar*Rewards incentives funding for 2018-2020, and no Solar*Rewards program after 2021. Capacity targets also are included for net-metering only installations. Impacts of customer-sited behind-the-meter solar installations are extracted from this forecast to develop adjustments to reduce the class-level sales for Minnesota and the NSP System peak demand forecast. The sales and peak demand forecasts are not adjusted for community solar gardens or distribution-connected utility-scale solar because these do not affect customers' loads.

Electric Vehicles. The Residential sales and system peak demand forecasts are adjusted to account for the impact of light-duty electric vehicles. The EV forecast is developed internally based on assumptions related to both adoption (energy) and charging behavior (demand) as described in Part C of this section. Inputs to the adoption model include electricity prices, vehicle battery prices, gasoline prices, car ownership, car usage, and efficiency. The charging behavior is estimated using representative datasets from Idaho National Lab's EV Project, combined with assumptions about the share of charging done at homes and the penetration of managed charging solutions.

Large Customer Adjustments. We may also make adjustments to the forecast to account for planned changes in production levels for large customers. For example, we may add sales and demand related to a customer's new incremental additional capacity that we become aware of. We may also make adjustments to reduce our requirements due to the scheduled installation of a customer-owned Combined Heat and Power generator.

b. Data Sources

MWh Sales and MW Peak Demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh Sales and MW Peak Demand. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand used in the modeling process.

Weather Data. Weather data (dry bulb temperature and dew points) were collected from weatherunderground.com for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data. The Company uses a 20-year rolling average of weather conditions to define normal weather.

Economic and Demographic Data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

In terms of changes to our load forecasting methodology as it relates to DER, we starting incorporating distributed solar PV beginning in 2014, and in 2018 began including EVs.

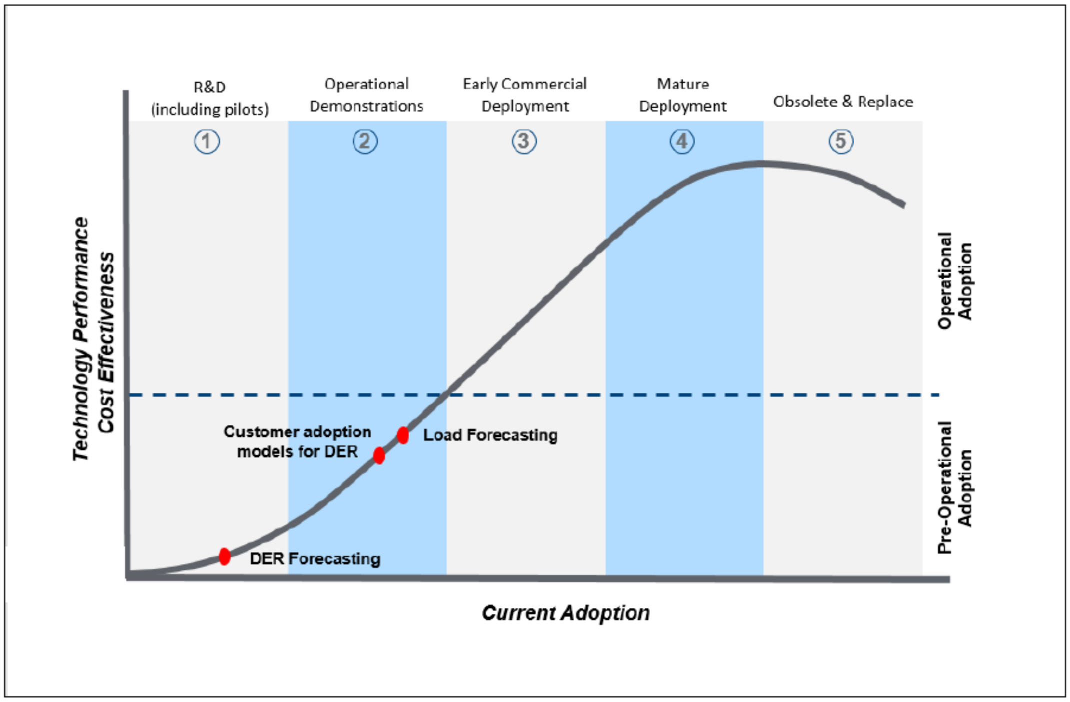
2. DER Treatment in the Distribution Planning Load Forecast

As we discussed in the System Planning section above, we do not currently factor DER into the feeder-level forecasts we use for system planning purposes. However, these forecasts are rooted in historic actual peak information, so are reflective of energy efficiency and load management. Additionally, we validate our rolled-up feeder level forecasts against the corporate load forecast, which as described in part 1 above, is adjusted for several types of DER. As we have noted and discuss further below, we are taking action to mature our DER planning capabilities through foundational advanced grid capabilities and enhanced planning tools.

The good news in terms of DER integration – from a distribution planning perspective – is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. At this time, the level of DER on our system and the historical rate of interconnections have not had a significant impact on our forecasts. This changed somewhat in the recent past as a result of the initial response to our CSG program. Long-term, we believe integrating various forecasts will be beneficial to our planning efforts, and we are currently evaluating early enhanced planning tools that are becoming available and are expected to facilitate this integration as they mature over time.

As shown in Figure 54 below and as we have previously noted, the availability of adequate forecasting tools has not reached full commercial deployment at this point, but we anticipate that they will in the near future. This function serves as the basis of distribution planning, and must be properly developed to enable more advanced planning and decision making.

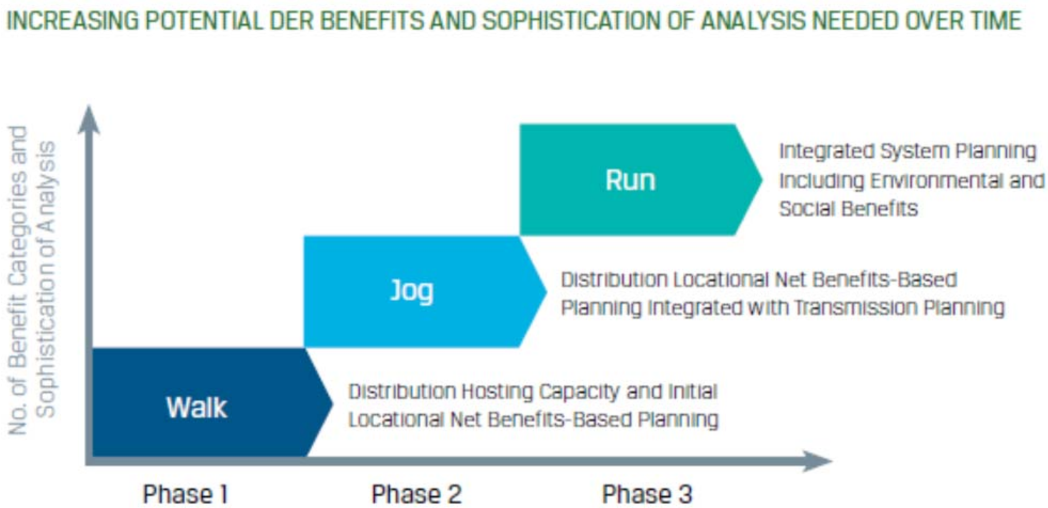
Figure 54: Forecasting DER and Demand – Adoption Maturity Analysis



Source: *Modern Distribution Grid, volume II: Advanced Technology Maturity Assessment* by U.S. DOE Office of Electricity Delivery & Energy Reliability, version 1.1 (March 27, 2017). *See* U.S. DOE DSPx Modern Distribution Grid Vol. II

While there are no definitive answers at this point as to how, and how fast enhanced planning for DER will occur, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run,"– is important. See Figure 55 below for one potential scenario for how the progression may occur.

Figure 55: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. *See* https://www.icf.com/resources/white-papers/2015/value-in-distributed-energy.

We agree that a staged and measured approach to enhanced planning is necessary. The August 2016 ICF report where the above phased approach was portrayed explains that the answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular utility and state, considering both the current stage of DER adoption, level of distribution grid modernization, and the desired policy objectives.

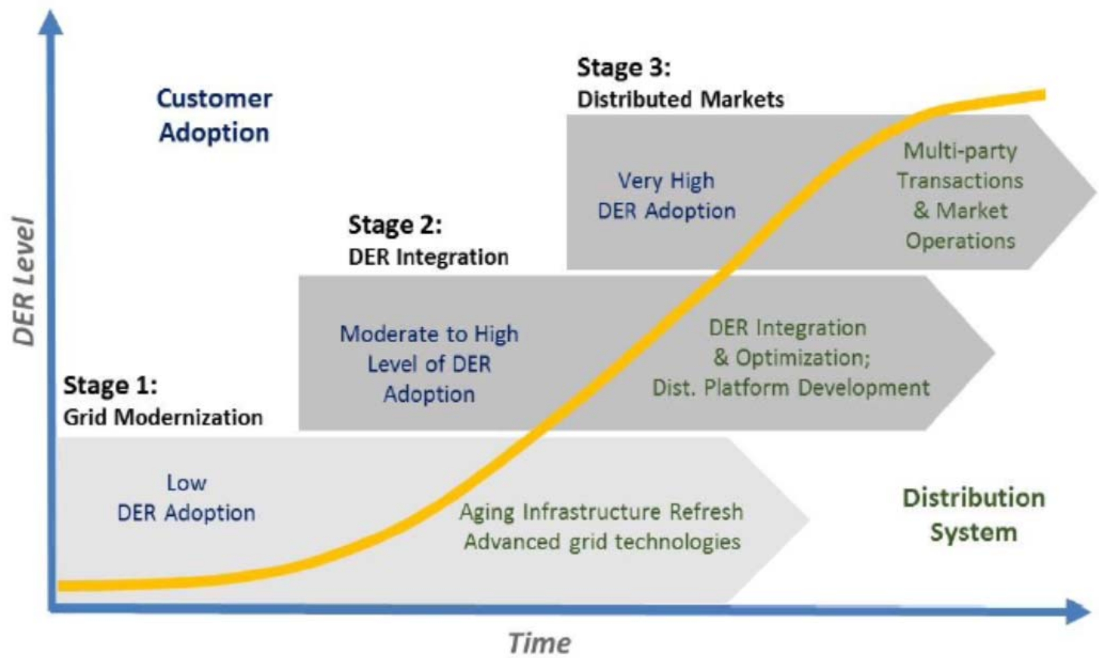
Numerous efforts from states, the DOE, and other organizations have used the customer driven Distribution System Evolution Framework shown below in Figure 56 to describe how the growth in DER adoption and related policies correspond to the distribution modernization capabilities required. Public policy varies on a state-by-state basis, and state policy is a key driver of DER adoption. Policies like net energy metering, renewable portfolio standards, or investment tax credits may make the adoption of DER technologies more financially-attractive and drive higher levels of penetration.[61] As policy evolves and penetration levels of DER increase, it will be important for distribution system capabilities to keep pace.

Various changes in both distribution planning and operations are needed in each stage

[61] These policies are described broadly as influential across the country and may apply to Minnesota in varying degrees.

to ensure reliable distribution operations – all resting on foundational elements that enable increased utility tools and information to be in place. It is important to note that Minnesota's DER penetration is substantially lower than other states, such as California and Hawaii. Much of the recent and expected DER growth in Minnesota is from CSG. In considering the staged evolution portrayed in Figure 56 below, we believe Minnesota falls squarely into Stage 1 in terms of DER penetration, which the DOE further describes as grid modernization, focusing on "enhancing reliability, resilience and operational efficiency while addressing aging infrastructure replacement."

Figure 56: Distribution System Evolution (Source: DOE)

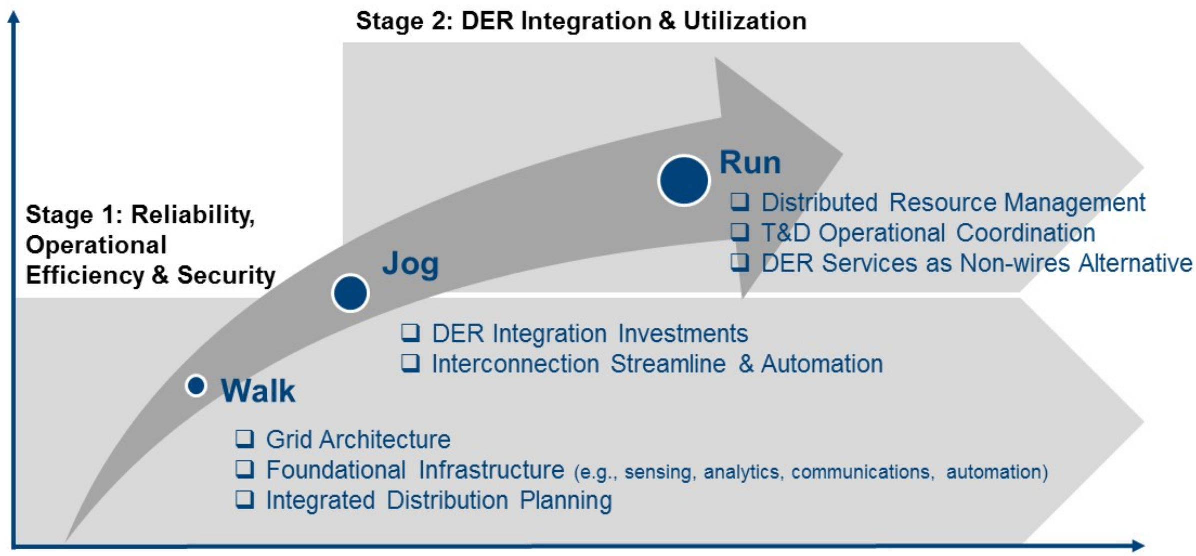


Source: *See Modern Distribution Grid, Volume III: Decision Guide*, Page 15, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

The investments that we are currently making in asset health and grid modernization, such as ADMS help to lay the foundation for continued resiliency and reliability. Near-term future planned investments such as AMI and FLISR further cement it, and will allow the Company to gradually respond to increased DER penetration.

The DOE has also observed that U.S. utilities are in Stage 1 in terms of timing and pace toward a modern distribution grid. As shown in Figure 57 below, DOE also incorporated evolving distribution planning processes and tools into this evolution. Stage 1 also includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication systems such as the FAN that is in our near-term advanced grid plans.

Figure 57: Timing and Pace Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

Stage 1 is also focused on other foundational infrastructure we are intending to implement, including additional sensing, analytics, and automation capabilities such as the FLISR initiative that is part of our near-term advanced grid plans. According to this concept, Minnesota is with the rest of the industry sitting squarely in Stage 1, with DER integration analysis and planning occurring in Stage 2 after maturing foundational advanced grid capabilities.

Using these concepts as a base, we provide a snapshot of how we contemplate evolving our planning tools and process, applying to our tools, process steps, and actions as sophistication of analysis and processes increase over time as Table 19 below. We note that this Table is an extension of Figure 27 in the System Planning section above, which portrays our present planning tools.

Table 19: Potential Planning Tools Evolution

		Current Process Steps						Future Planning Actions			
	TOOLS	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Design and Construct / EDP Memo	Long Range Plans	Interconnection Processing**	Scenario Planning	Integrated Resource Planning	Locational Net Benefit Analysis
Current Tools	**Synergi Electric**		X	X			X	X			X
	~~Distribution Asset Analysis*~~	~~X~~	~~X~~	-	-	-	-	-			
	MS Excel		X		X		X				
	CYMCAP		X								
	GIS			X			X	X	X		X
	SCADA	X									X
	Workbook (internal)		X	X	X	X					X
	DRIVE* **		X	X				X			
Expanded Tools	**New Forecasting Tool***	X					X	X	X	X	X
	ADMS	X							X		
	SAP					X					

* ***New Forecasting Tool*** **replaces DAA and adds more functionality**
**** Planning has larger role in interconnection process**
***** Hosting Capacity becomes integrated into planning process**

Walk | Jog | Run

B. Current Levels of Distributed Resources

In this section, we present current DER volumes for the DER types specified in the IDP DER definition on our Minnesota distribution system, volumes in the interconnection queue, and discuss geographic dispersion.

1. Current and In-Queue DER Volumes

In Table 20 below, we present the DER volumes on our Minnesota distribution system in compliance with IDP Requirement Nos. 3.A.17, 18, 19, 20, 23, 24, and 25

Table 20: Distribution-Connected Distributed Energy Resources – State of Minnesota

(as of September 2018)[62]

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Solar PV				
Rooftop Solar	44	3,696	23	934
Community Solar[63]	445	145	372	275
RDF Projects	13	30	3	12
Grid Scale (Aurora)	103	19	0	0
Wind	12	60	<1	7
Storage/Batteries[64]	N/A	6	N/A	34
Energy Efficiency	1,012	N/A	N/A	N/A
Demand Response	658	668,314	N/A	N/A
Electric Vehicles	N/A	5,693[65]	N/A	N/A

Note: Energy Efficiency and Demand Response are portrayed in Gen MW; Energy efficiency is cumulative since 2005.

For reference, below are the IDP requirements fulfilled in the Table 20 above:

IDP Requirement 3.A.17 requires the following:

> *Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. In 2017, these details were provided

[62] Energy Efficiency and Demand Response are as of December 31, 2017.

[63] Community Solar Gardens are limited to 1 MW applications. However, prior to September 25, 2015, garden operators were allowed to submit applications to co-locate up to 5 MW per site. Projects in this table are by site, not application.

[64] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.

[65] We do not have information that ties our customer accounts to electric vehicle users. *Source*: Xcel Energy Compliance Filing, IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON RESIDENTIAL ELECTRIC VEHICLE (EV) CHARGING TARIFF, Attachment A at page 1, Docket No. E002/M-15-111 (June 1, 2018).

in Docket No. E999/PR-18-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/M-18-205) to name a few.

Each of these reporting dockets have differing requirements, details and timing, therefore leading to inconsistent numbers depending upon filing. In an effort to resolve these conflicts, the Company is working as part of the Commission's Distributed Generation Advisory Group to finalize an updated and consistent reporting process for DER generation systems as part of the present Distribution Interconnection filing on March 1st of each year.

For purposes of this IDP requirement, we provide the information in Table 20 above.

IDP Requirement 3.A.18 requires the following:

> *Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. In 2017, these details were provided in Docket No. E999/PR-18-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/18-0205) to name a few.

Each of these reporting dockets have differing requirements, details and timing, therefore leading to inconsistent numbers depending upon filing. In an effort to resolve these conflicts, we are working as part of the Commission's Distributed Generation Advisory Group to finalize an updated and consistent reporting process for DER generation systems as part of the Distribution Interconnection filing on March 1st of each year.

For purposes of this IDP requirement, we provide the information in Table 20 above.

IDP Requirement 3.A.19 requires the following:

> *Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined*

solar/storage, storage, etc.).

The Company provides information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2018, with data as of end-of-year 2017, this information was provided in Docket No. E999/PR-18-10. We clarify however, that we are not able to provide the distribution system location for current energy efficiency and DR. This is due in part to the types of DSM programs offered. For example, we do not track individual, residential customer purchases of high efficiency lighting. Also, our systems to administer DSM programs are separate from the systems that support the planning and operations of our distribution system. As we continue to evaluate enhanced distribution planning tools, we will gain a better understanding of the breadth of capabilities available and whether tracking of DSM by points on the distribution system for purposes of reporting is possible.

IDP Requirement 3.A.20 requires the following:

Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

See Table 20 above.

IDP Requirement 3.A.23 requires the following:

Number of units and MW/MWh ratings of battery storage.

See Table 20 above. Also, we provide information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2018, with data as of end-of-year 2017, this information was provided in Docket No. E999/PR-18-10.[66]

IDP Requirement 3.A.24 requires the following:

MWh saving and peak demand reductions from EE program spending in previous year.

See Table 20 above.

IDP Requirement 3.A.25 requires the following:

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[66] We clarify that the information provided in this IDP may not be identical. The primary reason is because the quantities reported in this IDP are in terms of MW/AC and portions of the information contained in the E999/PR-18-10 docket are in terms of MW/DC.

Amount of controllable demand (in both MW and as a percentage of system peak).

See Table 20 above for the MW. In terms of percent of system peak, our 658 MW of DR in the state of Minnesota is approximately 10 percent of our Minnesota system peak of 6,484 MW.

2. *Electric Vehicles and Charging Stations in Service Area*

IDP Requirement 3.A.21 requires the following:

> *Total number of electric vehicles in service territory.*

Following is an excerpt from our June 1, 2018 Compliance filing in Docket No. E002/M-15-111 that provides current and anticipated EV penetration information:[67]

> *At the beginning of 2018, there were 5,693 registered plug-in vehicles in our Minnesota service territory. Approximately 55% were plug-in hybrids while 45% were full battery electric drive trains. The most popular vehicle has been the Chevy Volt followed by the Nissan Leaf. While the bulk of vehicles reside in Minneapolis, Saint Paul, and the surrounding suburbs – electric vehicles are registered in nearly every zip code we serve.*
>
> *Over the next five years, we expect electric vehicle options to grow and driver economics to improve. However, the unsubsidized purchase price of electric vehicles will likely remain above the price of equivalent internal combustion engine options, limiting growth of the electric vehicles during this timeframe.*
>
> *Our preliminary modeling suggests our Minnesota service territory may see adoption of more than 40,000 electric vehicles by 2023. Our modeling also suggests the possibility of significantly more or less adoption over this horizon as well. For this reason, we believe planning for transportation electrification must contemplate a variety of future state scenarios. We are currently preparing electric vehicle adoption scenarios in support of our 2019 Integrated Resource Plan.*

IDP Requirement 3.A.22 requires the following:

> *Total number and capacity of public electric vehicle charging stations.*

According to the Department of Energy's Alternative Fuels Data Center, there are approximately 237 public EV chargers in our Minnesota service territory, with 622

[67] *See* Compliance filing, Attachment A at page 1, IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON RESIDENTIAL ELECTRIC VEHICLE (EV) CHARGING TARIFF, Docket No. E002/M-15-111 (June 1, 2018).

individual connectors.[68] The total capacity of all the chargers is estimated to be about 8.5 MW, if all of the chargers were in use at once. However, at this point in the EV market, it is very unlikely that all of the EV chargers will be used at one time. Additionally, the installations are geographically diverse from a distribution system perspective. System impact would vary greatly based on the charging stations in use, the capacity of the charging stations, and the design of the local distribution system.

3. *Current DER Deployment – Type, Size, and Geography*

IDP Requirement 3.A.31 requires the following:

> *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.).*

The DER deployment in our Minnesota system by type and size is set out above in part 1. We provide associated geographic dispersion information and the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2018, with data as of end-of-year 2017, this information was provided in Docket No. E002/PR-18-10.

IDP Requirement 3.A.32 requires the following:

> *Information on areas of existing or forecasted high DER penetration. Include definition and rational for what the Company considers "high" DER penetration.*

We are not able to forecast DER in terms of its expected geography. As we discuss elsewhere in this IDP, tools to perform or services available to purchase forecasts such as this are very limited at this time. Additionally, due to the Company's cost-causation regulatory construct that requires interconnecting parties to mitigate potential system issues prior to interconnecting, DER is not expected to impact system operation.

In terms of defining "high" DER penetration, we note that this is somewhat of a general term that will likely vary across utilities and the industry. We believe one way to define high DER penetration is when the connected DER output exceeds feeder load, resulting in reverse power flow. When backward flow occurs, mitigations become necessary.[69] Under this definition, the amount of DER considered to be "high penetration" would vary from feeder to feeder by, among other things, the type

[68] *See* public online portal at https://www.afdc.energy.gov/stations/#/find/nearest

[69] Mitigations may be required for other conditions below this level, such as potential voltage issues or line capacity.

of DER, and how it operates, the feeder design, and the feeder voltage and other attributes.

C. DER Forecasting in the Industry

In this section, we discuss the state of the industry with respect to forecasting DER.

In the industry, there are limited tools and experience predicting customer behavior and other key drivers of DER adoption at a system level. DER penetration analysis and forecasting at a granular *feeder* level for purposes of informing distribution planning is much more complex that doing so at a system level, and is becoming an emergent industry issue. As we have discussed, system planning involves forecasting each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecasted by type, because each type has different characteristics and impacts on the system. This exponentially complicates an already complex feeder-level planning process.

Regulators, utilities, stakeholders, service providers, and others are working to determine methodologies, processes, and tools that will meet the forecasting needs that are emerging in states such as California, New York, and Hawaii. The good news – from a distribution planning perspective – is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. Further, our present tariffs require interconnecting parties to mitigate adverse impacts identified in the interconnection application process. This means that we have time to take the measured approach that is necessary to properly address this issue – and develop or acquire the necessary capabilities, methodologies, and tools that will facilitate this type of complex analysis.

There are several existing models to predict DER adoption, using policy outcomes, macro-economic factors, or rooftop potential to predict DER adoption. However, a recent EPRI technical report notes several shortcomings of these models, including the challenges in making granular adoption forecasts for individual circuits, challenges verifying consumer behavior, and scarce information about the physical premises that impacts actual potential.[70]

In short, it is challenging to predict which customers will adopt which technologies,

[70] *See* Applying Discrete Choice Experiment Modeling to Photovoltaic Adoption Forecasting, Electric Power Research Institute, Palo Alto, CA, p. 13 (November 22, 2017).
See https://www.epri.com/#/pages/product/3002011011/?lang=en

and what the impact on the circuit associated with those customers will be. This is exacerbated in Minnesota with comparatively low adoption levels for PV, EV and energy storage. Predicting accurate forecasts for new and emerging technologies at a system level is challenging, based in part on a lack of good historical, predictable data. At a circuit or feeder level this issue becomes more exacerbated, as there are accuracy issues with forecasting at smaller geographic levels. In addition, there is not a significant sample size of historic installations on a circuit to use for trend analysis and forecasting.

To provide perspective, in New York, the Reforming the Energy Vision (REV) effort has been underway since 2014. As early as 2015, the five investor owned utilities (collectively known as the Joint Utilities of New York) noted the challenges associated with DER forecasting. In their initial and reply comments to the guidance for their Distribution System Implementation Plans (DSIPs – similar in content requirements to the Minnesota IDP), the Joint Utilities note:

- "The proposed DSIP Guidance reflects the inherent tension between providing as much information as possible as soon as possible to inform DER locational value and the fact that the models and data necessary to support increased DER penetration do not yet exist."[71]
- The "enhancements necessary to produce valid demand and DER forecasts are likely to evolve over several years."[72]

In its latest DSIP, Consolidated Edison noted, "Con Edison is refining its forecasting methodologies to include DER at more granular levels, using a combination of top-down and bottom-up forecasting"[73] There is currently no detail on how granular these forecasts will get or a timeline for when the more granular level forecasts will be incorporated into the load forecasts.

Our initial steps to enhance our forecasting capabilities are to include DER into bulk system forecasts, move to forecast the intrinsic (i.e., not utility program-driven) market adoption of solar PV, and evaluate and implement tools to identify more granular inputs of DER on load forecasts. Efforts to enhance forecasting capabilities may extend beyond more granular inputs to include new approaches such as scenario analysis and probabilistic planning.

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[71] *See* Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case 14-M-0101, Page 8, Initial Comments of the Joint Utilities on the October 2015 Staff Proposal: Distributed System Implementation Plan Guidance (December 2015).
[72] Ibid., Page 18.
[73] Distributed System Implementation Plan, Page 56, Consolidated Edison, New York (July 2018).

We will need enhanced planning tools to understand the locational and temporal impacts of DER. Although more sophisticated planning tools can provide more forecasting granularity, the challenge of achieving a more geographically accurate forecast in an emerging market remains. Market adoption in an early adoption stage is less predictable, there is less historical information, and the dynamic and competitive nature of the market impacts local adoption trends. By taking a measured approach, we are able to learn from early adopters in the industry and in turn reduce long run implementation and integration costs. That said, we used our present tools and methodologies to inform the forecasts we provide in this IDP.

D. DER Forecasts and Methodologies

In this section, we present our forecasts for each DER type and summarize our forecast methodologies, which responds to IDP Requirement 3.C.1 as follows:

> *In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.*

This section also responds to IDP Requirement 3.C.2, which requires the following:

> *Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.*

Given the context we have portrayed, we have fulfilled these DER forecasting requirements to the best of our ability. In some cases, additional information such as studies to inform additional scenarios are outstanding at this time. We discuss each type of DER in turn below, providing our forecast, as well as the information that informed the forecast.

1. DER Forecast – Distributed Solar PV

We offer several programs to customers interested in solar as a renewable opportunity. Specifically we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. Until its discontinuance, customers also had the opportunity to participate in the Minnesota's Made in Minnesota program. In addition, for larger systems we offer a net-metering option. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.

a. Reference Case Assumptions

In determining our Reference Case, we updated our goals to be consistent with 2017 legislative outcomes that: (1) increased 2018-2020 Solar*Rewards incentive funding, (2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net-metering only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program in this scenario. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and applied these to program application forecasts to derive final installation estimates.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting additions of 673 MW through 2020 in this filing. For our Reference Case assumptions through the IDP planning period, we assume Solar*Rewards Community adjusts to approximately 6 MW per year after 2021 to account for significant early adoption of CSGs and reduction in tax benefits.

Table 21 below provides our Reference Case forecast of distributed solar PV additions.

Table 21: Reference Case – Per-Year Distributed Solar Additions (MW/AC)

Year	Solar* Rewards	Made in MN	Made in MN Bonus	Net-metering	S*R Community
<=2017	10.2	11.5	4.9	11.1	246.0
2018	9.4	2.1	0.0	5.8	259.1
2019	8.1	0.0	0.0	8.1	124.5
2020	4.5	0.0	0.0	9.3	43.7
2021	3.1	0.0	0.0	9.3	54.1
2022	1.2	0.0	0.0	10.4	6.2
2023	0.2	0.0	0.0	11.7	6.2
2024	0.0	0.0	0.0	12.4	6.2
2025	0.0	0.0	0.0	12.4	6.2
2026	0.0	0.0	0.0	12.4	6.2
2027	0.0	0.0	0.0	12.4	6.2
2028	0.0	0.0	0.0	12.4	6.2
Total	**36.7**	**13.6**	**4.9**	**127.7**	**770.8**

b. Medium and High Forecasts

The Medium and High scenarios hold the Reference Case for Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in the majority of cases, that these programs are substitutes for each. Therefore the incremental growth in one category is interchangeable with another category. For example, we are estimating that total solar PV in 2028 is approximately 1,200 MW – of which, approximately 1,150 MW is net metering and CSG.

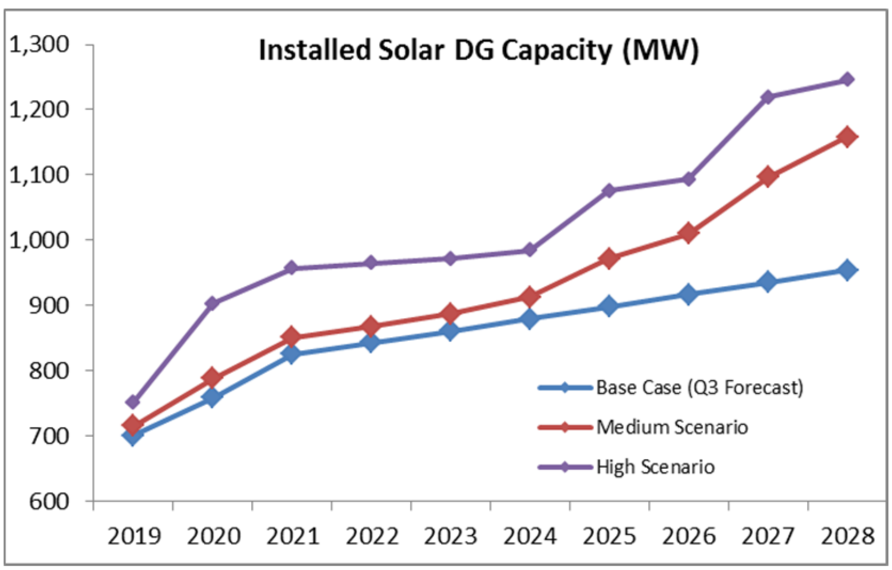
We used the average of a Bass diffusion and a Payback model estimate to derive the Medium scenario, which is around 1,158 MW for total installed distributed solar by 2028. For the High scenario, we used a Payback adoption model with lower installation costs. We also applied a 10 percent reduction to the solar installation cost curve starting in 2020. Solar installation costs in the High scenario are set to be higher for the first year due to new import tariffs and contracts already in place. Hence, there is a low probability that the solar installation prices will drop significantly below the Medium scenario for 2019. The adoption of solar is flat in the early 2020s, because the decline in solar installation cost is offset by the decline in Investment Tax Credit (ITC). The Payback model results indicate around 1,246 MW for total installed distributed solar by 2028.

We provide a tabular and graphical view of the forecast in Table 22 and Figure 58 below.

Table 22: Distributed Solar PV Forecast

	Total Base (MW)	Total Medium (MW)	Total High (MW)
2019	700.8	715.1	752.0
2020	758.3	787.5	902.4
2021	824.8	850.7	956.7
2022	842.6	867.7	964.8
2023	860.7	887.4	971.9
2024	879.3	912.4	984.6
2025	897.9	971.4	1,075.8
2026	916.5	1,009.7	1,093.5
2027	935.1	1,096.8	1,219.6
2028	953.7	1,158.2	1,246.3

Figure 58: Distributed Solar PV Forecast



2. *DER Forecast – Distributed Wind Generation*

We presently have very little distributed wind our system, with a total of 40 projects that comprise 12 MW and believe future DER growth will be through solar PV and distributed storage. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption, compared to wind. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we are not providing forecasts in conjunction with this IDP. We will continue to evaluate the levels of distributed wind interconnected to our system and the market over the next year and will provide an update in our 2019 IDP.

3. DER Forecast – Distributed Energy Storage

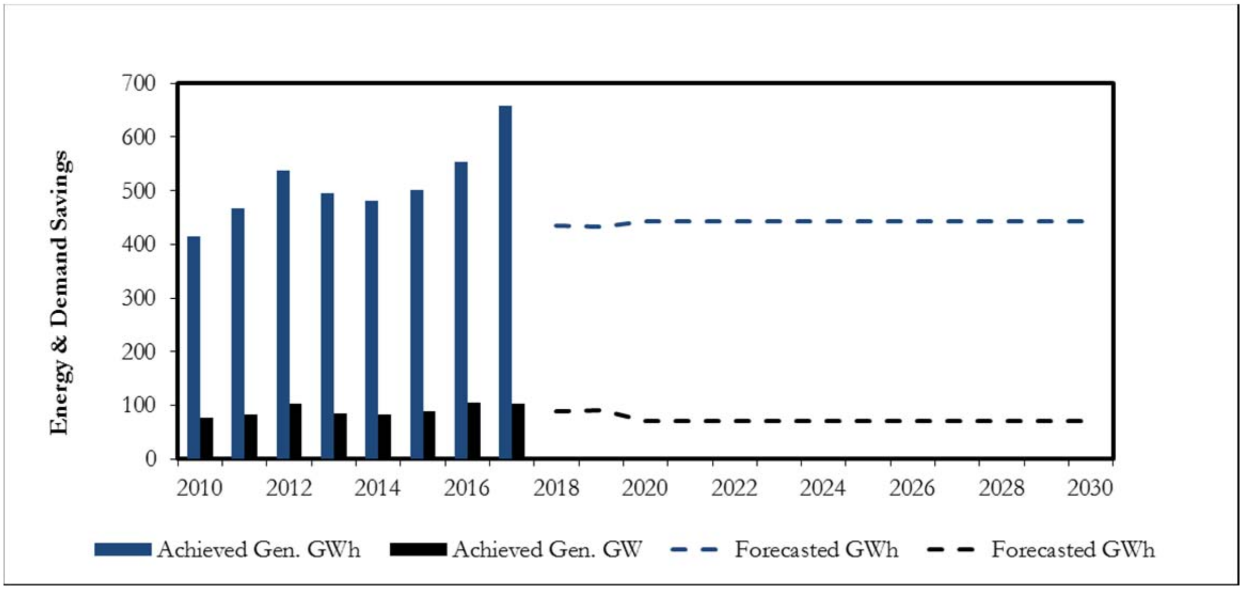
In the years 2017 through October 2018, we have received approximately 40 interconnection applications for energy storage on our distribution. Given the nascent nature of this market in Minnesota, we are not able to credibly forecast energy storage adoption at this time. We will continue to evaluate the levels of storage interconnected and in the queue to interconnect to our system over the next year, as well as the availability of forecasting tools or information, and provide an update in our 2019 IDP.

4. DER Forecast – Energy Efficiency

Our IDP Reference Case for energy efficiency reflects our currently-approved goal, which is 1.5 percent of annual sales, or 444 GWh, as established in our 2016 to 2030 Upper Midwest Integrated Resource Plan in Docket No. E002/RP-15-21.[74] This will be the same Reference Case we will use in the IRP we submit in 2019.

[74] *See* Order Point No. 11 of the Commission's January 11, 2017 Order.

Figure 59: Energy Efficiency Reference Case Forecast – Energy and Demand Savings



We are awaiting the results of the currently pending Minnesota Energy Efficiency Potential Study (2020-2029) to inform additional scenarios and sensitivities that we will model in the IRP we submit in 2019.[75] Because the results of this study were not available at the time of this IDP filing, we are not providing medium and high cases for energy efficiency at this time.

5. *DER Forecast – Demand Response*

Like energy efficiency, the Reference Case for DR reflects our current portfolio of DR resources and the additional 400 MW that the Commission required we add to our portfolio by 2023, in our 2016 to 2030 Upper Midwest Integrated Resource Plan in Docket No. E002/RP-15-21.[76] We clarify that we believe this Reference Case will be the same as what we use in the IRP we submit in 2019.

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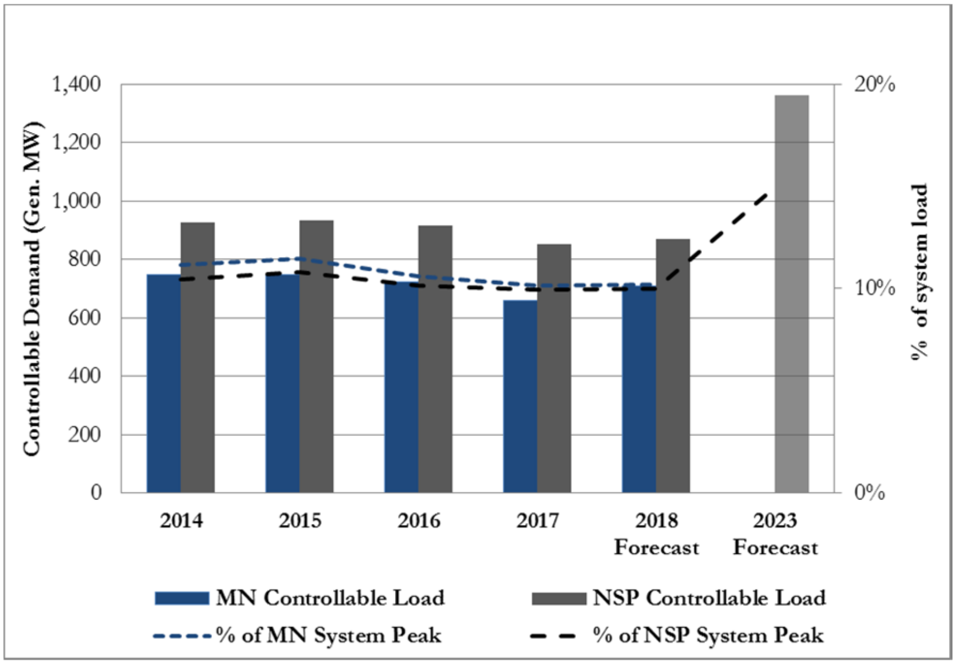
[75] This Study is funded by a grant from the Minnesota Department of Commerce Division of Energy Resources, through the Conservation Applied Research and Development (CARD) program; Center for Energy and Environment (CEE) is the lead researcher.
[76] *See* Order Point No. 10 of the Commission's January 11, 2017 Order.

Figure 60: Demand Response Reference Case Forecast – Energy and Demand Savings



In terms of additional scenarios, we note that we are currently working with the Brattle Group to conduct a cost-effectiveness analysis of acquiring the incremental 400 MW, and engaging with stakeholders to inform our program development process. The Brattle potential study will inform our scenario analysis, but it is pending at the time of this IDP. Because the results of this study were not available at the time of this IDP filing, we are not providing medium and high cases for energy efficiency at this time. Consistent with energy efficiency, we will use the results of the pending study to inform scenarios and sensitivities in the IRP we submit in 2019.

6. DER Forecast – Electric Vehicles

As reported in our June 1, 2018 Compliance filing in Docket No. E002/M-15-111, at the beginning of 2018, there were 5,693 registered plug-in vehicles in our Minnesota service territory. We continued, discussing our preliminary modeling that suggests our Minnesota service territory may see adoption of more than 40,000 electric vehicles by 2023 – with the possibility of significantly more or less adoption over this horizon as well. As we stated at that time, we continue to believe planning for transportation electrification must contemplate a variety of future state scenarios.

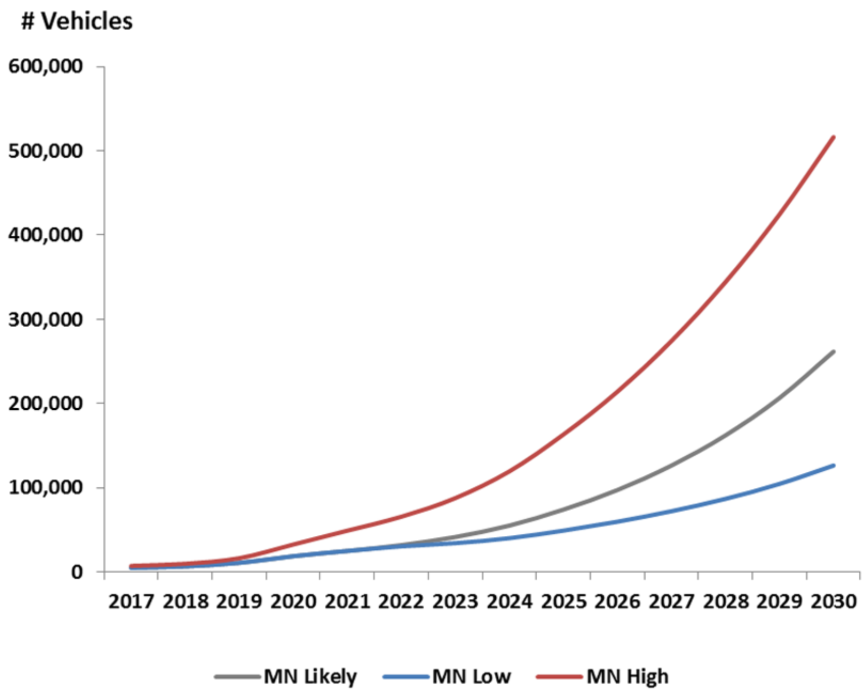
Our work to prepare electric vehicle adoption scenarios in support of our 2019 Integrated Resource Plan has continued since our June filing in the 15-111 docket, and is ongoing. Therefore in this IDP, we provide the EV forecast that informed our June 1, 2018 filing in Docket No. E002/M-15-111. This same forecast also informed our January 11, 2018 response to Minnesota Public Utilities Commission Staff Information Request No. 8 in our hosting capacity proceeding in Docket No. E002/M-17-777.

In that IR response, we explained that we have a low, high and likely forecast of EV counts in our service territory, which is based on an internally-developed methodology that incorporates both economic payback and Bass diffusion (technology adoption) model.[77] We further explained that the scenarios are created based on gasoline prices to derive adoption estimates.

For purposes of this IDP, the "likely" forecast would equate to the Reference Case. While this forecast does not include a Medium scenario, it does include a High scenario, which frames a range of potential adoption, given the inputs and assumptions at the time of our analysis. We provide this forecast in Figure 61 below.

[77] The Bass Model or Bass Diffusion Model was developed by Frank Bass. It consists of a simple differential equation that describes the process of how new products get adopted in a population. The model presents a rationale of how current adopters and potential adopters of a new product interact. The basic premise of the model is that adopters can be classified as innovators or as imitators and the speed and timing of adoption depends on their degree of innovativeness and the degree of imitation among adopters. The Bass model has been widely used in forecasting, especially new products' sales forecasting and technology forecasting.

Figure 61: Forecast of EV counts under Low, High, and Likely EV Penetration Scenarios



Source: Xcel Energy January 11, 2018 Response to MPUC-7 in Docket No. E002/M-17-777.

Forecasting is very sensitive to various assumptions, especially for new technologies like EVs that are in early stages of adoption. Forecasts are also sensitive to several externalities like policy changes (such as incentives), technology changes (such as battery improvements and autonomous vehicles), geopolitical issues (such as trade and tariff issues), availability of raw materials (such as shortages of lithium or cobalt), etc. Additionally, many of the inputs change frequently and could produce significant swings in the model outputs.

In addition to continuing the work we are doing around electrification to support our upcoming IRP, we intend to perform a benchmarking study in 2019 to validate our internal forecasting models and assumptions. We clarify that the forecast we use in the IRP will likely differ from this forecast due to the work that we are doing to update our internal forecast models, and efforts we have underway to support various aspects of our IRP analysis – including electrification.

E. DER Integration Considerations

IDP Requirement 3.C.3 requires the following:

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.*

1. Processes and Tools

Modernization of the distribution infrastructure, new planning approaches, and investment in foundational technologies are all necessary to manage increasingly complex distribution systems and to safely enable higher penetrations of DER. Through additional monitoring and data analytics, we will have more visibility into DER and its impact on the system. Through additional control and automation, we can better manage the complexities of more dynamic grid. With these improvements we can move toward integrating higher amounts of renewable energy than today's thresholds. The industry as a whole continues to learn about technologies and best practices that can integrate more DER and these findings are often shared across the industry.

*Interconnection Review.*_ Through our existing DER interconnection review process, we review each project for its impact on the grid. Each project is evaluated to determine impact on the grid during minimum load and other key periods. If system upgrades are required based on the DER impacts, the customer or developer will need to pay for the upgrades. In other cases, the customer may be required to adjust inverter settings on the DER system.

In 2016, we hired consultant ICF to conduct a review of our solar interconnection processes. As part of this review, ICF conducted interviews with a representative sample of solar developers active in our programs; they also compared our practices to industry best practices. As a result of this review, we identified approximately two dozen findings and recommendations that could be undertaken to further improve those interconnection processes. We submitted a report summarizing this review and the outcomes in Docket No. E002/M-13-867.[78]

Hosting Capacity Analysis (HCA). HCA also serves as a valuable precursor to the interconnection process – helping customers or developers guide future installations. These studies that provide an indication of feeder capacity for DER will also help the Company identify trends from year-to-year.

[78] *See* the Company's *Report on Solar*Rewards Community Interconnection Process* filed in Docket No. E002/M-13-867 on December 29, 2016.

Planning Tools. As otherwise discussed in this IDP, we are investigating new planning tools that will allow us to perform more robust planning and scenario analyses of DER penetration at the feeder level.

2. System Impacts and Benefits that May Arise from Increased DER Adoption

In this section, we discuss potential system impacts of certain types of DER

Distributed Solar PV. In terms of PV, in the introduction of NREL's High Penetration Photovoltaic Case Study Report, NREL summarizes of the system impacts with PV as follows:[79]

> *Technical concerns with integrating higher penetrations of photovoltaic (PV) systems include grid stability, voltage regulation, power quality (voltage rise, sags, flicker, and frequency fluctuations), and protection and coordination. The current utility grid was designed to accommodate power flows from the central generation source to the transmission system and eventually to the distribution feeders. At the distribution level, the system was designed to carry power from the substation toward the load. Renewable distributed generation, particularly solar PV, provides power at the distribution level, challenging this classical paradigm. As these resources become more commonplace the nature of the distribution network and its operation is changing to handle power flow in both directions.*
>
> *A large portion of distribution system components, including voltage regulators and protection systems, were not designed to coordinate with bidirectional power flow and bidirectional fault currents from distributed generation, and PV systems in particular. Coordinating these devices in the presence of high penetration PV areas introduces additional challenges to feasibility and system impact studies. Some cases require modification of existing protection schemes, additional distribution equipment, or reactive power requirements on the PV inverters.*

We believe this is good, concise summary of some of the issues associated with high PV penetration and other types of DER issues. As we perform our interconnection review for each of the customer DER applications, we look for the issues that NREL has identified.

As we discuss in Section VIII below, if upon review of the DER interconnection, it is

[79] *See High Penetration Case Study Report*, NREL Technical Report NREL/TP-5500-54742 at page 1 (January 2013) at https://www.nrel.gov/docs/fy13osti/54742.pdf

determined that the DER will cause a system impact, the customer or developer is notified and the Company estimates the cost of the changes needed to accommodate the DER. Historically, the necessary changes to accommodate PV integration have been centered primarily around Solar*Rewards Community and other large PV. System upgrades or modifications required include power factor correction, conductor upgrades and installation of a Voltage Supervisory Reclosing device (VSR) at the substation for protection measures.

EV Impacts. EV impacts on the grid will be determined by the number of customers adopting the technology, customer behavior, and the technology itself. For example, EV adoption is low in Minnesota today, but as adoption spreads past early adopters, driving patterns (influencing the number of miles in between charges) may change, which influences charging patterns and charging requirements.

In addition, battery technology itself is changing, with the trend focused on decreasing charging time – thus increasing power draw requirements (kW) and increasing overall battery size (kWh). Since residential customers are not required to notify the utility when they install an EV charging system, we will not have visibility into some of these behaviors. We expect to see issues at the levels closest to the residential customer, such as at the secondary, transformer, and service levels – not at the primary and bulk system levels, at least initially.

Fortunately, we will have the opportunity to learn from other utilities whose EV adoption rates are much higher. Today, these utilities are not describing significant issues. We also optimistic about the flexibility of our customers to adjust their EV charging times (i.e. load shifting) to reduce impacts on the system. This could be through a managed charging approach (the technology for some of these approaches are still maturing) or through price signals from a TOU rate. In addition, the situational awareness we will gain through our ADMS implementation that is in process – and future implementation of AMI capabilities will also be helpful.

Energy Efficient and Demand Response. We do not expect to see issues with the energy efficiency and DR levels projected. In general, energy efficiency and DR can provide benefits to the grid by reducing the load or part of the peak demand on a distribution feeder. As those programs have been historically focused on reducing system peak, there is often not a perfect correlation with the distribution feeder peak.

3. Potential Barriers to DER Integration

Minnesota has a cost-causation regulatory construct for DER, which requires the "cost causer" to pay the costs – shielding other customers from the costs. As such, individuals or developers proposing to interconnect DER to the system may incur costs for necessary system changes to accommodate the DER. Based on our regulatory requirements in our Section 10 tariff, the customer or developer who causes this system pays for the cost of the upgrade or modification for DER integration. In some cases the developer or customer chooses not to pursue the modification and the project does not move forward. This construct limits the amount of negative impacts that DER can cause on the distribution system, enabling the Company to continue to provide safe and reliable service. It also protects the majority of customers from incurring costs generated by a few.

4. *Types of System Upgrades that Might be Necessary to Accommodate DER at the Listed Penetration Levels*

In general, with the medium and high case PV scenarios, we believe the system impact would be low. One of the primary reasons we believe the impact would be low is because we have experience with the estimated level of PV (outside of Solar*Rewards Community) projected through 2026; it is similar to what we already have on our Public Service Company of Colorado (PSCo) operating company affiliate system. At the end of the 2017, there was 311 MW of customer-sited PV connected to the PSCo system.

According to our forecast, by 2028 we could experience higher PV adoption than our current PSCo levels in Minnesota, but we expect to also continue to learn more and gain experience with PV adoption in the coming years. We also expect to have significant system changes and upgrades by then, that could accommodate additional solar (e.g. Advanced Grid Initiative and additional SCADA deployments). In addition, there are additional accommodations that we could make with smart inverters, as we discuss in the Hosting Capacity and Interconnections section of this IDP.

F. DER Scenario Analysis and Integration Considerations

In this section, we discuss the state of DER scenario analysis and integration of distribution-connected DER in wholesale and regional markets.

1. *DER Scenario Analysis*

To clarify, our view of DER Scenarios is that they are alternative future states of the distribution system. For example, high adoption of DER, no DER, a portion of DER with storage, DER on/DER off, high load growth/low load growth, etc. We believe the distribution planning process would benefit from using multiple scenarios, when the planning tools evolve to allow for systematic examination of multiple scenarios and multiple inputs. We also believe the value from assessing the impacts of various levels and types of DER will be realized when the distribution operating model evolves to include energy, capacity and operating profiles to use in the planning process.

We believe probabilistic analysis will be a critical aspect of incorporating DER into the distribution planning process. Without having a solid foundation of probabilistic analysis it will be difficult to reliably forecast the impact of DER on the distribution system. We believe distribution planning will evolve to include:

- Historical and forecasted weather,
- Forecasted quantities and availability of DER
- Forecasted impacts of conservation and load control,
- Electric vehicle adoption,
- More granular forecasts, and hourly data rather than solely the peak load – to the extent we have sufficient SCADA capabilities,
- Storage implications, and
- Inputs from an integrated energy supply/transmission/distribution planning process.

Therefore, scenarios that contemplate high and low variations of the above – and variations such as customer mix, customer load profiles, load density and weather would additionally add value to the planning process. Finally, utilities will need better planning and forecasting tools that have the capabilities to incorporate these criteria.

we believe that there could be some scenarios that apply to all utilities, like there are in IRPs. However, this issue is being addressed different ways nationally. The California Working Group on DER and Load Forecasting recommended different forecasting methodologies/scenarios be used between the utilities – but that common principles be followed:[80]

- Use statistically appropriate, data-driven methodologies for each DER, customer segment, and level of disaggregation.

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[80] *See* http://drpwg.org/wp-content/uploads/2017/04/Joint-IOU-Draft-Assumption-and-Framework-Document.pdf

- Develop approaches to manage uncertainty associated with granular allocation of DER.
- Periodically re-assess the modeling approach for each DER as increased adoption leads to better data.
- Share best practices and leverage learning process to strive for continuous improvement both in forecasting and in using the forecasts for distribution planning.
- Integrate data from DER industry partners to enhance forecasting accuracy.

Because distribution planning is grounded in location on the system, there is enough variability between utilities that we believe the majority of the planning analysis needs to be unique. Relevant variables include whether the utility is winter versus summer peaking, whether the system (or portions of the system) serve rural areas versus urban/dense population areas, types of DER being utilized, level of risk willing to be taken, corporate goals, company incentives, etc.

As we have discussed, the distribution planning process is rooted in specific forecasts of load densities at a feeder level – and the distribution system is our direct connection point with customers, does not have the same redundancy and back-up as exists at the transmission and energy supply level, and generally requires solutions within short timeframes. Distribution planning outcomes therefore generally require more immediate action than an IRP, for example, to ensure customer reliability. So, any changes we make in our planning processes will need to ensure our focus remains on ensuring the reliability of the system for our end use customers.

2. Expected DER Output and Generation Profiles

IDP Requirement 3.D.2 requires the Company to provide …c*osts and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.).*

For more robust scenario analyses on a feeder, DER generation profiles are helpful. With PV systems, we can refer both to our internal generation profiles developed from load research on our customer PV systems or utilize a public tool like National Renewable Energy Laboratory's (NREL) PV Watts tool. We have also made some assumptions on EV charging usage, and hope to obtain additional information through our residential EV service pilot program. We additionally have several end-use load shapes available through our DSM program. These energy efficiency load shapes are generally used to determine the avoided marginal energy benefits of various

DR and energy efficiency achievements.[81] With a full AMI deployment, we will also have greater opportunity to refine load shapes by analyzing meter information.

3. *Changes Occurring at the Federal Level*

IDP Requirement 3.C.4 requires the following:

> *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 [RTO] and Independent System Operators [ISO]).*

Federal Energy Regulatory Commission (FERC) Order No. 841 addresses two different levels of participation of storage resources in wholesale markets. First, the rule requires that RTOs and ISOs accommodate the various types of services that transmission-interconnected resources can provide, including transmission system support, energy, capacity and ancillary services. Xcel Energy Services Inc. (Xcel Energy) filed comments supporting these aspects of the proposed rule in the FERC rulemaking process in FERC Docket No. RM16-23 on behalf of Northern States Power Company, a Minnesota corporation (NSPM) and the other Xcel Energy Operating Companies[82] and is optimistic that expanded utilization of electric storage resources interconnected at transmission level will bring added value to customers and add security and reliability of the grid, though the pace of adoption of storage technology remains unclear.

While Xcel Energy supports FERC Order No. 841 as it relates to resources interconnected at transmission level, we have concerns about implementation of Order 841 as it relates to storage resources interconnected at distribution level.[83] Xcel Energy also has concerns about FERC's proposal in Docket No. RM18-9-000,

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[81] The Company's Conservation Improvement Program (CIP) Annual Status report shows the energy efficiency and demand response achievements including load shape information.

[82] XES has participated in several FERC rulemaking dockets regarding participation of storage resources and DER in wholesale markets filing comments on behalf of all of the Xcel Energy Operating Companies, namely NSPM, Northern States Power Company, a Wisconsin corporation (NSPW), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS). A copy of XES's comments filed in Docket No. RM16-23-000 and AD16-20-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14538803.

[83] XES filed a request rehearing of various aspects of FERC Order No. 841 as it relates to resources interconnected at distribution level. A copy of XES's request for rehearing is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14651369

Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, which would expand the requirements of FERC Order No. 841 to all types of energy resources interconnected at distribution level (DERs), not just storage resources.[84]

Even at low penetration levels of DERs, FERC's expectation that storage resources and DERs be enabled to participate in wholesale RTO or ISO markets poses challenges for both utilities and their customers. The implications of these challenges become more significant at higher penetration levels. For example:

- *Metering*. Participation of distribution-interconnected storage resources raises the question about how metering will distinguish between charging for wholesale purposes as opposed to charging for retail usage in the case of dual-use facilities. Charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be usage for a retail purpose.
- *Distribution Operations*. Distribution system operators (DSO) will need to have the capability to monitor activities of DERs in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced communications systems between the DSO, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; and additional operations personnel to effectively manage the impacts of DER participation in markets. Cost causation principles dictate that the DER owners and operators should be

[84] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

responsible for the costs associated with these enhancements because such costs would not be incurred "but for" the participation of DERs in wholesale markets. However, absent fairly significant DER penetration levels it is not clear how these costs can be effectively allocated and recovered. At low penetrations there will simply be an insufficient number of customers to bear the costs of these infrastructure upgrades. FERC has not proposed a mechanism to address this issue. In the meantime, distribution system operators will have to find ways to manage DER resource participation reliably, cost-effectively, and in a manner that does not shift costs to other customers.

- *Distribution system upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DERs. The costs of such upgrades should be directly assigned to the DER causing such costs to be incurred.
- *Wholesale market issues.* In addition to the direct distribution-level impacts of DERs participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include the ability to determine where individual DERs involved in an aggregation are located in order to ensure that resources are paid the appropriate nodal price, whether technology exists to effectively manage the state of charge of storage resources, and whether market software can effectively be deployed to manage large numbers of relatively small resources. Xcel Energy expects these issues to be addressed by FERC on rehearing of Order No. 841, through the final rule in FERC Docket No. RM18-9-000, or through appeals thereof.

The provisions of Order No. 841 regarding participation of distribution-interconnected storage resources in wholesale RTO markets have not been stayed pending rehearing. MISO must make a compliance filing with FERC by December 3, 2018 and has a year thereafter to implement provisions of its compliance filing. MISO is actively working through its stakeholder process to develop its compliance filing.

One of the key aspects of MISO's compliance filing will be the relationship between MISO, the DER, and the applicable distribution system operator (DSO). After reviewing MISO's draft agreement with the DER, we have tentatively concluded that it may be appropriate to file a tariff at FERC that would address aspects of DER participation in wholesale markets. If the Company were to go forward with this concept, the tariff would address matters such as direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER.

Xcel Energy plans to evaluate this issue further and take appropriate steps to move forward to ensure that DER participation in wholesale markets is not subsidized by other retail customers and that such participation is conducted in a manner that does not threaten reliability of the distribution system.

XII. HOSTING CAPACITY, SYSTEM INTERCONNECTION, AND ADVANCED INVERTERS/IEEE 1547

In this Section, we summarize our hosting capacity analysis (HCA) in the context of our overall interconnection processes and how we have evolved our HCA. In part B, we generally discuss our interconnection processes and provide interconnection statistics. In Part C, we discuss advanced inverter functionality and recent changes associated with IEEE 1547.

A. Hosting Capacity

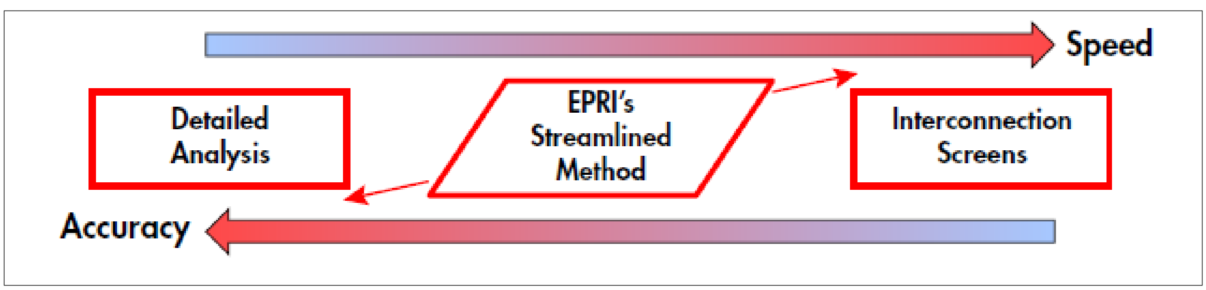
IDP Requirement 3.B.1 requires the following:

> *Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.*

Xcel Energy recognizes hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we conducted and submitted annual hosting capacity studies in 2016 and 2017.[85] We will submit our latest HCA study on November 1, 2018. These studies provide hosting capacity results by feeder serve three purposes: (1) provide an indication of distribution feeder capacity for DER, (2) streamline interconnection studies, and (3) inform annual long-term distribution planning.[86]

On December 1, 2016 we submitted the results of our first hosting capacity study in Docket No. E002/M-15-962. We used the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. The analysis is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI in order to screen for voltage, thermal, and protection impacts from DER. Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine the minimum and maximum range of hosting capacity. The electric system's hosting capacity is mainly impacted by DER location and system characteristics.

Figure 62: Balancing Speed and Accuracy in Analysis



As indicated by Figure 62 above, EPRI's method is intended to strike a balance between speed and accuracy. While it does not replace a detailed analysis, it provides more value than a traditional interconnection screening, such as the criteria found in the FERC Small Generator Interconnection Procedure. The result is a more complete and efficient way to understand a feeder's ability to integrate new DER.

For our hosting capacity analysis, we created over 1,000 feeder models in our Synergi

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85 *See* Distribution System Study, Docket No. E002/M-15-962 (December 1, 2016) and Hosting Capacity Report, Docket No. E002/M-17-777 (November 1, 2017).

86 See Integrated Distribution Planning Report Prepared for the Minnesota Public Utilities Commission, ICF International (August 2016).

Electric tool. The information for these models primarily came from our GIS, but was supplemented with data from our 2017 load forecast – as well as actual customer demand and energy data. Once the models were verified, load was allocated to the feeders based on demand data and customer energy usage – and analyzed using the DRIVE tool.

Generally, it is challenging to fully predict where future DER will be located – even with an interconnection queue. For instance, a large PV interconnection may be required to make some line upgrades to accommodate the proposed generation. The line upgrades and configuration changes for that interconnection are not reflected in our GIS until the design and construction phases are complete. This means that those system modifications do not enter GIS and subsequently the feeder models in a timeframe that is well-suited for forecasting accurate hosting capacity results.

Through engaging with our customers and stakeholders, learning from other utilities around the country, and leveraging our partnership with EPRI, we have made notable improvements from our initial hosting capacity analysis in 2016. These improvements include:

- Presenting results as heat-map visual, in addition to tabular results
- Including existing DER into the analysis
- Adopting a simplified methodology (IEEE-1453) to determine voltage fluctuation thresholds
- Application of Reverse Power Flow Threshold to better align with the criteria we use in the interconnection process.
- Adjustment of Voltage Deviation Threshold to better align with how we perform interconnection studies
- Using a methodology for large centralized generators to more accurately reflect the characteristics of DER deployment most commonly seen in Minnesota – and associated with programs such as Solar*Rewards Community
- Refining our hosting capacity tool to include advanced inverter settings for fixed power factor (discussed in more detail in the IEEE-1547 section below)
- Including energy storage that is acting as a source of power
- Excluding back-up DER to improve the accuracy of hosting capacity results by analyzing of only those systems that are operating in grid-connected mode
- Modifying breaker reduction of reach thresholds to strike an appropriate balance between identifying areas where system protection impacts require

closer review while not masking other limiting factors

As EPRI continues to enhance the DRIVE tool, and we continue to refine our use of DRIVE for the Minnesota HCA, we will continue to improve our HCA results – including the report we are submitting in a separate docket November 1, 2018. Furthermore, we anticipate the near-term advanced grid investments we outline in this IDP will provide enhanced system visibility to improve the data inputs and the analytical tools to further refine the analysis output. Additionally, in the longer term, investments like more advanced control schemes coordinating action with smart inverters and utility devices will improve the hosting capacity of circuits with voltage threshold constraints.

Hosting capacity analysis also serves as a valuable input prior to the interconnection process, helping customers or developers gather information about a location before an application is submitted. Interconnection studies are necessary to ensure the proposed generator can safely interconnect without adversely impacting electric delivery to surrounding customers and at what cost. With better data inputs and more analytical tools available to distribution engineers, we will be able to more efficiently respond to interconnection study requests and streamline the process for interconnecting customers. The interconnection process and associated studies will make use of the latest in technology and standards, such as IEEE-1547-2018, discussed in further detail in the section below and align with applicable regulatory guidance developed in the Interconnection and Operation of Distributed Generation Facilities proceeding (Docket No. E999/CI-16-521).

B. System Interconnections

In this section, we provide Company cost and customer charge information associated with interconnections on our distribution system. We also provide other information about the interconnection process as specified in the IDP requirements.

1. Company Costs and Customer Charges Associated with DER Generation Installations

The information we provide below fulfills the following IDP requirements:

IDP Requirement 3.A.15 requires the following:

> *Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).*

IDP Requirement 3.A.16 requires the following:

> *Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.).*

IDP Requirement 3.A.27 requires the following:

> *All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation).*

We calculate our actual DER costs on a project basis and perform this calculation at the time we charge this actual cost to the DER customer. This occurs after the DER is interconnected to our network. Large projects, such as community solar gardens, may straddle more than one calendar year. This means that when we calculate the costs for a given project, the calculated costs typically include costs from prior calendar years. Similarly, if a bill for a given project under construction is not issued in a given calendar year then our tracked and reported costs will not reflect these costs until we issue a bill.

DER installation costs are based on the detailed design and the subsequent installation work as noted in our Electric Rate Book, Section 10 Tariff. We currently calculate costs at a substation and distribution level for all community solar gardens (Docket No.E002/M-13-867) and can report on the DER costs for community solar garden projects as shown in bills sent in a calendar year. In 2017, the Company billed Community Solar Garden projects $4.792 million in substation costs and $11.288 million in distribution costs for an approximate total of $16 million dollars.

In addition to this, we separately charge an engineering study fee. In 2017, these fees totaled approximately $3.542 million. Our administrative fee for administering the analysis of DER generation applications, in addition to the customer fees, was approximately $1.864 million.[87]

For DER that is not a community solar garden, we currently do not have a process or system to report on the total substation or distribution costs incurred or billed other than application fees where applicable. It would take a significant amount of time and resources to gather this information for historical or current projects. For future DER

[87] This is an approximation based on our fees and invoices that we have from our outside consultants.

installations subject to the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) process (Docket No. E999/CI-16-521), we will begin to collect data through our application tracking system at the substation and distribution levels. The MN DIP interconnection rules will apply to interconnection applications submitted after June 17, 2019.

For the sake of clarity, the information we provide for this IDP Requirement is only Xcel Energy costs. Where a customer has provided the Company information on its costs to install the generation system, we report this in our annual DG interconnection filing each March 1 in the "xx-10" Docket.[88]

We provide further detail for regarding our other programs and the compliance filings completed yearly below.

Solar*Rewards Community – Docket No. E002/M-13-867

- Annual Report filed by April 1 every year.
- 2017 Annual Report filed on March 30, 2017.
- Deposits: Xcel Energy received $2.7 million for new projects into our deposit accounts and $10.5 million for new projects held in Escrow. These fees will be refunded back to garden operators upon commercial operation.
- Application Fees: The Company collected a total of $207,600 in application fees.
- Participation Fees: Annual participation fees were $12,000.
- Metering Fees: The Company administers metering charges for single-phase projects at $5.50 per month and for three-phase projects at $8.00 per month. These monthly metering fees are specified in the Section 9 Tariff, Sheet 75 and are consistent with previously approved metering charges for the A51 tariffed rate.

Solar*Rewards – Docket No. E002/M-13-1015

- Annual Report filed by June 1 every year.
- 2017 Annual Report filed on June 29, 2017.
- Engineering Fees administered in 2017: $117,500

[88] See, for example, Docket No. E999/PR-18-10, available at this link: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=viewDocument&documentId={C079E361-0000-C21F-8058-219C34801664}&documentTitle=20183-140701-02&userType=public

For future DER applications that will be subject to the MN DIP, we will begin to collect additional data at a more detailed level such as the inclusion of specific engineering fees by interconnection process.

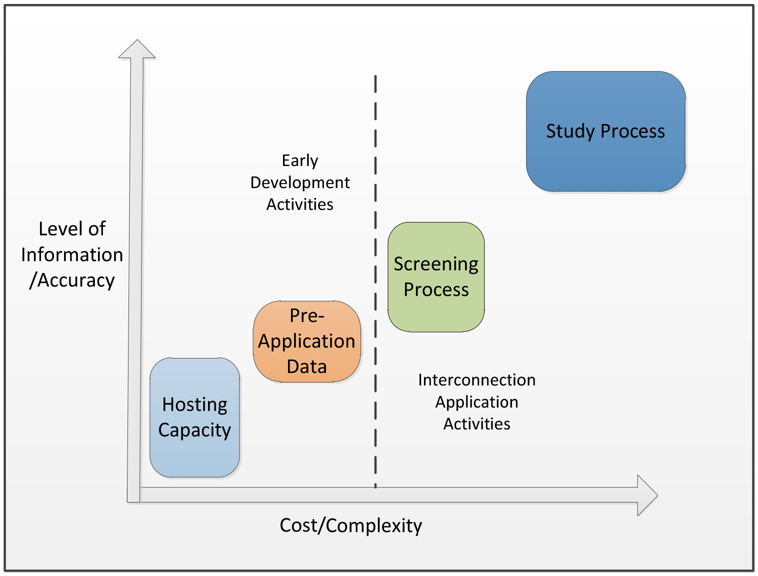
2. *Interconnection Process*

In this section, we generally discuss our interconnection process and respond to IDP requirement 3.B.2 regarding data sources and methodology to complete the initial review screens in the MN DIP process.

The determination of exactly where and how much DER can be added to our system is determined through the interconnection process. Our annual HCA study has the potential to streamline the interconnection process both in the short- and longer-term. Today, the hosting capacity results are available to the public and can assist developers in choosing sites that require only screening or a less involved study. Screening is less expensive than engineering studies and typically can be completed on a shorter timeline.

Figure 63 below shows how the different components of our interconnection process currently works. The lower cost and complexity options of hosting capacity and pre-application data provide information developers information they can use to target points on the distribution system for interconnection prior to submitting an application. The screening and study processes occur after an application has been submitted and entered into engineering review.

Figure 63: Interconnection Processes



IDP Requirement 3.B.1 requires the following:

> *Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.*

MN DIP initial review screens use simple analysis with assumptions or readily available data to determine if a project requires further analysis due to the potential for grid impacts. The ten MN DIP initial review screens must be applied in concert to determine if a project has needs further analysis on voltage, thermal, or protection impacts. A few of the screens are related to the proposed DER being located in the Company's service territory and of a compatible wiring configuration. The specific initial review screen(s) that fail can inform more targeted analysis for the specific impact (i.e. voltage constraints). For example, one initial review screen states that the aggregate DER shall not exceed 15 percent of the peak annual loading on a given line segment. This screen approximates when reverse power flow may occur – a condition necessitating further analysis for steady state voltage rise and voltage fluctuation. For failure of any screens, the next level of analysis is performed in the MN DIP supplemental review process.

The MN DIP initial review screening methodology is relatively simple analysis that we implement in part through a spreadsheet tool. Other screens that check qualitative aspects of the interconnection are performed through review of application documentation. The initial review screens use system data and load characteristics available through a number of Company systems. We use our Geospatial Information System (GIS) to determine if the interconnection is within the Company's service area. GIS also assists in determining the aggregate amount of generation on a segment of interest. Feeder maps or GIS can be used to determine the presence of a voltage regulator, which is a relevant factor in one screen. Peak load information is retrieved from our DAA system, which we also use for system planning. Fault current can be retrieved by the OMS or a spreadsheet analysis tool.

C. Advanced Inverter and IEEE 1547 Considerations and Implications

In this section, we begin with general discussion regarding inverter advancements, then address IDP Requirements 3.A.7 and 3.A.33, as follows:

IDP Requirement 3.A.7

> *Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).*

IDP Requirement 3.A.33

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

Finally, we discuss our view of the impact of IEEE Std. 1547-2018 on interconnection standards/processes.

1. Inverter Advancements

Inverters can be utilized as one measure to reduce system impacts from PV and other inverter-based DER. A revision to the standard governing of the interconnection of DER with electric power systems (IEEE 1547) was published in April 2018.[89] The standard provides requirements on the performance, operation, testing of the interconnection and interoperability interfaces of DER. This revision includes several new requirements that address the technical capabilities associated with smart inverters and considerations necessary for the proliferation of DER on distribution systems, such as the ability to keep DER online – 'ride-through' – during abnormal conditions, controlling real power, and regulating reactive voltage. Furthermore, the latest revision of the standard specifies interoperability requirements, a design consideration in all of our advanced grid investments.

[89] See IEEE Publishes Standard Revision for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2018). http://standards.ieee.org/news/2018/ieee_1547-2018_standard_revision.html

Currently, smart inverters that are compliant with and certified to the new standard are not available, but will be required by statewide technical requirements when available. The standard for test and conformance procedures necessary to certify inverters, IEEE 1547.1, is under development. Once available, Underwriters Laboratory will develop their testing certification standard (UL 1741). Once the inverter certification standard is available, equipment manufacturers will require time to change product lines. While the timeframe for standards development activities is fluid, we anticipate compliant and certified equipment will be available in or after the year 2020 or 2021.

An early step will be to adopt well-understood and in-use functions like fixed power factor, which are in use today and offer many of the benefits of the revised standard's functions. A recent EPRI study on a modeled radial distribution feeder with a large (almost 2 MW) solar system concludes that fixed power factor control resolves almost all voltage violations and that "modest control of reactive power can significantly reduce the voltage rise from the generator"[90] This is particularly important in Minnesota for the CSG large distributed generation systems, which are often deployed in remote areas where maintaining adequate voltage can be more challenging due to smaller conductor and a lower system strength.

Fortunately, we will have the opportunity to learn from peer utilities in states such as Hawaii and California, who have greater DER penetration levels. Since 2014, California has required smart inverters with seven autonomous functions, including both fixed power factors and dynamic Volt-VAr operation; however, even though inverters were installed with advanced capabilities, the use of these functions is being phased deliberately to confirm the various functions work as modeled.[91]

There are commercially-available inverters that meet this advanced functionality based on California rules without being certified to the IEEE 1547-2018 standard. As we learn more about the capabilities of inverters that are IEEE 1547-certified – or that meet California's standards – and we phase-in the investments of our advanced grid roadmap, we will be able to advance our related capabilities over time. Our stepped approach begins primarily with managing inverters to a fixed power factor – and as

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[90] *See Voltage Regulation Support from Smart Inverters,* Electric Power Research Institute, Palo Alto, CA, Page 8 (December 2017).

[91] *See* INTERIM DECISION ADOPTING REVISIONS TO ELECTRIC TARIFF RULE 21 FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO REQUIRE "SMART" INVERTERS, Decision 14-12-035, Rulemaking 11-09-011, Page 4 (December 2014).

they become available, adopting the standard settings for Volt-Var and Volt-Watt operations in some situations. The inverters will inherently have "ride-through" capabilities that in aggregate will prevent contributing to grid instability during a short-term transmission or generation event. Looking ahead, as we develop our modeling and simulation capabilities and phase in our investments, we will be able to evaluate more updated inverter capabilities and evaluate the benefits.

2. *Planning Considerations Associated with IEEE 1547-2018*

IDP Requirement 3.A.7 requires the following:

> *Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).*

Advanced functions may offer additional capabilities from the DER side, but modeling and simulation tools for distribution planning must evolve to make use of the functions while protecting grid integrity (i.e. safety and reliability).

The standard IEEE 1547-2018 scope is focused on the interconnection and interoperability requirements for DER. These requirements are specified through standard interfaces for both power and communications for the purpose of integrating DER into safe and reliable grid operations. A degree of optionality exists in the standard for advanced functions and capabilities. For example, the standard required DER be capable of a producing or consuming a range of reactive power, while it also specifies the default setting use no reactive power.

Distribution System Planning considerations include integrating DER into capacity expansion plans and grid support functions required by IEEE 1547-2018 may provide additional tools mitigate voltage conditions caused by DER. It is important that the standard requires DER equipment be capable of providing a range of reactive power control for the lifetime of the DER as it provides necessary future proofing for mitigating voltage issues due to changes in system configuration or other anticipated changes to grid conditions. The Company currently uses a non-unity fixed power factor approach for mitigating DER caused voltage issues and reserves a power factor range of +/- 0.9 in operating agreements. While the reactive power range in use today aligns with IEEE 1547-2018, the standard offers additional control modes. The Company is evaluating the use of other real and reactive power control modes to determine benefits, drawbacks, and most suitable use of each.

In order for the advanced function to be fully integrated into distribution planning processes, industry modeling tools must evolve to incorporate advanced functions. The changes required to modeling tools to incorporate advanced functions may be significant and this is an area of active research.[92] For example, an inverter volt-var function can interact with utility voltage regulation equipment since both have a time element to their control logic. This type of interaction could a reliability issue due to voltage regulation equipment failing prior to end of life. In order to protect grid integrity when incorporating advanced functions, modeling may be required to include a time-series component, which is a departure from static models most commonly in use today. We are tracking the progress of industry modeling tools that incorporate advanced inverter functions. While we do not anticipate the advanced functions increase hosting capacity when compared to current approach, they do offer the potential for increasing the efficiency of power delivery on the distribution system (i.e. reduced losses).

The interoperability capabilities required by IEEE 1547-2018 are related to exchanging information with the DER, including monitoring and control points. This aspect of the standard is the most future-leaning and is unlikely to be in widespread use across the United States in the near term. Any DER advanced function required by the standard can be changed remotely if a communication network is established between the utility and DER system in order to make use of the DER interoperability interface. In the more distant future, it is possible that different advanced functions are employed during different times of the day or year through a centralized control system such as DERMS. This flexibility to change between functions to better meet grid conditions at the time might offer yet another tool for mitigating DER-caused issues during distribution planning processes that involved power flow studies.

Similar to the case for implementing advanced functions on an autonomous basis, the modeling and simulation tools are not in place today for the use described here. The field communication networks and backend control systems are also not in place to employ this type of use, but the Company continues to explore how the interoperability interface can best be used for integrating DER into all aspects of utility operations.

[92] Smith, Jeff & Rylander, Matthew & Boemer, Jens & Broderick, Robert & Reno, Matthew & Mather, B. (2016). Analysis to Inform CA Grid Integration Rules for PV: Final Report on Inverter Settings for Transmission and Distribution System Performance. *See* https://prod.sandia.gov/techlib-noauth/access-control.cgi/2016/169164r.pdf

3. Advanced Inverters Response to Abnormal Grid Conditions

IDP Requirement 3.A.33 requires the following:

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

A driving factor for modifying national interconnection standard IEEE 1547-2018 is to require DER to provide support for wide area grid disturbances originating from the bulk electric system (Transmission and Generation). The standards apply to all DER, including PV inverter-based generation. Historically, DER was required to trip for minor grid disturbances. A large amount of DER tripping all at once has the potential to worsen the grid condition that caused the DER to trip in the first place. IEEE 1547-2018 requires the capability to ride-through grid voltage or frequency disturbances and allows a wide range of trip settings to provide Regional Transmission Operators, Independent System Operators, Transmission Operators, and Distribution Operators with options that balance the sometimes differing technical objectives of these stakeholders. MISO has initiated a process to collect stakeholder input and provide guidance on preferred DER settings associated with response to abnormal grid conditions.

Abnormal grid conditions such as voltage or frequency disturbances are difficult to forecast as they are typically associated with rare events such as large generators tripping or transmission line faults. Furthermore, the location of a faulted circuit greatly impacts the resulting voltage disturbance observed across the system. In contrast, any frequency disturbances observed in Minnesota are system wide phenomena across the entire Eastern Interconnect. Transmission line faults and voltage disturbances are the more common when compared to generator tripping and frequency disturbances. In general, system studies that evaluate the impact of abnormal conditions look at the worst case anticipated condition. Using a voltage disturbance to illustrate, one would look to find the most severe voltage depression caused by a transmission line fault in order to anticipate and mitigate any adverse impact to the electric system. The Company anticipates analysis along these lines will be part of the MISO stakeholder process and that appropriate guidance will be issued on the use of advanced inverter abnormal response function. The Company views Minnesota statewide DER Technical Interconnection and Interoperability Requirements being developed in Phase II of E999/CI-16-521 docket as the proper place to address DER abnormal response functions.

4. *Impact of IEEE 1547-2018 on Statewide Interconnection Standards*

As we have discussed, IEEE 1547-2018 is a recently published DER interconnection and interoperability standard. We are in the process of adopting the standard and determining implementation pathways for the numerous options it offers.

The revised standard addresses three new broad types of capabilities for DER: local grid support functions; response to abnormal grid conditions; and exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E999/CI-16-521 docket, especially in Phase II which considers statewide technical standards, and other details are expected to be associated with Company business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E999/CI-16-521 docket. The response from MISO included a plan to convene a stakeholder group so that guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows the Company to specify how local grid support functions are used. The Company is exploring a stepped approach for implementing more advanced functions, such as volt-var, with the objective of enabling for segments of DER in a way that has the greatest benefit on hosting capacity while maintaining grid operating capabilities. The Company proposed in the E999/CI-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future-leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication network would be necessary for making use of the interoperability interface. The Company is evaluating pathways for implementing the interoperability interface in the future.

XIII. EXISTING AND POTENTIAL NEW GRID MODERNIZATION PILOTS

In this section, we discuss the status of existing grid modernization pilot projects and potential new pilot programs.

IDP Requirement 3.D.2 requires the Company to provide:

> [the] …*status of any existing pilots or potential for new opportunities for grid modernization pilots.*

A. Grid Modernization Pilots

1. Time of Use Rate Pilot

As discussed in this document previously, we previously sought and received Commission approval for a residential TOU rate pilot that involves two-way communication FAN infrastructure and AMI.[93] The pilot will start in 2020 and will provide select residential customers with variable pricing based on the time of day energy is used. Through the pilot, we will provide participants with new metering technology, increased energy usage information, education, and support to encourage shifting energy usage to daily periods where the system is experiencing low load conditions. Strategies that shift load away from peak may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

We will deploy advanced meters to approximately 17,500 residential customers in two geographic locations. Pilot participants will be enrolled on a new rate structure, with time periods corresponding to the system's profile at on-peak, off-peak, and "super off-peak" times.

The pilot was developed with the engagement of stakeholders and with the benefit of learnings from our pilot in our Colorado service territory. Through the pilot, we will study the impact of rigorously designed price signals and technology-enabled data on customer usage patterns for a subset of customers. We intend to operate the pilot for

[93] See Docket No. E002/M-17-776.

two years and will share learnings about the effectiveness of these techniques to generate peak demand savings. We will explore the performance of the selected technology, the impact of the price signals, and the effectiveness of customer engagement strategies, and will use the pilot experience to inform future consideration of a broader TOU rate deployment in Minnesota.

2. *Pena Station/Panasonic Battery Demonstration Project*

Through a public/private partnership, Xcel Energy, Panasonic, and Denver International Airport are partnering on a battery demonstration project.[94] The pilot project – located at Panasonic's Denver operations hub within the new 400-acre Peña Station NEXT development just southwest of the Denver airport – will examine how a battery storage system helps: (1) facilitate the integration of renewable energy, (2) Enhance reliability on the distribution system, (3) assist in providing voltage management and peak reduction, and (4) provide power to Panasonic in case of a grid outage by functioning as a microgrid.[95]

The demonstration project is composed of four primary components: (1) a 1.3 MW ac carport solar installation (the carport is owned by the airport, but the solar system is owned by Xcel Energy (2) a 0.20 MW ac rooftop PV system at Panasonic's facility, owned by Panasonic, (3) a 1 MW/2 MWh lithium ion battery system supplied by Younicos, owned by Xcel Energy, and maintained by Panasonic, and (4) the switching and control systems to operate the energy storage system and microgrid functionality, owned by Xcel Energy.

Figure 64: 1.3 MW Carport Solar Installation

[94] See Colorado PUC Docket 15A-0847E.
[95] For additional information, *see* https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-Panasonic-Fact-Sheet.pdf

Figure 65: 1 MW Battery System

Note: The 1MW battery system is the white equipment and the associated switchgear is in the blue box

In the event of a grid outage, an "islanding" switch will automatically form a microgrid, allowing the battery to provide power to the Panasonic building. In microgrid mode, both the battery and the rooftop PV will provide power to Panasonic. Panasonic's building management system can prioritize and shed non-critical loads to keep critical services – such as its network operations center (NOC), which monitors and manages a nationwide network of largescale PV projects totaling hundreds of megawatts – up and running. Should power from the PV system exceed the building's needs, excess generation will be stored in the battery. Once grid power has been restored, the microgrid will seamlessly transition out of islanding mode and back to grid mode.

During a two-year demonstration period, the system will be tested under multiple scenarios to determine how it can be used to increase reliability and resiliency for both Xcel Energy's electric grid and Panasonic. After the demonstration is complete and the collected data analyzed, the battery will operate at its optimal settings. It will function at these settings for the rest of its life span – which is approximately eight additional years, or about ten years in total.

3. *Stapleton Battery Storage Project*

The Stapleton project is aimed at examining how battery storage can help integrate higher concentrations of PV solar energy on our system.[96] As part of an energy storage demonstration project, Xcel Energy is installing six in-home batteries and six larger batteries on the distribution feeder in Denver's Stapleton neighborhood. The batteries will operate to manage solar integration and also support other areas of the grid. For the six large scale batteries, we are installing two sets of 18 kW batteries,

[96] See CPUC Docket 15A-0847E

two sets of 36 kW batteries and two sets of 54 kW batteries. The customer in-home batteries are six 6 kW batteries. Xcel Energy is particularly interested in learning about how battery storage can help: (1) increase the ability to accommodate more solar energy on our system, (2) manage grid issues such as voltage regulation and peak demand, and (3) reduce energy costs.[97]

Figure 66: Residential and Large Scale Battery Comparison

RESIDENTIAL

LARGE-SCALE

Electric vehicles are often combined into discussions related to grid modernization – and EVs are included in the Commission's definition of DER for purposes of integrated distribution planning in Minnesota. Therefore, we also summarize EV pilots we have underway and that we have recently proposed.

B. Electric Vehicle Pilots

We recently requested Commission approval of two new electric vehicle (EV) pilot Programs: a Fleet EV Service Pilot and a Public Charging Pilot.[98] Again, these pilots were developed with the significant engagement of stakeholders.

[97] *See* also https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-StapletonBatteryProject-Info-sheet.pdf
[98] See Docket No. E002/M-18-643.

1. *Fleet EV Service Pilot*

Under this three- year pilot, the Company would install, own, and maintain EV infrastructure for fleet operators in order to reduce these customers' upfront costs for EV adoption. Fleet operators participating in the pilot would be required to take service under time-of-use rates for their EV charging. Additionally, the Company would provide advisory services to fleet operators, including information relative to fleet conversion decisions. We estimate this pilot would be able to facilitate installation of over 700 charging port for fleet customers, serving charging needs for light-duty vehicles and buses.

Customers who operate fleets are a prime market segment for piloting new services for transportation electrification. Several large fleet operators in our Minnesota service territory already have begun converting their fleets to EVs. This pilot offering enables us to work with these early adopters—who are motivated by both economic and environmental considerations—to convert their fleets. Due to the size of fleets, piloting EV services for these customers has the potential to impact the market, especially where improving project economics can support fleet conversion more quickly than otherwise would have occurred. We are currently working with three fleet customers expected to participate in this pilot if it is approved by the Commission: Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis.

2. *Public Charging Pilot*

In the Public Charging Pilot, the Company would install, own, and maintain EV infrastructure for developers of public charging stations along corridors and at community mobility hubs. Unlike the Fleet EV Service Pilot, the Company would not own or maintain any charging equipment. The goal of such investments is to increase publicly available charging options by decreasing these customers' upfront costs. Customers participating in this pilot would be required to pay time-of-use rates for their EV charging. Under this pilot, we estimate we would be able to facilitate installation of approximately 350 charging ports.

Our pilot seeks to support both corridor fast charging and community mobility hubs, leveraging available public and private funding under both scenarios. Specifically, we propose to make this pilot available to applicants who invest in deploying fast-charging stations along corridors in our service territory, specifically targeting applicants seeking funds from Minnesota's Diesel Replacement Program funded by the Volkswagen Environmental Mitigation Settlement (VW Settlement) and administered by the Minnesota Pollution Control Agency (MPCA). In addition, we plan to partner with the cities of Saint Paul and Minneapolis to support installation of community mobility hubs, for which the cities have selected HOURCAR as the anchor tenant. The cities are pursuing Federal Congestion Mitigation Air Quality (CMAQ) funds to purchase vehicles, chargers, and operating services for this new mobility service. These charging hubs may be utilized by car-sharing services, transportation network companies (*e.g.*, Uber and Lyft), and the public, including customers who do not have EV charging capabilities at home.

Although there has been limited deployment of public charging to date, it is a critical enabler for EV market expansion. Key reasons for including the public charging component in our EV portfolio are that it can support longer distance driving, address range anxiety, and provide charging solutions for those who are not able to charge at home.

C. New Pilots

With regard to new opportunities for grid modernization and electric vehicle pilots, we are currently evaluating the following pilots and will bring them forward to the Commission for approval as necessary in the future.

- *Residential EV Subscription Service Pilot:* Offering our residential customers a different rate option for study: a preset monthly subscription fee for dedicated EV charging service during off-peak hours, with additional charges for on-peak charging.
- *Residential Smart Charging Pilot:* Studying how a combination of incentives or rewards encourages smart charging of EVs, enabling the management of EV charging as a demand-response resource. This pilot would be proposed as a modification to our current CIP plan.
- *Workplace Smart Charging Pilot:* Studying the provision of workplace EV charging coupled with DER, such as solar generation. The pilot will assess—and explore options to mitigate—the coincidence of workplace charging and system peak.
- *Vehicle-to-Grid Demonstration with School Buses:* Studying the potential of electric school buses as grid resources. During the school year, daily driving schedules could support off-peak charging during nighttime and weekend hours; during the summer, the buses could operate as grid resources, charging when demand for power is low and discharging power when system demand is high.

XIV. ACTION PLANS

In this section, we provide a 5-year action plan as part of a long-term plan for the distribution system, as required by filing requirements 3.D.1 and 3.D.2.

IDP Requirement 3.D.1 requires the following:

> *Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.*

IDP Requirement 3.D.2 requires the following:

> *Xcel shall provide a 5-year Action Plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:*
>
> - *Overview of investment plan: scope, timing, and cost recovery mechanism*
> - *Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.7*
> - *Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.*
> - *System interoperability and communications strategy*
> - *Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)*
> - *Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)*
> - *Customer anticipated benefit and cost*
> - *Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)*
> - *Plans to manage rate or bill impacts, if any*

- *Impacts to net present value of system costs (in NPV RR/MWh or MW)*
- *For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis*
- *Status of any existing pilots or potential for new opportunities for grid modernization pilots.*

We summarize our 5-year and long-term action plans and associated customer impacts below. However, rather than attempt to summarize our fulfillment of each of the above requirements in this section, we provide a roadmap of where we have addressed them elsewhere in the body of this IDP filing via an Action Plan Roadmap, provided as Attachment F.

We additionally request that the Commission consider consolidating IDP requirements 3.D.1 and 3.D.2 for future IDP filings, as we view the more narrow requirements of 3.D.1 to be fully reflected in the broader 3.D.2. As such we indicate our compliance with IDP Requirement 3.D.2.

A. Near-Term Action Plan

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, and FLISR, and securing enhanced system planning tools to advance our abilities to incorporate DER and NWA analysis into our planning. We will continue to finalize the details of our customer strategy and related advanced grid investment plan – and in 2019, we will bring the costs and benefits to the Commission for approval through a future certification request in the grid modernization/IDP filings or through a general rate case. Pending Commission action, we will implement our advanced grid plan.

In the balance of this section, we summarize near-term actions by subject, where we intend or expect to take specific actions. We also use this section to comply with the portions of IDP Requirement D.2 that we have not yet addressed elsewhere in this IDP.

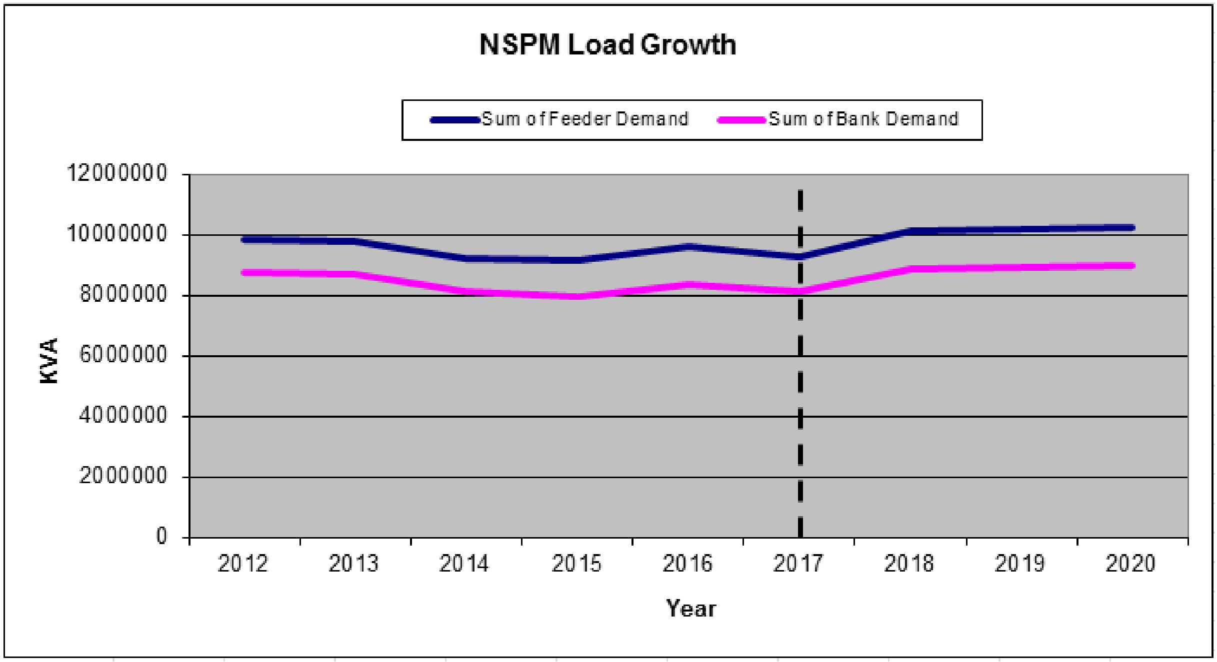
1. Load Growth Assumptions

IDP Requirement D.2 requires, in part:

> *The 5-year action plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years…*

Figure 67 below provides the load growth assumption stemming from our Fall 2017 system planning analysis, as described in Section V.B. above.

Figure 67: Distribution System Planning Load Growth Assumptions NSPM Electric Jurisdiction



We additionally provide load growth assumptions for smaller portions of the NSPM geography in Minnesota that stemmed from this same analysis as Attachment G to this IDP. Please also see the capital projects list sorted into the IDP driver categories that we provide as Attachment B to this IDP. These pieces of information together with the detailed discussion in this IDP about our analyses and assumptions fulfill this IDP requirement.

2. *Grid Modernization*

While discussed in detail above in this IDP, we summarize here that our advanced grid roadmap is the continuation of efforts that have been underway for several years. The early steps of this transition are focused on building the foundational elements needed to enable more advanced applications at the "pace of value" for our customers. This means that investments are logically sequenced to build capabilities as they are needed and incrementally upon each other.

Accounting for this foundational approach and grid modernization principles and goals, our current near-term plans involve three advanced grid projects: (1) AMI, (2) FAN and (3) FLISR as we have described in this IDP. However, as we are still determining the details of our customer strategy and a variety of related investment decision points, we are not yet seeking certification of these three investments. As we have explained, all costs and numbers we provide for this effort in this IDP are intended to be directional and used as a point of context and are thus subject to change as we continue to refine our strategy and investment plans. We intend to bring the costs associated with these projects to the Commission for approval through a certification request in the grid modernization/IDP filings or through a general rate case in 2019.

3. Distribution Planning Enhancements

The step change that is underway in the distribution utility business will require utilities to plan their systems differently, which will involve not only new processes and methodologies but also new and different tools and capabilities. As we have discussed, we will need to advance our system planning tools and capabilities to facilitate greater capabilities to factor-in DER, more systematically be able to evaluate NWA, and more-so integrate our distribution, transmission, and resource planning processes, among other things. Enhanced planning tools have started to emerge in the industry, but will take some time to mature. Toward that end, we will continue our participation with others in the industry to examine the types of capabilities that may be needed. We are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

4. Grid Modernization and EV Pilot Projects

As we have discussed, we have a number of pilots, both proposed and in-process underway. We have also outlined several new opportunities for grid modernization and electric vehicle pilots that we are currently evaluating. We intend to bring them forward to the Commission for approval, as appropriate.

5. Investment Plan and Customer Rate Impacts

IDP Requirement D.2 requires the following, in part:

> *Overview of investment plan: scope, timing, and cost recovery mechanism.*

As we are not specifically proposing any advanced grid initiatives or other distribution system developments and investments in grid modernization at this time, we have generally described the scope, timing, and costs of our near-term plans that we intend to bring forward in either a general rate case or in a grid modernization filing. We have also described our other planned investments and presented our 5-year capital and O&M budgets. We believe these comply with the above portion of IDP Requirement D.2.

Additionally, IDP Requirement D.2 requires the following, in part:

> …*Plans to manage rate or bill impacts, if any.*
>
> *Impacts to net present value of system costs (in NPV RR/MWh or MW)*…

As we have discussed, we are not proposing any specific grid modernization initiatives at this time. Similarly, we are not expecting any change in customer rates or bill impacts from our other general distribution plans. Therefore, we have not attempted to quantify customer rate or bill impacts. We will attempt to estimate any impacts in conjunction with a formal proposal or request for cost recovery in the future.

We do, however, provide a calculation of the NPV of the Distribution function as Attachment H to this IDP, in compliance with the above requirement.

6. *Demand Side Management*

The five year action plan for Demand Side Management, which includes both energy efficiency and demand response, will be largely determined through our Integrated Resource Plan.

a. Energy Efficiency

In terms of energy efficiency, our expectation is that the 1.5 percent goal will be the central focus of energy efficiency during the 10-year IDP period, but will be considering the additional analysis provided by Minnesota's Statewide Conservation Improvement Plan Potential Study as it is completed over the next few months. In order to continue meeting and exceeding this goal, we will invest in expanding existing opportunities and bringing new opportunities to market. We will also be looking to new ways to maximize benefits for customers that may alter traditional delivery strategies and tactics that will support the integration of renewable resources and DER. We will detail our specific plans and implementation strategies for these in our upcoming 2020-2022 CIP Triennial filing, which we will submit

b. Demand Response

Demand Response will be heavily influenced by our efforts to achieve the incremental 400 MW by 2023 requirement that stemmed from our most recent IRP in Docket No. E002/RP-15-21. We expect our delivery of DR in the next 5-year period to shift in order to achieve this goal in the future, and take a broader approach to where DR opportunity can be achieved. Traditionally, DR has focused on load curtailment; however, a broader approach will likely be needed to take advantage of load shifting and behavioral actions. Modifications to existing programs or additions of new programs will require regulatory filings, at a minimum, several months in advance of implementation. Additionally, we are anticipating changes at the MISO level to influence future programs and cost-effectiveness screens, which will factor into our plans and program design.

We are in the process of completing an analysis of cost-effective future potential, and working through a thorough stakeholder engagement process identifying new programs for adjusting our peak through curtailment or shifting of load. We intend to provide a more detailed 5-year plan with our IRP in 2019.

B. Long-Term Action Plan and Customer Impacts

In this section, we address the long-term plan IDP requirements – discussing primarily the long-term trajectory of our near-term investments.

IDP Requirement 3.D.3 requires the following:

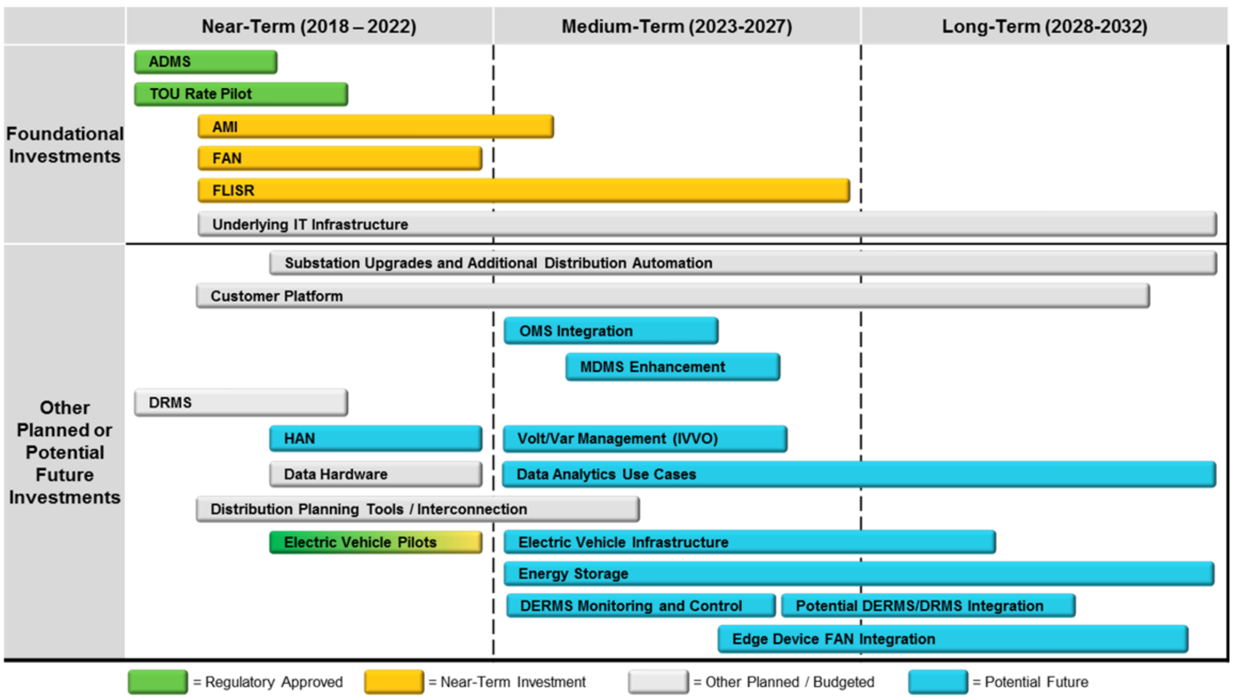
> *In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term plan discussion should address the long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.*

1. Long-Term Grid, Tools, and Capabilities Focus

As we have discussed, our long-term focus for the distribution system is to advance the grid and our capabilities through first building foundational capabilities then further leveraging that foundation with advanced capabilities. This includes enhanced distribution planning tools to advance our capabilities to bring DER into our planning – and to perform DER futures analyses, as we have discussed in this IDP.

Although also provided above in this IDP, for easy reference, we again provide a 15-year view of the sequencing of planned and potential advanced grid investments in Figure 68 below.

Figure 68: Advanced Grid Initiatives 15-Year View



The sequencing of initiatives aligns with the measured approach adopted by the Company that initially focuses on foundational investments, while also realizing some early capabilities and benefits for customers. This approach positions the Company to make prudent investments over time in more advanced capabilities, while maintaining flexibility to adapt to changing customer priorities, trends in DER penetration, and future policy direction. As previously mentioned, the Company has received certification approval for both ADMS and the TOU Pilot. Each of these investments is an important step along the advanced grid roadmap.

In addition to discrete advanced grid investments, our corporate Information Technology (IT) infrastructure will require attention and investment on an ongoing basis to continue to meet increasingly demanding cybersecurity, data traffic, reliability, and compliance requirements along with the service expectations of our customers. Many of the investments discussed within this report involve additional data and communication needs, and a current IT infrastructure is critical to supporting those efforts. Shown in Figure 68 as a single foundational investment, this is actually composed of a series of investments in data management hardware, systems integrations, and cybersecurity protections.

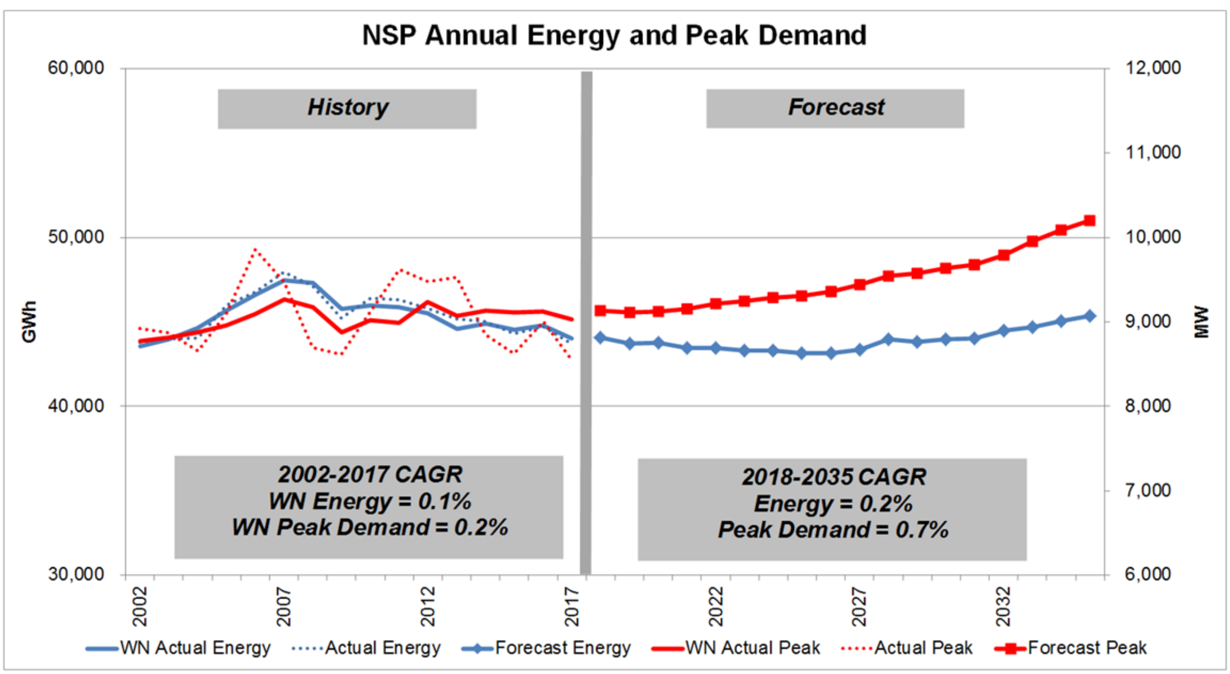
Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities as we have discussed and portrayed in Figure 8 previously.

2. *Long-Term Load Growth Assumptions*

As we have discussed in this IDP, distribution system planning is performed for a 5-year planning horizon. In the case of this IDP, that period is 2019-2023. In part 1 above, we provided our load growth assumptions that resulted from our Fall 2017 distribution planning process.

For load growth assumptions beyond the distribution planning period, we provide our corporate load growth forecast, as follows:

Figure 69: NSP System Annual Energy and Peak Demand Forecast



XV. STAKEHOLDER ENGAGEMENT

In this Section we discuss our stakeholder engagement in advance of this IDP.

IDP Requirement 2 requires the following:

Xcel should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.

At a minimum, Xcel should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.

In an effort to educate and build a better understanding of our work and stakeholder's needs, and to comply with the Commission's August 30, 2018 Order, we held two Distribution Planning stakeholder workshops in advance of this IDP.

The goal for the workshops was to begin an iterative and ongoing dialogue to build a mutual understanding of our processes and the IDP- both for this instant report as well as future reports. As we are currently slated to produce an IDP on an annual basis, we will need to have these stakeholder conversations frequently and on an ongoing basis to inform future reports and processes going forward. Even if we are unable to produce certain data points right now, we are interested in learning what stakeholders would find meaningful and what goals, objectives, and tools we should be looking into and planning for in this rapidly evolving space.

We engaged Great Plain's Institute (GPI) as a third party facilitator and invited all interested parties and commenters from the most recent IDP docket as well as our most recent IRP due to the overlap between the two efforts. We held our first workshop at Xcel Energy on September 12, 2018. It was a four hour long interactive workshop intended to address our proposed 5 year distribution system investments as well as the anticipated capabilities and customer benefits from those investments. The meeting objectives were stated as follows:

- Review the Commission's distribution planning objectives and the functions and technologies needed to achieve those objectives.
- Establish a shared understanding of how Xcel Energy does Distribution Planning today and how distribution planning is evolving.
- Describe and get feedback on how Xcel Energy is proposing to prioritize its distribution system investments.

Xcel Energy presented on the process we use to plan our distribution system and how that is evolving, we presented our five year budget and several examples and benefits, and finally discussed our advanced grid plans and components. We held table activities throughout the meeting and participants were able to relay their questions and expectations. We also held another table activity at the end of the workshop and asked participants whether the format was helpful, how they plan to use the information, and what topics they wanted to see in the future. We had approximately 50 participants and people were incredibly engaged and appreciative.

We held our second workshop on September 26, 2018 at Sunrise Banks in St. Paul. The focus of this four hour meeting was to address the load and DER forecasts. Specifically, the meeting objectives were as follows:

- Establish a shared understanding of how Xcel Energy does DER forecasting today, how forecasting is evolving, and what Xcel Energy plans to do in the future.
- Describe and get feedback on Xcel Energy's DER Forecasting Roadmap

After a recap of the previous work session and addressing questions related to that, Xcel Energy presented on the current DER and IDP landscape- discussing efforts across the United States and comparing and contrasting policy positions. Next, we discussed Xcel Energy's current internal forecasting methodologies and potential future options/methodologies as well as DER planning tools. After the presentations concluded, we gathered stakeholder feedback on the workshop and information presented. It again proved to be a productive and engaging conversation among approximately 50 people where information and perspectives were shared.

GPI will soon be issuing a stakeholder survey to gain additional insights and provide another opportunity for people to weigh in and provide feedback. We will add this to the feedback we have already received and continue to improve and build upon our IDP report and internal processes to make our IDP as meaningful as possible.

Next stakeholder outreach steps after this filing involve meeting with stakeholders to walk through this IDP filing, answer questions and take feedback- both individually and in a workshop that will soon be scheduled and noticed in this docket. From there, and after the Comment period has passed, we will begin preparing our 2019 IDP and soon schedule a series of stakeholder workshops to gather feedback on this 2018 report and also to build upon these efforts for future reports.

XVI. INTEGRATED DISTRIBUTION-TRANSMISSION-RESOURCE PLANNING

In this Section, we discuss the present state of Distribution-Transmission Resource Planning and our longer-term view of how we envision them becoming increasingly integrated.

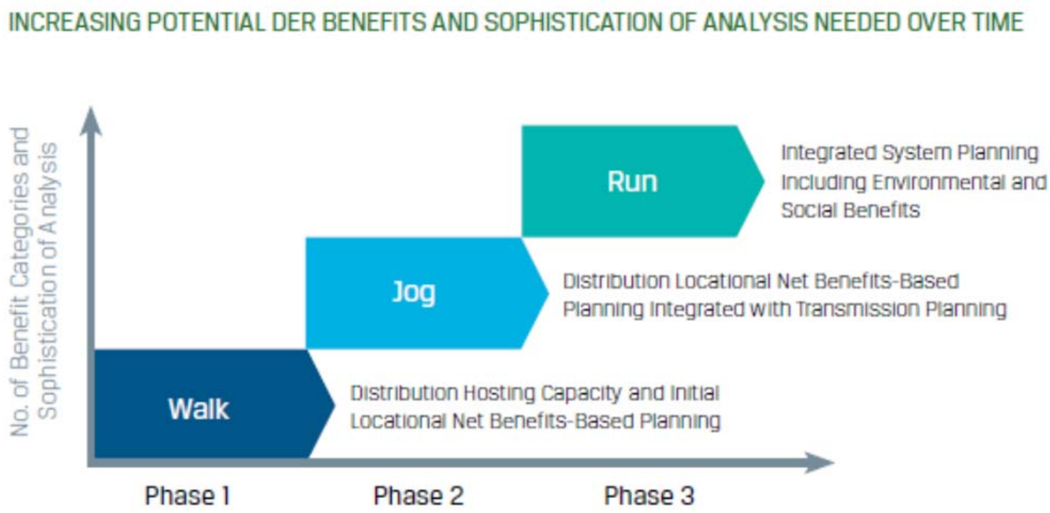
IDP Requirement 3.A.5 requires the following:

> *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.*

Today, the distribution and transmission planning groups meet twice per year, and additionally work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed. The work that we are doing now on customer adoption-based of DER and electrification is helping to bring these planning processes closer together – and we believe will result in better informed sensitivities to ultimately inform both IRP and IDP. However, there are fundamental differences in these planning processes that will continue to challenge integration, at least in the near-term.

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere. While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The stages are illustrated in Figure 70 below.

Figure 70: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. *See* White Paper.

Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, DER, the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or resource planning.

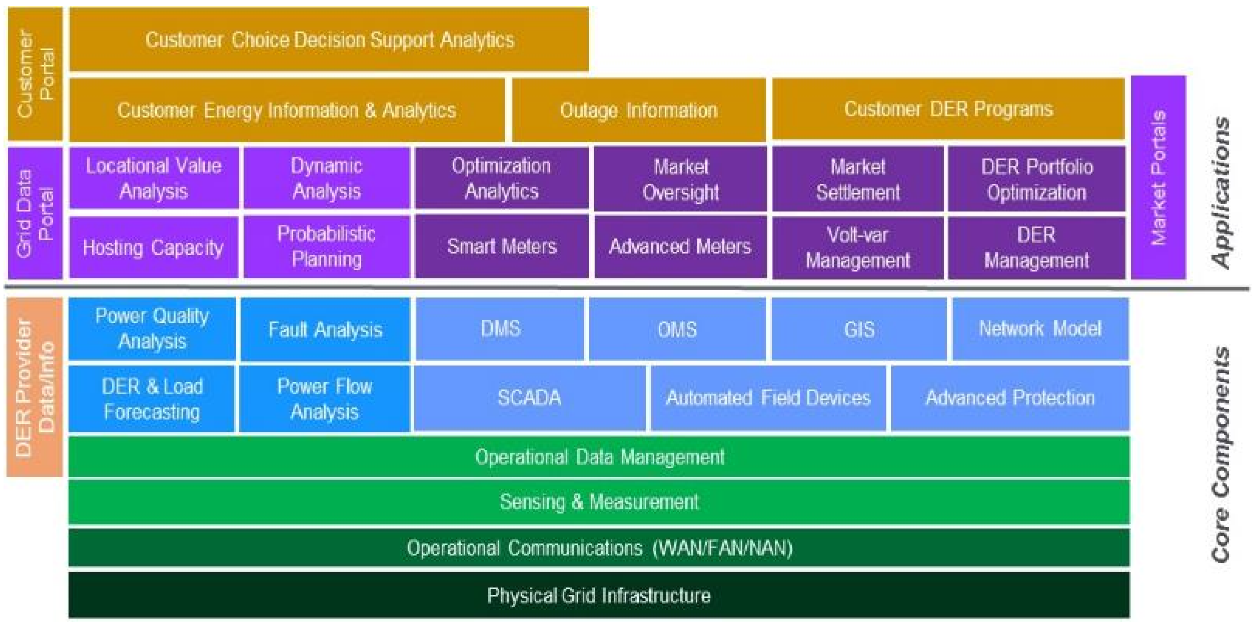
Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[99] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient, and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy (DOE), as part of its collaboration with state commissions and industry to define grid modernization in the context of states'

[99] Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* https://emp.lbl.gov/publications/distribution-systems-high-distributed

policies is developing a guide for modern grid implementation that similarly recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in Figure 71 below.

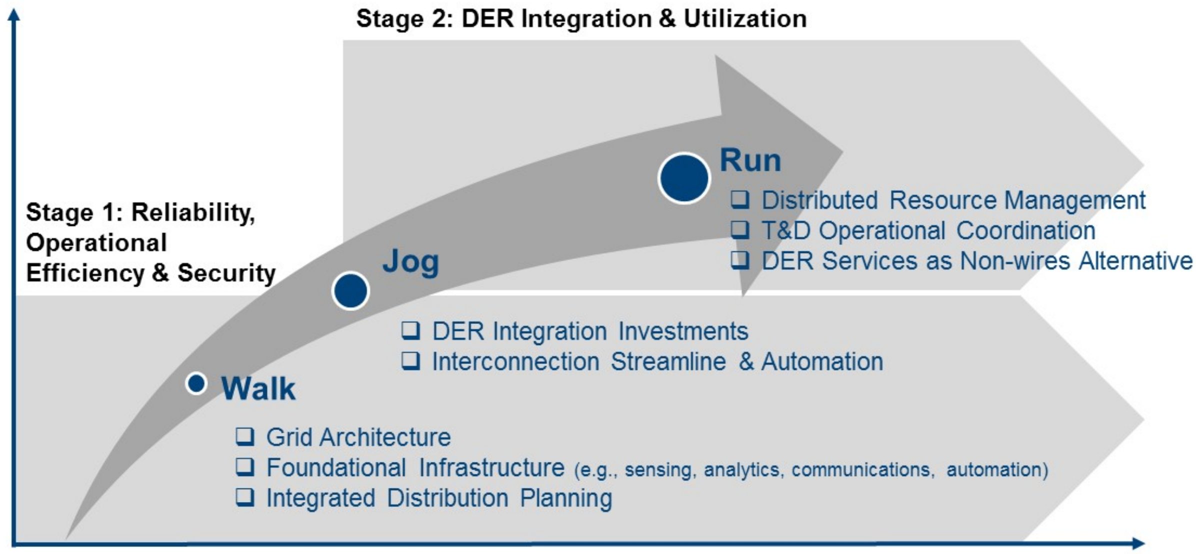
Figure 71: Platform Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

The DOE's efforts also recognize timing and pace considerations, as shown in Figure 72 below.

Figure 72: Timing and Pace Considerations



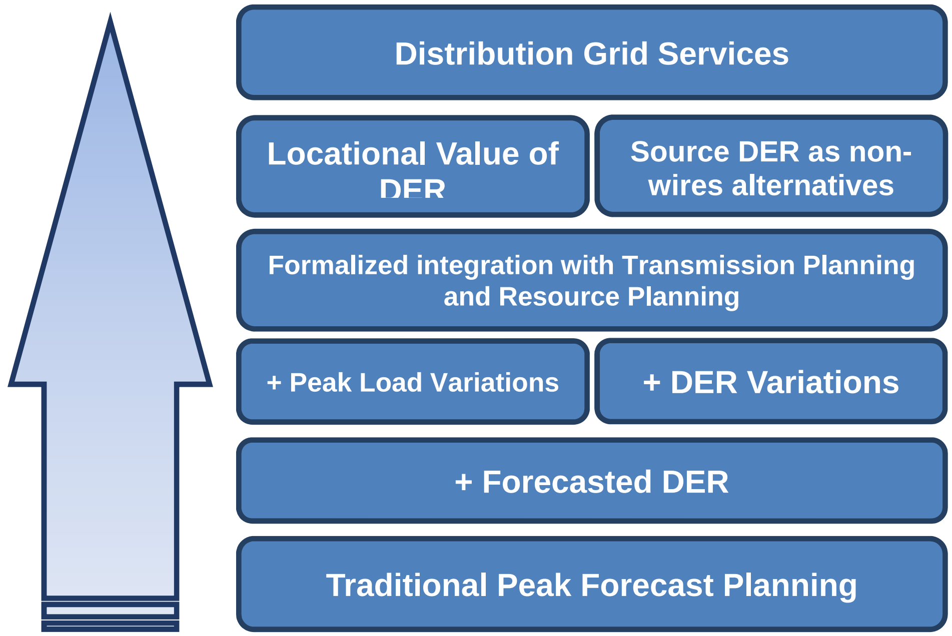
Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We would agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 73 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.

Figure 73: Potential Evolution in Planning Practices



We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.[100] These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates

[100] Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "The Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

to the five-year action plan period of an IRP, which is generally a continuation of past IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight – avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value.

We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future. Fundamentally, they are rooted in contradictory planning paradigms – with resource planning concerned with size, type, and timing, distribution concerned with location, and transmission somewhere in between. In the near term, the work that we are doing together around customer adoption-based DER forecasting and electrification will be apparent in the IRP. It will allow us to consider many different possible outcomes, and think about how we can design an optimal portfolio of resources that best meets our overall customer load needs under a range of potential outcomes.

CONCLUSION

This IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value and that the fundamentals of our distribution business remain sound.

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
2	Stakeholder Meetings	Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	XV
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	V.C
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	IV.C.1
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	IV.C.1
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	IV.C.2 IX
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	XVI
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DER is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	XI.A
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018).	XII.C
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	IV.C.3
3.A.9	Baseline Distribution System and Financial Data System Data	For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system	IV.C.4
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	IV.C.5
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	IV.C.6
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	IV.C.7
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	IV.C.8

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	IV.C.9
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 in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	XI.B.1 XII.B.1
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	XII.B.1
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory	XI.B.2
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public electric vehicle charging stations	XI.B.2
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	XI.B.1
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	XI.B.1
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)	XI.B.1
3.A.26	Baseline Distribution System and Financial Data Financial Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other The Company may provide in the IDP any 2018 or earlier data in the following rate case categories: a. Asset Health b. New Business c. Capacity d. Fleet, Tools, and Equipment e. Grid Modernization For each category, provide a description of what items and investments are included.	II.D.2

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.27	Baseline Distribution System and Financial Data Financial Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	XII.B.1
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	II.D.2, Figure 4, 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, 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	Attachments B & C
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	Attachment E
3.A.31	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	XI.B.3
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	XI.B.3
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	XII.C.3
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources4, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.	XII.A
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.5 (Footnote: Forthcoming Order, E999/CI-16-521, MN DIP 3.2 Initial Review)	XII.B.2
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.	XI.D
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	XI.D

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
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.	XI.E
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 8416 (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)	XI.F.3
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	1. Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and the DER future scenarios.	XIV Attachment _
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	See Attachment F which lays out the full 3.D.2 requirement and where it is addressed.	XIV Attachment F
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	IX XIV.B
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	VI
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide information on the following: •Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) •A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) •Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed •A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	VI

IDP Requirement 3.A.29 requires the following:
Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include:
a. Age-Related Replacements and Asset Renewal
b. System Expansion or Upgrades for Capacity
c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects
f. Projects related to local (or other) government-requirements
g. Metering
h. Other

			2019	2020	2021	2022	2023
Age-Related Replacements and Asset Renewal							
Blanket	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	3,380,000	3,380,000	3,380,000	3,380,000	3,380,000
	E114.018177	MN - OH Rebuild All Other Type Blkt	4,865,000	4,865,000	4,865,000	4,865,000	4,865,000
	E114.018178	MN - OH Services Renewal Blanket	6,980,000	6,980,000	6,980,000	6,980,000	6,980,000
	E114.018274	MN - UG Conversion/Rebuild Blanket	35,000	35,000	35,000	35,000	35,000
	E114.018275	MN - UG Services Renewal Blanket	460,000	460,000	460,000	460,000	460,000
	E114.018354	MN - OH Street Light Rebuild Blanket	801,000	822,000	844,000	865,000	888,000
	E114.018355	MN - UG Street Light Rebuild Blanket	768,000	788,000	809,000	830,000	852,000
	E141.017359	MPLS - New UG Network	480,000	492,000	504,000	516,000	516,000
	E151.016697	St. Paul UG Network	238,000	244,000	250,000	256,000	256,000
Failure	E103.001736	MN-Sub Equipment Replacement	2,800,000	2,800,000	2,800,000	2,800,000	2,800,000
	E103.012618	Reserve 69/13.8 kV 28 MVA Transformer - NSPM	0	0	0	550,000	0
	E103.013577	reserve 70 MVA 115/34.5 kV transformer	0	800,000	0	0	0
	E103.016837	Replace Failed Substation Transformers	1,500,000	2,000,000	2,000,000	3,000,000	3,000,000
	E103.019028	Reserve Transformer 70MVA at 115-34.5kV	800,000	0	0	0	0
	E103.019030	Reserve Transformer 14MVA at 69-13.2kVA	350,000	0	0	0	0
Program	E103.006458	Retire 6 NSPM Abandoned Subs	200,000	200,000	200,000	200,000	200,000
	E103.009150	SPCC NSPM Oil Spill Prevention	1,000,000	700,000	0	0	0
	E103.011890	Feeder Breaker Replacement - NSPM	1,000,000	1,000,000	2,700,000	3,250,000	3,250,000
	E103.011891	Substation Switch Replacement	100,000	100,000	300,000	300,000	300,000
	E103.012586	ELR - Substation Relay Funding - NSPM	300,000	300,000	750,000	1,000,000	1,000,000
	E103.012603	ELR - Substation Regulator Funding - NSPM	300,000	300,000	300,000	450,000	450,000
	E103.012606	Substation Fence Improvement - NSPM	250,000	250,000	750,000	750,000	750,000
	E103.012612	Substation Transformer Replacements - NSPM	0	0	1,500,000	3,000,000	3,000,000
	E103.013521	ELR - NSPM RTU	104,555	104,577	418,060	627,033	626,605
	E103.017653	Replace End of Life Substation Batteries	180,000	180,000	780,000	780,000	780,000
	E114.018129	MN - Pole Replacement Blanket	7,000,000	11,000,000	12,000,000	12,000,000	12,000,000
	E141.001664	Network Vault Top 735 marquette	200,000	750,000	1,000,000	1,000,000	1,000,000
	E141.017906	FST Network RTU Replacement	0	200,000	0	0	0
	E141.018795	MPLS Network Protector Replacement	600,000	1,700,000	1,800,000	1,800,000	1,500,000
	E151.013639	STP Vault Top Replacement	300,000	1,000,000	1,000,000	1,000,000	800,000

		2019	2020	2021	2022	2023
	E151.018796 STP Network Protector Replacements	600,000	1,225,000	1,108,000	1,300,000	400,000
Project	E141.012673 Install Fifth Street switchgear	3,399,000	1,740,000	0	0	0
	E141.017673 ALD Sub, Transfer controls to Transm house	1,500,000	2,500,000	2,500,000	0	0
	E144.000791 SSI: Install La Crescent TR2 13.8kV 14 MVA	0	0	0	0	300,000
	E144.000793 SSI: Install 12.47kV Zumbrota #2	0	0	150,000	0	0
	E144.011180 SSI: Upgrade Clark's Grove to 23.9kV	0	0	0	100,000	2,000,000
	E144.013448 SSI: Add 2nd 23.9kV Transformer and feeder at Waterville	1,950,000	0	0	0	0
	E144.013600 SSI: Convert Butterfield from 4kV to 13.8kV	0	0	100,000	2,700,000	0
	E144.013622 SSI: Convert Lafayette 4kV	0	0	100,000	1,950,000	0
	E144.017589 YLM211 and YLM212 Reinf OH lines	500,000	1,450,000	1,450,000	1,400,000	0
	E144.018411 CLC221 Reinf OH Lines	800,000	600,000	0	0	0
	E150.018891 Replace Linde TR1	3,100,000	0	0	0	0
	E154.013603 SSI: Convert Bird Island 4kV to 13.8kV	0	100,000	2,450,000	0	0
	E154.013605 SSI: Convert GLD021 4kV area to 12.5kV	0	0	0	150,000	0
	E154.013611 SSI: Convert Echo 4kV to 23.9kV	75,000	0	0	0	0
	E154.013613 SSI: Convert Belgrade 4kV to 13.8kV	0	0	100,000	2,600,000	0
	E154.013633 SSI: Convert Hector 4kV to 13.8kV	0	0	0	100,000	2,700,000
	E154.013635 SSI: Convert Sacred Heart 4kV to 23.9kV	0	0	0	250,000	0
WCF	E114.018276 MN - Line Asset Health WCF Blanket	11,000,000	11,000,000	10,113,000	11,774,000	11,600,000
System Expansion or Upgrades for Capacity						
Blanket	E103.001735 MN-Sub Capacity Reinforcement	300,000	300,000	300,000	300,000	300,000
	E114.018181 MN - OH Reinforce Blkt Tap/Back/Sec	565,000	565,000	565,000	565,000	565,000
	E114.018182 MN - OH Reinforce Blkt All Other	318,000	318,000	318,000	318,000	318,000
	E114.018279 MN - UG Reinforce Blkt Tap/Back/Sec	184,000	184,000	184,000	184,000	184,000
	E114.018280 MN - UG Reinforce Blkt All Other	276,000	276,000	276,000	276,000	276,000
	E114.018342 MN - New Business Network Blanket	1,251,000	1,282,000	1,313,000	1,345,000	1,345,000
Program	E103.018426 Feeder Load Monitoring DCP Capacity Reinforcement	900,000	1,100,000	1,800,000	2,500,000	2,500,000
Project	E141.009145 Install 13.8kV 50 MVA Midtown TR2	0	0	100,000	1,900,000	0
	E141.009146 Hiawatha West HWW TR02 install	0	100,000	1,400,000	0	0
	E141.010910 Crosstown new 13.8kv sub 2 fdrs	600,000	4,550,000	4,650,000	0	0
	E141.011164 North Main- I694 & Main St 13.8kV sub-2 Fdrs	0	0	0	100,000	3,900,000
	E141.015729 Moore Lake new feeder	0	0	0	990,000	0
	E141.015818 ELP84 - cut to HWW61	0	250,000	0	0	0
	E141.017687 TER065, extend TER073 to provide load relief	0	150,000	0	0	0
	E141.017739 MST075, Extend MST074 to relieve MST075 and TER066	0	0	300,000	0	0
	E141.017747 TER066, Extend MST074	0	350,000	0	0	0
	E142.011024 Reinf MND TRs and WWK SD	0	0	0	550,000	0
	E142.011721 Install 2nd transformer at Orono	0	0	100,000	2,900,000	0
	E143.016724 Reinforce WSG feeder capacities	0	550,000	0	0	0
	E143.016727 Install tie for EBL064	0	0	0	150,000	0
	E143.016730 Install tie for WIL081	0	0	300,000	0	0
	E143.017702 Install new VKG feeder	0	0	0	1,000,000	1,500,000
	E143.017703 Blue Lake reinforce banks to 50MVA and add feeder	0	0	0	100,000	3,100,000

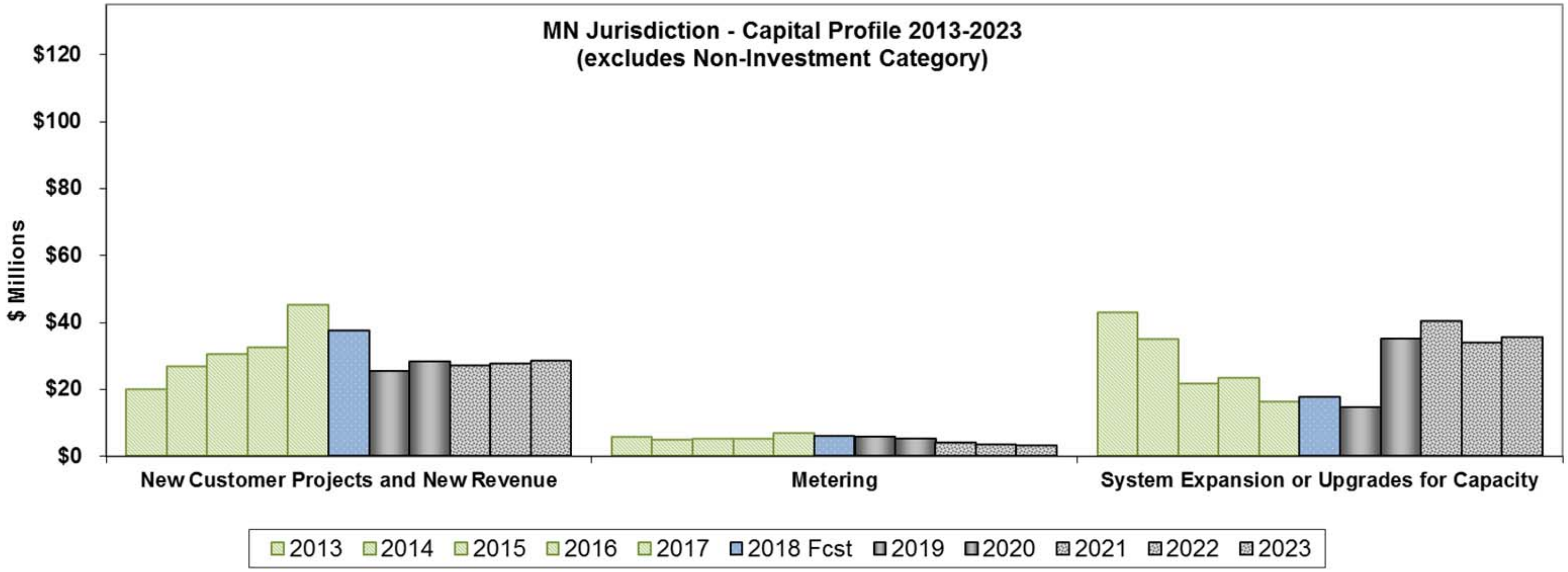
	2019	2020	2021	2022	2023
E143.019054 Upgrade EDA062 feeder capacity	0	0	0	500,000	0
E143.019055 Upgrade SAV063 and SAV067 feeder capacities	0	100,000	1,100,000	0	0
E144.000791 SSI: Install La Crescent TR2 13.8kV 14 MVA	0	0	0	300,000	1,610,000
E144.000793 SSI: Install 12.47kV Zumbrota #2	0	100,000	2,020,000	0	0
E144.002712 Add 3rd feeder to Goodview Bank #2	0	0	1,100,000	0	0
E144.007793 Reinforce FAPTR1 69/13.8kV to 28MVA and add 1 feeder	100,000	1,600,000	0	0	0
E144.010920 Reinforce Burnside TR2 to 28MVA	0	0	100,000	2,600,000	0
E144.013436 Reinforce Kasson TR1 and Fdrs	0	100,000	2,050,000	0	0
E144.013520 Add EWITR2 and one feeder	0	0	0	100,000	2,900,000
E144.014484 Serve Essig from Local REA	0	0	0	225,000	0
E144.016592 Upgrade Bushings and CTs on SIP TRs	0	0	0	0	100,000
E144.017637 Transfer Load from ESW062 to SMT061	0	0	100,000	0	0
E144.018970 Upgrade Medford Junction TR1 to 14MVA	100,000	2,200,000	0	0	0
E144.018971 Upgrade VESTR1 and add VES022	0	100,000	2,650,000	0	0
E147.011058 Convert Hollydale Sub to 115kV	3,000,000	8,000,000	5,800,000	0	0
E147.012463 Install feeder tie for CRL033	0	0	0	1,250,000	0
E147.014465 Upgrade BRP062 feeder capacity	0	0	0	0	200,000
E147.015637 Install tie for OSS063	0	0	100,000	0	0
E147.016645 Install section switch for BRP072	0	0	0	50,000	0
E147.017741 Upgrade OSS062 feeder capacity and transfer	0	0	0	200,000	0
E147.019056 Upgrade BCR062 feeder capacity	0	0	250,000	0	0
E150.010904 Add 70MVA 115/34.5kV Rosemount TR2	100,000	1,100,000	2,200,000	0	0
E150.010914 Add STY TR3 and two new feeders	100,000	2,800,000	4,000,000	0	0
E150.012576 New South Afton Substation and feeders	500,000	4,400,000	0	0	0
E150.015662 Build New CHE065 Feeder	0	0	0	1,200,000	0
E150.018967 Extend RRK063	0	0	0	100,000	0
E150.019059 TAM - Upgrade RRK TR2	50,000	670,000	0	0	0
E151.012409 Add TR3 and feeders at WES	0	0	2,200,000	3,050,000	0
E151.018961 New MPK075-GPH061 Feeder Tie	0	250,000	0	0	0
E154.003375 Install 35KV transformer at Salida Crossing	2,600,000	0	0	0	0
E154.003388 Reinforce Montrose transformer to 14 MVA	0	0	0	100,000	1,000,000
E154.010157 Install 2nd transformer at Albany	0	0	0	100,000	2,050,000
E154.010161 Install 2nd tansformer at Sauk River	1,545,000	0	0	0	0
E154.015728 Reinforce SCL TR2 to 70MVA	2,000,000	0	0	0	0
E154.016772 Install new FIC fdr to serve MTV area	0	975,000	0	0	0
E154.018960 Reinforce Glenwood sub equipment	0	40,000	600,000	0	0
E156.007927 Install TR3 70 MVA GLK Sub	0	0	0	1,800,000	1,800,000
E156.010177 Install new KOL feeder to serve OAD	0	800,000	0	0	0
E156.011061 Install new Wyoming feeder	0	0	1,650,000	0	0
E156.011749 Reinforce LEX ties	0	0	0	0	950,000
E156.011752 Install new LIN fdr	0	0	0	0	650,000
E156.011764 Reinf sub equip on TLK TR1 and TR2	0	0	0	0	200,000
E156.011874 Install new sub near Birch	0	0	0	0	1,470,284

			2019	2020	2021	2022	2023
	E156.013545	Expand AHI substation	0	0	100,000	3,500,000	3,500,000
	E156.014539	Reinforce feeder ties for TLK	0	0	0	400,000	0
	E156.015749	Add 2 New Baytown Feeders	0	1,200,000	600,000	0	0
	E156.015811	Reinforce TLK66 feeder ties to OAD	0	0	0	275,000	0
WCF	E114.018281	MN - Line Capacity WCF Blanket	0	600,000	2,000,000	4,758,000	5,000,000
Projects Related to Local (or Other) Government-Requirements							
Blanket	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	3,323,000	3,323,000	3,323,000	3,323,000	3,323,000
	E114.018174	MN - OH Reloc All Other Type Blkt	2,946,000	2,946,000	2,946,000	2,946,000	2,946,000
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	2,069,000	2,069,000	2,069,000	2,069,000	2,069,000
	E114.018272	MN - UG Reloc All Other Type Blkt	887,000	887,000	887,000	887,000	887,000
	E114.018273	MN - UG Service Conversion Blanket	962,000	962,000	962,000	962,000	962,000
Program	E114.018479	MN - Pole Transfer 3rd Party Blanket	500,000	500,000	500,000	500,000	500,000
Project	E141.016840	Relocate UG and OH Facilities for Bottineau LRT - Minneapolis	500,000	4,500,000	4,000,000	0	0
	E141.017519	35W Relocation 40th to Franklin	(1,000,000)	0	0	0	0
	E141.018906	8th Street Relocation Hennepin to Chicago	11,436,000	0	0	0	0
	E141.018907	4th St Reloc 2nd Ave N to 4th St S	5,000,000	5,000,000	0	0	0
	E141.019192	Relocate UG and OH Facilities for SWLRT - Minneapolis	2,600,000	1,800,000	(150,000)	0	0
	E143.013574	Relocate UG and OH Facilities for SWLRT	7,800,000	5,400,000	(450,000)	0	0
	E147.016563	Relocate UG and OH Facilities for Bottineau LRT - Maple Grove	500,000	4,500,000	4,000,000	0	0
WCF	E114.018175	MN - Mandate WCF Blanket	2,687,000	3,068,000	8,000,000	12,000,000	12,000,000
	E141.017929	Minneapolis Mandates	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
Metering							
Blanket	E103.001040	MN-Electric Meter Blanket	5,885,000	5,141,000	3,904,000	3,450,000	3,142,000
New Customer Projects and New Revenue							
Blanket	E114.018045	MN - OH New Street Light Blanket	343,000	352,000	362,000	371,000	380,000
	E114.018046	MN - UG New Street Light Blanket	709,000	728,000	747,000	767,000	787,000
	E114.018171	MN - OH Extension Blanket	2,950,000	3,032,000	3,117,000	3,203,000	3,291,000
	E114.018172	MN - OH New Services Blanket	3,456,000	3,553,000	3,653,000	3,753,000	3,856,000
	E114.018268	MN - UG Extension Blanket	11,736,000	12,065,000	12,403,000	12,744,000	13,094,000
	E114.018269	MN - UG New Services Blanket	6,247,000	6,422,000	6,602,000	6,783,000	6,970,000
Program	E114.018792	MN LED Post Top Conversion	0	2,000,000	0	0	0
Other							
Blanket	C115.006786	Logistics-NSPM Tools Blanket	76,114	168,288	249,079	253,861	253,689
	E103.001041	MN-New Bus Transformer	17,224,000	17,867,000	18,254,000	18,546,000	18,624,000
	E103.002265	Capitalized Locating Costs-Elec UG MN	400,000	400,000	400,000	400,000	400,000
	E153.011934	Logistics-NSPM Tools Blanket - SD	1,743	3,486	4,355	4,354	4,351
Program	C103.002156	Transportation-NSPM Fleet Blanket	2,126,000	2,386,458	1,925,959	1,810,100	1,809,126
	C145.008061	Fleet New Unit Purchase Common Ops-NSPM-North Dakota	9,956	9,956	9,951	9,950	9,944
	E103.003617	Fleet New Unit Purchase El Ops-NSM	4,977,514	7,819,042	15,132,744	16,220,122	6,722,391
	E103.018427	Feeder Load Monitoring COMM - Communication/Other	435,644	435,739	609,671	870,880	870,284
Project	E103.014467	Fiber Communication Cutover	1,742,576	2,178,696	2,177,398	1,741,759	0
Tool	C103.002113	Transportation-NSPM Tools	80,120	160,274	240,269	240,247	240,084
	C103.013336	NSPM Locating - Tools and Equipment	30,446	60,904	90,501	90,493	90,432

			2019	2020	2021	2022	2023
	E103.001738	MN-Dist Sub Tool & Equip	200,396	435,739	435,480	435,440	435,142
	E103.001739	MN-Construct Dist Sub Tool & Equip	33,109	66,232	66,193	66,187	66,142
	E103.002099	NSPM Metering Sys-Tools & Equip	34,852	69,718	69,677	69,670	69,623
	E103.002100	EUC-Tools & Equip	102,812	149,023	148,934	148,920	148,819
	E141.001133	HUGO Training Center Tools & Equip	20,040	40,088	59,225	59,220	59,179
		Metro West-Electric Tools & Equip	197,782	287,588	287,416	287,390	287,194
		Trouble Electric Tools & Equip	133,307	196,083	195,966	195,948	195,814
	E144.001190	Southeast-Elec Tools & Equip	124,594	172,553	172,450	172,434	172,316
	E145.001206	ND-Electric Tools & Equip	53,149	70,590	70,548	70,541	70,493
	E151.001252	Metro East-Elec Tools & Equip	147,248	219,613	219,482	219,462	219,312
	E153.001257	SD-Tools & Equip	76,673	101,963	101,902	101,893	101,823
	E154.001273	Northwest-Elec Tools/Equip	64,475	86,276	86,225	86,217	86,158
System Expansion or Upgrades for Reliability and Power Quality							
Program	E114.018179	MN - REMS Blanket	850,000	850,000	850,000	850,000	850,000
	E114.018180	MN - FPIP Blanket	1,000,000	1,000,000	1,500,000	1,500,000	1,500,000
	E114.018277	MN - URD Cable Replacement Blanket	15,500,000	20,500,000	21,000,000	21,000,000	21,000,000
	E114.018471	MN - Feeder Cable Repl Blanket Proactive	4,000,000	5,000,000	5,000,000	5,000,000	5,000,000
	E114.019275	MN Incremental Customer Investment	0	0	85,000,000	88,000,000	40,000,000
Non-Investment							
Blanket	E141.001140	Electric New Construction Contributions in Aid	(1,037,000)	(1,074,000)	(1,066,000)	(1,098,000)	(1,098,000)
	E142.001155	Electric New Construction Contributions in Aid	(319,000)	(330,000)	(328,000)	(338,000)	(338,000)
	E143.001170	Electric New Construction Contributions in Aid	(282,000)	(292,000)	(290,000)	(299,000)	(299,000)
	E144.001183	Electric New Construction Contributions in Aid	(339,000)	(351,000)	(348,000)	(358,000)	(358,000)
	E147.001216	Electric New Construction Contributions in Aid	(336,000)	(350,000)	(346,000)	(356,000)	(356,000)
	E150.001230	Electric New Construction Contributions in Aid	(379,000)	(391,000)	(389,000)	(401,000)	(401,000)
	E151.001245	Electric New Construction Contributions in Aid	(289,000)	(305,000)	(300,000)	(309,000)	(309,000)
	E154.001279	Electric New Construction Contributions in Aid	(312,000)	(323,000)	(320,000)	(330,000)	(330,000)
	E156.001291	Electric New Construction Contributions in Aid	(308,000)	(317,000)	(315,000)	(324,000)	(324,000)
Grand Total			199,982,105	230,325,887	322,252,485	325,100,121	261,787,204

Note: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative in the IDP

Figure 1: Distribution Capital Profile Trend (2013 to 2023)
State of Minnesota Electric Jurisdiction



New Business –

- Based on estimated cost per meter and growth assumptions. Analysis does not include 2018 results and will be refreshed in 2020-2025 budget create cycle.
- Growth assumptions based on historical results; National housing start data and known trends in service territories.
- 2017 and 2018 expenditures are elevated by the LED Conversion project (scheduled to be completed by the end of 2018).

Metering –

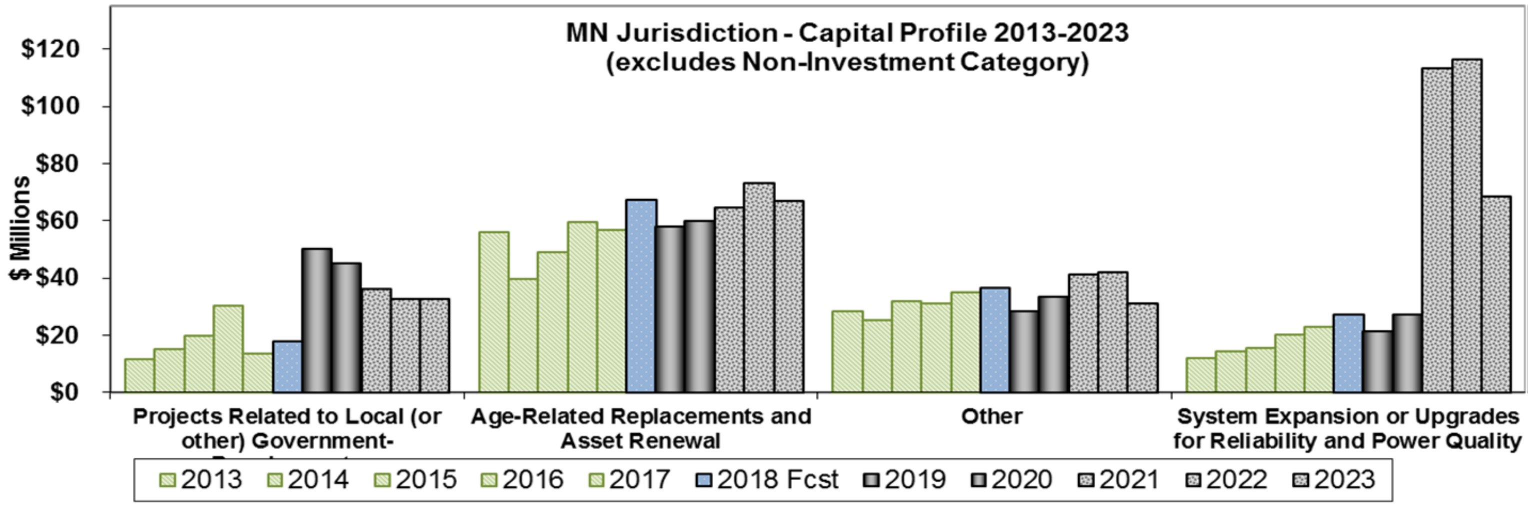
- Includes meter purchases. No significant changes identified.

Capacity –

- Capacity fluctuates with needs and available funding.

Note: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative in the IDP.

Figure 2: Distribution Capital Profile Trend (2013 to 2023)
State of Minnesota Electric Jurisdiction



Projects Related to Local (or other) Government –

- Significant uptick in 2019 driven by road projects in Minneapolis including 8th Street Relocation, 4th Street Relocation, Southwest Light Rail Transit, Hennepin Ave Relocation and the Blue Line Light Rail Transit Extension.
- Placeholders based on high-level estimates, to be refined as design estimates are completed.
- Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.
- Budgets represent a snapshot in time with changes anticipated as project scopes and associated timelines are better defined.

Other:

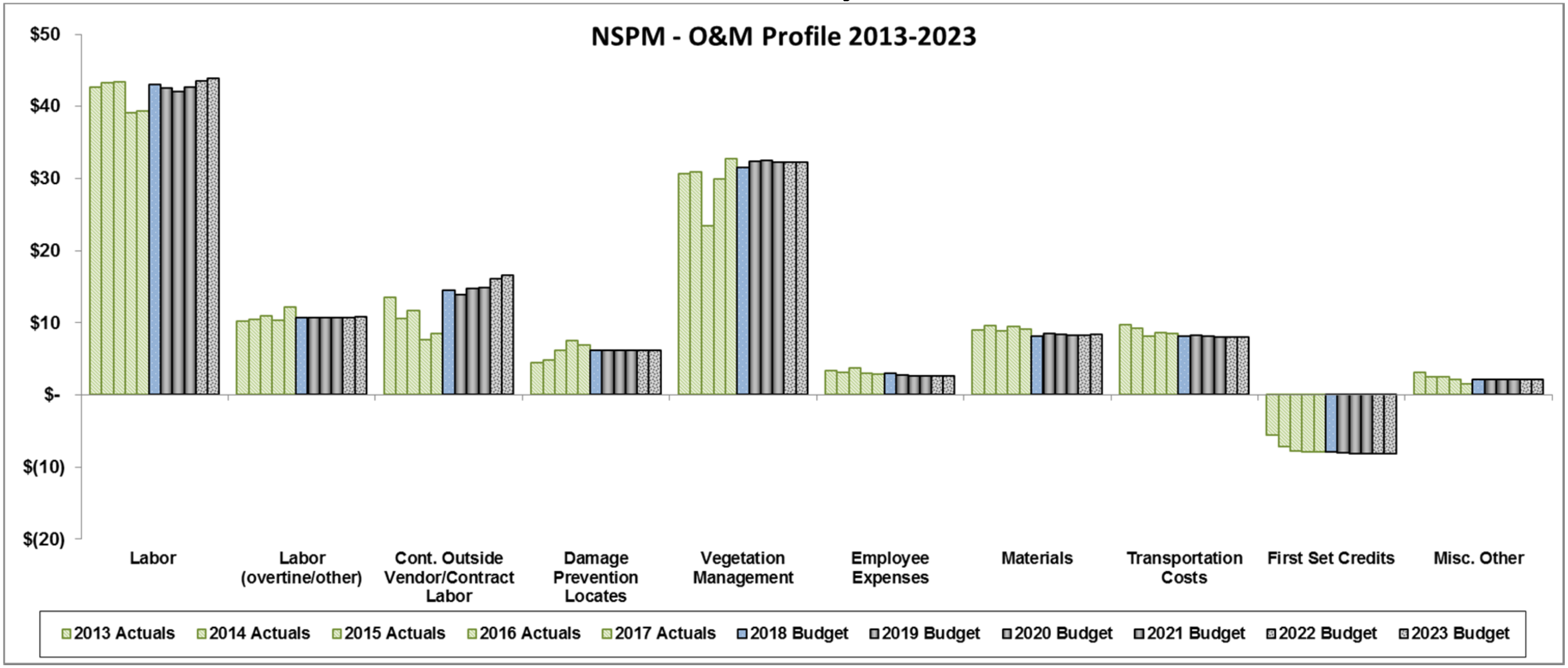
- Includes fleet, tools, communication equipment and transformer purchases.

System Expansion or Upgrades for Reliability and Power Quality

- Cable replacement program is the main driver in this category.
- Elevated spend beginning in 2021 includes a placeholder for the Incremental Customer Investment program currently being developed.

Note: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative in the IDP.

**Figure 1: Distribution O&M Profile Trend (2013 to 2023)
State of Minnesota Electric Jurisdiction**



1. Labor (overtime): The 2017 increase was driven by the reduced workforce whereas 2018 - 2023 flattens.
2. Contract Outside Vendor/Contract Labor: The upward trend is in line with the capital assumptions. New construction and reconstruction work has an overall average O&M component ranging anywhere from 2% to 20%.
3. Damage Prevention: Vegetation Management , Employee Expenses, Materials, Transportation cost, First Set Credis and Misc. other are all trending with flat assumptions for 2019-2023.

Note: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative in the IDP.

Plymouth and Medina Electrical System Assessment

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Brian Monson

June 1, 2016

Contents

1.0: Executive Summary

The Plymouth and Medina Electrical System Assessment ("Report") was completed as part of the Company's continued efforts to study alternatives available to address the reliability issues in the Plymouth area in accordance with the Minnesota Public Utilities Commission's May 2014 order in Docket Nos. E002/TL-11-152 and ET2/CN-12-113. The electrical improvements examined in this Report are needed to address distinct deficiencies on the distribution and transmission systems in the Plymouth area. Since both transmission and distribution needs are dependent on each other, the solution that is implemented must solve both of these system's identified needs. Therefore, all alternatives proposed in this study are configured to solve both distribution and transmission needs for 20 years based on 1% load growth in the Transmission Area of Concern. This Report also identified conceptual solutions for the 20-40 year timeframe, given 1% load growth. If the Transmission Area of Concern experiences a higher than 1% load growth, these solutions may need to be implemented earlier than 20-40 years. However, if the Transmission Area of Concern experiences a lower than 1% load growth, these solutions will last longer than 20-40 years.

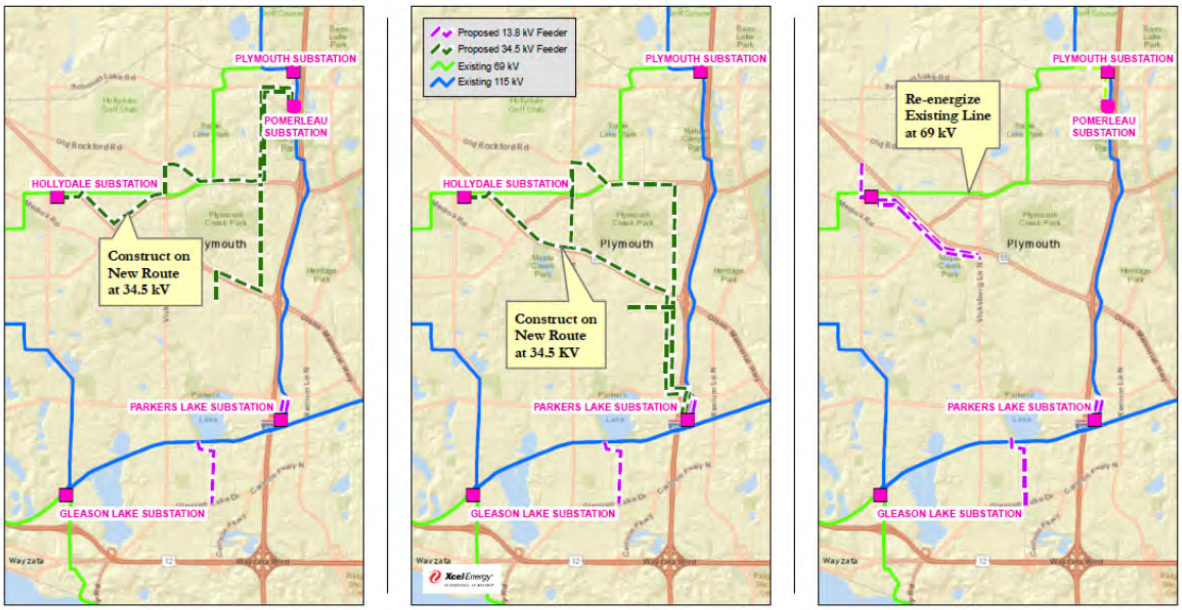
The distribution need is driven by a deficit in the distribution system's load serving capability of a Focused Study Area centered around western Plymouth. The distribution delivery system in the Focused Study Area has experienced steady load growth in recent years and is forecasted to exceed the capability of the existing distribution feeders by 30 MW in 2016. Additionally, the load is forecasted to exceed the capacity of the existing substation transformers in the Focused Study Area by 11 MW in 2016. These capacity issues could lead to an increase in the duration of outages during contingency operation as the load in the Focused Study Area continues to grow in the future.

The transmission need is driven by increasing demand on the distribution system and deficiencies on the transmission system under contingency conditions to serve the load in the Transmission Area of Concern. As the load on the distribution system in the Transmission Area of Concern grows, the transmission need to serve that load increases. The transmission system capabilities are forecasted to be exceeded by 13 MW in 2016

System alternatives presented in this study solve the capacity issues identified on the distribution system and the contingency issues identified on the transmission system. All three alternatives assume that the Gleason Lake to Parkers Lake 115 kV double circuit line is rebuilt to two single circuits, due to the condition of the existing line, and that a 40 MVAR capacitor bank is installed at the Gleason Lake substation. Maps of the near-term facilities in each alternative are shown in Figure 1.1, followed by a description of the required facilities for each alternative.

Figure 1.1: Maps of Near-term Facilities for each Alternative

Alternative A **Alternative B** **Alternative C**



Note: All three alternatives include the age and condition rebuild of the Gleason Lake to Parkers Lake 115 kV double circuit lines rebuilt to two single circuits and a 40 MVAR capacitor bank installed at Gleason Lake substation.

Alternative A:

- Construct Pomerleau Lake 115/34.5 kV substation
- Construct two 34.5 kV feeders out of Pomerleau Lake going west
- Reinforce existing feeders and construct an extension of one 13.8 kV feeder at Parkers Lake

Alternative B:

- Expand Parkers Lake substation
- Construct two 34.5 kV feeders out of the expansion at Parkers Lake going west
- Reinforce existing feeders and construct an extension of one 13.8 kV feeder at Parkers Lake

Alternative C:

- Expand Hollydale substation to accommodate three additional 13.8 kV feeders
- Construct Pomerleau Lake 115/69 kV substation
- Construct a short extension of the existing 69 kV line to Pomerleau Lake; re-energize Hollydale-Pomerleau Lake 69 kV line, Medina-Hollydale 69 kV line remains energized
- Reinforce existing feeders and construct an extension of one 13.8 kV feeder at Parkers Lake

Alternatives A and B utilize 34.5 kV feeder lines while Alternative C utilizes 13.8 kV feeder lines. Both alternatives that include 34.5 kV feeders (Alternatives A and B) require 12 pad mounted step-down transformers and 12 pad mounted switching cabinets to interconnect with the existing 13.8 kV system. Figure 1.2 includes a detailed comparison of the three alternatives.

Figure 1.2: Evaluation and Comparison of System Alternatives.

	Evaluation of Alternatives	Impacts	Performance

Plymouth Area Alternatives	**Alternative A**
	Construct 34.5 kV distribution lines from new Pomerleau Lake Substation to Hollydale Substation
		• 8 miles near-term (9 miles long-term) of new distribution line
		  o 1 mile where no lines currently exist
		  o 7 miles near-term (8 miles long-term) where there are already lines
		• 145 homes along new distribution line routes
		• 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet)
		• New Pomerleau Lake substation site
			• Provides good solution for near-term (roughly 20 years).
			• Pomerleau Lake Substation makes future improvements to meet future needs east of I-494 less challenging and expensive.
			• Provides limited ability to efficiently increase load serving capacity long-term to serve additional electrical demand

	Alternative B
	Construct 34.5 kV distribution lines from Parkers Lake Substation to Hollydale Substation
		• 10 miles near-term (11 miles long-term) of new distribution line
		  o 0 miles where no lines currently exist
		  o 10 miles near-term (11 miles long-term) where there are already lines
		• 98 homes along new distribution line routes
		• 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet)
		• Expansion of Parkers Lake Substation site would occur on privately-owned land (parking lot, drainage easement)
		• No new substation site
			• Provides adequate solution for near-term (roughly 20 years)
			• Additional improvements will be needed east of I-494 and will be more challenging and expensive without a new Pomerleau Lake Substation.
			• Does not provide ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand.
			• A large amount of load would be served from Parkers Lake Substation which increases reliability risk.

	Alternative C
	Re-energize existing 69 kV line east of Hollydale Substation and construct 13.8 kV distribution lines from Hollydale Substation & 0.7 miles of 69 kV line to connect existing line to new Pomerleau Lake Substation.
		• 4 miles of new distribution line
		  o 0 miles where no lines exist
		  o 4 miles were there are already lines
		• 26 homes along new distribution line routes
		• 0.7 miles of new transmission line
		• No new pad-mounted transformers needed
		• Vegetation management required on unmaintained 69 kV line right-of-way east of Hollydale Substation (4 miles / approximately 63 residential lots)
		• New Pomerleau Lake Substation site
			• Provides good solution for near-term (roughly 20 years).
			• Pomerleau Lake Substation makes additional improvement needs east of I-494 less challenging and expensive.
			• Provides ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand.

The best performing alternative from an engineering perspective for the Transmission Area of Concern and Focused Study Area is Alternative C, due to the system flexibility, lowest capital investment, and least amount of new infrastructure. Alternative A is the next best solution due to the system flexibility to serve additional load that is provided with the addition of Pomerleau Lake substation . However, all three alternatives were designed to comparably meet the immediate, near-term, and long-term load serving needs in the Transmission Area of Concern and Focused Study Area. Since all three alternatives are comparable solutions, input on non-engineering factors will be gathered during the permitting process that will help determine which alternative is selected for construction.

2.0: Project History.

2.1: Initial Electrical Studies

In 2005 and 2006, the distribution system in Plymouth experienced historic peak loads and Xcel Energy's distribution planning engineers observed that the existing distribution system was inadequate to serve these load levels. As a result, Xcel Energy's distribution planning engineers began to study long-term solutions to address the distribution needs in this area. In 2010, distribution planning published the *Plymouth Load Serving Study* which was a compilation of various study efforts undertaken since historic peak levels were reached in 2005 and 2006. The *Plymouth Load Serving Study* evaluated three alternatives to address the need for a new source to the Plymouth distribution system. These alternatives were evaluated based on system performance, operability, future growth, cost, and electrical losses. The *Plymouth Load Serving Study* concluded that the best performing alternative included constructing a new 115 kV transmission line between a new substation near Schmidt Lake Road and Interstate 494 and the existing Hollydale and Medina substations and modifications of associated transmission facilities (Alternative A1).

In response to a request from distribution planning for additional load serving capacity at the Hollydale Substation, Xcel Energy's transmission planners published the *Hollydale/Meadow Lake Load Serving Study* in June 2011. This study evaluated three transmission alternatives to provide additional capacity to the Hollydale Substation and the impact of these alternatives on the area transmission system. This study also documented that because of load growth in the western metro area, particularly outside the I-494 loop, that the transmission system in the studied area is very near its load serving capacity. This study also identified the loss of the Gleason Lake to Parkers Lake 115/115 kV double circuit line as a key contingency that must be considered when determining which alternative to select to provide a new connection to the Hollydale Substation. In evaluating the needs of distribution and transmission, this study concluded that Alternative A1 was the best transmission alternative based on power performance, price, distribution system losses, the ability to provide additional capacity at the Hollydale Substation, and future expansion capability.

2.2: Route Permit and Certificate of Need Proceedings

On June 30, 2011, Xcel Energy and Great River Energy filed an application with the Minnesota Public Utilities Commission (Commission) for a route permit for the Hollydale 115 kV Transmission Project. As proposed in this route permit application, the Hollydale 115 kV Transmission Project included the rebuild of 8 miles of existing 69 kV transmission line to 115 kV capacity in the cities of Medina and Plymouth and constructing 0.8 miles of new 115 kV transmission line and a new substation near Schmidt Lake Road and Interstate 494 (Hollydale Project). The proposed facilities were intended to meet both the distribution and transmission needs of the studied area through the mid-century based on forecasted load growth.

On August 25, 2011, the Commission accepted the Route Permit application as substantially complete and authorized the Minnesota Department of Commerce to process the application under the alternative permitting process set forth in Minnesota Rules 7850.2800 to 7850.3900.

In October 2011, a public information and environmental scoping meeting was held to provide information about the Hollydale Project and to identify issues and alternatives to study in the environmental assessment (EA). This scoping meeting was attended by 250 to 300 people and over 450 written comments were submitted.

On December 7, 2011, the Department issued a scoping decision that included 26 route alternatives to be evaluated in the EA. While the Hollydale Project as proposed included less than 10 miles of new 115 kV transmission facilities and would not have required a Certificate of Need under Minnesota Statutes §§ 216B.243, subd. 2 and 216B.2421, subd. 2(3), several of the route alternatives included in the scoping decision would have required a Certificate of Need if they were selected by the Commission. Given the possibility of the Commission selecting a route that would have required a Certificate of Need, Xcel Energy and Great River Energy filed a Certificate of Need Application for the Hollydale Project on July 2, 2012.

During the Certificate of Need proceeding, Xcel Energy prepared the Hollydale Need Addendum (Addendum) to evaluate how distribution alternatives put forth during that proceeding performed compared to the Hollydale Project. The study further evaluated the three alternatives initially proposed in the *Plymouth Load Serving Study* as well as two new alternatives. The Addendum was filed in January 2013 and recommended approval of the Hollydale Project.

2.3: Hollydale Law

During the 2013 legislative session, the Minnesota legislature passed a law, 2013 Minnesota Laws Chapter 57 Section 2, which established a Certificate of Need requirement and modified need criteria for the Hollydale Project (Hollydale Law). Specifically, the Hollydale Law, enacted on May 14, 2013, requires the Commission to review the Hollydale Project in a Certificate of Need proceeding regardless of the final length of the transmission line. In addition, the Hollydale Law, requires that prior to issuing a Certificate of Need that the Commission must find "by clear and convincing evidence that there is no feasible and available distribution level alternative to the transmission line. In making its findings the [C]omission shall consider the factors provided in applicable law and rules including, without limitations, cost-effectiveness, energy conservation, and the protection or enhancement of environmental quality." The Hollydale Law also suspended the Route Permit proceeding until the Commission determines that the Hollydale Project is needed.

2.4: Additional Electrical Studies

To comply with the Hollydale Law, Xcel Energy filed a supplement to the Certificate of Need Application in August 2013 (Supplement). The Supplement evaluated the Hollydale Project compared to 15 other alternative projects to meet the distribution and transmission needs in

Plymouth and Medina. These 15 alternatives included a distribution only alternative, alternatives that required no new transmission in the studied area, alternatives that defer construction of transmission until a later date, and the originally proposed Hollydale Project. The Supplement evaluated these alternatives based on technical feasibility, cost effectiveness, and other Certificate of Need criteria.

After compiling peak load data for the summer of 2013, Xcel Energy updated the information in the Supplement in the *Hollydale Project 2013 Peak Voltage Analysis* (Peak Analysis) filed in October 2013.

2.5: Withdrawal of Route Permit and Certificate of Need Applications

In November 2013, public hearings were held on the Certificate of Need application. Approximately 300 people attended these hearings to express their concerns about the Hollydale Project and the preferred route.

On December 10, 2013, Xcel Energy and Great River Energy filed a petition requesting permission to withdraw the pending Certificate of Need and Route Permit applications for the Hollydale Project. The petition noted that during the Certificate of Need and Route Permit proceedings, landowners, parties, and other stakeholders had expressed concern about route preferred by the companies for the new 115 kV line. In this petition, the companies requested permission to withdraw these pending applications to allow time to develop other alternatives to meet the electrical needs of the community that would be more acceptable to the community.

2.6: Commission Order on Withdrawal

On May 12, 2014, the Commission issued an order granting Xcel Energy and Great River Energy's request to withdraw the pending applications for the Hollydale Project. The Commission's order also acknowledged that there are electrical issues in Plymouth and Medina that remain to be addressed. The Commission's order required the companies to "demonstrate the need for any new transmission they propose for the Plymouth or Medina project area." The Commission order further required that the companies file updates (six months after the date of the order and then quarterly thereafter) documenting their public outreach efforts, improvements made to the distribution system, load-serving capacity of the distribution system, and a report of demand-side management and other resources to address the reliability needs of the area.

3.0: Study Scope

This study is part of Xcel Energy's continued study of the electrical needs of the Plymouth and Medina areas and the Company's continued evaluation of different alternatives to meet those needs.

4.0: Need Overview

The alternative proposed in this Report are needed to address two distinct needs. The distribution need is driven by a deficit in the distribution system's load serving capability of a Focused Study Area centered around the western Plymouth area. The transmission need is driven by load growth on the distribution system in a larger area than the distribution Focused Study Area (Transmission Area of Concern) and deficiencies on the transmission system under contingency conditions to serve this load. As the load on the distribution system in the Transmission Area of Concern grows, the transmission need to serve that load increases. Since the two needs are so interrelated, the solution that is implemented must solve both of the identified needs. Therefore, all solutions proposed in this study solve both distribution and transmission needs.

4.1: Distribution Need.

4.1.1: Principles of Distribution Planning

(a) Distribution System Overview

Distribution feeder circuits for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder circuit causes a customer outage, which is an allowed outcome for a distribution system. Feeders are designed to facilitate restoration of mainline capacity and restoration of service to most customers with simple manual field switching with some exceptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour.

(b) Distribution Substations

Xcel Energy plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. The maximum ultimate design capacity established in Xcel Energy planning criteria is three transformers at the same distribution voltage.[1] This maximum size balances substation and feeder circuit costs with customer service considerations including limitations of feeder circuit routes emanating from substations, circuit exposure of long feeder circuits, ease of operation, cost of operation, customer outage restoration, and the electrical losses. Over time, transformers and feeder circuits are incrementally added within the established footprint until the substation is built to ultimate design capacity.

(c) Distribution Feeder Circuits System Intact and First Contingency Planning

Normal operation (also called system intact or N-0 operation) is the condition under which all-electric infrastructure equipment is fully functional. First contingency operation (also called N-1 or contingency operation) is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. Each distribution main feeder is generally composed of three equal sections. A feeder circuit should be loaded to no more than 75% of capacity during N-0 conditions. For example, a 12 MVA feeder circuit is designed to be loaded to 9 MVA during normal operating conditions. To achieve this goal, a main feeder is generally designed so that each section is loaded to approximately 25% of the total capacity for the main feeder. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Figure 4.1 depicts a main feeder circuit, including the breaker and the three sections. The red and green lines in the diagram represent switches that can be activated to isolate or connect sections of a feeder line.

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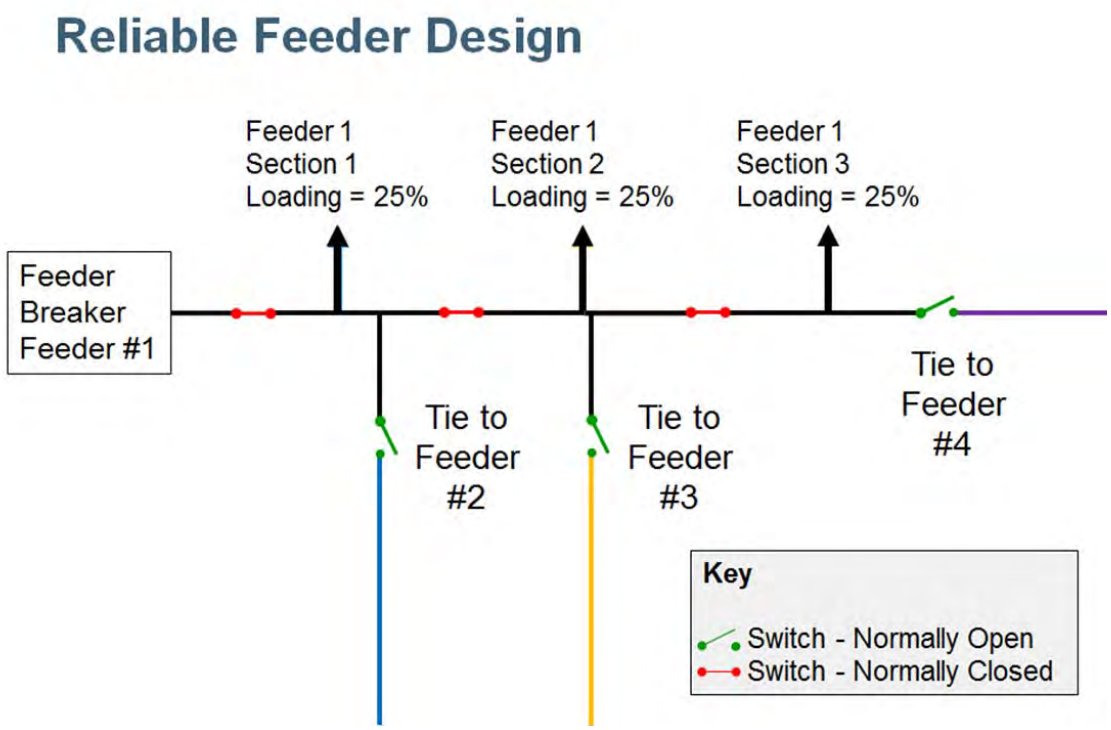
[1] There is one exception to this criteria. In downtown Minneapolis, the Fifth Street Substation houses four transformers to serve the significant load.

Figure 4.1: Typical Distribution Feeder Circuit Mainline with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations



(d) Distribution System Design and Operation

Distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact and first contingency conditions. A distribution delivery system that has adequate N-1 capacity is one in which all customer load can be restored through distribution system reconfiguration by means of electrical switching in the event of the outage of any single element.

Adequate N-1 substation transformer capacity, no feeder normal (N-0) overloads, and adequate field tie capability for feeder first contingency (N-1) distribution restoration are key design and operation objectives. To achieve these objectives, Xcel Energy uses distribution planning criteria to achieve uniform development of Xcel Energy's distribution systems. Distribution Planning considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies.

(e) Planning Criteria, Distribution Feeder Circuits

While the distribution guidelines vary depending on the specific distribution system, there are several basic design guidelines that apply to all areas of Xcel Energy's distribution system. They are as follows:

- Voltage at the customer meter will be maintained within 5% of nominal voltage, which is typically 120 volts.

- Voltage imbalance goals on the feeder circuits are less than or equal to 3%. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.

- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.

- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75% of capacity. Xcel Energy developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss because adding load to the remaining feeder circuits would cause them to overload. By targeting a 75% loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A typical feeder circuit capable of delivering 12 MVA, for example, is normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

(f) Limitations to Installing Feeder Circuits

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in Electric Distribution Bulletins ("EDB"): UND6 and CAL2 for underground and the Construction & Design Manual C-26 for overhead.

When new feeder circuits are added to a mature distribution system, minimum spacing between feeder circuit main line cables sometimes cannot be achieved because of right-of-way limitations or a high concentration of feeder cables. Adding express feeders to serve distant high-load concentrations requires cable installation across distribution service areas where they do not serve any customer load. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks". When feeder circuits are concentrated in duct banks, those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use CYMCAP software for determining maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks.

When underground feeders fill existing duct lines to the rated thermal capacity, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted.

(g) Planning Criteria, Distribution Substation Transformers

Transformers have nameplate ratings that identify capacity limits. Xcel Energy's Transformer Loading Guide provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The Transformer Loading Guide is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers ("ANSI/IEEE") standard for transformer loading, ANSI/IEEE P77.92.

The Xcel Energy Transformer Loading Guide consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures. The top-oil and hottest-spot temperatures in the Xcel Energy Transformer Loading Guide are the criteria used by Substation Maintenance engineers to determine Normal and Single-Cycle transformer loading limits that Capacity Planning Engineers use for transformer loading analysis. When internal transformer temperatures exceed pre-determined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life". Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer operation generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, Xcel Energy's loading objective for transformers is 75% of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75% are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization, the higher the risk that service will be interrupted in the event of a transformer outage.

(h) Ongoing Distribution System Reliability Assessment

Distribution Planning regularly evaluates loads to determine overloads. Mitigations (projects) are developed to address the overloads. In general, infrastructure additions that address overloaded distribution system elements is an ongoing process.

Distribution Planning annually compares feeder circuit historical and forecast peak load demands to distribution feeder circuit maximum loading limits to identify feeder circuits overloaded under system intact (N-0) conditions and feeder circuits overloaded under single contingency (N-1) conditions during peak loading.

Distribution Planning also annually compares substation transformer historical and forecasted peak load demands on substation transformers to capacity load limits under system intact (N-0) and single contingency (N-1) conditions. Distribution Planning provides distribution substation transformer loads to the Transmission Planning Department ("Transmission Planning"). Distribution and transmission planners routinely coordinate to identify distribution load impacts to the transmission system.

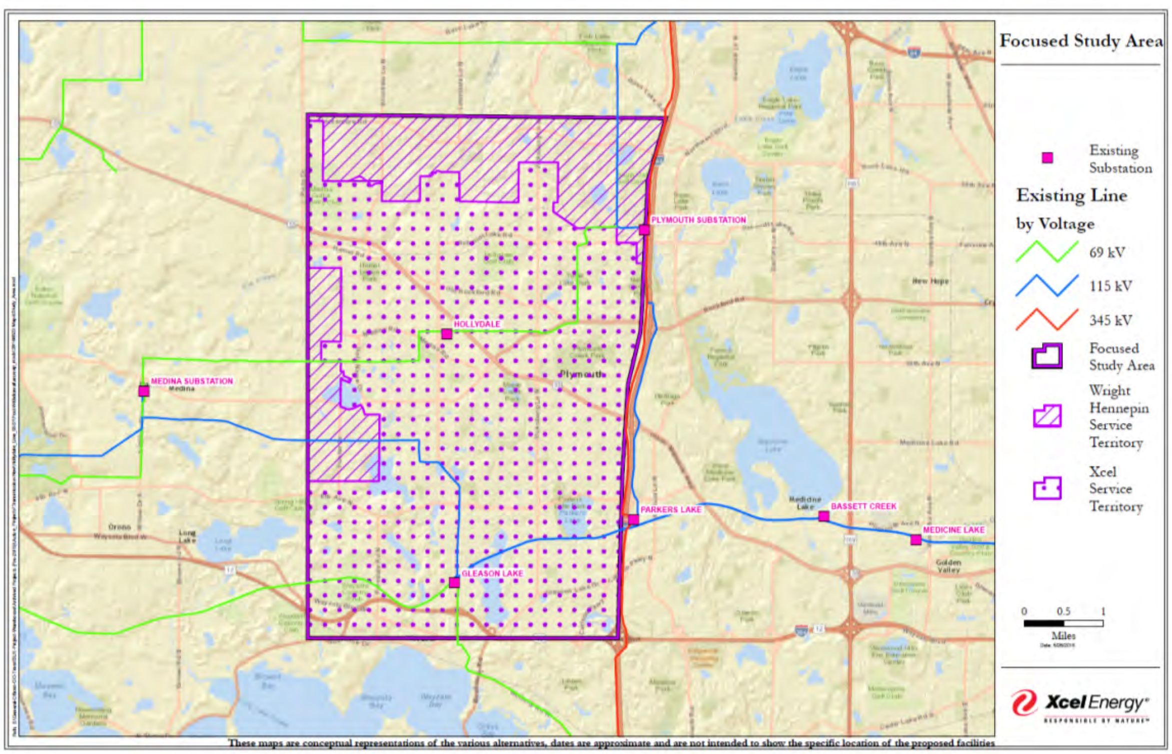
Distribution Planning then quantifies the amount of overload and the duration of peak loading for feeder circuit and substation transformer overloads under system intact (N-0) and single contingency (N-1) conditions, determines the approximate cost of mitigating the overloads, and identifies the most critical distribution system needs.

When Distribution Planning determines that a distribution system requires additional capacity from a new distribution source, it makes a formal request to Transmission Planning to interconnect to the transmission system. Transmission Planning takes the request and Distribution Planning and Transmission Planning coordinate to develop several alternatives that will address the distribution system deficiencies. Transmission Planning performs analyses to determine the impact of the selected alternatives on the transmission system.

4.1.2: Hollydale Focused Study Area Distribution System Difficiencies

The Focused Study Area comprises approximately 24-square miles in Plymouth and is depicted in Figure 4.2. The Focused Study Area distribution load is primarily fed from three 115 kV transmission lines: (1) Medina – Gleason Lake, (2) Gleason Lake – Parkers Lake, and (3) Parkers Lake – Medicine Lake. Thirteen feeder circuits emanating from three substations (Gleason Lake, Hollydale, and Parkers Lake) serve the Focused Study Area.

Figure 4.2: Map of Focused Study Area.



The current demand for power in the Focused Study Area exceeds the capabilities of the existing electrical system. In 2014, the most recent peak year, the distribution feeders in the Focused Study Area reached an actual non-coincident peak loading of 121 MW. In 2015, the distribution feeders in the Focused Study Area reached an actual non-coincident peak loading of 110 MW. In 2014, the two Gleason Lake 13.8 kV transformers peaked at 44 MW and the one 34.5 kV Gleason Lake transformer peaked at 45 MW. In 2015, the two Gleason Lake 13.8 kV transformers peaked at 41 MW and the one 34.5 kV Gleason Lake transformer peaked at 40 MW. In 2014, the peak loads exceeded the distribution systems' planned contingency capacity by 11 MW on the 34.5 kV transformer, a total of 14 MW on the 13.8 kV feeders and 13 MW on the 34.5 kV feeders (rounded).

The 2014 peaks were similar to peaks in the recent years of 2011, 2012 and 2013, while the 2015 peaks were abnormally low. The decrease in load from 2014 to 2015 is likely due to cooler weather during the summer of 2015. It can be expected that when typical warm temperatures return in future summers, feeder and transformer loads will meet or exceed historic peak load levels. The feeder peak loading reached 122 MW in 2011, 124 MW in 2012 and 123 MW in 2013. At the Gleason Lake substation, for the 13.8 kV transformers the historic peak was 49 MW in 2011 and for the 34.5 kV transformer the historic peak was 46 MW in 2013.

In 2006, the peak loads exceeded the distribution system's capacity. After these historical peak loads were experienced, it became apparent that the distribution system in the area was becoming increasingly vulnerable to more frequent and longer duration overloads. As a result, in 2008, Xcel Energy intensified its analysis of the distribution system to develop a long-term solution to serve the growing load. A distribution study and the subsequent Certificate of Need, Addendum and Supplement documented the load serving needs and identified various solutions. In this update, the more recent peak loads will be used to show the load serving needs.

4.1.3: Distribution Feeders in the Focused Study Area

The distribution system in the Focused Study Area consists of eleven 13.8 kV feeders and two 34.5 kV feeders. Of the 13.8 kV feeders, six are sourced from Parkers Lake substation, three from Gleason Lake substation and two from Hollydale substation. The two 34.5 kV feeders are sourced from Gleason Lake substation. The entire Hollydale substation is fed by one of the Gleason Lake 34.5 kV feeders.

For the 13.8 kV feeders, at projected peak load in 2016, some of these are currently experiencing overloads under normal configuration. Overloads also occur under contingency configuration while picking up load after the outage of an adjacent feeder. Overloads reduce the life of distribution system devices. Overhead wires can sag and potentially create clearance concerns; underground cables become distorted, which reduces the capability of the insulation. Other distribution equipment can overheat and not operate properly. If an overload is high enough in magnitude or sustained for long enough in duration, an overhead line will melt, leading to a failure and then an outage.

There are two 13.8 kV feeders with overloads ranging from 104% to 111%. Based on typical utilization limits, there is a deficit of about 14 MW of load in total on individual 13.8 kV feeders under contingency conditions. For the 34.5 kV feeders, at peak load none are currently experiencing overloads under normal configuration but do have overloads under contingency configuration while picking up load after the outage of an adjacent feeder. Based on typical utilization limits, there is a deficit of about 16 MW total load on individual 34.5 kV feeders under contingency conditions in 2016.

The loading (utilization) of feeders will continue to increase and is forecasted to grow at approximately 1% per year in the coming years. While utilization varies from 54% to 111% on individual feeders the current utilization for the total of all 13.8 kV feeders in the Focus Study Area is at 79%. Assuming an evenly loaded system the desired utilization is 75%. This indicates that even if it were physically possible to reconfigure the load such that all feeders are evenly loaded, the system would still exceed the desired utilization. Therefore, the entire area load needs additional capacity. As load grows, individual feeder loads will be rearranged to reduce specific overloads but considered as a whole, the distribution system in the Focused Study Area is short of capacity. As load grows and utilization increases the ability to rearrange feeders to serve load during normal and contingency conditions decreases.

4.1.4: Distribution Substation Transformers in the Focused Study Area

The distribution system substation transformers in the Focused Study Area consist of two 13.8 kV transformers and one 34.5 kV transformer. Both are located at the Gleason Lake substation. For the 13.8 kV transformers, at peak load in 2016, there will be no overloads under normal configuration. Under contingency configuration while picking up load after the outage of an adjacent transformer, there is only about 1 MW of additional capacity available before a deficit occurs. For the 34.5 kV transformer, at peak load in 2016 there is no overload under normal configuration but there is an overload under contingency configuration while picking up load after an outage of this transformer. Since there is only one 34.5 kV transformer at the Gleason Lake substation, for loss of the transformer all load must be transferred to 34.5 kV feeders at nearby substations through existing feeder ties. Based on the currently available 34.5 kV transfers, there is a deficit of about 14 MW under contingency in 2016.

4.2: Transmission Need.

4.2.1: Planning criteria

The Transmission need in the Transmission Area of Concern is driven by the need to comply with NSP Transmission Planning Criteria under NERC TPL Standards. The NSP Transmission Planning Criteria is available at www.misoenergy.org. The criteria for voltage and thermal limitations are listed below in Table 4.1.

Voltage Criteria

Table 4.1: Voltage Planning Criteria

	Maximum voltage (p.u.)	Minimum voltage (p.u.)	Maximum voltage (p.u.)	Minimum voltage (p.u.)
Facility	Pre Contingent		Post Contingent	
Default for all buses > 100 kV	1.05	0.95	1.05	0.92
Default for all buses < 100 kV*	1.05	0.95	1.05	0.92
Default for all generator buses**	1.05	0.95	1.05	0.95

*For 34.5 kV load serving buses, pre and post contingent voltage of above .90 PU would be acceptable.
**For all Category A, B and C contingencies, except Category P6. After a Category P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

Line loading criteria

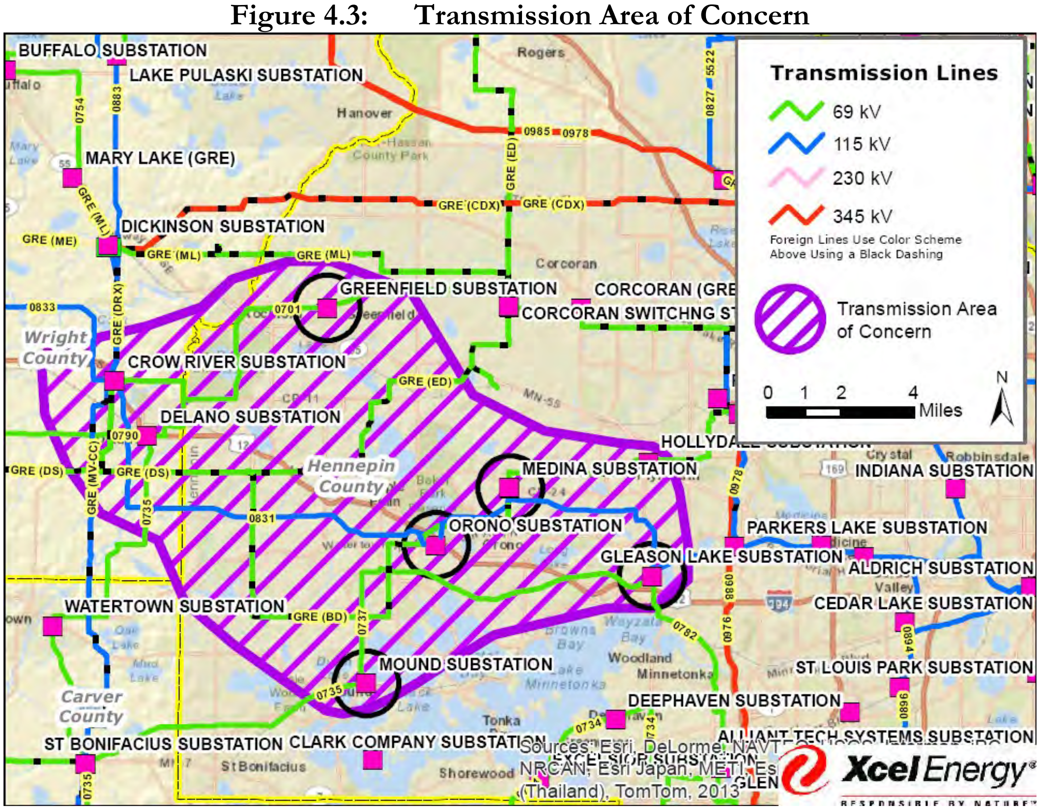
The ratings for facilities owned by NSP are specified in the NSP Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment, and relay loadability limits, as specified in NERC FAC-008 and FAC-009 standards.

When planning NSP's system for system intact conditions, the current flowing through a facility should not exceed the normal rating of that facility. When studying contingency conditions, the current flowing through a facility should not exceed the emergency rating of that facility. During transmission outages, it should be assumed that the system operators would take remedial action when the current on a facility is lower than the emergency rating and greater than the normal rating. When such remedial action is not available, the normal rating of the facility should be used.

4.2.2: Transmission Area of Concern Difficiencies

The transmission system in the western metro around the cities of Plymouth, Medina, and Minnetonka stretching west to Greenfield has reached its load serving limits. This region will be referred to going forward as the Transmission Area of Concern and is served by five substations: Gleason Lake, Greenfield, Medina, Mound, and Orono. Figure 4.3 below shows a map of the Transmission Area of Concern.

Figure 4.3: Transmission Area of Concern



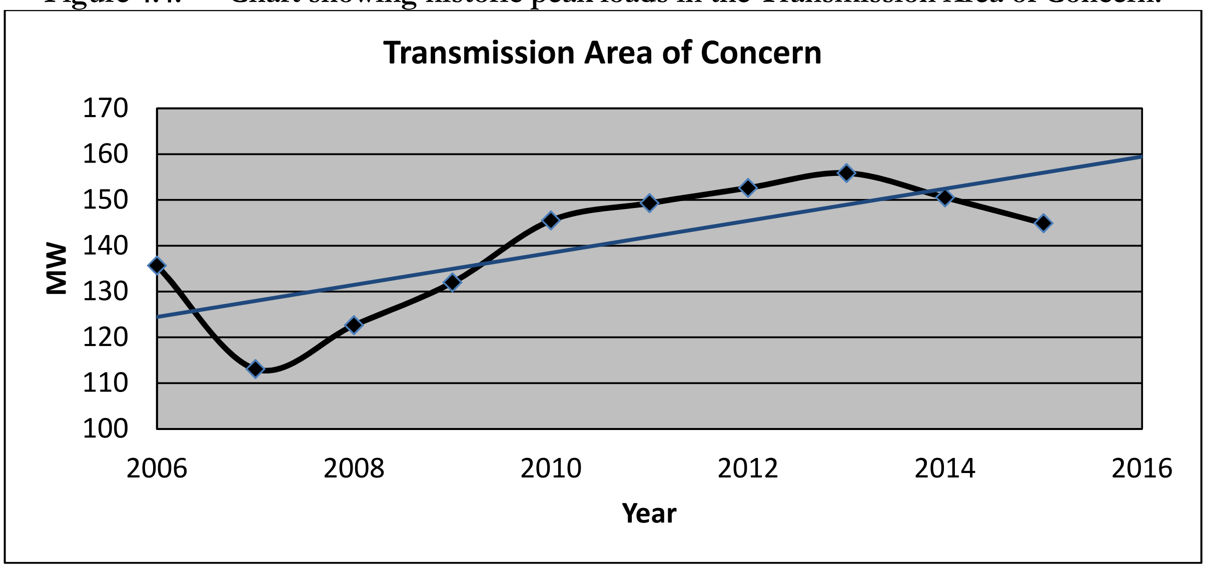
The load in the Transmission Area of Concern peaked in 2013. The load level achieved in 2013 exceeded the capabilities of the transmission system under contingency. Due to this potential NERC violation, Xcel Energy installed Under Voltage Load Shedding (UVLS) to protect the transmission system until a permanent solution is built. The peak load in this area for the last ten years is listed below in Table 4.2:

Table 4.2: Historic peak load in the Transmission Area of Concern.

Transmission Area of Concern	
Year	**MW**
2015	144.90
2014	150.54
2013	155.86
2012	152.62
2011	149.29
2010	145.51
2009	131.97
2008	122.63
2007	113.07
2006	135.67

Figure 4.4 below shows the peak loads for the last ten years plotted. The trend line in blue shows the overall load growth trend in Transmission Area of Concern.

Figure 4.4: Chart showing historic peak loads in the Transmission Area of Concern.

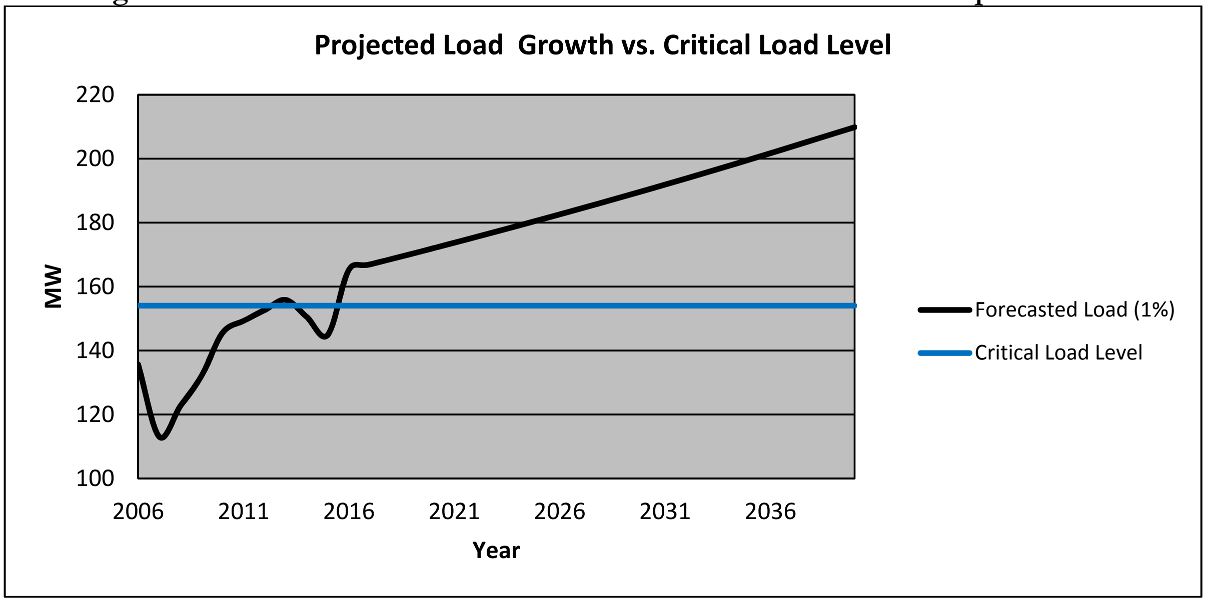


The historical load in the Transmission Area of Concern shows strong load growth, while showing the financial crisis that the US experienced in 2007-2008 which temporarily reduced peak load during that period. The trend line above represents approximately 3.5% load growth; however Xcel Energy believes this is not sustainable over the next 40 years. Since this study is looking at 40 years, a load growth rate of 1% will be analyzed. Note that the load growth is not as important as the total load served in the Transmission Area of Concern. If load growth occurs faster or slower than the analyzed rates, the need year of additional facilities will change accordingly.

Figure 4.5 below shows the peak loads for the last ten years and the future projected loads on a single plot. Power flow simulations were used to identify voltage violations in the Transmission Area of Concern, occurring at 153 MW of area load. This critical load level of 153 MW in the

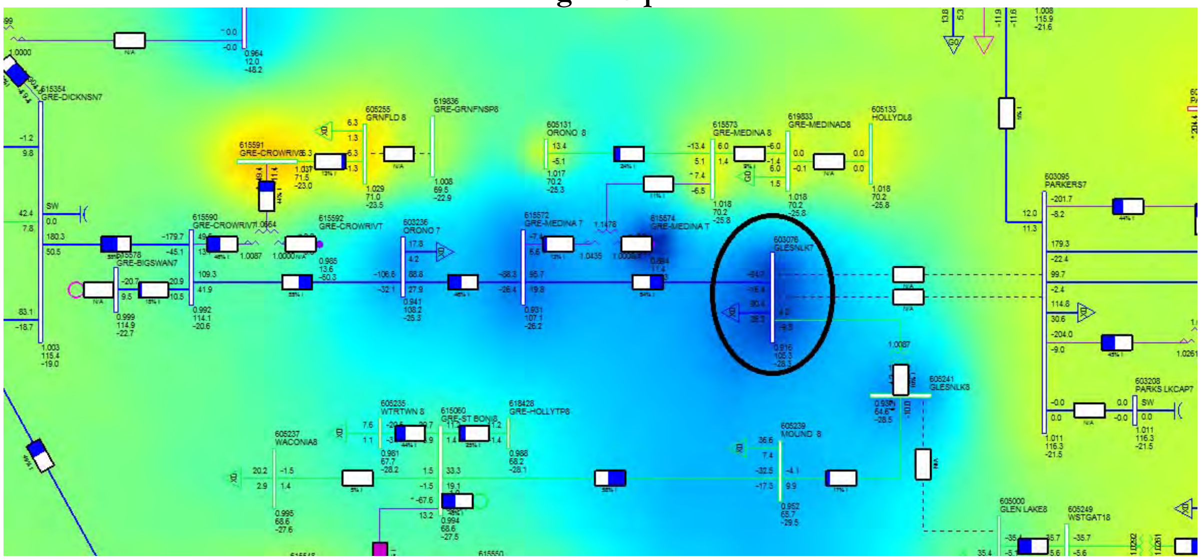
Transmission Area of Concern, which triggers the transmission need, is indicated by the blue line in the figure. The critical load level is independent of load growth and simply states the amount of load which triggers needed system improvements. The black line shows the forecasted loads in the Transmission Area of Concern using a 1% load growth after known load additions have been taken into account. As can be seen in the graph, the critical load level is exceeded in 2016 and beyond.

Figure 4.5: Transmission Area of Concern historic and forecasted peak loads.



Under system peak conditions, the critical contingency condition in the Transmission Area of Concern is the Gleason Lake – Parkers Lake 115 kV double circuit line outage. During this condition, the entire Transmission Area of Concern load is served from a 115 kV path from Dickinson in the west and a 69 kV path connecting to St. Bonifacius in the south. These two sources are not strong enough to support the large load at Gleason Lake, which is located the furthest distance from either source. Figure 4.6 shows the area in a power flow simulation tool which shows the Transmission Area of Concern under the critical condition during a simulated 2013 peak (156 MW). Under this critical condition, the load at Gleason Lake is below acceptable voltage levels. Note that blue means low voltage and red means high voltage, the color gets darker as the voltage gets more severe. Gleason Lake substation is circled in black.

Figure 4.6: Power flow results for Transmission Area of Concern under critical condition during 2013 peak.



5.0: Analysis of the Plymouth Electric Distribution Delivery System in the Focused Study Area

5.1: Feeder circuits

Distribution Planning assessed the electric distribution delivery system's ability to serve existing and future electricity loads in the Focused Study Area by evaluating the historical and forecasted load levels and utilization rates of the 13 feeder circuits (11-13.8kV and 2-34.5kV) that serve the Focused Study Area over a period of 20 years (*i.e.*, target year of 2036). The Planning Engineers then identified existing and anticipated capacity deficiencies resulting in overloads during N–0 (system-intact) and N–1 (single contingency) operating conditions.

In conducting this Study, Planning Engineers relied on the following resources:

- Synergi Electric software package. Synergi is a software tool that can be used to explore and analyze feeder circuit reconfigurations. When historical peak load data is added from the Distribution Asset Analysis ("DAA") software package, Synergi is capable of providing load flow and voltage regulation analysis. Synergi is a tool that can generate geographically correct pictures of tabular feeder circuit loading data. This functionality has been achieved through the implementation of a Geographical Information System ("GIS") extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. All distribution feeders that are part of the Focused Study Area were extracted from the GIS software and imported into Synergi.
- Xcel Energy Distribution Planning Load Forecast for N-0 feeder circuit and substation transformer analysis. Planning Engineers used DAA to record historical non-coincident peak

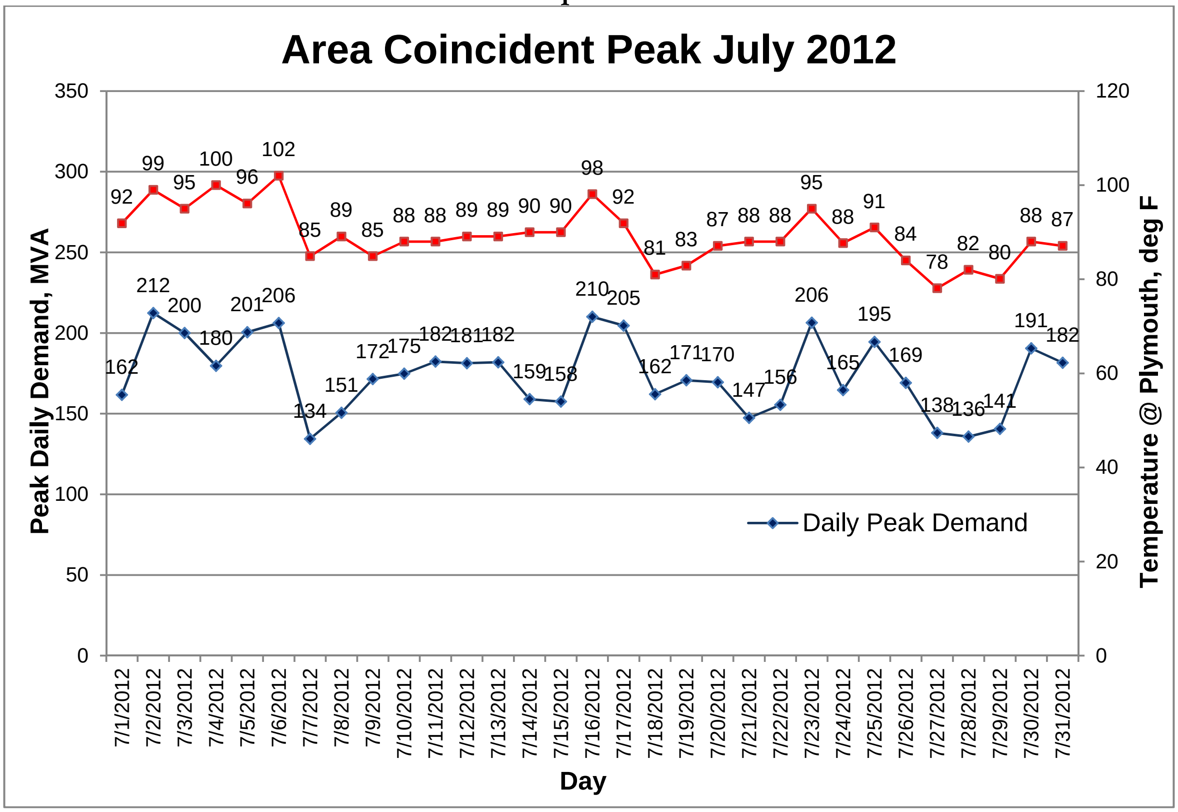
loads on distribution feeder circuits and distribution substation transformers. Distribution Planning Engineers annually examine each distribution feeder circuit and distribution substation transformer for peak loading. They use specific knowledge of distribution equipment, local government plans and customer loads to forecast future electrical load growth. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government sponsored development or redevelopment.

- Xcel Energy Feeder Status Sheets for feeder circuit N-1 load allocation and N-1 analysis. Planning Engineers used Feeder Status Sheet software ("FSS") to allocate measured peak loads to main line feeder sections. Engineers validate and record feeder main line additions and reconfigurations using this tool. They analyze the N-1, first contingency breakdown of each distribution feeder circuit for the forecasted years.
- Xcel Energy Substation One Line Drawings. Planning Engineers used Xcel Energy Computer Aided Design software ("CAD") to develop CAD drawings modified by substation engineers as needed to reflect present substation configurations.
- Xcel Energy Distribution Feeder Maps. Planning Engineers used Xcel Energy CAD software to develop CAD drawings to reflect present feeder circuit mainline and tap configuration.
- Plymouth Maps. Planning Engineers used Internet live search maps to make a map of the area, GIS software and Synergi software tool to make geographic based pictures of the feeder circuit configuration and to illustrate feeder circuit loading levels.

5.1.1: Feeder Circuit Historical Load

Feeder circuit peak loading in the Plymouth area is measured during the summer. Both feeder circuit and substation transformer load correlates to summer temperatures based on customer air conditioning usage in response to summer temperatures. This is illustrated in Figure 5.1, which compares the Gleason Lake and Parkers Lake substation transformer measured peak load and outside temperature during July 2012.

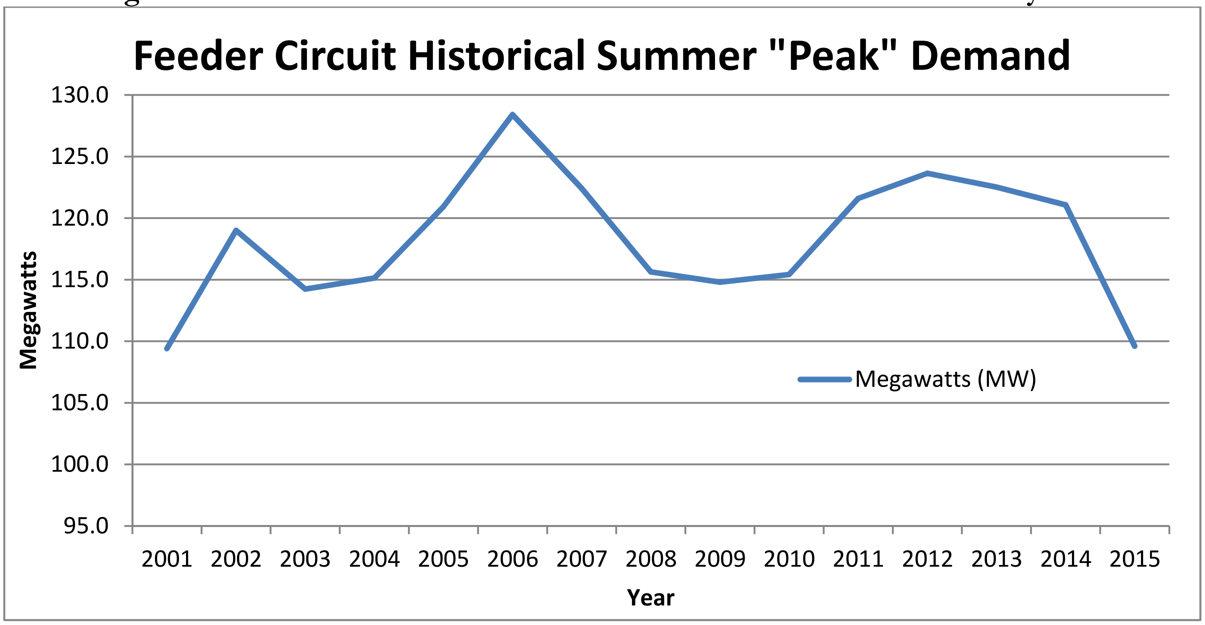
Figure 5.1: July 2012 Gleason Lake and Parkers Lake Substation Peak Load and Outside Temperatures



Each distribution feeder in the Plymouth area has three phase meters located in the substation, which are read monthly and the data recorded in Passport, a record-keeping software. These meters record the monthly peak for the feeder. The distribution feeders in the Focused Study Area also have a SCADA system that monitors the real time average or three phase amps on the feeder. This system feeds a SCADA data warehouse and the DAA warehouse where hourly data is stored so the feeder load history can be viewed by Electric System Planning and Field Operations. When three phase load data is available, the highest recorded phase measurement is used in the distribution forecast. Each feeder circuit non-coincident peak history from 2001 through 2015 is used to forecast 2016 through 2036 peak loads.

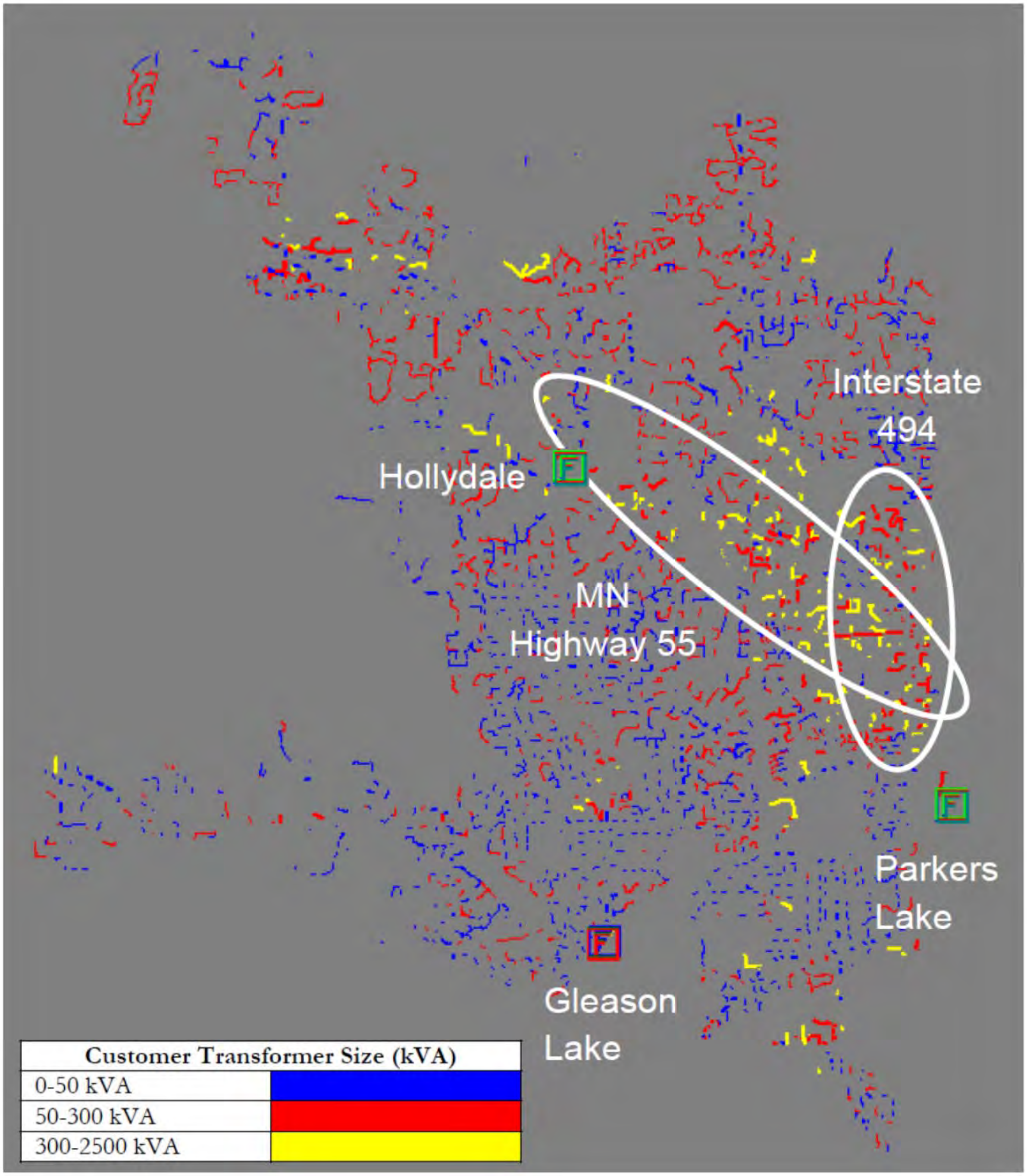
Measured peak loads fluctuate from year to year due to the impacts of the duration and intensity of hot weather and customer air conditioning usage. In the Focused Study Area, feeder circuit load fluctuates in a bandwidth of 5 MW to 14 MW from cooler years to historic peaks occurring in 2002, 2006 and 2012. Even though the measured peak load decreases in cooler years, the historic peak represents latent load levels that will recur in years that have higher temperatures. The measured peak load for feeders increased an average of 0.8% per year in the eight years between 2001 and 2014, the most recent peak year. The historical loads for the feeder circuits serving the Focused Study Area from 2001 through 2015 are shown below in Figure 5.2 and are also detailed in Appendix B.

Figure 5.2: Historical Summer "Peak" Demand for the Focused Study Area



In addition to peak loads, Planning Engineers researched existing customer load density. Individual distribution transformers serve a single customer or multiple customers. As customer load grows in developed areas such as the Focused Study Area, distribution transformers are changed to higher capacity equipment when customer demand exceeds the capacity of the original transformer. Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand. Figure 5.3 is a graphic, developed using Synergi software, illustrating distribution transformer installation by size (which indicates present customer load density) in the Focused Study Area.

Figure 5.3: Distribution Transformer Sizes (Which Is Indicative of Customer Load Density) in Focused Study Area



The customer load serving transformers shown in Figure 5.3 are colored based on the size of the transformer. The largest commercial customers in Plymouth are shown in yellow. Customers in large multi-residence buildings (more than 100 units), large multi-use buildings, large retail stores, or corporate data centers typically have one or more transformers depicted as yellow dots. Customers in small and mid-sized commercial buildings, including retail stores and restaurants are served by smaller transformers that are shown as red. Residential customers and other lowest usage customers are shown in blue. Red and yellow show high density load corridors along MN Highway 55 and Interstate 494.

5.1.2: Feeder Circuit Load Forecasts

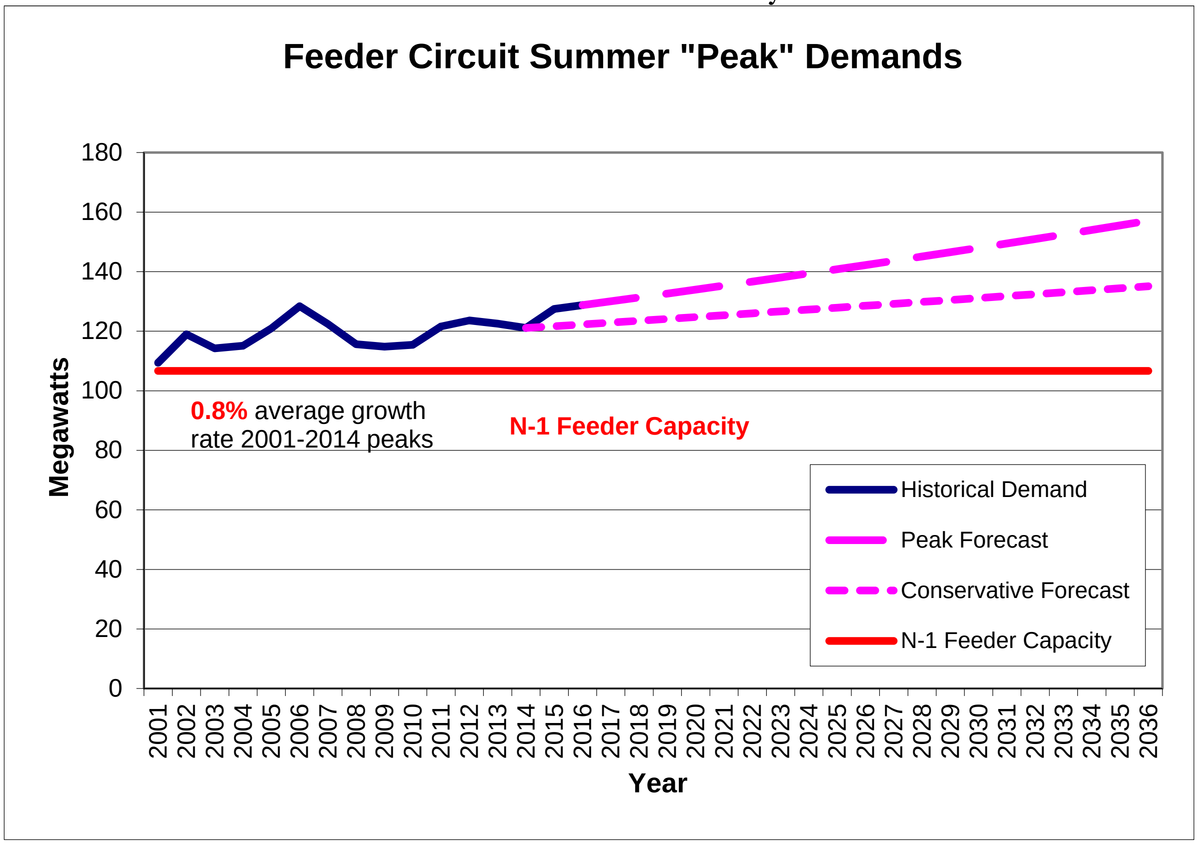
The feeder circuit load is forecasted for each feeder circuit. Feeder circuit load forecast evaluation uses a trending method, which considers a combination of historical growth, customer reported load additions, local government and developer projects or plans, and any additional information that impacts the circuit load growth. The table entries were calculated using the individual feeder circuit forecasts provided in Appendix B.

The historical data analysis of Focused Study Area in the previous section combined the 13.8 kV areas and 34.5 kV areas in order to gain an accurate representation of historical load growth within the Focused Study Area from 2001-2015. The historical load data indicated that the load has been growing within the Focused Study Area over the last decade. To analyze the distribution system for the future and to identify the capacity needs, the 13.8 kV and 34.5 kV areas as identified in Section 3.1 of this Study, also need to be analyzed separately for N-1 contingency capacity. The 34.5 kV feeder analysis includes the embedded Hollydale 13.8 kV feeder load to reflect the impact of the 34.5 kV source at Hollydale.

Distribution Planning took a conservative outlook for forecasting feeder circuit load for this Study because of anticipated customer conservation and a soft economy. Distribution Planning forecasted the feeder loads in 2016 based on recent 2011 to 2013 historic peaks and used a growth rate of 1.0% to forecast load levels on the eleven 13.8 kV feeders and two 34.5 kV feeders for the next 20 years, representing growth in demand of approximately 28 MW by 2036.

Figure 5.4 is a linear depictions of the load growth on the eleven 13.8 kV feeder circuits and the two 34.5 kV feeder circuits in the Focused Study Area from 2001 through 2036. The "Conservative Forecast" line depicts loads forecast based on the lower year peak loads from 2014 and with a 0.5% growth rate. The upper limit peak load forecast is also shown ("Peak Forecast") from 2016 based on 2011 to 2013 historic peak loads for the feeders. By 2036, this upper limit forecast is 14 MW above the conservative peak load forecasts shown in the figure. Actual peak loads will likely fall between the conservative forecast demand and the historic peak levels. Average load growth for the time period is calculated by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period.

Figure 5.4: Historical and Forecasted Load Growth on Eleven 13.8 kV and Two 34.5 kV Feeder Circuits in Focused Study Area



Over time, demand on the distribution system generally trends upward, with some dips due to weather or economic downturns. The historic downturns have been followed by increases in demand that reach levels equal to or greater than the prior peak. For example, from the year 2002 to the year 2004, demand declined. Then, from the year 2004 to the year 2006, demand increased again reaching a new peak. From year 2006 to 2009, there was a similar decline in demand from the 2006 peak. Again, from the year 2010 to the year 2012, demand increased, reaching a new peak. For the years 2014 a small dip was again seen. It can be reasonably expected that higher summer peak load levels will recur within the next several years once temperatures approach the same levels that occurred in the 2012 summer season.

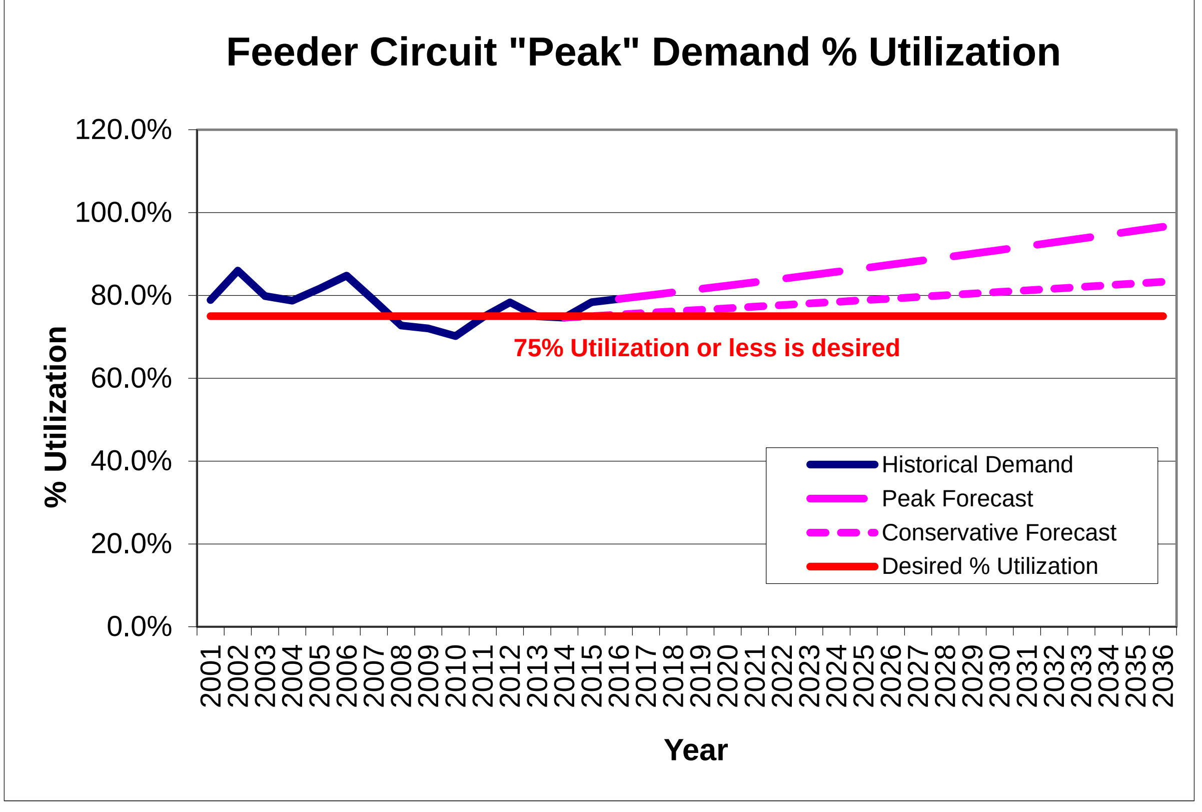
5.1.3: Feeder Circuit Overloads and Utilization Percentages

As discussed in Section 4.1, Distribution Planning aims to maintain utilization rates at or below 75% on distribution feeder circuits to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. This desired loading level of 75% only applies to the 13.8 kV feeder circuits, the 34.5 kV feeder circuits have a unique configuration and therefore have a different desired loading level. There are only two 34.5 kV feeder circuits in this geographical area and therefore the feeder circuits only have one tie for backup during a contingency situation, while the 13.8 kV feeders generally have 3 ties, as described in Section 4.1. Since the 34.5 kV feeder circuits only have one tie as opposed to three, their desired loading level is 50%. At 50% utilization, each feeder circuit can fully back the other one up during N-1 conditions.

To assess the robustness of the system in the Focused Study Area over time, Planning Engineers analyzed the historical utilization rates and projected utilization rates of the 13.8 kV and 34.5 kV feeder circuits based on forecast demand. Planning Engineers examined the historical loading and utilization of the eleven 13.8 kV feeder circuits and two 34.5 kV feeder circuits that serve Focused Study Area load. Figure 5.5 and Figure 5.6 show the conservative forecast linear growth ("Conservative Forecast") of feeder circuit utilization for the eleven 13.8 kV and two 34.5 kV feeder circuits between 2001 and 2036 as well as the upper-limit peak load forecast ("Peak Forecast") based on historic peak load levels forecasted to 2016.

The feeder circuit load history shown is actual average non-coincident peak loading of the eleven 13.8 kV feeder circuits and the two 34.5 kV feeder circuits measured at the beginning of the feeder circuit in the substation. The sum of the individual feeder circuit peak loads is compared to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year.

Figure 5.5: Focused Study Area – Eleven 13.8 kV Feeder Circuits, Utilization Percentage



The above analysis demonstrates a capacity need on the 13.8 kV distribution system within the Focused Study Area. Utilization rates of the 13.8 kV feeder circuits have exceeded the desired 75% utilization level most years since 2001. Even using the more conservative forecast based on the lower summer peaks of 2014, average utilization rates on the 13.8 kV feeder circuits will exceed 80% by approximately 2036 unless system improvements are made. A peak load forecast starting from 2016 based on the recent 2011-2013 peak levels provides an upper forecast limit well above the conservative forecast utilization levels in Figure 5.5.

Figure 5.6: Focused Study Area – Two 34.5 kV Feeder Circuits, Utilization Percentage

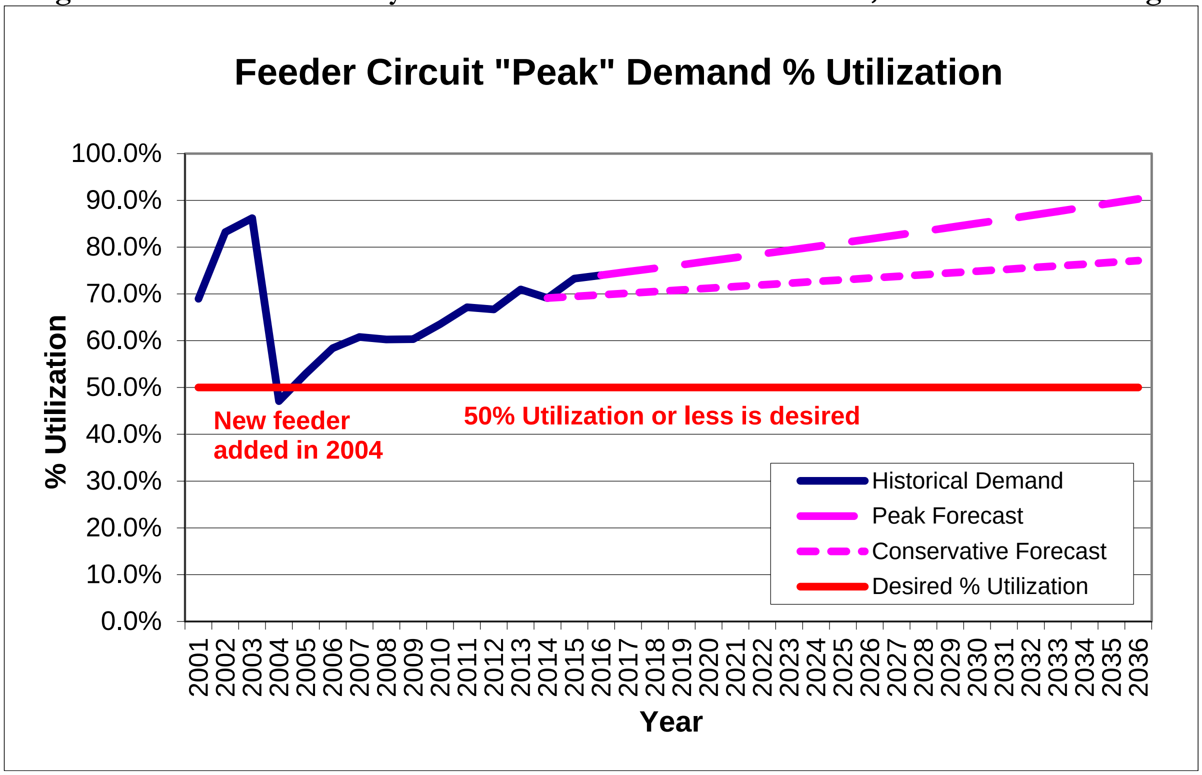


Figure 5.6 shows the same analysis of the 34.5 kV feeder circuits as depicted in Figure 5.5 for the 13.8 kV feeder circuits. This analysis also demonstrates a capacity need on the 34.5 kV distribution system within the Focused Study Area. The change in utilization from 2003 to 2004, is due to the addition of the second 34.5 kV feeder circuit in the Focused Study Area. Even with this capacity addition, peak load levels still continued to exceed the desired 50% loading level. Just as on the 13.8 kV distribution system within the Focused Study Area, these utilization levels are only projected to increase unless system improvements are made.

More than the 13.8 kV feeders in Figure 5.5, Figure 5.6 shows that demand on the 34.5 kV system generally trends upward. Unlike the 13.8 kV feeders, there are no significant dips due to weather or economic downturns, indicating that the 34.5 kV system has experienced significant growth over the last decade. It can be expected that steady growth on the existing load should be expected to occur especially since the 34.5 kV system serves several new load growth areas.

Figure 5.7: Focused Study Area – Two 34.5 kV Feeder Circuits without Hollydale 13.8 kV load

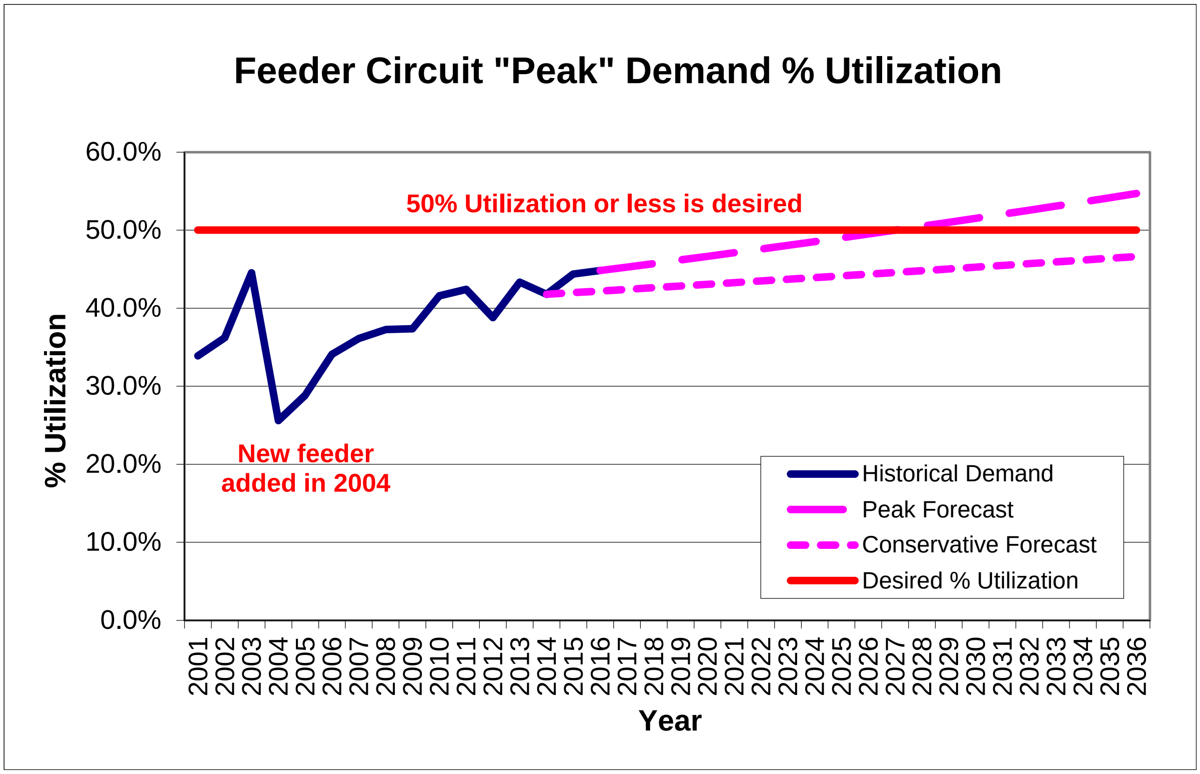


Figure 5.7 shows an analysis of the 34.5 kV feeder circuits as depicted in Figure 5.6 but without the two 13.8 kV feeder circuits, HOL061 and HOL062, sourced from a 34.5 kV feeder at Hollydale substation. This analysis also demonstrates a capacity need on the 34.5 kV distribution system within the Focused Study Area even without the Hollydale load. If there was another source to serve Hollydale substation, the peak load levels are still forecasted to exceed the desired 50% loading level.

Table 5.1 and Table 5.2 provide additional detail on the historical and anticipated utilization percentages and overloads for the eleven 13.8 kV feeder circuits and two 34.5 kV feeder circuits in the Focused Study Area for various years between 2001 and 2036.

Table 5.1: Summary of Feeder Circuit Utilization and Overloads for the Eleven 13.8 kV Feeder Circuits in the Focused Study Area

Historical and Peak Forecast Feeder Circuit Utilization and Overloads									
	2001	2006	2012	2014	2016	2020	2025	2030	2036
# of Circuits	11	11	11	11	11	11	11	11	11

MW Capacity	124	124	124	124	124	124	124	124	124
Feeder Actual	2001-2014 Average								
% Growth	-0.4%								
% Utilization	81%	87%	80%	81%					
Forecast					2016-2036 Average				
% Growth					1.0%			1.0%	
% Utilization					81%	84%	88%	93%	98%
N-0 Overloads									
# Severe >115%	0	2	0	1	0	1	1	2	4
# of Circuits > 100%	2	4	4	3	2	4	5	5	5
MW > 100%	1.4	5.3	2.1	2.3	1.6	3.1	5.3	8.3	12.1
N-1 Conditions									
# of Circuits > 75%	7	7	5	5	6	6	6	7	8
MW > 75%	15.0	19.1	13.5	14.0	13.6	16.1	19.4	23.2	28.5

Table 5.2: Summary of Feeder Circuit Utilization and Overloads for the Two 34.5 kV Feeder Circuits in the Focused Study Area

Historical and Peak Forecast Feeder Circuit Utilization and Overloads									
	2001	**2006**	**2012**	**2014**	**2016**	**2020**	**2025**	**2030**	**2036**
# of Circuits	1	2	2	2	2	2	2	2	2

MW Capacity	34	68	68	68	68	68	68	68	68
Feeder Actual	2001-2014 Average								
% Growth	7.7%								
% Utilization	69%	58%	67%	69%					
Forecast					2016-2036 Average				
% Growth					1.0%			1.0%	
% Utilization					74%	77%	81%	85%	90%
N-0 Overloads									
# Severe >115%	0	0	0	0	0	0	0	0	0
# of Circuits >100%	0	0	0	0	0	0	1	1	1
MW > 100%	0	0	0	0	0	0	1.3	3.1	5.4
N-1 Conditions									
# of Circuits > 50%	1	1	1	2	2	2	2	2	2
MW > 50%	6.5	5.7	11.4	13.0	16.4	18.4	21.1	23.9	27.5

The information in Table 5.1 and Table 5.2, which was extracted from the detailed feeder circuit forecast data in Appendix B, shows that the Focused Study Area distribution system experienced stable or steady peak growth in the decade leading up to 2014 loads that increasingly exceeded circuit capacities with increasing numbers of circuits overloaded in both system intact N-0 and first contingency N-1 conditions for the 34.5 kV feeders since they serve more of the new load areas and were used to relieve the 13.8 kV feeders. Table 5.3 summarizes the additional feeder circuit capacity (in MW) needed to mitigate the overloads detailed in Table 5.1 and Table 5.2. The assumption was made for purposes of analysis new feeders would be 13.8 kV and if 34.5 kV distribution system was expanded a comparable amount would be added. A single new 13.8 kV feeder circuit will have 13.6 MW of capacity and will serve 10 MW of load at 75% utilization. A single new 34.5 kV feeder circuit will have 34 MW of capacity and will serve 17 MW of load at 50% utilization.

Table 5.3: Summary of Feeder Circuit Capacity Required to Mitigate the Feeder Circuit Overloads

Minimum Number of Feeders Required to Correct N-0 and N-1 Overloads									
	2001	**2006**	**2012**	**2014**	**2016**	**2020**	**2025**	**2030**	**2036**
N-0 Deficiency (MW)	1.4	5.3	2.1	2.3	1.6	3.1	6.6	11.4	17.5
Minimum # of New Feeders Needed	1	1	1	1	1	1	1	1	2
N-1 Deficiency (MW)	21.5	24.8	24.9	27.0	30.0	34.5	40.5	47.1	56.0
Minimum # of New Feeders Needed	3	3	3	3	3	4	4	5	6

Note: Minimum number of feeders assumes 13.6 MW feeder circuits loaded to 75% or less.

This analysis shows that there is currently a total deficit of approximately 30 MW in the Focused Study Area based on the individual feeder 2016 peak load forecast and the feeder capacities under N-1 conditions. 2016 loading levels represent established overloads for connected load that exists on the electrical system, forecasted growth and peak loading that has been previously reached under the most recent hottest weather conditions. Using conservative forecasting methods, which use the cooler summer peaks of 2014 as a starting point; by 2036, the area deficit based on evenly loaded feeders will be 29 MW, essentially returning to the 2016 total deficit level.

Areas like Plymouth that experience strong and steady growth and redevelopment go through several stages of overload operating conditions, starting with isolated feeder circuit overloads and progressing to widespread overloads that exceed substation transformer capacity limits.

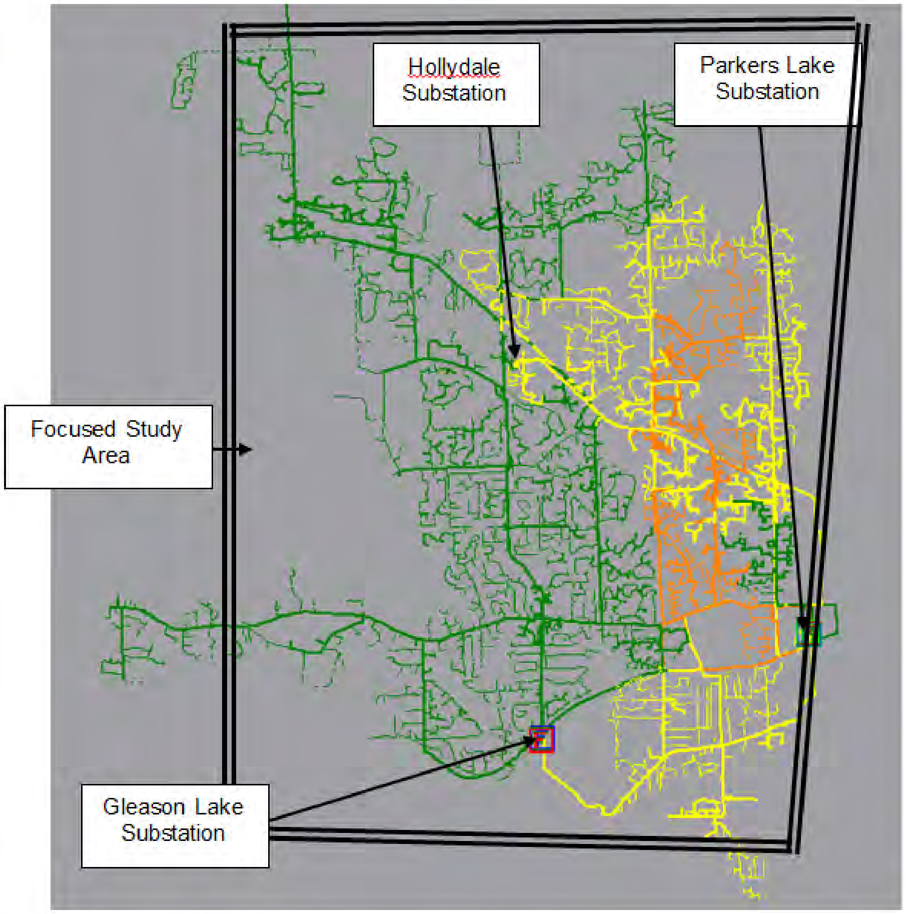
Isolated feeder overloads, which can be characterized by average feeder utilization percentage less than 75% (50% on the 34.5 kV distribution system), typically occur when there is redevelopment that increases load demand within a small part of the distribution system. While the average utilization percentage generally indicates the loading level of the entire Focused Study Area, feeders that are located geographically distant from each other can have either satisfactory capacity to serve customer load or alternately measure severe overloads. This variant is often caused by customer load mobility that can be characterized by new load or area redevelopment and revitalization.

Widespread feeder overloads, which can be characterized by average feeder utilization percentage of more than 75% (50% on the 34.5 kV distribution system), typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or City initiatives. Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

To better illustrate the number, concentration and location of the historical and forecasted overloads, Planning Engineers developed distribution system maps depicting the overloaded feeder circuits in N-0 system intact and N-1 first contingency operating conditions for 2016 and future forecast year 2036 based on the peak forecast. These distribution system maps are depicted in Figure 5.8 and Figure 5.9 for N-0 and Figure 5.10 and Figure 5.11 for N-1. The color codes in the distribution system maps represent rows in Table 5.1 and Table 5.2 for the labeled years as follows:

- <u># Severe > 115%, N-0 Overloads</u>: The quantity of feeder circuits that are severely overloaded under system intact conditions are identified as shown in red.
- <u># of Circuits >100%, N-0 Overloads</u>: The quantity of feeder circuits that are overloaded under system intact conditions are identified as shown in orange and red depending on the severity of the overload with red feeder circuits having the most severe overloads.
- <u># Circuits > 75%, N-0 Conditions</u>: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in yellow, orange, and red. Yellow circuits are feeder circuits with the lowest first contingency overloads.
- <u># Circuits < 75%, N-0 Conditions</u>: The quantity of feeder circuits that are loaded below 75% capacity indicating no first contingency overload conditions are identified as shown in green.
- <u># Circuits > 75%, N-1 Conditions</u>: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in red.
- <u># Circuits < 75%, N-1 Conditions</u>: The quantity of feeder circuits that are loaded below 75% capacity indicating no first contingency overload conditions are identified as shown in green.

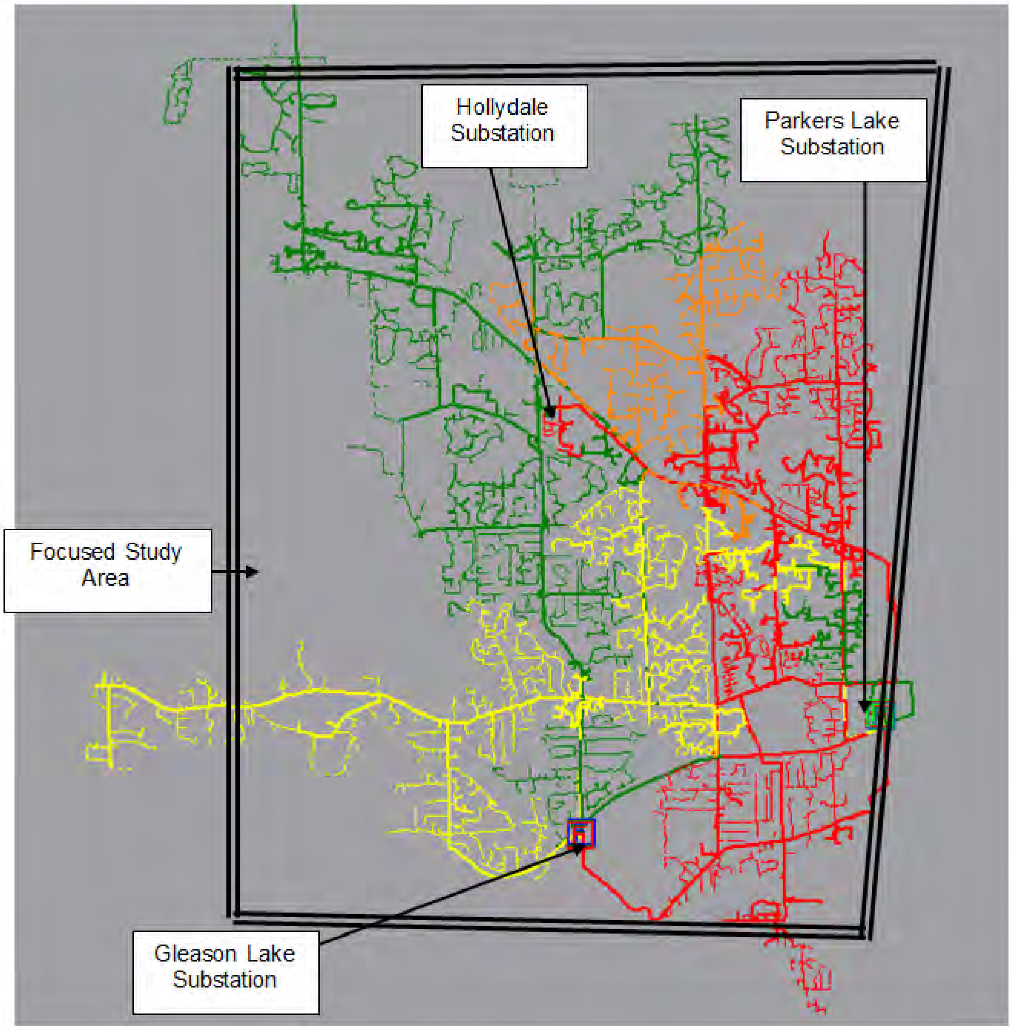
Figure 5.8: Focused Study Area 2016 N-0 Feeder Circuit Loading – System Intact



Feeder Circuits Colored by N-0 Circuit Loading:		
5 Circuits	<75% or<50%	
6 Circuits	50or75%-100%	
2 Circuits	100%-115%	
0 Circuits	>115%	

Figure 5.8 shows that of the thirteen feeder circuits in the Focused Study Area, in the forecasted feeder peak year of 2016, under system intact N-0 conditions, 5 feeders were utilized at less than 50% or 75%, 6 feeders were utilized between 50% or 75%-100%, 2 feeders were utilized between 100%-115%, and 0 circuits were utilized at greater than 115%. Note that many of the most severe overloads occur along previously identified areas of more concentrated load and faster load growth.

Figure 5.9: Focused Study Area 2036 N-0 Feeder Circuit Loading – System Intact



Feeder Circuits Colored by N-0 Circuit Loading:		
3 Circuits	<75%or<50%	
4 Circuits	50or75%-100%	
2 Circuit	100%-115%	
4 Circuits	>115%	

Figure 5.9 shows that of the thirteen feeder circuits in the Focused Study Area, based on 2036 forecasted load under system intact N-0 conditions, 6 feeders will be overloaded. The 6 overloaded feeders consist of 2 feeders utilized between 100%-115%, and 4 circuits utilized at greater than 115%.

Overloads are even more widespread across the feeder circuits in the Focused Study Area under N-1 loading conditions. Figure 5.10 and Figure 5.11 color codes represent first contingency overloads existing for 2016 and forecasted for 2036. A comparison of Figure 5.10 and Figure 5.11 shows that forecasted load levels result in increasing N-1 overload conditions. When a typical single feeder circuit fails during peak loading conditions, the main-line of the failed circuit is switched into three sections (the whole feeder is switched on a 34.5 kV feeder) and each one of the three sections is transferred to a separate adjacent feeder circuit. Adjacent feeders must not be already encumbered by the load of a prior feeder circuit failure or scheduled switching event. The N-1 data provided in this section of the Study for the feeder circuits serving the Focused Study Area are based on the loss of a single mainline feeder circuit. The circuits that will experience an overload under first contingency conditions are shown in red. Feeder circuits shown in red demonstrate the cumulative effect on the feeder circuits of switching the load from any single feeder circuit failure during peak loading conditions.

Figure 5.10: Focused Study Area 2016 N-1 Feeder Circuit Loading – Single Contingency

Feeder Circuits Colored by N-1 Circuit Loading:		
5 Circuits	No N-1 Risk	
8 Circuits	N-1 Risk	

Above Figure 5.10 shows that of the 13 feeder circuits in the Focused Study Area, in 2016 under single contingency N-1 conditions, 8 feeders would be at risk for experiencing overload conditions.

Figure 5.11: Focused Study Area 2036 N-1 Feeder Circuit Loading – Single Contingency

Feeder Circuits Colored by N-1 Circuit Loading:		
3 Circuits	No N-1 Risk	
10 Circuits	N-1 Risk	

Above Figure 5.11 shows that of the thirteen feeder circuits in the Focused Study Area, under 2036 forecasted load under single contingency N-1 conditions, 10 feeders would be at risk for experiencing overload conditions.

The data demonstrates that the Focused Study Area has been experiencing higher than optimal utilization rates on its feeders for over a decade. Without additional capacity additions in the area, these high utilization rates will increase the number and duration of overloads on feeders. Based on this analysis, Distribution Planning concluded that to ensure continued reliable service in the area, additional improvements are required.

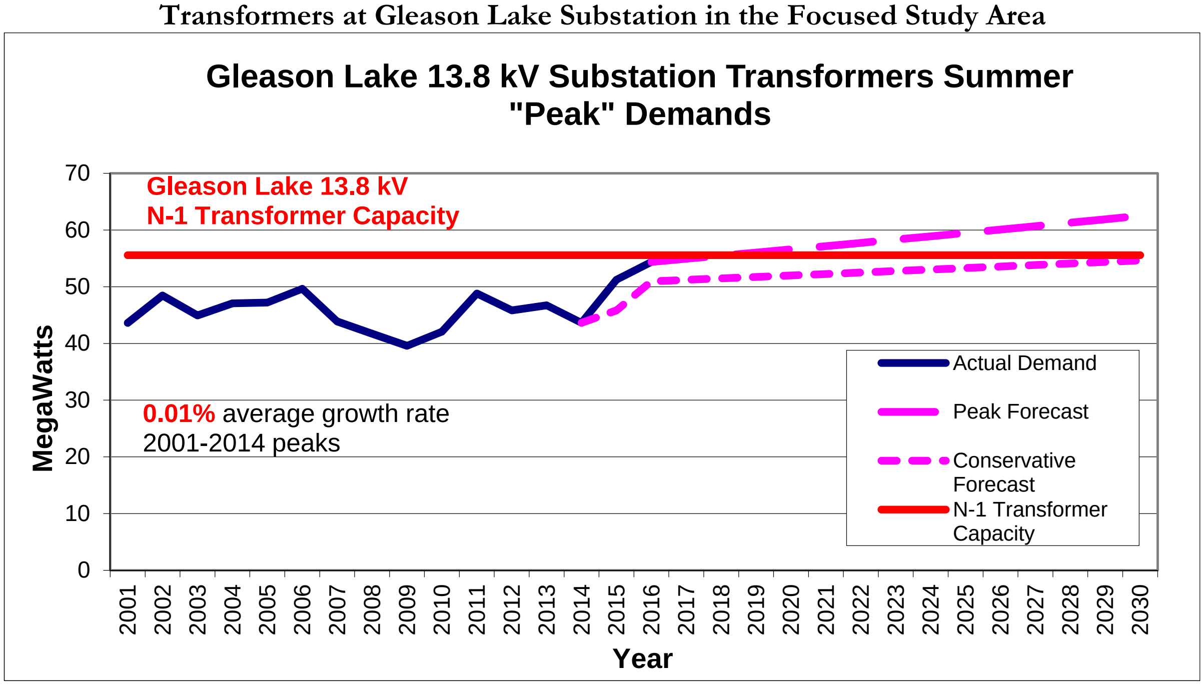
5.2: Gleason Lake Substation Transformers

After examining feeder circuit peak demands, Distribution Planning Engineers looked at the loading levels for the two 13.8 kV transformers and the one 34.5 kV transformer housed at the Gleason Lake Substation. Gleason Lake Substation is the only substation served by transmission that is in the Focused Study Area. Hollydale substation also lies within the Focused Study Area however, as discussed earlier, its ability to provide additional capacity is dependent on the available 34.5 kV capacity at Gleason Lake substation

5.2.1: Gleason Lake Substation Transformer Historical Load and Load Forecasts

The historical and forecasted loads for the two 13.8 kV and one 34.5 kV Gleason Lake Substation transformers serving the Focused Study Area from 2001 through 2036 are included in Appendix A and B. Figure 5.12 shows the conservative load growth ("Conservative Forecast") on the two 13.8 kV substation transformers at the Gleason Lake Substation from 2001 through 2036 as well as the upper limit forecast load based on 2016 forecast peak load levels ("Peak Forecast").

Figure 5.12: Historical and Forecasted Load Growth on Two 13.8 kV Substation Transformers at Gleason Lake Substation in the Focused Study Area



Gleason Lake Substation transformer loads fluctuate in a narrow bandwidth between historic peak load years in 2002, 2006 and 2011 and lower peak load levels during other years. The significant load increase in 2015 and 2016 is from a known large development in Wayzata. Actual peak load levels will likely fall between the conservative forecast demand and the historic peak forecast load levels illustrated in the above figure.

Above Figure 5.12 indicates that historically the 13.8 kV load levels at Gleason Lake substation have approached the N-1 substation limit, but have not exceeded the limit. Using the peak forecast demand load projections, there is roughly only 1 MW of additional load serving capacity on the 13.8 kV Gleason Lake distribution system in 2016. Using the conservative forecast demand load projections, there is roughly 5 MW of additional load serving capacity on the 13.8 kV Gleason Lake distribution system in 2016. Earlier analysis in Table 5.1 demonstrates that even with this 5 MW of additional load serving capacity, the capacity deficiencies on the 13.8 kV distribution system within the Focused Study Area cannot be fully solved.

Figure 5.13 shows the same analysis done on the 34.5 kV substation transformer at Gleason Lake substation.

Figure 5.13: Historical and Forecasted Load Growth on One 34.5 kV Substation Transformers at Gleason Lake Substation in the Focused Study Area

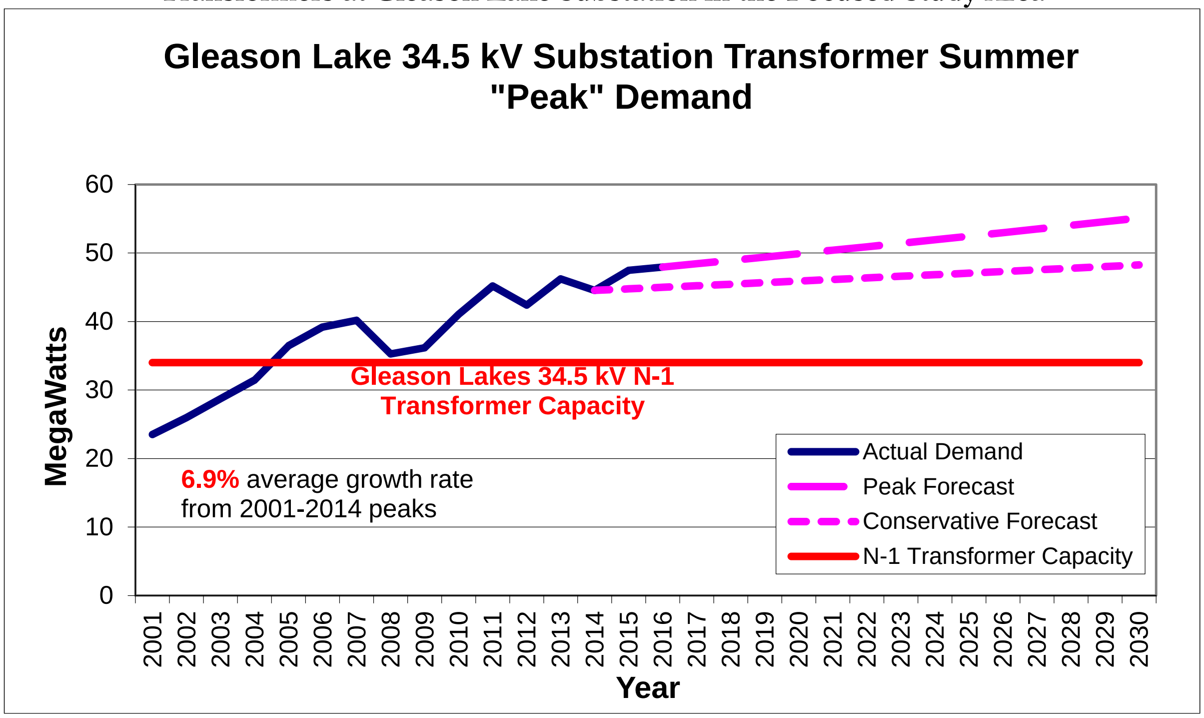


Figure 5.13 shows that the 34.5 kV substation transformer at Gleason Lake substation has experienced loading a larger load growth compared to the 13.8 kV substation transformers. The load on the 34.5 kV substation transformer has exceeded the N-1 limit. Using the peak forecast demand load projections, the load serving capacity is exceeded by roughly 14 MW on the 34.5 kV Gleason Lake transformer in 2016. Using the conservative forecast demand load projections the load serving capacity is exceeded by roughly 11 MW on the 34.5 kV Gleason Lake transformer in 2016. Using the peak or conservative forecast demand projections, there is no additional load serving capacity on the 34.5 kV Gleason Lake distribution system. As previously stated, there is not enough capacity to solve the deficiencies on the distribution system in the Focused Study Area. Combining the shortage of load serving capacity on the 34.5 kV substation transformer with the available capacity on the 13.8 kV substation transformers, the deficiencies cannot be fully solved.

With Gleason Lake substation presently at its maximum design capacity, coupled with the analysis above, Distribution Planning concluded that Gleason Lake substation transformers do not have the required capacity to solve the capacity issues within the Focused Study Area.

6.0: Transmission Reliability Analysis

6.1: NERC Criteria

For this study, North American Electric Reliability Corporation (NERC) TPL-001-4 Standard Category P0-P7 contingencies were analyzed. Table 6.1 below shows the table of NERC Definitions for TPL-001-4 Standard Category P0-P7 contingencies, which is available at www.nerc.com.

Table 6.1: NERC TPL-001-4 Category P0-P7 Definitions

Table 1 – Steady State & Stability Performance Planning Events

Category	Initial Condition	Event 1	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments9	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on	SLG	EHV	No[9]	No

stuck breaker[10])		one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section		HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

6.2: Models

The base steady state model used in this study was a MRO 2014 series 2015 Summer Peak model. The only topology changes made were to correct the transformer tap ratio at Gleason Lake and lock the Dickinson cap. The Dickinson capacitor was locked off due to the recommendation of Great River Energy, the company who owns and operates Dickinson substation. To create the primary case used in this study, the loads in the base model were changed to mimic the 2013 peak loads for the Transmission Area of Concern and then scaled to meet the latest forecast for a 2016 case. All future cases were scaled based on this 2016 case.

No dynamic models were used and no dynamic analysis was completed as part of this study because engineering judgment determined dynamic simulations were not required.

No short circuit models were used and no short circuit analysis was completed as part of this study because engineering judgment determined a short circuit study was not required at this time.

6.3: Load Forecast for Transmission Area of Concern

Table 6.2 includes the forecasted loads in MW from the 2015 Distribution Forecast. These forecasted values were used in the transmission planning study. Note that Table 6.2 has a 1% load growth rate. Table 6.3 has a 2% growth rate and was used as a sensitivity in the transmission planning analysis.

Table 6.2: Forecasted loads in MW in the Transmission Area of Concern using a 1% growth rate

1% Growth	Gleason Lake	Medina	Mound	Orono	Greenfield	Total
2016	97.8	6.3	38.8	17.8	4.6	165.3
2017	98.8	6.4	39.2	18.0	4.6	166.9
2020	101.8	6.6	40.3	18.5	4.8	172.0
2025	107.0	6.9	42.4	19.5	5.0	180.8
2030	112.5	7.2	44.6	20.4	5.3	190.0
2035	118.2	7.6	46.8	21.5	5.6	199.7
2040	124.2	8.0	49.2	22.6	5.8	209.9

Table 6.3: Forecasted loads in MW in the Transmission Area of Concern using a 2% growth rate

2% Growth	Gleason Lake	Medina	Mound	Orono	Greenfield	Total
2016	97.8	6.3	38.8	17.8	4.6	165.3
2017	98.8	6.4	39.2	18.0	4.6	166.9
2020	104.9	6.8	41.5	19.1	4.9	177.2
2025	115.8	7.5	45.9	21.1	5.4	195.6
2030	127.8	8.2	50.6	23.2	6.0	216.0
2035	141.1	9.1	55.9	25.7	6.6	238.4
2040	155.8	10.0	61.7	28.3	7.3	263.3

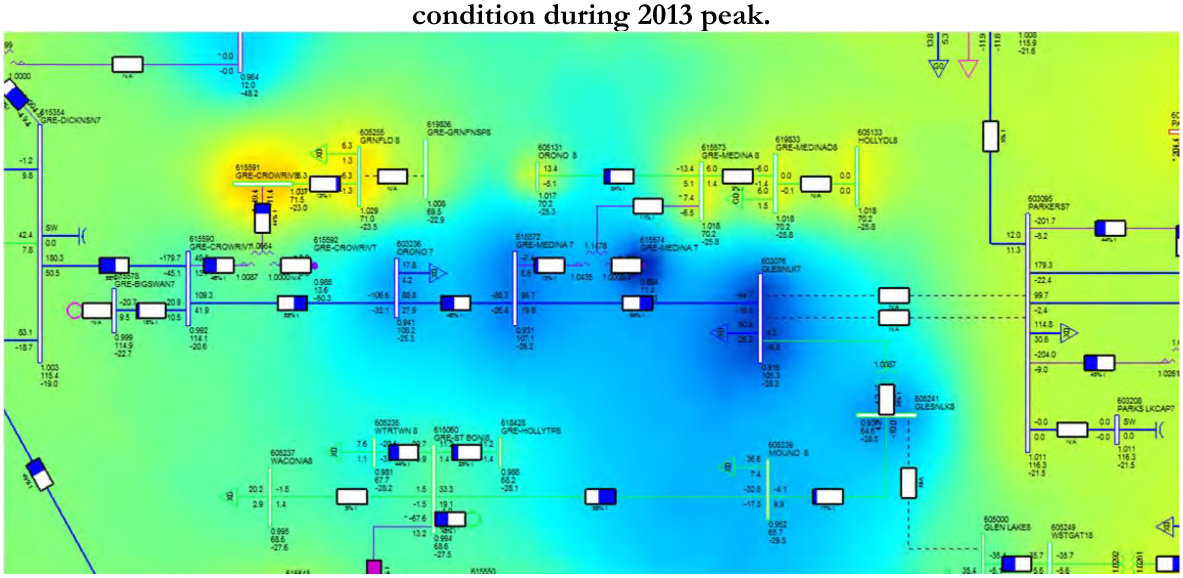
6.4: Powerflow Analysis

6.4.1: Worst Contingencies

Three contingencies were identified during the ACCC analysis as causing thermal or voltage violations. The first contingency, showing violations at 153 MW, is a Category P7 which results in the loss of the Gleason Lake – Parkers Lake 115 kV double circuit line causing low voltage at Gleason Lake substation (Contingency #1). The second, showing violations at 153 MW, is a Category P6 which results in the loss of both Gleason Lake – Parkers Lake 115 kV lines causing low voltage at Gleason Lake substation (Contingency #2). The third, showing violations around 195 MW, is a Category P6 which includes the loss of the Dickinson 345/115 kV transformer coupled with the loss of one Gleason Lake – Parkers Lake 115 kV, which causes the other Gleason Lake – Parkers Lake 115 kV line to overload (Contingency #3). The difference between Contingency #1, Contingency #2, and Contingency #3 is that Contingency #1 is a single initiating event and no system adjustments are allowed. Contingency #2 and Contingency #3 include the loss of two system elements, with system adjustment in between each event.

Figure 6.1 shows the Transmission Area of Concern in a power flow simulation tool under the critical condition of Contingency #1 during a simulated 2013 peak (156 MW). Under this critical condition, the load at Gleason Lake is below acceptable voltage levels. Note that blue means low voltage and red means high voltage, the color gets darker as the voltage gets more severe.

Figure 6.1: Power flow results for the Transmission Area of Concern under the critical condition during 2013 peak.

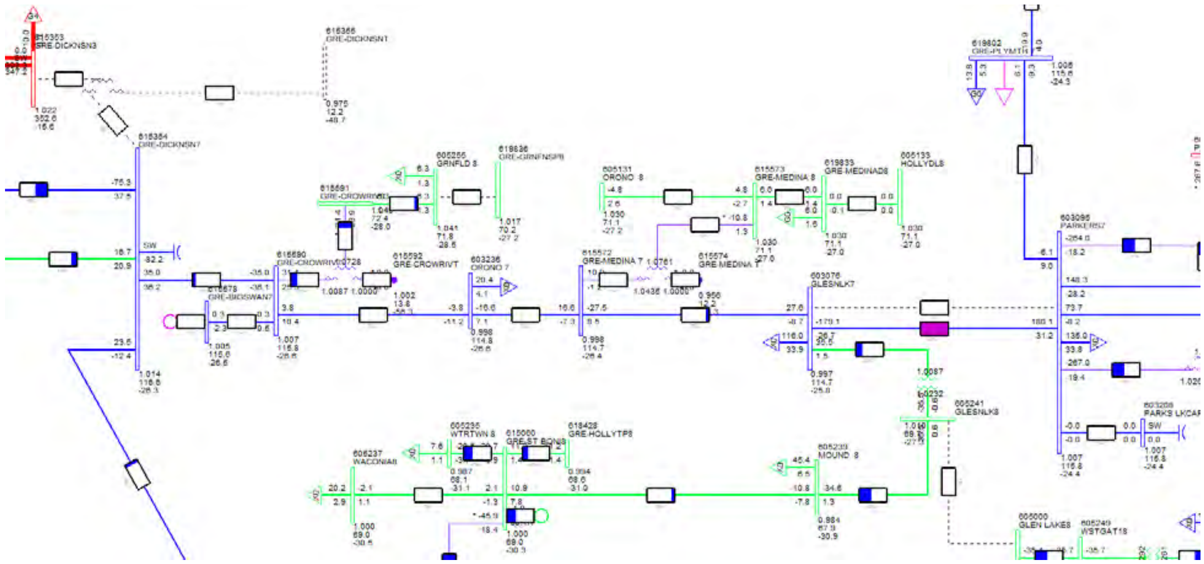


Due to the low voltage at Gleason Lake under the critical condition, Under Voltage Load Shedding (UVLS) has been installed at Gleason Lake until a permanent project is constructed. The UVLS will automatically shed customer load if triggered. Currently there are two feeders on the first step of this UVLS, which totals as much as 41 MW on peak. As load grows in the Gleason Lake area, the amount of load on UVLS would likely increase.

Since Contingency #1 and Contingency #2 are very similar conditions, but Contingency #1 is more limiting, the initial analysis focused on Contingency #1 as the critical condition. Contingency #2 becomes the critical condition if Contingency #1 is eliminated.

Contingency #3 is a P6 contingency resulting in loss of Dickinson 345/115 kV transformer along with one Gleason Lake – Parkers Lake 115 kV line. Under this P6 condition, the loading on the remaining Gleason Lake – Parkers Lake 115 kV line is above its thermal loading emergency rating. Figure 6.2 shows the Transmission Area of Concern in a power flow simulation for Contingency #3. This overload occurs at approximately 195 MW, which equates to 2025 if 2% load growth is assumed and 2032 if 1% load growth is assumed. Note that the Dickinson capacitor bank is operated on because the contingency includes the loss of the 345 kV transformer, which is the reason why the capacitor bank was installed.

Figure 6.2: Power flow results for the Transmission Area of Concern under the P6 condition



6.4.2: Possible Solution Components

As part of this study, two high level ways to solve the identified distribution and transmission deficiencies were identified; move load away from the existing transmission line onto a different transmission line or re-energize an existing transmission line and provide distribution with a new source into the area. Additionally, the age and condition of existing transmission lines in the area were analyzed for potential advancements. Listed below are the components that were used to form the final alternatives listed in Chapter 7.

(a) Separate Gleason Lake – Parkers Lake 115 kV Double Circuit Line

During the analysis into the condition of the existing transmission lines, the Gleason Lake – Parkers Lake double circuit 115 kV line was identified as a line in need of replacement. Advancing the rebuild of this line to two single, paralleled circuit lines will eliminate Contingency #1 as the lines would no longer be on the same structure. Additionally, rebuilding the Gleason Lake – Parkers Lake 115 kV lines to single circuits will alleviate the thermal violations in Contingency #3, as the lines would be rebuilt using larger conductor.

(b) Gleason Lake Capacitor Bank

In general, adding a capacitor bank on the system is the easiest way to alleviate low voltage problems, assuming there are not too many capacitor banks already installed. For the Transmission Area of Concern, the ideal location for a capacitor bank is at Gleason Lake. Gleason Lake is the most effective location on the system to boost the voltage due to the large load located there and the fact that it is at the end of a long radial under the critical contingency. The issue with locating a capacitor bank at Gleason Lake is that under the critical contingency, the voltage rise would likely exceed our requirements. In order to mitigate this voltage rise concern, the installation of a capacitor bank at Gleason Lake would need to be combined with the Gleason Lake – Parkers Lake line rebuild component. Combining these two components allows for the capacitor bank to be switched without any voltage concerns, since the capacitor bank would be switched into service during the system adjustment period allowed between P6 contingencies. The Gleason Lake capacitor bank was sized as an ultimate of 60 MVAR, but the installation of only 40 MVAR. Installing 40 MVAR gives the system operators the appropriate capacitor bank size for now and the flexibility to add more in the future if necessary.

(c) Distribution Load Transfers

To make all alternatives last for the long-term, additional load must be transferred away from the Transmission Area of Concern to a nearby transmission line. Table 6.4 shows approximately when load would need to be transferred by distribution, based on the most logically transfers available. These load transfers assume that the Gleason Lake – Parkers Lake line rebuild and Gleason Lake 40 MVAR capacitor bank are completed. After these two are completed, the Transmission Area of Concern would be able to serve approximately 210 MW. The load transfers would occur in blocks and the target years are based on when the area would exceed the load serving threshold and therefore need a block of load transferred. Note that all transfers are moving load away from Gleason Lake since there is no other substation in the Transmission Area of Concern where transferring load is feasible. The two possible locations for the load transfers are Parkers Lake and a new substation called Pomerleau Lake on the Plymouth to Parkers Lake 115 kV line.

Table 6.4: Approximate timing for load transfers away from Gleason Lake under various load growth scenarios

Distribution Load Transfers	Load Growth		
	1%	1.5%	2%
18 MW	2040	2032	2028
10 MW	2048	2037	2032
19 MW	2052	2040	2034
30 MW	---	2045	2038

Figure 6.3 and Figure 6.4 provide an example of how the distribution transfers could work together with the 40 MVAR Gleason Lake capacitor bank and rebuilding the Gleason Lake – Parkers Lake 115 kV double circuit to two separate circuits. Figure 6.3 shows the Transmission Area of Concern at 210 MW with a low voltage problem. Figure 6.3 assumes the installation of the capacitor bank at Gleason Lake and the rebuild of the Gleason Lake to Parkers Lake 115 kV lines to separate circuits.

Figure 6.3: Contingency #2: Transmission Area of Concern at 210 MW

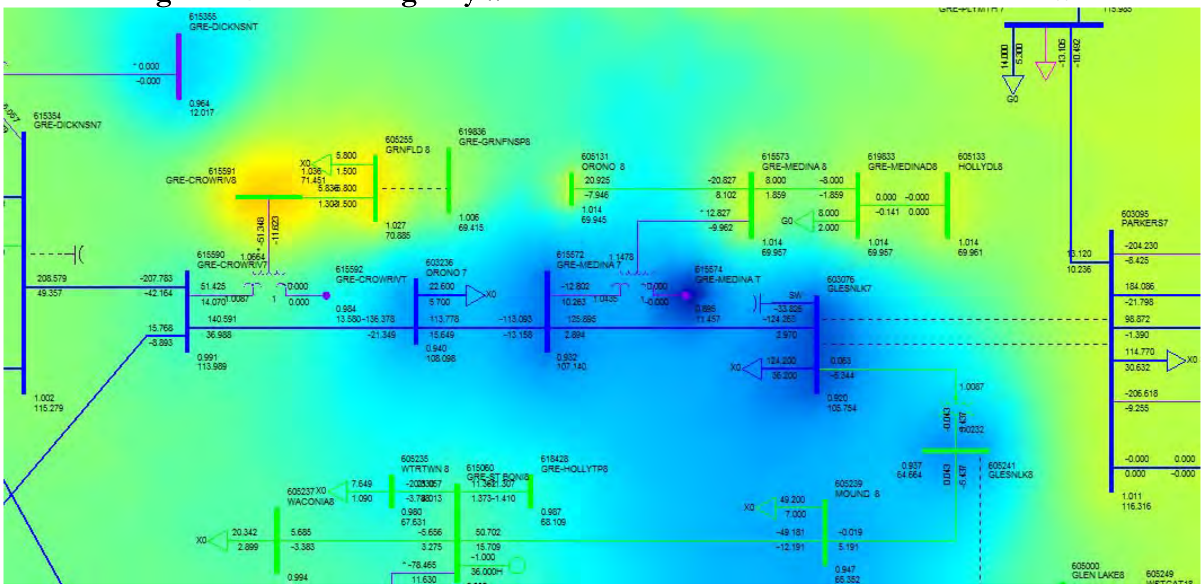
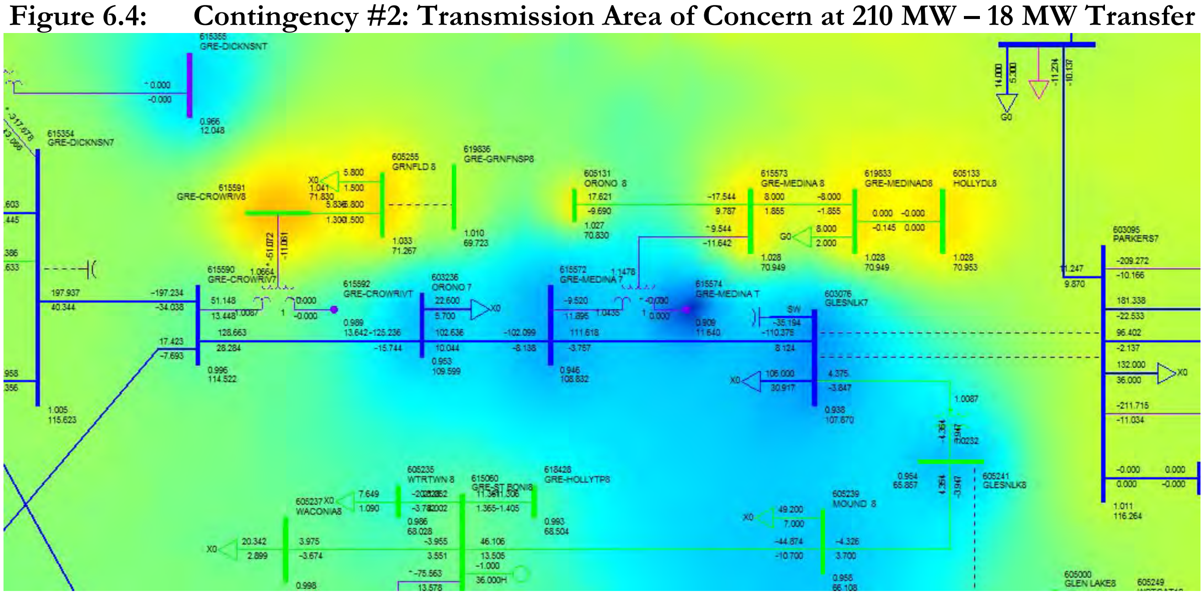


Figure 6.4 shows the same situation after the first phase of distribution transfers (totaling 18 MW) has occurred.

Figure 6.4: Contingency #2: Transmission Area of Concern at 210 MW – 18 MW Transfer



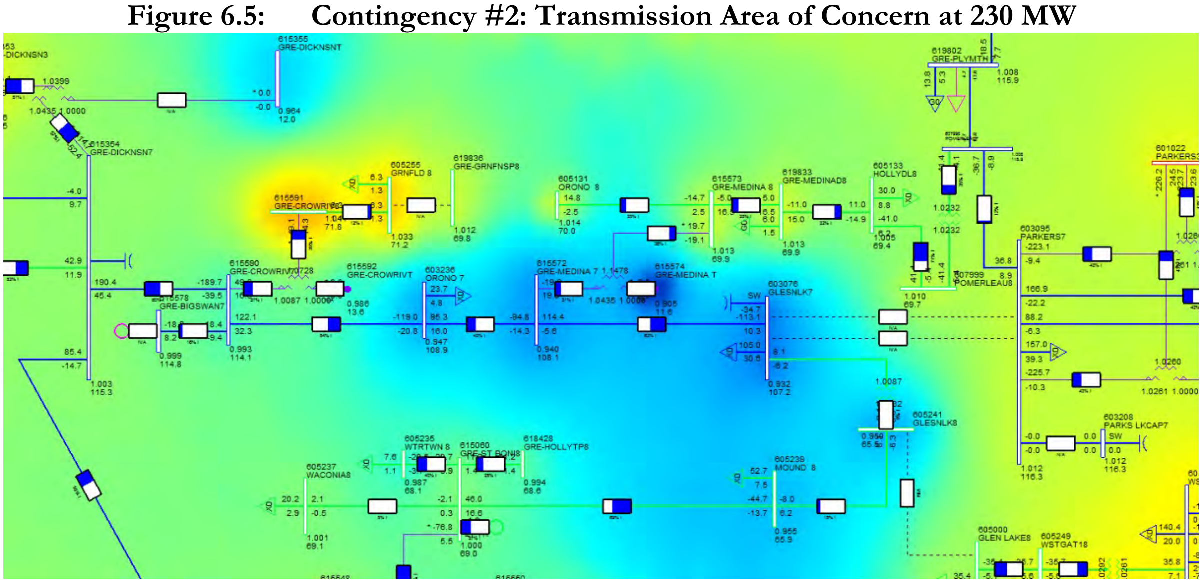
After the load transfer, the system does not have any voltage concerns. However, transferring load for transmission issues is unusual and requires new infrastructure to be built somewhere else to handle the transferred load.

(d) Re-energization of the 69 kV Line East of Hollydale

Similar to the distribution load transfers, this component would be used to move load off of the Transmission Area of Concern transmission lines. However, re-energizing the existing 69 kV line east of Hollydale would achieve this by adding a new source into the area and energizing the Hollydale substation from 69 kV instead of the current 34.5 kV. This component would also work in conjunction with the installation of a Gleason Lake 40 MVAR capacitor bank and rebuilding the Gleason Lake – Parkers Lake 115 kV double circuit line to two separate circuits. In order for the existing Hollydale 69 kV line to be re-energized, a small portion of new 69 kV line and a new substation called Pomerleau Lake would need to be constructed. The new Pomerleau Lake substation would intersect the existing Plymouth – Parkers Lake 115 kV line and bring it in and out of the substation. The re-energized 69 kV line would run from Medina to Hollydale and then Hollydale to Pomerleau Lake. The Hollydale substation would become primarily served from the 69 kV line and effectively transfer the existing Hollydale load from Gleason Lake. This configuration provides flexibility for load serving in the Transmission Area of Concern by using the transmission system to serve the distribution system.

Additionally, if this configuration were to run out of load serving capabilities, the distribution load transfers would still be available to accommodate additional load growth. The 69 kV line was assumed to be operated normally closed, however a reverse power relay would be installed at Pomerleau Lake to disconnect the transformer if two sections of the Elm Creek to Parkers Lake 115 kV line were out of service and the Hollydale 69 kV line was the only source to the remaining 115 kV loads. Without the reverse power relay, the 69 kV lines serving Hollydale would need to be operated normally open or would overload under this condition. Figure 6.5 shows the Transmission Area of Concern at 230 MW, beyond the normal 210 MW threshold, with a no low voltage issues.

Figure 6.5: Contingency #2: Transmission Area of Concern at 230 MW

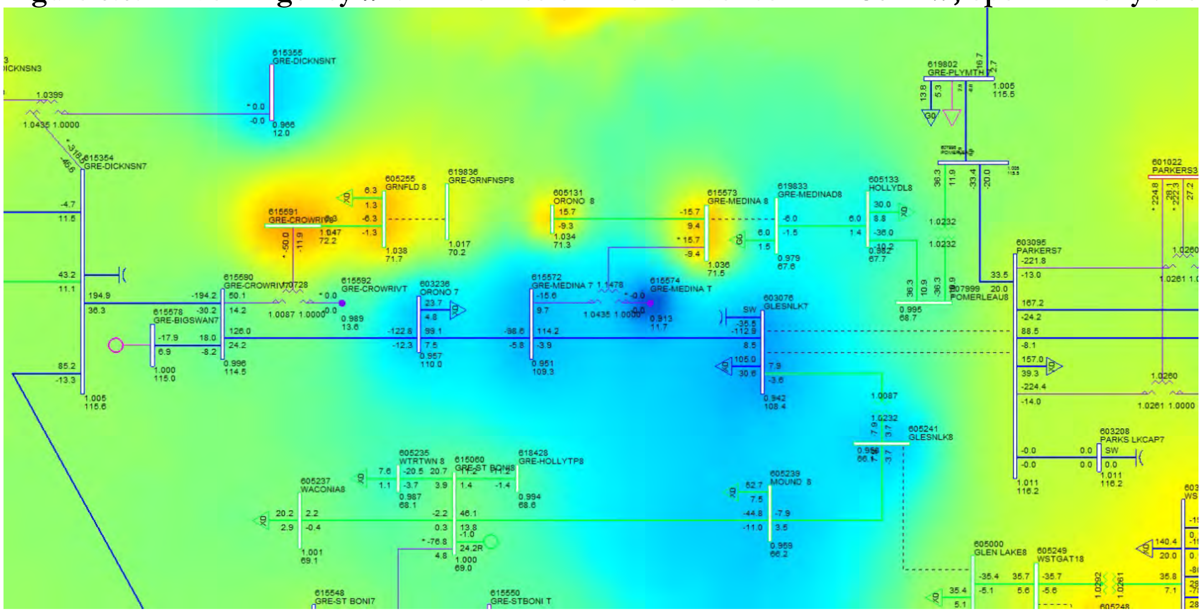


Note that the load that used to be only at Gleason Lake is now split between Hollydale and Gleason Lake. The biggest difference between this configuration and one with load transfers is that without any transfers, the system can easily handle load growth up to the normal 210 MW threshold.

Another potential way to operate this system is to open the 69 kV line at Hollydale looking towards Medina as a system adjustment once either Gleason Lake – Parkers Lake 115 kV line is out of service. This puts the Hollydale load on the Elm Creek – Parkers Lake 115 kV line and allows the Transmission Area of Concern to handle even more load under the critical contingency. Figure 6.6

shows the Transmission Area of Concern at 230 MW, with an open between Medina and Hollydale. The resulting configuration proves even more capable then having the 69 kV line closed through.

Figure 6.6: Contingency #2: Transmission Area of Concern at 230 MW, open at Hollydale



7.0: Overview of Alternatives Analyzed (timing and facilities).

All alternatives in this report solve the transmission and distribution needs. The three alternatives below were created using the components in Chapter 5 and Chapter 6. The names of each alternative and the components of each alternative are shown in Table 7.1.

Table 7.1: Overview of components of each alternative

Project	Distribution Voltage	Gleason Lake Cap	Gleason Lake - Parkers Lake Rebuild to Single Circuits	New Pomerleau Substation	Hollydale Expansion and Re-Energization of Hollydale – Pomerleau 69 kV	Parkers Lake Expansion on existing property	Parkers Lake Expansion on new property
Alternative A	34.5 kV	X	X	X		X	
Alternative B	34.5 kV	X	X			X	X
Alternative C	13.8 kV	X	X	X	X		

Common to Alternatives A, B, and C are the separation of the Parkers Lake – Gleason Lake 115 kV double circuit line into two separate circuits and installation of a transmission capacitor bank at Gleason Lake. Alternative C is the only alternative that re-energizes the existing Hollydale 69 kV line west of Hollydale and adds a small new extension of that line into a new Pomerleau Lake substation. In all alternatives, there is an initial transfer of load at Hollydale away from Gleason Lake. However as load grows, all alternatives except Alternative C require future transfers of distribution load away from the Gleason Lake substation to provide capacity for the transmission system.

The distribution capacity additions and transfer of load required by transmission is accomplished in different ways in the various plans. Common to all projects is the reinforcement of 13.8 kV feeders from Parkers Lake substation. In Alternative A, Pomerleau Lake is installed and 34.5 kV feeders are used to satisfy capacity needs and most load transfers. In Alternative B, Parkers Lake is expanded and 34.5 kV feeders are used in a similar fashion as Alternative A. Alternative C expands Hollydale substation and uses 13.8 kV feeders to satisfy capacity needs, with no load transfers required.

7.1: System Improvements to Address Distribution Needs.

The proposed distribution system improvements include new substation transformers and feeders in the Focused Study Area. This can be accomplished by three main methods, a substation located within the area such as Alternative C, an existing substation on the perimeter of the area such as Alternative B, or a new substation on the perimeter of the area such as Alternative A. To meet the existing system needs, either a voltage of 13.8 kV or 34. kV can be used to serve load. In each alternative, a combination of voltages were used to best utilize the existing system and proposed additions.

All alternatives were designed to meet both the required transmission needs as well as the identified distribution needs. In all alternatives, the transmission need is met by transferring load away from the Gleason Lake substation 34.5 kV transformer. However, in Alternatives A and B, the load is transferred to other distribution 34.5 kV facilities. In Alternative C, the load is transferred directly to the 69 kV transmission source at the Hollydale substation. Therefore, Alternatives A and B require additional capacity that is reserved for the Hollydale substation load and is not available to meet distribution system needs or supply load growth.

The distribution components of each alternative include new feeders and substation transformers as detailed in Chapter 8.0: of this report. These feeders will follow public right-of-way with standard construction of overhead lines unless required to be placed underground. Cost assumptions for this report assumed underground feeder construction as that will be the most conservative method for comparison of costs. The transformers installed are of standard capacity size and will be installed in either an expanded existing substation or a new substation.

While Distribution long range plans typically study the load growth over a 20 year period, we evaluated a 40 year forecast. Projecting the load out to 2056 on the eleven 13.8 kV feeders in the Focused Study Area, the load grows to 146 MW, the area contingency overload rises to 53 MW, and has a utilization of 118% on the existing system. If we install the proposed facilities in the plans we will have increased the area capacity so that in the year 2056 the utilization is reduced to 82% which equates to about a 12 MW area contingency overload. This capacity need would be met by adding additional substation transformer capacity and new feeders into the area. While all plans would provide the ability to add capacity to meet this need, Alternative C would give the most flexibility by providing expansion capabilities at Hollydale, Pomerleau Lake, and Parkers Lake substations to address additional load growth.

7.2: System Improvements to Address Transmission.

To meet the combined transmission and distribution need in the Transmission Area of Concern, Transmission Planning and Distribution Capacity Planning came up with three alternatives. All alternatives meet the needs in the area for 40 years under 1% growth. All alternatives require the installation of a capacitor bank at Gleason Lake and the rebuild of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two separate circuits. Alternative A and Alternative B will each be coupled with moving load away from Gleason Lake to provide long-term distribution and transmission load serving capabilities. Moving load from Gleason Lake is achieved using 34.5 kV lines. These alternatives provide adequate system flexibility but require additional large investments if the area grows at 2% or higher load growth.

Alternative C is coupled with the creation of a new Pomerleau substation and re-energizing the existing Hollydale – Pomerleau 69 kV line, enabling the Hollydale substation to be served from this 69 kV line. By serving Hollydale from the 69 kV line, the Hollydale load is removed from Gleason Lake. This alternative provides the most system flexibility, least investment, and longest load serving capabilities.

Table 7.2 shows the total investment cost and project components of all three alternatives, assuming 1% load growth.

Table 7.2: Total investment cost and project components of the three alternatives under 1% growth scenario

1% Growth in Transmission Area of Concern									
	Distribution Voltage	Gleason Lake Cap	Gleason Lake - Parkers Lake Rebuild to Single Circuits	New Pomerleau Substation	Hollydale Expansion	Parkers Lake Expansion on existing property	Parkers Lake Expansion on new property	Gleason Lake Expansion on new property	Total
Alternative A	34.5 kV	X	X	X		X			$65.8M
Alternative B	34.5 kV	X	X			X	X		$68.8M
Alternative C	13.8 kV	X	X	X	X				$47.6M

This analysis also looked at the possibility of higher than expected load growth for the Transmission Area of Concern. Table 7.3 shows the total investment cost and project components of all three alternatives, assuming 2% load growth.

Table 7.3: Total investment cost and project components of the three alternatives under 2% growth scenario

2% Growth in Transmission Area of Concern									
	Distribution Voltage	Gleason Lake Cap	Gleason Lake - Parkers Lake Rebuild to Single Circuits	New Pomerleau Substation	Hollydale Expansion	Parkers Lake Expansion on existing property	Parkers Lake Expansion on new property	Gleason Lake Expansion on new property	Total
Alternative A	34.5 kV	X	X	X		X		X	$103.6M

Alternative B	34.5 kV	X	X			X	X	X	$106.6M
Alternative C	13.8 kV	X	X	X	X	X			$61.4M

If 2% growth does occur over the next 40 years, the investment costs of all alternatives except Alternative C reach $100 million. This means that if 2% growth occurs, Alternative C will cost roughly half as much as the next closest alternative.

Detailed maps of each alternative are located in Appendix A.

8.0: Comparison of Alternatives.

Alternatives A, B, and C are all designed to meet the distribution and transmission system needs for the next 40 years assuming 1% load growth. Each alternative achieves the same objective in a different way and all alternatives have pros and cons. A comparison of the benefits and shortcomings of each alternative is shown below. The plans for longer range (beyond 2038) facilities are conceptual at this time, and may change depending on how load in the area develops in the future.

	Evaluation of Alternatives	Impacts	Performance
Plymouth Area Alternatives	**Alternative A** Construct 34.5 kV distribution lines from new Pomerleau Lake Substation to Hollydale Substation	• 8 miles near-term (9 miles long-term) of new distribution line o 1 mile where no lines currently exist o 7 miles near-term (8 miles long-term) where there are already lines • 145 homes along new distribution line routes • 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet) • New Pomerleau Lake substation site	• Provides good solution for near-term (roughly 20 years). • Pomerleau Lake Substation makes future improvements to meet future needs east of I-494 less challenging and expensive. • Provides limited ability to efficiently increase load serving capacity long-term to serve additional electrical demand
Plymouth Area Alternatives	**Alternative B** Construct 34.5 kV distribution lines from Parkers Lake Substation to Hollydale Substation	• 10 miles near-term (11 miles long-term) of new distribution line o 0 miles where no lines currently exist o 10 miles near-term (11 miles long-term) where there are already lines • 98 homes along new distribution line routes • 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet) • Expansion of Parkers Lake Substation site would occur on privately-owned land (parking lot, drainage easement) • No new substation site	• Provides adequate solution for near-term (roughly 20 years) • Additional improvements will be needed east of I-494 and will be more challenging and expensive without a new Pomerleau Lake Substation. • Does not provide ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand. • A large amount of load would be served from Parkers Lake Substation which increases reliability risk.

Alternative C Re-energize existing 69 kV line east of Hollydale Substation and construct 13.8 kV distribution lines from Hollydale Substation & 0.7 miles of 69 kV line to connect existing line to new Pomerleau Lake Substation.	• 4 miles of new distribution line o 0 miles where no lines exist o 4 miles were there are already lines • 26 homes along new distribution line routes • 0.7 miles of new transmission line • No new pad-mounted transformers needed • Vegetation management required on unmaintained 69 kV line right-of-way east of Hollydale Substation (4 miles / approximately 63 residential lots) • New Pomerleau Lake Substation site	• Provides good solution for near-term (roughly 20 years). • Pomerleau Lake Substation makes additional improvement needs east of I-494 less challenging and expensive. • Provides ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand.

8.1: Alternative A: Install new 34.5 kV source at Pomerleau Lake.

8.1.1: Overview

- Facilities and Timing:
  - 2018: Construct Pomerleau Lake substation; two 34.5 kV feeders at Pomerleau Lake; reinforce feeders at Parkers Lake; construct extension of one 13.8 kV feeder at Parkers Lake; install 40 MVAR capacitor at Gleason Lake; rebuild Gleason Lake – Parkers Lake 115/115 kV line as two separate lines;
  - 2040 and 2048: extend 34.5 kV feeders at Pomerleau Lake;
  - 2052: expand Parkers Lake substation; two 34.5 kV feeders at Parkers Lake.
- Total Additional Feeder Length: 8.5 miles near-term, 9.1 miles long-term
- Average Additional Feeder Length: 1.8 miles
- Distribution System Capacity Added under N-1 conditions: 70 MW
- Total Investment: $65.8 million (non-escalated)
- Net Present Value for 2016: $45.1 million

8.1.2: Distribution System Performance

Alternative A has long feeder circuits totaling approximately 8.5 miles. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. Although the new feeders installed in Alternative A will have full life expectancy when they are installed, the longer feeder circuits will increase exposure to external elements, due to their length, that could ultimately negatively impact reliability. Additionally, no alternatives discussed in this study will impact reliability at the tap-level of the feeder circuit, as the feeder loads will be transferred to the new feeders at the mainline level. Continued work is expected to mitigate reliability concerns due to tap level failures. Overall, despite the full life expectancy of a new feeder circuit, longer feeder circuits will increase exposure and could potentially negatively impact reliability.

Alternative A does not perform as well as Alternative C since it installs additional substation transformer capacity at a substation farther from the identified load center in the Focused Study Area.

With respect to operability, Alternative A uses additional devices such as step-down transformers and switching cabinets, making Alternative A more vulnerable during overload and outage conditions. Alternative A also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions.

With respect to future growth, Alternative A provides for future capacity additions at Pomerleau Lake with a potential third transformer. Alternative A also does not exhaust capacity at the Gleason Lake and Parkers Lake 13.8 kV substations. As a result, the Gleason Lake and Parkers Lake transformers could be replaced with larger units to serve additional load in the future.

8.1.3: Transmission System Performance

Alternative A includes the separation of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two 115 kV lines. The line separation is combined with a Gleason Lake 115 kV capacitor bank to eliminate all of the critical contingencies in the Transmission Area of Concern for the near-term timeframe. These facilities are the first step in solving the transmission problem for the long-term.

Future load growth will exceed the transmission capabilities provided by these facilities and will then require load to be moved away from Gleason Lake. Requiring distribution to move load because of a transmission need is very unusual and is not sustainable for the long-term. Transferring load away from existing assets at Gleason Lake requires more assets to be installed to handle the transferred load. In an ideal situation, it is best to serve load in an area from multiple substations and spread out the load density to provide the most reliable service. Consolidating loads into fewer substations means that when a contingency occurs, there will be fewer ways to backup loads and bring customers' power back. The resulting condition is more customers out of power for longer periods of time.

Lastly, serving 2% load growth in Alternative A requires two direct 34.5 kV feeders from Parkers Lake to Gleason Lake and the expansion of Gleason Lake substation beyond land currently owned by Xcel Energy. This expansion and set of express 34.5 kV feeders is not a normal distribution planning solution, since these feeders would only be used to transfer load away from Gleason Lake substation for the benefit of the transmission system. If the load does grow at a faster than expected rate, and before these last facilities would go in service, the system would need to be re-evaluated to determine the best solution.

8.2: Alternative B: Expand Parkers Lake substation with new 34.5 kV source.

8.2.1: Overview

- Facilities and Timing:
    - 2018: expand Parkers Lake substation; two 34.5 kV feeders at Parkers Lake; reinforce 13.8 kV feeders at Parkers Lake; construct extension of one 13.8 kV feeder at

Parkers Lake; install 40 MVAR capacitor at Gleason Lake; rebuild Gleason Lake – Parkers Lake 115/115 kV line as two separate lines;
    - 2040 and 2048: extend 34.5 kV feeders at Parkers Lake;
    - 2052: expand Parkers Lake substation; two 34.5 kV feeders at Parkers Lake.
- Total Additional Feeder Length: 10.5 miles near-term, 11.0 miles long-term
- Average Additional Feeder Length: 2.2 miles
- Distribution System Capacity Added under N-1: 70 MW
- Total Investment: $68.8 million (non-escalated)
- Net Present Value for 2016: $41.7 million

8.2.2: Distribution System Performance

Alternative B has long feeder circuits totaling approximately 11 miles. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. Although the new feeders installed in Alternative B will have full life expectancy when they are installed, the longer feeder circuits will have increase exposure to external elements that could ultimately negatively impact reliability. Additionally, no alternatives discussed in this study will impact reliability at the tap-level of the feeder circuit, as the feeder loads will be transferred to the new feeders at the mainline level. Continued work is expected to mitigate reliability concerns due to tap level failures. Overall, despite the full life expectancy of a new feeder circuit, longer feeder circuits will increase exposure and could potentially negatively impact reliability.

Alternative B does not perform as well as Alternative C since it installs additional substation transformer capacity at a substation farther from the identified load center in the Focused Study Area.

With respect to operability, Alternative B uses additional devices such as step-down transformers and switching cabinets, making Alternative B more vulnerable during overload and outage conditions. Alternative B also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions.

With respect to future growth, Alternative B provides for less future capacity additions because no new substation is built and expansion capabilities at 34.5 kV have been used up at Parkers Lake. However, it does not exhaust capacity at the Gleason Lake and Parkers Lake 13.8 kV substations. As a result, the Gleason Lake and Parkers Lake transformers could be replaced with larger units to serve additional load in the future.

Alternative B requires installation of additional distribution facilities at the Parkers Lake Substation. Installing more distribution facilities at Parkers Lake involves an increased risk. It is not typical to have more than three distribution transformers at one distribution substation on the Northern States Power-Minnesota ("NSPM") system. There is risk of "putting all the eggs in one basket" with this alternative. A common failure of all the transformers at the Parkers Lake Substation would put a large quantity of load in the area at risk. Though this should not be considered a primary driver of design, it should be considered. A common failure could be due to a tornado or other disasters that could require de-energization of the Parkers Lake Substation and put a large quantity of load at risk.

8.2.3: Transmission System Performance

Alternative B includes the separation of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two 115 kV lines. The line separation is combined with a Gleason Lake 115 kV capacitor bank to eliminate all of the critical contingencies in the Transmission Area of Concern for the near-term timeframe. These facilities are relatively inexpensive and provide a great first step in solving the transmission problem for the long-term.

Future load growth will exceed the transmission capabilities provided by these facilities and will then require load to be moved away from Gleason Lake. Requiring distribution to move load because of a transmission need is very unusual and is not sustainable for the long-term. Transferring load away from existing assets at Gleason Lake requires more assets to be installed just to handle the transferred load. Also, expanding Parkers Lake's load serving capabilities puts more load at one location and the concern of placing "all your eggs in one basket" more pronounced. In an ideal situation, it is best to serve load in an area from multiple substations and spread out the load density to provide the most reliable service. Consolidating loads into fewer substations means that when a contingency occurs, there will be fewer ways to backup loads and bring customers' power back. The resulting condition is more customers out of power for longer periods of time.

Lastly, serving 2% load growth in Alternative B requires two direct 34.5 kV feeders from Parkers Lake to Gleason Lake and the expansion of Gleason Lake substation beyond land currently owned by Xcel Energy. This expansion and new set of 34.5 kV is beyond normal planning solutions. If the load does grow at a faster than expected, and before these last facilities would go in service, the system would need to be re-evaluated to determine the best solution.

8.3: Alternative C: Expand Hollydale substation, utilize existing transmission line corridors, construct Pomerleau Lake substation.

8.3.1: Overview

- Facilities and Timing:
    - 2018: rebuild Hollydale substation; three 13.8 kV feeders at Hollydale; construct Pomerleau Lake substation; construct extension of 69 kV line to Pomerleau Lake; re-energize Hollydale-Pomerleau Lake 69 kV line; reinforce feeders at Parkers Lake; construct extension of one 13.8 kV feeder at Parkers Lake; install 40 MVAR capacitor at Gleason Lake; rebuild Gleason Lake – Parkers Lake 115/115 kV line as two separate lines;
    - 2049: expand Hollydale.
- Total Additional Feeder Length: 4.1 miles
- Average Additional Feeder Length: 1.0 miles
- Distribution System Capacity Added under N-1: 56 MW
- Total Investment: $47.6 million (non-escalated)

- Net Present Value in 2016: $38.9 million

8.3.2: Distribution System Performance

Compared to Alternatives A and B, Alternative C best satisfies distribution planning criteria. With respect to system performance, the Alternative C installs additional substation transformer capacity at a substation nearest to the identified load center in the Focused Study Area. As a result, Alternative C has the shortest total miles of feeders at approximately 4 miles. Shorter feeder circuits consist of less equipment, have fewer elements that can fail, and have less exposure to external factors that increase the chance of feeder outages. In addition, shorter feeders have less electrical losses compared to longer feeders. The decreased exposure from shorter feeders in conjunction with the full life expectancy from new distribution feeders leads to the expectation that Alternative C will be more reliable than Alternatives A and B. However, Alternative C will not impact reliability at the tap-level of the feeder circuit, as the feeder loads will be transferred to the new feeders at the mainline level. Continued work is expected to mitigate reliability concerns due to tap level failures. Alternative C is capable of maintaining adequate voltage on feeder circuits.

Alternative C also has the best operability. Alternative C is an extension and reconfiguration of the existing distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. Additionally, Alternative C does not require any step down transformers or switching cabinets.

With respect to future growth, the Alternative C provides the most possibilities of all the alternatives for future capacity additions. Alternative C does not exhaust capacity at the Gleason Lake and Parkers Lake substations. As a result, the Gleason Lake and Parkers Lake transformers could be replaced with larger units to serve additional load in the future. Alternative C also allows for additional distribution capacity to be added at Pomerleau Lake in the future as load grows in the area. In addition, the 69 kV transmission line into the Hollydale Substation would be able to source an additional new third transformer at this substation without adding additional transmission lines in the area.

Alternative C has a lower cost than the other alternatives in the near-term and significantly lower cost in the long-term because it uses many existing facilities.

8.3.3: Transmission System Performance

Alternative C includes the separation of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two 115 kV lines. The line separation is combined with a Gleason Lake 115 kV capacitor bank to eliminate all of the critical contingencies in the Transmission Area of Concern for the near-term timeframe. These facilities are a good first step in solving the transmission problem for the long-term. Additionally, Alternative C includes the re-energization of the Hollydale – Pomerleau 69 kV line. This line provides load serving capabilities for the long-term as it takes the Hollydale load off of the Gleason Lake substation and onto the 69 kV line.

Alternative C utilizes many existing facilities and allows for the most system expandability of any alternative. For example, if a large spot load emerged in the area, Alternatives A and B may not be able to support the new load. However, Alternative C would have the available capacity to accommodate this load addition. Alternative C can handle the most load growth because it does not require the extra distribution load transfers that Alternatives A and B require. As a result, all of the distribution components in the other alternatives remain available if necessary.

Table 8.1 shows a comparison of Alternatives A, B, and C in regards to feeder improvements, distribution capacity, total investment, and net present value of each alternative. Based on these criteria and the performance criteria outlined above, Alternative C is the best performing alternative.

Table 8.1: Comparison of the three alternatives with respect to feeder improvements, distribution capacity, total investment cost, and net present value.

Project	Total Additional Feeder Length	Average Additional Feeder Length	Distribution System Capacity Added Under N-1	Total Investment	Net Present Value for 2016
Alternative A	9.1 mi	1.8 mi	70 MW	$65.8 M	$45.1 M
Alternative B	11.0 mi	2.2 mi	70 MW	$68.8 M	$41.7 M
Alternative C	4.1 mi	1.0 mi	56 MW[1]	$47.6 M	$38.9 M

[1] Alternative C could have a total of 126 MW of additional distribution system capacity under N-1 conditions by utilizing Pomerleau Lake substation for distribution.

8.4: Cost.

Table 8.2 shows the total investment cost and net present value for 2016 assuming load growth rates of 1% and 2%.

Table 8.2: Total Investment and Net Present Value Cost for the Three Alternatives, assuming 1% and 2% Load Growth

Project	Total Investment	Net Present Value for 2016	Total Investment	Net Present Value for 2016
	1% Growth		2% Growth	
Alternative A	$65.8 M	$45.1 M	$103.6 M	$46.7 M
Alternative B	$68.8 M	$41.7 M	$106.6 M	$43.3 M
Alternative C	$47.6 M	$38.9 M	$61.4 M	$39.5 M

Table 8.3 shows the near-term and long-term investment costs for each alternative, assuming 1% load growth.

Table 8.3: Total Near-term and Long-term Investment Cost for Each Alternative, assuming 1% Load Growth

Project	Near-term Investment	Long-term Investment
	1% Growth	
Alternative A	$50.7 M	$65.8 M
Alternative B	$46.2 M	$68.8 M
Alternative C	$44.6 M	$47.6 M

9.0: Recommended Alternative.

The best performing alternative from an engineering perspective for the Transmission Area of Concern and Focused Study Area is Alternative C, due to the system flexibility, lowest capital investment, and least amount of new infrastructure. Alternative A is the next best solution due to the system flexibility it provides over Alternative B. However, all three alternatives were designed to comparably meet the long-term load serving needs in the Transmission Area of Concern and Focused Study Area. Since all three alternatives are comparable solutions, input on non-engineering factors will be gathered during the permitting process that will help determine the best alternative to construct.

Appendix A: System Alternatives Maps

Figure A. 1: Map of Alternative A

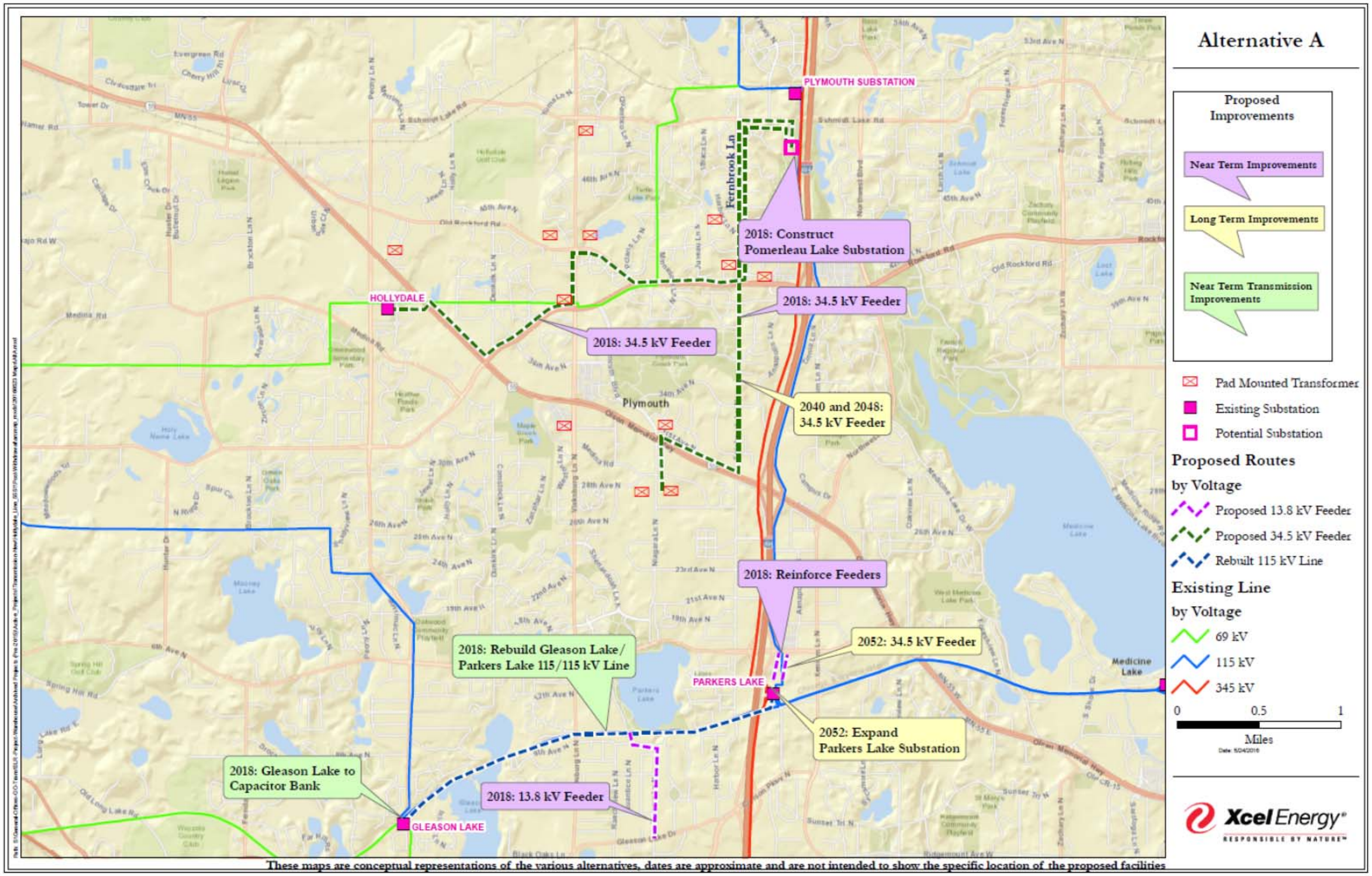


Figure A. 2: Map of Alternative B

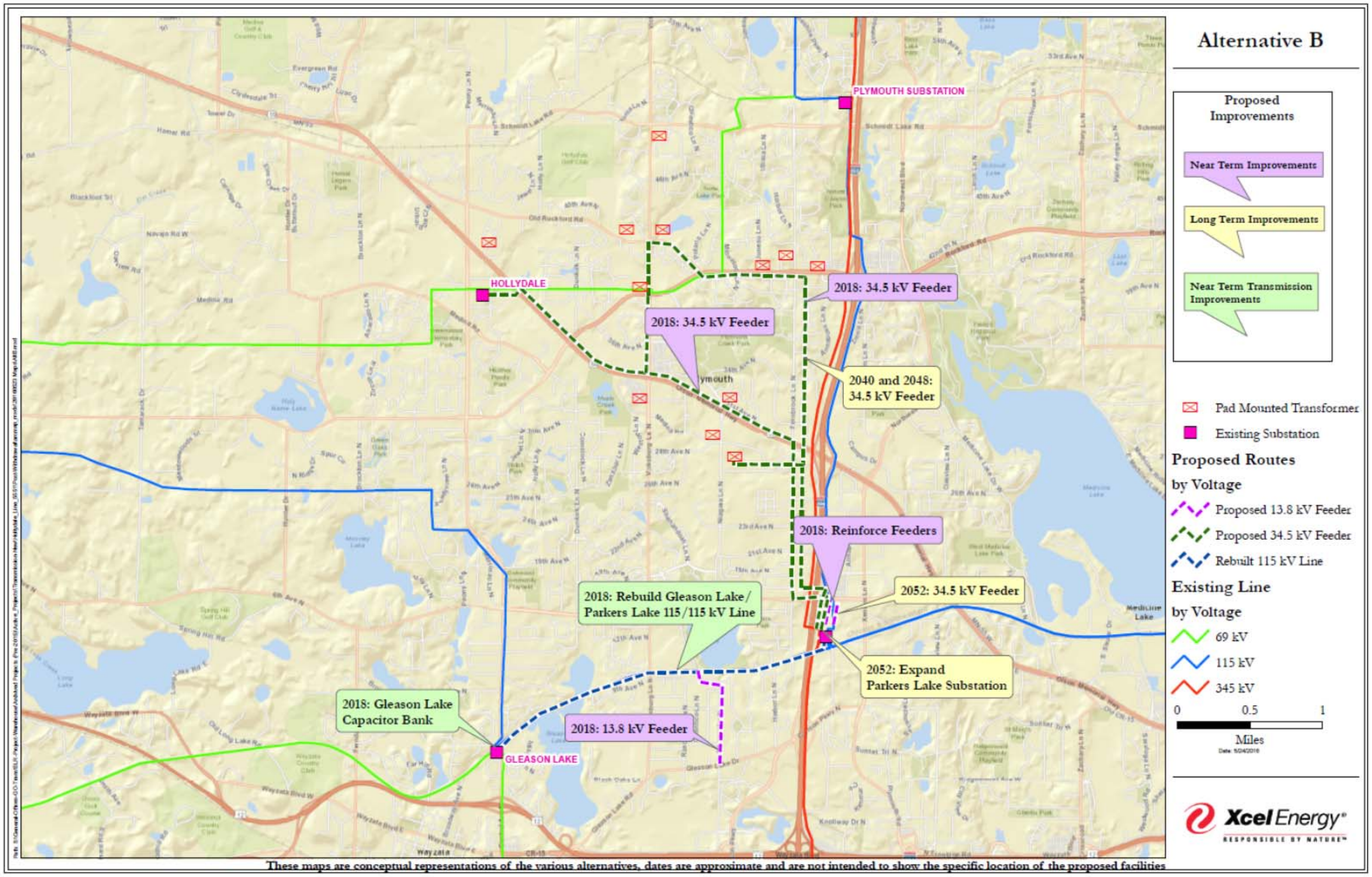
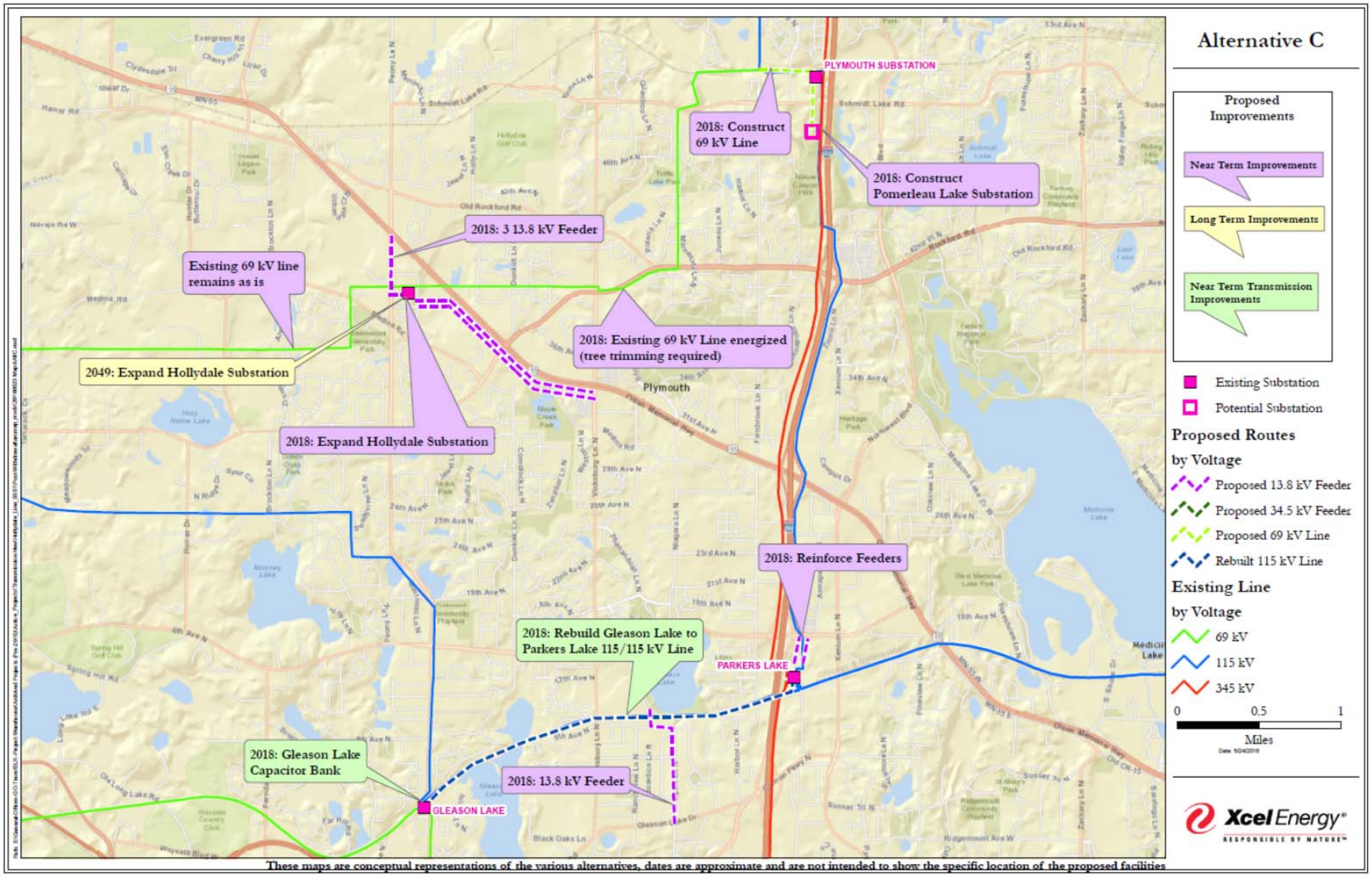


Figure A. 3: Map of Alternative C



Appendix B: Load Forecasts

Transmission Area of Concern
Forecasted Loads (MW)

1% Growth	2016	2017	2020	2025	2030	2035	2040	2045	2050
Gleason Lake	97.8	98.8	101.8	107.0	112.5	118.2	124.2	130.6	137.2
Medina	6.3	6.4	6.6	6.9	7.2	7.6	8.0	8.4	8.8
Mound	38.8	39.2	40.3	42.4	44.6	46.8	49.2	51.7	54.4
Orono	17.8	18.0	18.5	19.5	20.4	21.5	22.6	23.7	25.0
Greenfield	4.6	4.6	4.8	5.0	5.3	5.6	5.8	6.1	6.5
Total	165.3	166.9	172.0	180.8	190.0	199.7	209.9	220.6	231.8

2% Growth	2016	2017	2020	2025	2030	2035	2040	2045	2050
Gleason Lake	97.8	98.8	104.9	115.8	127.8	141.1	155.8	172.0	190.0
Medina	6.3	6.4	6.8	7.5	8.2	9.1	10.0	11.1	12.2
Mound	38.8	39.2	41.5	45.9	50.6	55.9	61.7	68.2	75.3
Orono	17.8	18.0	19.1	21.1	23.2	25.7	28.3	31.3	34.5
Greenfield	4.6	4.6	4.9	5.4	6.0	6.6	7.3	8.1	8.9
Total	165.3	166.9	177.2	195.6	216.0	238.4	263.3	290.7	320.9

Focused Study Area - Gleason Lake Sub Analysis 34.5 kV

Peak Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GSL TR4			48.0	48.4	48.9	49.4	49.9	50.4	50.9	51.4	51.9	52.4	53.0	53.5	54.0	54.6	55.1	55.7	56.2	56.8	57.4	57.9	58.5
Conservative Forecast	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
GSL TR4	44.6	44.8	45.0	45.2	45.4	45.7	45.9	46.1	46.4	46.6	46.8	47.1	47.3	47.5	47.8	48.0	48.3	48.5	48.7	49.0	49.2	49.5	49.7
includes HOL load																							

Focused Study Area - Gleason Lake Sub Analysis 13.8 kV

Peak Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GSL TR7			22.9	23.1	23.3	23.6	23.8	24.0	24.3	24.5	24.8	25.0	25.3	25.5	25.8	26.0	26.3	26.5	26.8	27.1	27.3	27.6	27.9
GSL TR8			31.5	31.8	32.2	32.5	32.8	33.1	33.5	33.8	34.1	34.5	34.8	35.2	35.5	35.9	36.2	36.6	37.0	37.3	37.7	38.1	38.5
TOTAL			54.4	54.9	55.5	56.0	56.6	57.2	57.7	58.3	58.9	59.5	60.1	60.7	61.3	61.9	62.5	63.1	63.8	64.4	65.1	65.7	66.4
Conservative Forecast	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
GSL TR7	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7	20.8	20.9	21.0	21.1	21.2	21.3
GSL TR8	24.5	26.6	31.7	31.8	32.0	32.1	32.3	32.5	32.6	32.8	33.0	33.1	33.3	33.5	33.6	33.8	34.0	34.1	34.3	34.5	34.6	34.8	35.0
TOTAL	43.6	45.8	51.0	51.2	51.5	51.7	52.0	52.2	52.5	52.8	53.0	53.3	53.6	53.8	54.1	54.4	54.6	54.9	55.2	55.5	55.7	56.0	56.3

Focused Study Area - Feeder Analysis 13.8 kV and 34.5 kV

Peak Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GSL341			18.1	18.3	18.4	18.6	18.8	19.0	19.2	19.4	19.6	19.8	20.0	20.2	20.4	20.6	20.8	21.0	21.2	21.4	21.6	21.8	22.1
GSL342			32.4	32.7	33.1	33.4	33.7	34.1	34.4	34.7	35.1	35.4	35.8	36.1	36.5	36.9	37.2	37.6	38.0	38.4	38.8	39.1	39.5
PKL062			6.8	6.9	7.0	7.0	7.1	7.2	7.3	7.3	7.4	7.5	7.5	7.6	7.7	7.8	7.9	7.9	8.0	8.1	8.2	8.3	8.3
PKL074			12.9	13.1	13.2	13.3	13.5	13.6	13.7	13.9	14.0	14.1	14.3	14.4	14.6	14.7	14.9	15.0	15.2	15.3	15.5	15.6	15.8
PKL075			9.4	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.9	11.0	11.1	11.2	11.3	11.4	11.5
PKL081			9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2	11.3	11.4	11.6	11.7
PKL083			9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	9.9	10.0	10.1	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2
PKL084			7.8	7.9	8.0	8.0	8.1	8.2	8.3	8.4	8.4	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.1	9.2	9.3	9.4	9.5
GSL061			6.9	7.0	7.1	7.1	7.2	7.3	7.4	7.4	7.5	7.6	7.7	7.7	7.8	7.9	8.0	8.0	8.1	8.2	8.3	8.4	8.5
GSL076			7.9	8.0	8.0	8.1	8.2	8.3	8.4	8.5	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.2	9.3	9.4	9.5	9.6
GSL079			7.7	7.8	7.8	7.9	8.0	8.1	8.2	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.8	8.9	9.0	9.1	9.2	9.3	9.4
TOTALS			128.7	130.0	131.3	132.6	134.0	135.3	136.7	138.0	139.4	140.8	142.2	143.6	145.1	146.5	148.0	149.5	151.0	152.5	154.0	155.5	157.1
Conservative Forecast	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
GSL341	17.7	17.8	17.9	18.0	18.1	18.2	18.3	18.4	18.4	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8
GSL342	29.4	29.6	29.7	29.9	30.0	30.2	30.3	30.5	30.6	30.8	30.9	31.1	31.2	31.4	31.5	31.7	31.9	32.0	32.2	32.3	32.5	32.7	32.8
PKL062	6.4	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.8	6.9	6.9	6.9	7.0	7.0	7.0	7.1	7.1	7.2
PKL074	12.1	12.2	12.3	12.3	12.4	12.4	12.5	12.6	12.6	12.7	12.8	12.8	12.9	13.0	13.0	13.1	13.2	13.2	13.3	13.3	13.4	13.5	13.6
PKL075	8.9	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.4	9.4	9.5	9.5	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0
PKL081	11.3	11.4	11.4	11.5	11.5	11.6	11.7	11.7	11.8	11.8	11.9	12.0	12.0	12.1	12.1	12.2	12.3	12.3	12.4	12.4	12.5	12.6	12.6
PKL083	9.4	9.5	9.5	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.2	10.3	10.3	10.4	10.4	10.5	10.5
PKL084	7.5	7.5	7.6	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.9	7.9	8.0	8.0	8.0	8.1	8.1	8.2	8.2	8.2	8.3	8.3	8.4
GSL061	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.8
GSL076	7.1	7.1	7.2	7.2	7.2	7.3	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6	7.7	7.7	7.8	7.8	7.8	7.9	7.9
GSL079	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1	7.1	7.2	7.2	7.2	7.3	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6
TOTALS	121.1	121.7	122.3	122.9	123.5	124.1	124.8	125.4	126.0	126.6	127.3	127.9	128.5	129.2	129.8	130.5	131.1	131.8	132.5	133.1	133.8	134.4	135.1

Substation Transformer Historical Summer "Peak" Demand

MW															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR7	20.1	21.5	20.8	21.4	20.2	21.7	19.6	18.6	17.6	17.7	22.1	20.0	19.8	19.0	16.1
GSL TR8	23.5	27.0	24.1	25.7	27.0	28.0	24.3	23.1	21.9	24.3	26.7	25.8	26.1	24.5	25.3
TOTAL	43.6	48.5	44.9	47.1	47.2	49.6	43.9	41.7	39.6	42.1	48.8	45.8	45.8	43.6	41.4
KVA															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR7	20500	21950	21260	21850	20570	22120	20000	19000	18000	18100	22560	20450	20160	19420	16410
GSL TR8	24000	27500	24600	26190	27600	28540	24780	23580	22390	24820	27245	26310	26610	25050	25860
TOTAL	44500	49450	45860	48040	48170	50660	44780	42580	40390	42920	49805	46760	46770	44470	42270

MW															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR4	23.5	26.0	28.7	31.4	36.5	39.2	40.2	35.3	36.2	41.1	45.2	42.4	46.2	44.6	40.4
KVA															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR4	24000	26500	29310	32080	37200	40000	41000	36000	36910	41890	46110	43270	47170	45460	41270

Feeder Circuit Historical Summer "Peak" Demand

Megawatts (MW)															
Feeder	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
HOL061	2.6	6.0	5.9	5.6	6.1	6.2	8.0	7.5	7.4	6.7	8.1	7.3	7.1	6.4	6.8
HOL062	9.4	10.0	8.3	9.1	10.3	10.4	8.8	8.1	8.3	8.2	8.8	11.7	11.8	12.3	11.3
PKL062	11.3	11.4	8.6	8.3	8.3	6.4	6.1	6.7	6.6	7.0	6.5	6.7	6.6	6.4	6.2
PKL074	12.7	13.2	12.7	12.2	12.4	14.3	12.8	10.9	11.8	11.3	13.7	12.7	12.1	12.1	12.1
PKL075	7.5	9.5	9.3	7.6	8.3	9.7	9.4	8.8	8.3	9.2	9.7	9.3	9.1	8.9	9.5
PKL081	9.4	10.5	10.0	11.7	11.2	11.6	11.2	9.5	8.6	9.6	10.4	10.3	9.7	11.3	7.6
PKL083	9.6	10.7	9.5	8.8	8.6	9.5	8.6	8.6	8.9	9.3	7.8	9.5	10.0	9.4	7.3
PKL084	9.5	9.8	9.3	9.3	10.1	10.3	10.0	10.0	9.3	8.2	7.8	7.5	7.6	7.5	6.8
GSL061	9.8	8.5	8.0	7.8	8.3	8.4	6.4	5.8	5.7	3.8	4.9	6.8	5.2	4.3	3.8
GSL076	8.6	9.3	8.8	8.7	9.5	9.8	8.3	7.5	7.4	7.2	7.7	7.7	7.1	7.1	6.9
GSL079	7.4	7.7	8.7	8.8	8.0	8.7	8.2	6.8	7.2	6.4	7.3	7.6	6.6	6.8	6.6
GSL341	23.5	28.4	29.4	29.2	30.0	31.4	32.3	31.4	29.9	31.6	16.4	16.7	16.4	17.7	17.9
GSL342	0.0	0.0	0.0	2.9	6.1	8.5	9.1	9.7	11.3	11.7	29.4	28.8	32.0	29.4	25.1
TOTALS (MW)	109.4	119.0	114.2	115.1	120.9	128.4	122.4	115.6	114.8	115.4	121.6	123.6	122.5	121.1	109.6

KVA																
Feeder	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	
HOL061	2605	6116	6000	5700	6240	6300	8200	7700	7500	6886	8254	7458	7209	6513	6911	Included with GSL342 feeder load (GSL341 prior to 2011)
HOL062	9596	10242	8500	9270	10541	10600	8974	8303	8500	8402	8974	11958	12010	12505	11485	Included with GSL342 feeder load (GSL341 prior to 2011)
PKL062	11515	11590	8760	8450	8500	6494	6200	6861	6713	7113	6615	6870	6781	6538	6290	
PKL074	13000	13500	12927	12430	12684	14548	13073	11095	12007	11580	13971	12952	12333	12390	12306	
PKL075	7677	9700	9450	7707	8497	9911	9553	8950	8424	9407	9905	9468	9274	9098	9671	
PKL081	9637	10690	10193	11932	11447	11793	11459	9711	8813	9796	10658	10536	9941	11546	7707	
PKL083	9800	10938	9695	8950	8764	9724	8728	8788	9043	9468	7930	9711	10208	9637	7433	
PKL084	9695	10000	9447	9447	10342	10500	10184	10200	9447	8416	7951	7635	7805	7656	6936	
GSL061	10000	8701	8204	7955	8452	8576	6500	5900	5800	3850	4950	6961	5290	4360	3900	
GSL076	8810	9500	9000	8870	9646	10000	8500	7632	7600	7380	7860	7905	7250	7234	7035	
GSL079	7500	7856	8900	8950	8204	8850	8400	6911	7300	6530	7490	7707	6750	6986	6687	
GSL341	24000	28962	30000	29790	30640	32000	33000	32000	30500	32280	16750	17029	16760	18086	18272	
GSL342	0	0	0	3000	6215	8639	9323	9944	11500	11960	30000	29396	32629	30018	25606	
TOTALS	111634	121437	116576	117481	123391	131035	124920	117992	117147	117780	124080	126170	125021	123549	111843	excludes HOL061 and HOL062

Appendix C: Demand-Side Management

Appendix C – Demand Side Management Alternatives

Demand Side Management Alternatives

Demand Side Management (DSM) Alternatives have been reviewed in accordance with the May 12, 2014 Commission Order in Docket No. E-002/12-113.

The Company has had a long-standing commitment to DSM through our Conservation Improvement Program (CIP). CIP programs, including both energy efficiency and demand response, have been developed in accordance with regulations set forth by the Minnesota Department of Commerce, Division of Energy Resources (DER). In 2014, these programs provided a peak demand reduction of 114 MW and 481 GWh of energy savings[1]. Since 1992, these programs have contributed enough demand savings to prevent the need to build 11 medium sized power plants.

Our CIP portfolio includes voluntary programs in two categories: Energy Efficiency and Demand Response. Energy Efficiency programs provide an incentive to customers for installing efficient technologies such as compact fluorescent lighting or high efficiency air conditioning through a rebate. These programs help reduce overall system growth and reduce the need to invest in additional generation resources. Demand Response programs are designed to provide immediate load reduction during times of high system load by providing customers an incentive to curtail their usage. Examples of these programs include our Saver's Switch® and Energy Rate Savings programs.

1. *Energy Efficiency Impact*

There has been strong participation in energy efficiency programs by customers within the affected area. Over the past five years nearly 5,200 separate rebates have been awarded within the Hollydale affected area, resulting in peak load reductions of 9.2 MW. The majority of these have been for residential efficiency measures given that the affected area is a predominantly residential customer base. Programs customers commonly take advantage of include; air conditioning replacement, lighting efficiency, home energy audits, refrigerator recycling, and cooling efficiency to name a few. New programs such as the Smart Thermostat pilot are also seeing adoption within the area. Table A below reflects the impact and participation for the last five years:

Table A: Energy Efficiency Participation and Impact

Year	Participants	Peak kW Reduction
2011	748	1,848
2012	752	1,534
2013	1,071	1,526
2014	1,330	2,124
2015	1,280	2,183
Total	**5,181**	**9,215**

[1] As filed on April 1, 2015, Docket No. E,G002/CIP-12-447.07

Efficiency programs have already helped mitigate constraints within the affected area by reducing peak demand. Unfortunately these efforts are not enough to solve the existing 2016 Distribution Substation Transformer Need of 14 MW outlined in section 4.1.4 of this report, nor the ~12 MW of Transmission Need identified in section 4.2.2. Even with increased marketing efforts it would not be feasible to meet these needs through efficiency programs. The benefit efficiency programs bring to the area is largely in controlling and reducing future load growth. This has been reflected in the "Conservative Growth Forecast" presented in section 4.1.2.

2. Demand Response (DR) Impact

Unlike Energy Efficiency programs which create a permanent reduction in load, demand response programs are designed to reduce load at specific times; traditionally when the electric system is at peak. These programs provide customers incentive to curtail load during certain hours of these critical days. The programs are voluntary and in most cases customers may cancel their enrollment at any time.

To date, the Company has utilized demand resources almost exclusively in situations when there is a system wide constraint. Demand Response programs were not originally designed to be dispatched for localized issues such as those occurring within the affected area. It would take system modifications and investments to use these resources for localized emergencies.

There are two programs already offered within the affected area are the Saver's Switch program and the Electric Rate Savings program. Through Saver's Switch (SS) the Company can remotely control central air conditioning loads using a load control switch installed at the customer's site. The Electric Rate Savings (ERS) program is designed for larger commercial and industrial customers. Participants are required to reduce load to a pre-determined level, with the minimum load reduction being at least 50 kW. Both the SS and ERS programs offer customers incentives on their electric bill for their participation. Existing participation rates are relatively high, with over 30% of the customer base enrolled in these programs (Reference Table B).

Table B: Demand Response Program Participation

Customer Type	Customer Count	DR Program Participation	Participation %
Residential	22,872	8,286	36%
Commercial	2,808	224	8%
Industrial	262	59	23%
Total	25,942	8,569	33%

Allowing that the necessary system modifications and investments were made these programs could provide approximately 3.8 MW of load relief to the Distribution constrained areas and 11.7 MW to the Transmission area. Though substantial, these load reductions do not meet the need in the area. The Company also looked at remaining demand response potential in the area and identified approximately 2 MW of additional DR resources, largely by increasing participation in the Saver's Switch program. Even including this additional potential, DR is unable to address the Distribution and Transmission needs (see table C). This is partly a result of the distribution of demand response resources. Some are located on feeders which could address the Transmission need, others on feeders addressing the Distribution need and a few on feeders which overlap the Transmission and Distribution areas. The conclusion is that even assuming DR programs were expanded to every eligible customer within the area the programs would not meet the Transmission and Distribution needs identified in 2016.

Table C: Demand Response Potential by Need within Affected Area

Need Addressed	Existing DR (MW)	Additional Potential (MW)	2016 MW Required	Remaining Shortfall
Distribution	3.8	0.4	14	10.2
Transmission	11.7	0.8	12	0.6

2. DSM Impact on Hollydale

Demand response and energy efficiency have impacted the affected area, helping to reduce overall load growth over the past ten years. However, the immediate needs identified within the affected area surpass the relief DSM can immediately bring to the system.

The Company continues to evaluate whether any alternative, non-traditional, CIP programs could be developed to address the particular transmission and distribution issues within this area and will continue to update the Commission on the results of further evaluation. In the meantime the Company will continue to market its continually evolving portfolio of conservation and demand response programs to the affected area.

Appendix D: Cost Estimates

Appendix D - Cost Estimates

Alternative A: Facilities and Costs
34.5 kV at Pomerleau Lake

Project	ISD Year	Location	Project Scope (excludes Permitting Costs)	SUB Costs
Alternative A	2018	Transmission	Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 1)	$50,729,000
			Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 2)	
			Replace Distribution underbuild on GSL-PKL line	
	2018	Gleason Lake	115 kV capacitor bank	
	2018	Parkers Lake	Reinforce Feeder Exits	
	2018	Hollydale	Substation improvements	
	2018	Pomerleau Lake	Land	
			GRE Xmsn In/Out	
			Install New Sub & 2- 115/34.5kV 70MVA TRs	
			2- Distribution feeders	
	2040	Pomerleau Lake	Distribution feeder reconfigure	$ -
	2048	Pomerleau Lake	Distribution feeder reconfigure	$ 300,000
	2052	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	$14,800,000
			2- Distribution feeders	
2.0% Growth	2060	PKL to GSL feeder	2- Distribution feeders	$15,800,000
	2060	Gleason Lake	Install 2- 34.5/13.8kV 28MVA TRs	$22,000,000

Total (1% Growth)	**$ 65,829,000**
Near Term	$ 50,729,000
Far Term	$ 15,100,000
2% Growth Long Term	$ 37,800,000

Alternative B: Facilities and Costs
34.5 kV at Parkers Lake

Project	ISD Year	Location	Project Scope (excludes Permitting Costs)	SUB Costs
Alternative B	2018	Transmission	Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 1)	$46,179,000
			Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 2)	
			Replace Distribution underbuild on GSL-PKL line	
	2018	Gleason Lake	115 kV capacitor bank	
	2018	Parkers Lake	Reinforce feeder exits	
	2018	Hollydale	Substation improvements	
	2018	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	
			2- Distribution feeders	
	2040	Parkers Lake	Distribution feeder reconfigure	$ -
	2048	Parkers Lake	Distribution feeder reconfigure	$ 300,000
	2052	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	$22,300,000
			Land	
			2- Distribution feeders	
2.0% Growth	2060	PKL to GSL feeder	2- Distribution feeders	$15,800,000
	2060	Gleason Lake	Install 2- 34.5/13.8kV 28MVA TRs	$22,000,000

Total (1% Growth)	**$68,779,000**
Near Term	$46,179,000
Far Term	$22,600,000
2% Growth Long Term	$ 37,800,000

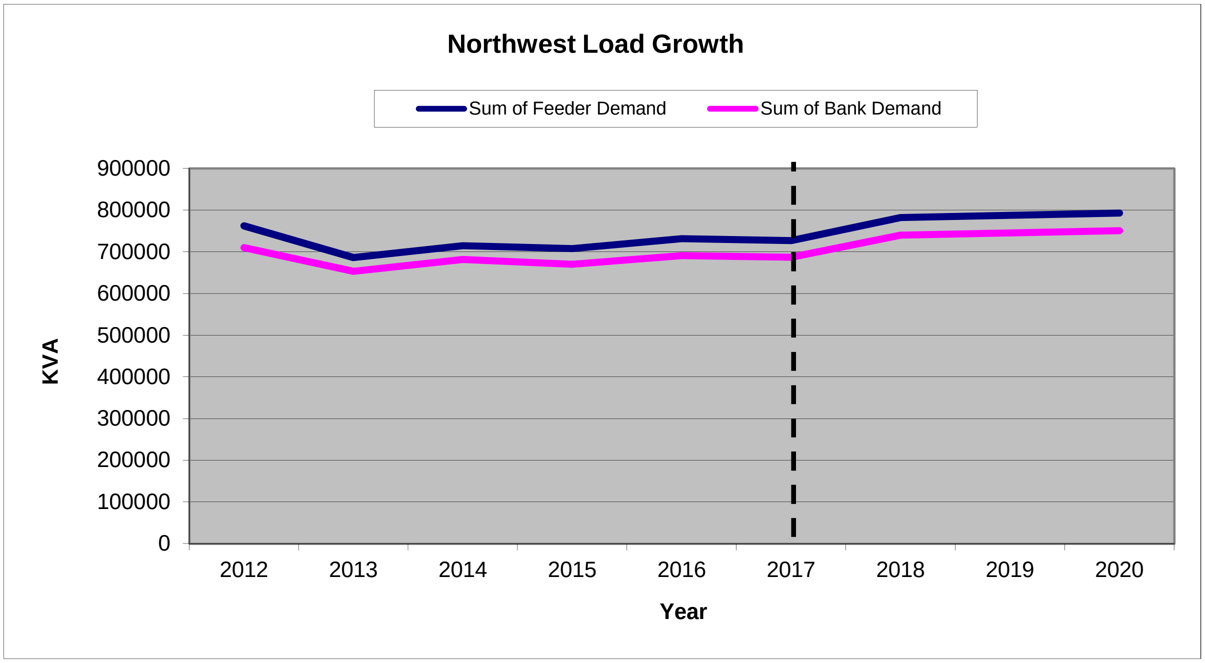
Alternative C: Facilities and Costs
69 kV line to Hollydale

Project	ISD Year	Location	Project Scope (excludes Permitting Costs)	SUB Costs
Alternative C	2018	Transmission	Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 1)	$44,624,000
			Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 2)	
			Replace Distribution underbuild on GSL-PKL line	
	2018	Gleason Lake	115 kV capacitor bank	
	2018	Parkers Lake	Reinforce feeder exits	
	2018	Hollydale	Substation improvements	
			Install 2- 28MVA 69/13.8kV TRs	
			3- Distribution feeders	
	2018	Pomerleau Lake	GRE Xmsn in/out	
			Land	
			Install NSP Sub & 1- 112MVA 115/69kV TR	
	2018	T line 69 kV	Medina-Hollydale-Pomerleau Lake 69 kV purchase, trim trees	
	2049	Hollydale	Install 1- 28MVA 69/13.8kV TR	$ 3,000,000
2.0% Growth	2060	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	$13,800,000
			2- Distribution feeders	

Total (1% Growth)	**$ 47,624,000**
Near Term	$ 44,624,000
Long Term	$ 3,000,000
2% Growth Long Term	$ 13,800,000

3.D.2 Action Plan Roadmap

Section	Requirement	Section
3.D.2	Xcel shall provide a 5-year Action Plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis.	XIV.A.2 IX
3.D.2	The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions)	XIV.A.1 V.B
	and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above).	II.D
3.D.2	Xcel should include specifics of the 5-year Action Plan investments.	IX
3.D.2	Topics that should be discussed, as appropriate, include at a minimum:	-
3.D.2 (i)	Overview of investment plan: scope, timing, and cost recovery mechanism	XIV.A.5 III IX
3.D.2 (ii)	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise. (Footnote: https://gridarchitecture.pnnl.gov/)	IX.A
3.D.2 (iii)	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	IX
3.D.2 (iv)	System interoperability and communications strategy	IX
3.D.2 (v)	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	XI.D
3.D.2 (vi)	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	IX
3.D.2 (vii)	Customer anticipated benefit and cost	IX
3.D.2 (viii)	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	X
3.D.2 (ix)	Plans to manage rate or bill impacts, if any	XIV.A.5 III IX
3.D.2 (x)	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Attachment H
3.D.2 (xi)	For each grid mod project in its 5-year action plan, Xcel should provide a cost-benefit analysis.	IX
3.D.2 (xii)	Status of any existing pilots or potential for new opportunities for grid mod pilots.	XIII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Sum of Bank Demand
KVA
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800000
700000
600000
500000
400000
300000
200000
100000
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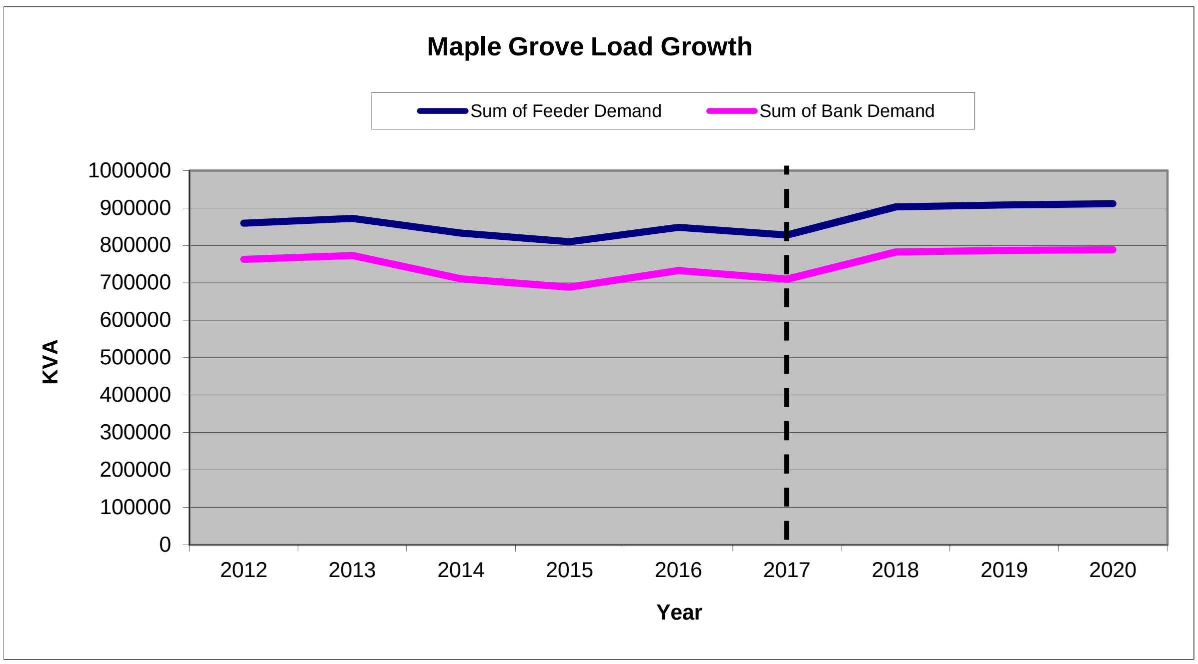
2012
2013
2014
2015
2016
2017
2018
2019
2020
Year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Sum of Bank Demand
KVA
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800000
700000
600000
500000
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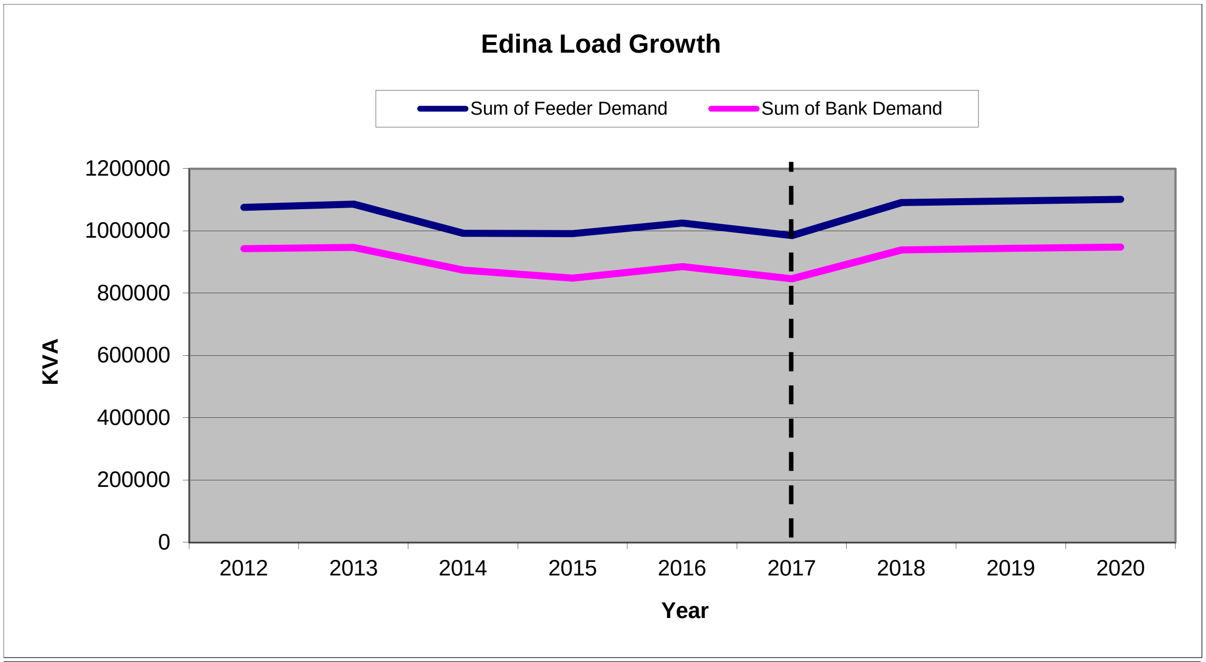
2018
2019
2020
Year


Edina Load Growth
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Sum of Bank Demand
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600000
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2012
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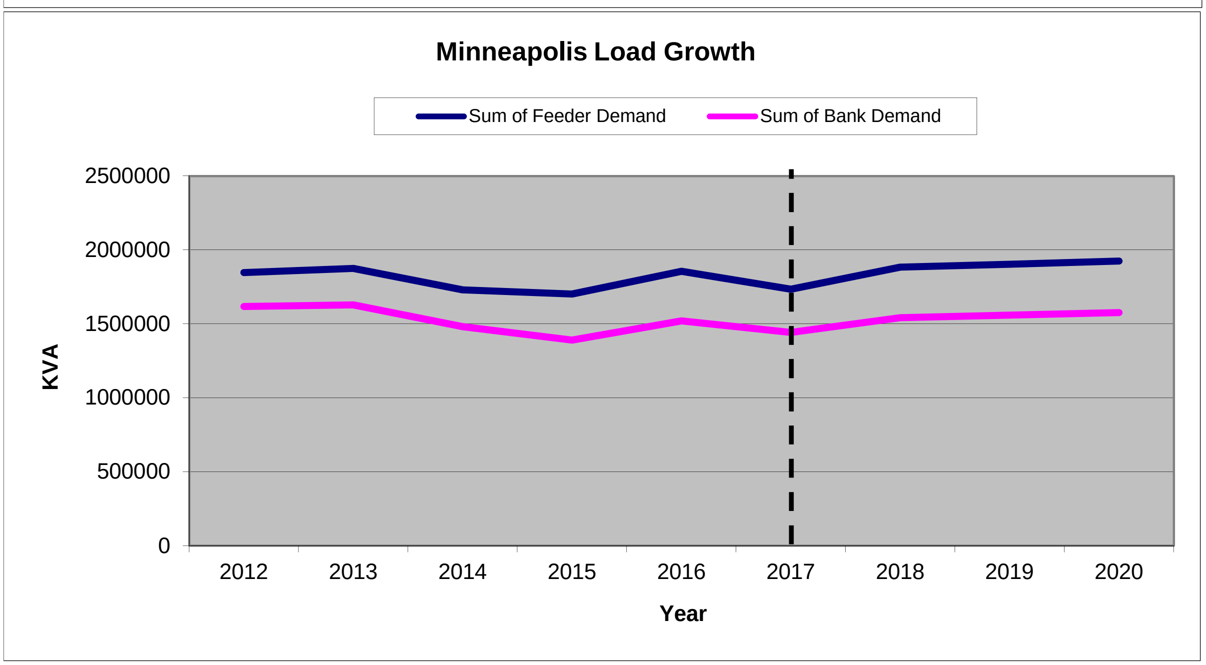
2017
2018
2019
2020
Year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Sum of Bank Demand
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2018
2019
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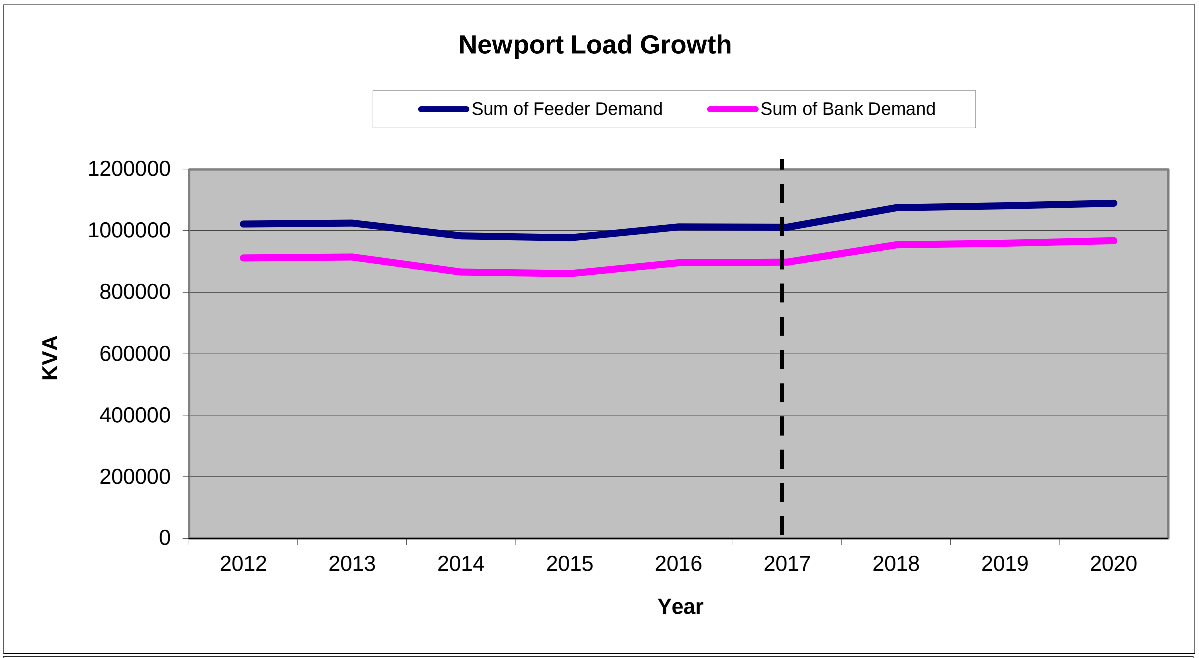
Year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Sum of Bank Demand
KVA
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800000
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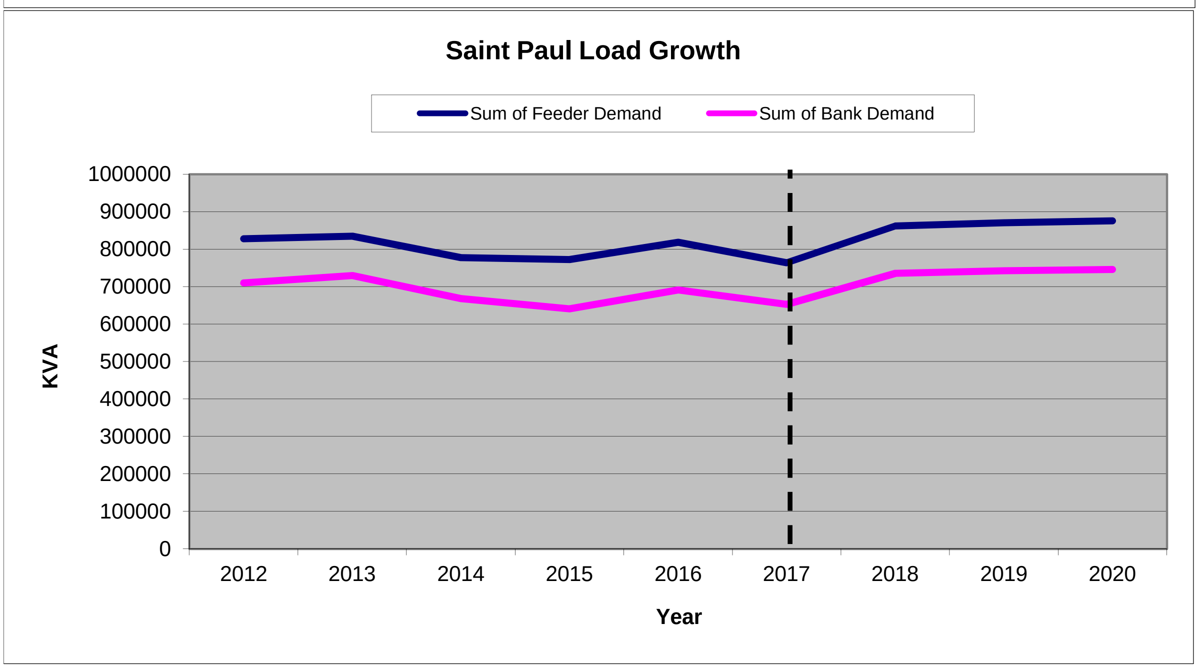
2017
2018
2019
2020
Year


Saint Paul Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
1000000
900000
800000
700000
600000
500000
400000
300000
200000
100000
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2012
2013
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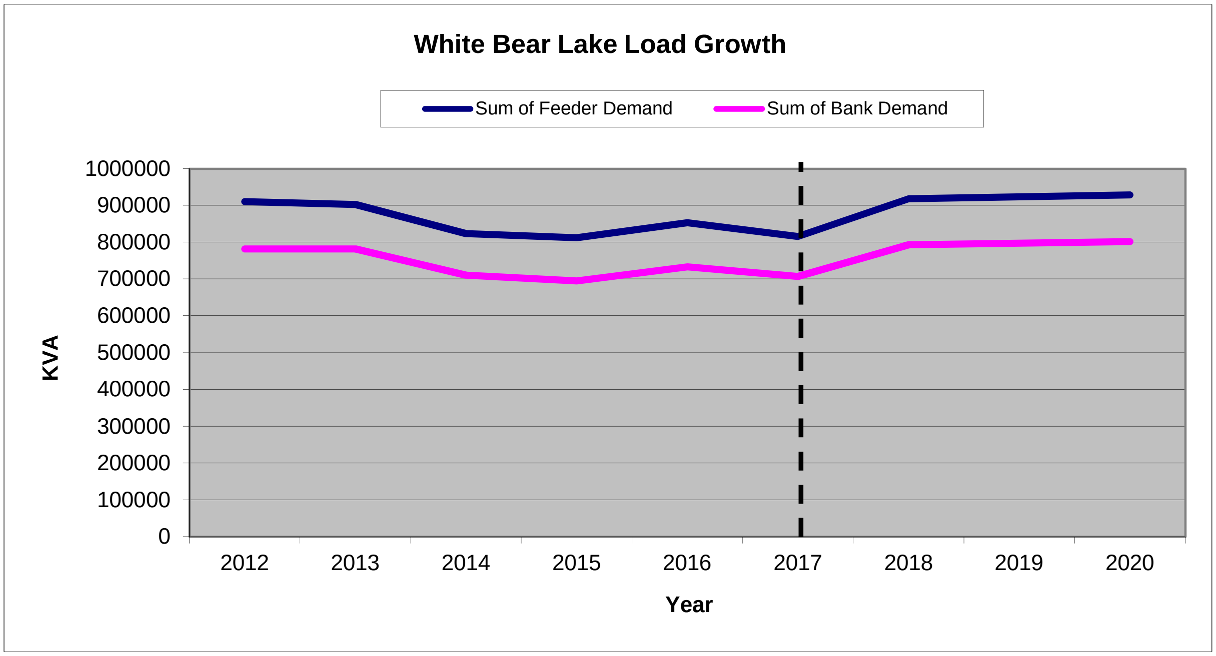
Year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Sum of Bank Demand
KVA
1000000
900000
800000
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600000
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300000
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2012
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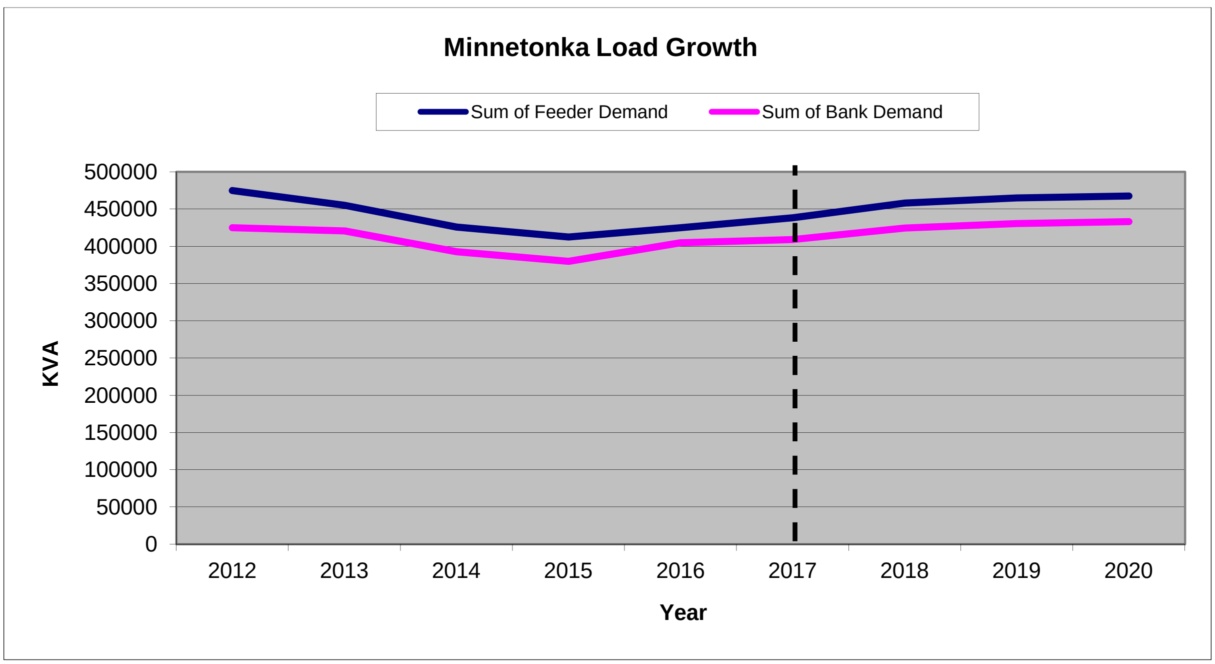
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Sum of Bank Demand
KVA
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450000
400000
350000
300000
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150000
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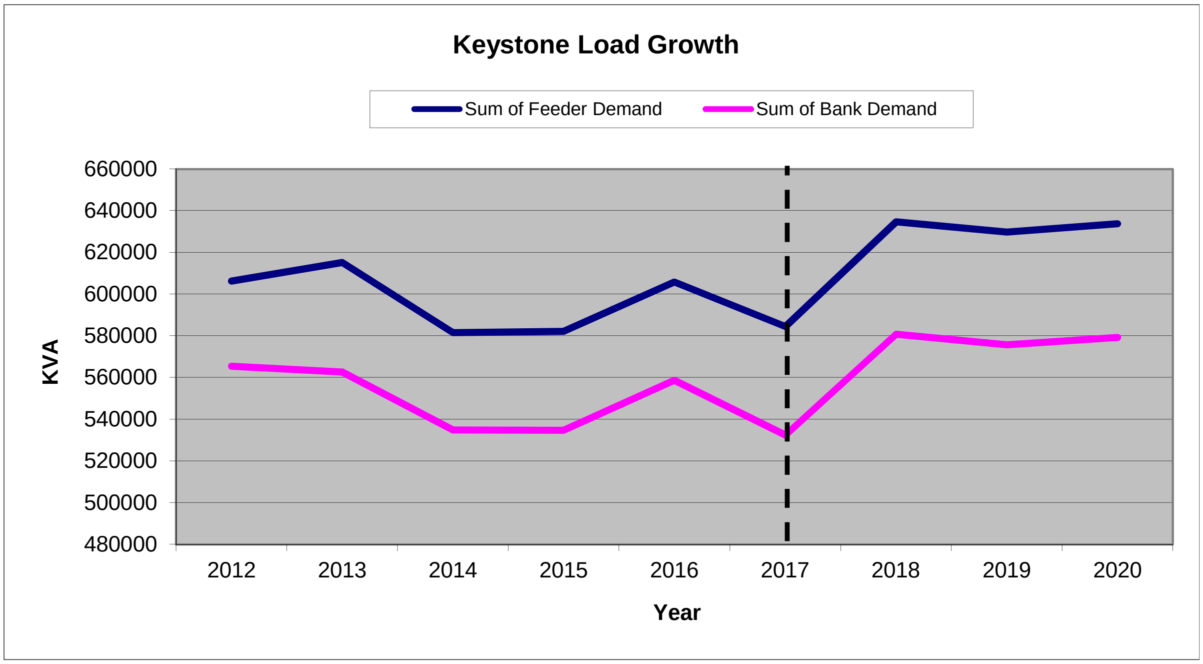
2017
2018
2019
2020
Year


Keystone Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
660000
640000
620000
600000
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560000
540000
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480000
2012
2013
2014
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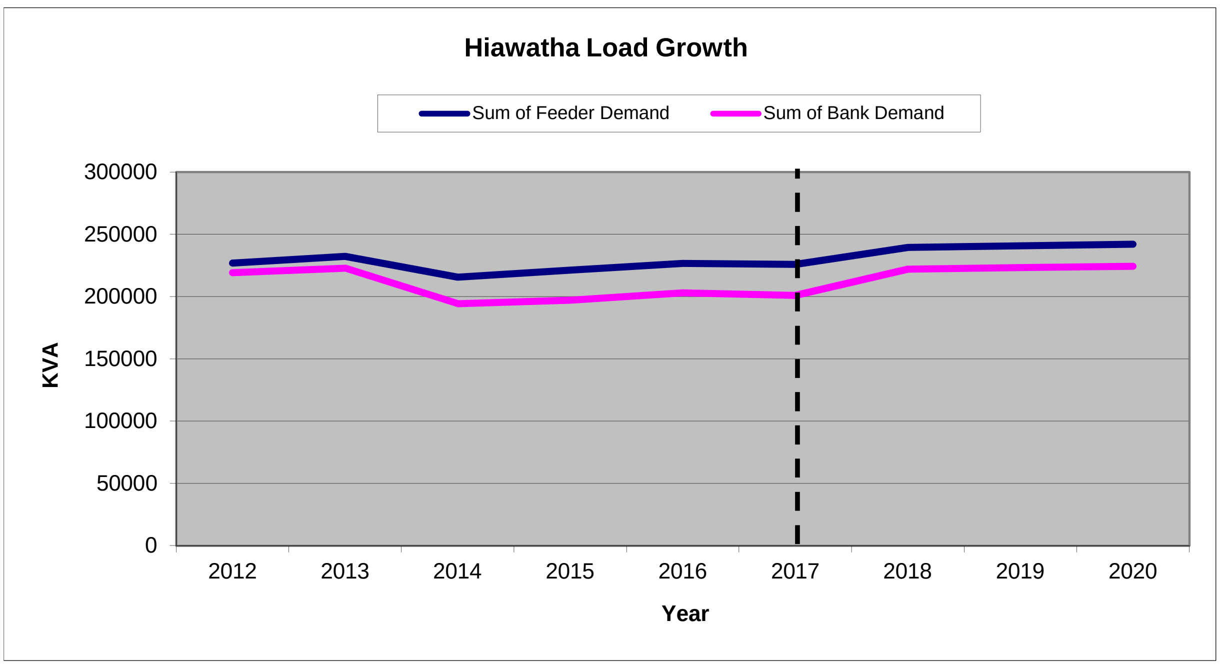
2018
2019
2020
Year


Hiawatha Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
300000
250000
200000
150000
100000
50000
0
2012
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2020
Year

IDP Requirement 3.D.2 (x) requires that we provide the "impacts to net present value (NPV of system costs (in NPV RR/Mwh or MW)." As we noted in our July 20, 2018 Reply Comments, we understand this requirement to be a calculation similar to that provided in conjunction with an Integrated Resource Plan. We continued, saying that there are differing characteristics associated with the distribution system that may make this complex to translate – and that we would provide some sort of distribution-level calculation – but at that time were working with various business units to ascertain how best to do so.

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

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

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

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

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

- *Pre-Funded Allowance for Funds Used During Construction (AFUDC).* In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in service, the recording of AFUDC ceases and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.
- *Other Rate Base*. Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. In general, it includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities.

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

Table 1: High Level Rate Base Calculation

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

For this Distribution Function NPV RR, we calculated the growth in revenue requirements over the 5-year budget period to derive an NPV of $124.5 million (in 2018 dollars).

	Annual Revenue Requirement						
	Electric Distribution Minnesota						
	2018-2023						
	(000's)						
		MN Jurisdiction					
	Rate Analysis	2018	2019	2020	2021	2022	2023
1	Average Balances:						
2	Plant Investment	3,560,786	3,693,172	3,850,127	4,134,609	4,520,725	4,842,866
3	Depreciation Reserve	1,334,862	1,392,516	1,465,254	1,539,239	1,617,701	1,707,519
4	CWIP	31,336	46,236	69,888	80,383	88,379	85,248
5	Accumulated Deferred Taxes	619,692	612,964	608,362	610,857	622,014	626,306
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	1,637,568	1,733,929	1,846,399	2,064,896	2,369,389	2,594,289
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53						
10							
11	Expenses:						
12	Book Depreciation	104,327	108,597	112,645	119,520	131,108	139,870
13	Annual Deferred Tax	(8,424)	(5,033)	(4,171)	9,161	13,154	(4,570)
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	51,751	54,436	55,088	57,155	63,259	69,077
16	subtotal expense = lines 12 thru 15	147,654	158,001	163,562	185,836	207,520	204,376
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	96,389	111,555	118,884	171,314	196,579	144,286
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	1,252	2,273	3,081	4,135	2,679	2,389
22							
23	AFUDC	1,591	2,905	4,368	6,414	4,043	3,864
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	37,009	39,013	41,544	46,460	53,311	58,372
27	Equity Return = line 6 x (line 46 + line 47)	79,095	83,749	89,181	99,734	114,442	125,304
28							
29	Tax Calculations:						
30	Equity Return = line 27	79,095	83,749	89,181	99,734	114,442	125,304
31	Taxable Expenses = lines 12 thru 14	95,903	103,565	108,474	128,681	144,261	135,299
32	plus Tax Additions = line 21	1,252	2,273	3,081	4,135	2,679	2,389
33	less Tax Deductions = (line 19 + line 23)	(97,980)	(114,460)	(123,252)	(177,728)	(200,622)	(148,150)
34	subtotal	78,269	75,126	77,484	54,823	60,759	114,843
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	31,570	30,302	31,253	22,113	24,507	46,322
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	31,570	30,302	31,253	22,113	24,507	46,322
39							
40	Total Capital Revenue Requirements	293,736	308,160	321,173	347,729	395,737	430,510
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	102,448	112,626	112,996	115,240	120,938	122,147
43	Total Revenue Requirements	396,184	420,786	429,316	462,970	516,675	552,658
		Weighted	**Weighted**	**Weighted**	**Weighted**	**Weighted**	**Weighted**
	Capital Structure	**Cost**	**Cost**	**Cost**	**Cost**	**Cost**	**Cost**
44	**Long Term Debt**	**2.2100%**	**2.1800%**	**2.1800%**	**2.1800%**	**2.1800%**	**2.1800%**
45	**Short Term Debt**	**0.0500%**	**0.0700%**	**0.0700%**	**0.0700%**	**0.0700%**	**0.0700%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**	**4.8300%**
48	**Required Rate of Return**	**7.0900%**	**7.0800%**	**7.0800%**	**7.0800%**	**7.0800%**	**7.0800%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
52	Growth in Total Revenue Requirements	0	24,602	13,382	28,801	53,706	35,983
53	Present Value of Growth in Total Revenue Requirements	124,475					

CERTIFICATE OF SERVICE

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

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

- xx electronic filing

Docket No. E002/CI-18-251

Dated this 1st day of November 2018

/s/

____

Carl Cronin
Case Specialist

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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