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Xcel Energy			
Docket No.:	E002/M-17-776		
Response To:	MN Public Utilities Commission	Information Request No.	2
Requestor:	Hanna Terwilliger, Michelle Rosier, Tricia DeBleeckere		
Date Received:	December 21, 2017		

Question:

Please provide any and all calculations, materials, data, and assumptions used to calculate the Value Assessment of FLISR implementation described on pages 31-37 of the company's initial filing in Docket 17-776. Please include data in spreadsheet (.xsls) format where appropriate.

Response:

Please see our responses to OAG Information Request (IR) Nos. 6, 9, and 10, which we provide as Attachment A to this response. We are also providing the attachment to OAG IR No. 6 in live Excel format.

Preparer:	Amber Hedlund
Title:	Case Specialist
Department:	NSPM Regulatory
Telephone:	612.337.2268
Date:	January 19, 2018

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Xcel Energy			
Docket No.:	E002/M-17-776		
Response To:	Office of the Attorney General	Information Request No.	6
Requestor:	Ryan Barlow		
Date Received:	November 22, 2017		

<u>Question:</u>

Reference: Report at 29 and 30

Xcel states that FLISR will improve reliability. Produce all analysis or documents estimating the reliability improvements that could result from FLISR. If Xcel does not produce any such documents, explain why not.

<u>Response:</u>

In response to the Question, we provide an Excel workbook named "NSPM FLISR Analysis" as Attachment A to this response, which contains the feeder implementation plan and estimated reliability benefits that form the foundation of our proposed FLISR implementation plan. We have included comments in the tabs and on header fields to help explain the data and the source of the numbers to aid understanding and navigation.

We determine feeder priority based on customer counts and actual feeder reliability performance. The reliability data that forms our proposed FLISR implementation plan is for the 2010 through 2016 time period, and contemplates feeders we expect to automate through 2023. As we have discussed, our implementation strategy is to automate the highest priority feeders in each area, so that we can produce the greatest benefit possible for our customers. These attributes, particularly reliability performance will change over time as we maintain and expand our system to meet customer needs, which may alter our implementation plan over time. For example, a feeder currently on the bottom of the list may get moved up in priority if there is a change in its reliability, such that the expected benefits increase. Similarly, a feeder identified for more immediate FLISR deployment may move down in priority if the expected benefits deteriorate. However, while feeders may move up or down in priority, we generally expect the total benefits from FLISR to remain relatively consistent.

We note that we additionally estimated the impacts of our planned FLISR implementation as part of our recent Reply Comments in our annual service quality reporting proceeding, which we provide as Attachment B to this response.

In responding to this question, we identified an error with Figures 6 and 7 of our November 1, 2017 Grid Modernization Report. As we worked with the spreadsheet for this response, we realized Figure 6 should be labeled "NSP Minnesota," rather than the present "State of Minnesota." We also realized that we did not carry over last minute changes that we had made in the spreadsheet to the Figure. These changes affect the Budgeted and Threshold dollar amounts for the "per CMO saved" and the "# of Feeders Automated." Finally, because this figure represents the overall value proposition of FLISR, we truncated the savings values. On Figure 7, we have changed the title to clarify the scope of the SAIDI savings as NSP Minnesota, but reflective of just the planned Minnesota deployment. Similar to Figure 6, we carried over the effects of the last minute spreadsheet updates, which resulted in a slight change to the estimated savings in the 2025-2027 timeframe. We provide the corrected Figures 6 and 7 within Attachment A to this response as tabs Fig 6 TotValue and Fig 7 MN DeployValTime respectively, and will additionally submit them in the docket. The corrections are denoted in **bold redline**.

Preparer:	Dan Lysaker
Title:	Senior Engineer
Department:	Grid Modernization
Telephone:	651.229.2382
Date:	December 1, 2017

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

September 29, 2017

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

—Via Electronic Filing—

RE: REPLY COMMENTS
ELECTRIC SERVICE QUALITY REPORT
DOCKET NOS. E002/M-16-281 AND E002/M-17-249

Dear Mr. Wolf,

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the August 31, 2017 Comments of the Minnesota Department of Commerce – Division of Energy Resources in the above-referenced docket.

We appreciate the opportunity to provide the Commission with this information. We have electronically filed this document with the Commission, and notice of the filing has been served on the parties on the attached service list.

Please contact Cyndee Harrington at cynthia.d.harrington@xcelenergy.com or 612-330-5953 if you have any questions regarding this filing.

Sincerely,

/s/

GAIL A. BARANKO
MANAGER, REGULATORY PROJECT MANAGEMENT

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON SAFETY, RELIABILITY, AND SERVICE QUALITY FOR 2015; AND PETITION FOR APPROVAL OF ELECTRIC RELIABILITY STANDARDS FOR 2016	DOCKET NO. E002/M-16-281 **REPLY COMMENTS**
IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL REPORT ON SAFETY, RELIABILITY, AND SERVICE QUALITY FOR 2016; AND PETITION FOR APPROVAL OF ELECTRIC RELIABILITY STANDARDS FOR 2017	DOCKET NO. E002/M-17-249 **REPLY COMMENTS**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Reply to the August 31, 2017 Comments of the Minnesota Department of Commerce – Division of Energy Resources on our Annual Safety, Reliability, and Service Quality Report for 2015; and Petition for Approval Reliability Goals for 2016 and our Annual Safety, Reliability, and Service Quality Report for 2016; and Petition for Approval Reliability Goals for 2017.

We appreciate the review of our annual reports by the Department and its recommendation that the Commission accept them and our proposed 2016 reliability goals pending submission of additional information. We provide our Reply to the Department's request for additional information below.

REPLY

I. RELIABILITY

In this section, we respond to the Department's comments in the areas of our CAIDI performance, a general timeline for installing remote reporting capabilities onto our remaining Minnesota substations and a discussion pertaining to one specific feeder in the Metro East work center which the Company identified as worst performing in 2014, 2015 and 2016.

A. CAIDI Performance

The Department asked that we provide information regarding our efforts to improve our CAIDI performance, including an update on past initiatives that would help guide expectations for future service quality reports. In this section, we provide updates on both work practice initiatives we have undertaken and the negative effect that our efforts to install intelligent field equipment is having on our CAIDI performance.

In short, we have largely internalized the improvements noted in past service quality proceedings – maximizing the identified benefits. At the same time, we are continuing to install intelligent switches on our feeders, which improves our system-wide performance – or SAIDI (duration) and SAIFI (frequency) – and thus customer reliability, but that can cause our CAIDI performance to decline. We also discuss our belief that CAIDI is not a reliable indicator of reliability performance or performance trends – nor a good indicator of the customer reliability experience. Finally, we acknowledge the Department's recommendation that we start reporting CEMI and CELID as measures of our customers' reliability experience.

1. *Work Practices to Improve CAIDI are Internalized*

In Reply to our 2013 and 2014 service quality reports, we discussed a number of work practice initiatives we had underway to improve our CAIDI performance. As the Department summarized in Comments, these efforts included a CAIDI improvement team, who had identified a number of opportunities to improve our CAIDI performance. We have largely internalized all of these improvements, which we have noted previously are expected to only maintain performance, rather than result in concrete improvements.

One notable update however, is that we have affected staffing changes in our Metro West service center. We implemented two staffing-related initiatives in late 2015 and early 2016, as we continue to work on improvements to safely and efficiently respond to electrical outages:[1]

- We removed phone shifts for our First Responders who had answered escalated outage calls – putting four more First Responders in the field. These calls are now being successfully handled by our Call Center; and
- We changed the reporting structure of four First Responders in our Metro West area. Previously, all Metro West First Responders reported to our Chestnut facility in Minneapolis. Now, two First Responders report in the Southern metro (Edina) and two First Responders to the Northern metro (Maple Grove).

Distributing the reporting locations for our Metro West First Responders saves significant drive time on customer outages, particularly during morning and afternoon rush hours – and, we believe, has positively affected customer restoration times since implementation. We note that we already have a similar distributed staffing structure in our Metro East area, so no reporting changes were necessary in this service area.

As we discuss in part 3 below, CAIDI on its own, is not a good indicator of reliability – nor is it a good indicator of the customer reliability experience. We continue to monitor CAIDI internally as part of our overall reliability management efforts, which considers CAIDI results in conjunction with other reliability indicators and information. This broad examination of reliability allows us to monitor the effectiveness of our work practices and other initiatives to identify changes that will improve reliability for customers. These changes include the Metro West staffing change we noted above, and the initiatives we identified in previous service quality proceedings. We will continue to emphasize proper time recording, restore before repair, maintaining appropriate staffing levels, and other initiatives that we have focused on through our CAIDI improvement team. However, our primary reliability focus continues to be on SAIDI and SAIFI as we have previously discussed. SAIDI and SAIFI are the best indicators of overall reliability, and are the industry standard measure of utility reliability.

2. Intelligent Field Equipment is Affecting our Results

We first addressed the issue of intelligent field equipment impacting our CAIDI performance in our July 2013 Reply Comments on our 2012 annual report.[2] In an effort to improve customer reliability, we have been steadily installing intelligent

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[1] These changes required negotiation with our labor unions.

[2] *In the Matter of the Petition of Northern States Power Company Annual Report on Safety, Reliability, and Service Quality for 2012; and Petition for Approval of Electric Reliability Standards for 2013*, MPUC Docket No. E002/M-13-255, REPLY COMMENTS OF XCEL ENERGY AT 2 (Jul. 31, 2013).

switches (Intelliteam devices, or something similar) on our Feeders. These devices reduce the number of outages, which is positive for customers – and both SAIDI and SAIFI – but they can cause our CAIDI performance to decline.

CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. Intuitively, some might think declining CAIDI results means that the utility is doing a worse job of restoring power; however, it is more likely that a worsening CAIDI simply means that the utility is experiencing fewer short duration outages.

Feeder level interruptions have always represented our shortest outages by a significant margin – and affect thousands of customers, so have a material effect on our metrics. CAIDI performance declines when the outages are more heavily concentrated on problems that take longer to correct. In our case, the intelligent switches we are installing on feeders are reducing the number of short duration outages by isolating the fault and automatically healing a portion of the feeder – negating an outage for the majority of customers on the feeder. The resulting sustained outage thus affects a smaller number of customers – creating a negative effect on CAIDI, but a positive reliability experience for the greatest number of customers.

Even without the intelligent switches, outage durations at the Feeder level are generally shorter than for interruptions at lower levels on the system, such as the Tap level, because we can often restore service to customers impacted by these events through a switching procedure. The bigger interruption events that the intelligent switches are now mitigating and preventing had previously diluted the effects of other smaller, longer duration outages on the system. So, while the intelligent switches are preventing mass extended outages on the system, which is good for customers – and can be seen in our positive SAIDI and SAIFI performance – viewing CAIDI in isolation masks what is actually a positive trend in our performance overall. We discuss the use of CAIDI as a reliability metric further in part 3 below.

As we have discussed in the Commission's Grid Modernization proceeding (Docket No. E999/CI-15-556), we intend to undertake a Fault Location Isolation and Service Restoration (FLISR) program that will automate a much larger percentage of our Feeders. FLISR consists of intelligent field switches, like our historic use of Intelliteam devices, that work automatically to detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary. We specifically plan to target Feeders that have the poorest performance on the mainline, and expect our overall customer reliability to improve. In terms of metrics, we expect our CAIDI performance to decline and our SAIDI and SAIFI performance to improve – making historic trending problematic for all of these reliability metrics.

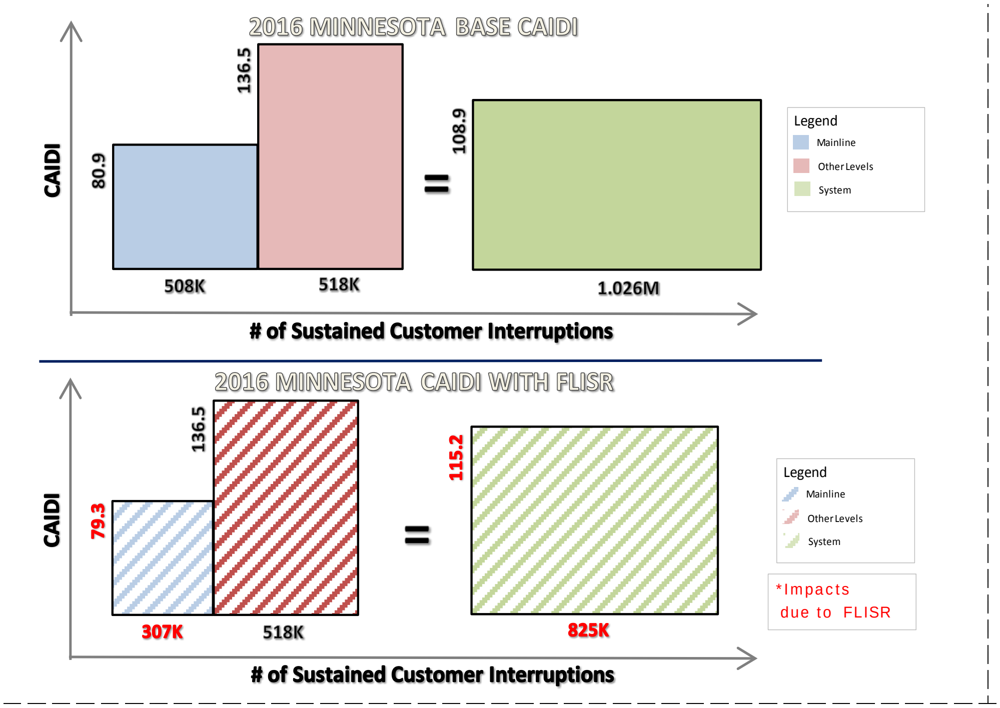
We provide an example of these effects using our 2016 performance year (the exact same outages) and assuming FLISR is fully installed on approximately 30 percent of our worst performing Feeders (based on SAIDI) as they currently exist. With these assumptions, we estimate that our 2016 Minnesota annual service quality report metrics would change as follows:[3]

- SAIFI would improve from 0.82 to 0.66
- SAIDI would improve from 89 to 76
- CAIDI would decline from 109 to 115

We portray the CAIDI impacts visually in Figure 1 below:

[3] For purposes of this illustration, we assumed that two-thirds (2/3) of the customers on a mainline event would experience only a momentary outage instead of a sustained outage, the remaining customers would have their outage shortened by 10 minutes, and all other outage durations and numbers of customers remain the same. This would lower our Customer Minutes Out (CMO) from 112 million to 95 million. The 2/3 reduction in customers experiencing a sustained event is an average expected improvement. Actual improvement will be based on the number of customers on each feeder and the ability to install switches at optimum locations. The 10-minute improvement is an estimate of the expected improved response time due to the improved location identification of the fault. In addition, we expect to see a small duration improvement to non-mainline outages due to the faster response to mainline outage, but at this time it is difficult to predict that improvement because of the assumptions and calculations required.

Figure 1: Illustrative FLISR Deployment Impact on CAIDI



The top half of Figure 1 portrays actual 2016 CAIDI results. The lower half portrays estimated CAIDI reliability impacts from the above-described FLISR implementation. As indicated in **red** text, Mainline/Feeder CAIDI *improves* to 79.3 – and results in a *40 percent reduction* in the number of impacted customers (307,000 rather than the 508,000 actually impacted in 2016). The "other" outage levels, which includes Taps, Transformers and Services remains the same at 518,000 customers impacted and a CAIDI of 136.5. The estimated total CAIDI for all levels *increases* to 115.2 from 108.9 – which in isolation, could be seen as a decline in performance. However, as shown in the bottom FLISR scenario, our customers' reliability experience is actually *improved* as evidenced by:

- The CAIDI improvement for customers at the Mainline/Feeder level;
- Over 200,000 fewer customers experiencing a sustained outage; and
- No change in CAIDI performance at the "other" levels.

We additionally provide a more detailed calculation of these illustrative impacts as Attachment A to this Reply.

The Commission currently measures the quality of electric utility service across a broad range of service categories including their responsiveness, reliability, safety, billing accuracy and customer protections. As we have discussed with respect to our

CAIDI performance, we expect our grid modernization efforts will impact aspects of our service quality. We are continuing installation of intelligent switches, and expect our CAIDI performance to continue to decline as compared to our historical performance. These affects will grow as our FLISR initiative gets underway.

While we believe reliability and grid resiliency are the most relevant and immediate aspect of service quality that will be implicated by increased system intelligence, other service areas may be impacted over time. We are happy to explain these impacts as part of our annual service quality report. However, there may be times when a benchmark or calculation methodology will need to be adjusted, to account for specific investments being made in the system that are expected to impact outage frequency, outage duration, or some other aspect of our service to customers. There may also be times where a metric or benchmark is no longer relevant – or a new metric or benchmark may be appropriate.

We believe any service quality impacts are best evaluated in the context of specific grid modernization investments. However, it will be important to carry those outcomes over into these annual service quality proceedings.

3. *CAIDI as a Performance Metric*

As we have discussed, we believe CAIDI is not a reliable indicator of performance on its own – or of the customer reliability experience. Richard E. Brown, a leading industry expert discusses the drawbacks of using CAIDI as a metric in his book *Electric Power Distribution Reliability*:[4]

> *Although popular with many utilities and regulators, CAIDI is problematic as a measure of reliability. In the authors opinion, this is because CAIDI does not mean what most think. Many view CAIDI as a measure of operational efficiency; when the utility responds more quickly after a fault, CAIDI will go down. This is true, but only part of the story. In fact CAIDI is mathematically equal to SAIDI divided by SAIFI. Therefore, CAIDI will increase if SAIFI improves more quickly than SAIDI. That is, reliability could be improving in both frequency and duration, but CAIDI could be increasing.*

As we have discussed, we rigorously and continuously review our reliability performance – which we outline in our annual service quality filings in Attachment M – from which we identify initiatives and implement changes in our work practices to improve our results. For example, we are currently monitoring the impact Emerald Ash Borers are expected to have on our reliability. While CAIDI continues to be an important metric internally as we examine it in the context of our overall reliability

[4] R.E. Brown, Electric Power Distribution Reliability, at 58 (2nd ed. 2008).

performance, we continue to believe that CAIDI is a poor indicator of our customers' reliability experience. In acknowledging our CAIDI performance trend in Comments, the Department observed that CAIDI seems to add less value in pinpointing customer-level service issues than the system-wide picture SAIDI and SAIFI provide.[5] We agree, and believe a better measure of the customer reliability experience is CEMI and CELID.

The Department recommended we propose specific CEMI and CELID metrics in our next annual service quality report. We note that we already report CEMI and CELID performance as part of our Quality of Service Plan (QSP) Tariff. There are nuances in the way that reliability indices can be calculated, and we recognize that the Department may want alternative views of our CEMI and CELID performance than our QSP Tariff presently provides.

We are open to further discussing with the Department our providing an additional view of our CEMI and CELID performance in these annual reports. However, we acknowledge that on September 22, 2017, the Commission opened Docket No. E002/CI-17-401 to investigate, identify and develop performance metrics and potentially incentives for our electric utility operations, which may be a forum for additional discussion.

4. *Summary*

In summary, SAIDI and SAIFI are the industry standard reliability indices and are the most appropriate measurement of the overall reliability of utility electric service. CAIDI on its own is not a reliable indicator of utility performance – and in any case, is not a good indicator of the customer reliability experience; CEMI and CELID are a much better indicator of the customer reliability experience. If the Commission determines further CEMI and CELID performance reporting beyond our current QSP reporting is necessary, we look forward to working with the Department as it relates to future service quality.

B. Unreported Major Service Interruptions

The Department commented on the Company's reporting procedures related to outage notifications to the Commission's Consumer Affairs Office (CAO) including the continued efforts the Company is making to monitor and improve our processes in this regard. The Department has requested that we provide a discussion regarding

[5] *In the Matter of the Petition of Northern States Power Company Annual Report on Safety, Reliability, and Service Quality for 2012; and Petition for Approval of Electric Reliability Standards for 2013*, MPUC Docket No. E002/M-13-255, COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE AT 29 (Aug. 31, 2017).

the general timeline of installing remote reporting capabilities in its remaining Minnesota substations.

As presented in our most recent Minnesota electric rate case,[6] the Company is supportive of technologies through investments that provide our control center the ability to monitor the real-time load on the transformer and remotely control them and/or feeder breakers during outage situations. System Control and Data Acquisition (SCADA) gives the control center the ability to see the real-time status of the breaker and indication if there is an outage. In addition, this data is typically connected to a telecom circuit or fiber line and usually has a 4-second scan rate that supports improved communication and control over distribution, and increases the speed of power restoration following an outage.

Specifically, SCADA-enabled switches and line reclosers can automatically detect the actual time when a feeder goes out (and eventually when it's back online), which improves the speed and quality of the data available to share with the CAO. However, we note there is still a human element in preparing and forwarding the alerts to the CAO therefore, on days with high volume of outages, it is possible that alerts are not prepared or sent for all qualifying outage events. Overall, this automation of outage data to our control center helps improve our ability to report outage information more accurately to the CAO during major outage events.

As of December 2016 we have SCADA installed in 132 distribution substations in Minnesota, with another 55 substations identified for SCADA installation. Given the importance of this technology to our system and the resulting benefits to our customers (e.g. significantly increases the speed of power restoration following an outage) we have outlined a capital investment plan to complete five SCADA substation installations during 2017, and an additional 25 to be completed over the next five years. More SCADA installations will be completed in the future beyond the current 5-year budget plan.

C. Worst Performing Feeder – Metro East

The Department requested that we provide further discussion regarding the progress of undergrounding one specific feeder in the Metro East work center which the Company identified as a worst performing feeder in 2014, 2015 and 2016, or whether other plans have been developed.

In 2015, the Company considered burying a few spans of the conductor behind the recloser of the referenced Metro East feeder due to repeat outages resulting from tree

[6] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-15-826, Direct Testimony of Kelly A. Bloch (Nov. 2, 2015).

contact. Due to the feeder's location, underground installation would be extremely difficult in this area due to several contributing factors including its hilltop location in a very rural and rustic area, which is surrounded by an extremely rough terrain. This is also a sparsely populated area without a tie to another source available.

Because of these issues Xcel Energy determined that upgrading more overhead conductors was the best solution for this problematic feeder given that the replacement conductors are bigger and stronger than the ones previously installed. As a result, the conductor where most of the tree contact occurred was partially upgraded in September 2016 and portions of the line were relocated to the opposite side of the road during fourth quarter of 2016, which has reduced the number of outages behind this recloser considerably. The largest contributor to the 2014 to 2016 performance on this feeder was due to outages occurring on the recloser noted above. For example, in 2015 we had five outages behind this recloser and following the upgrade, only one outage in 2016, and to date two outages in 2017 both of which were at the feeder level, the improvement work behind the recloser would not have had an impact on these outages. This shows that the overhead performance has improved. In addition, this feeder is also scheduled for its 5-year tree trimming cycle in first quarter of 2018. This effort will address the entire feeder including mainline and taps to reduce tree contact for five years until the next major trim on this feeder.

We note the work completed on this feeder occurred later in 2016 and thus any reliability improvements were not captured in the data used to determine the poor performing feeders for our 2016 annual report. While we have seen improvements in 2017 behind the recloser where the above improvements occurred, there have been several large outages on this feeder in 2017 due to substation events caused by animal contact, and events on the feeder that were caused by tree contact. Tree trimming should address the latter. As mentioned previously, the location of this feeder creates challenges to improvement however, we will continue to monitor it and determine if other actions can improve its reliability.

II. Emergency Medical Accounts

The Department requested we provide any insights we have regarding the approximate 90 percent increase the Company has experienced during the 2015 and 2016 timeframe in customers who have been certified as needing medical assistance; whether this is the new normal or merely a temporary increase; and whether any operational and/or service challenges have been experienced or addressed as a result of more than doubling the number of emergency medical status accounts.

A. Participation Levels

With regard to participation levels, we believe primary drivers contributing to this increase include more customers that are seeking protection under the provisions set forth in Minn. Stat. § 216B.098;[7] customers seeking assistance through government agencies or non-profit groups such as the Office of the Attorney General and Legal Aid group which are actively reaching out to customers with medical issues that result in overdue bills and/or high arrears; and the on-going outreach and communication efforts taken by the Company's Personal Account Representatives team which provides overall direct customer service to our low-income and medical/life-support customers. We also believe other drivers associated with the increase participation levels include:

- regional demographics point to an aging customer base;
- an increase in physician signed certification forms[8] that requests their patients be protected from electric service disconnections as a matter of critical care; and
- the availability of an increased level of home health care equipment that's dependent on electrical hook-ups such as;
    - Nebulizers
    - CPAP/BPAP
    - Oxygen/Oxygen Concentrators

B. Participation Forecast

Based on all of the above, we expect these participation levels to be the new normal, or even increase as our customer population continues to age.

C. Operational Concerns & Challenges

Operationally, the level of arrears currently associated with medical accounts exceeds $6 million[9] in Minnesota and we are taking steps to work with our customers and address this issue. This includes the Company's commitment in its recent electric rate case to expand the affordability program that resulted in our recently submitted medical affordability petition[10] filed with the Minnesota Commission in August 2017.

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[7] Customers with certain medical equipment and/or conditions are protected from disconnections and reconnection service issues once certified by a medical professional.
[8] Xcel Energy's Critical Life-Sustaining Medical Equipment and Medical Emergency Form.
[9] A contributing factor includes low-income customers that already have a medical emergency designation are being denied emergency financial assistance by the county. Counties determine that once medically certified they are protected from disconnection, therefore no further assistance is needed. The result has been large arrears due to the lack of customer payments.
[10] *In the Matter of the Application of Northern States Power Company for approval of a modification to its electric Low Income Energy Discount Program,* MPUC Docket No. E002/M-17-629 (August 24, 2017).

Our request proposes a customer bill payment assistance program exclusively for low-income customers with chronic or severe medical conditions. It includes a $3 million increase in funding annually to address medical and life support arrears that will be designed and managed consistent with our current PowerON program.

III. Estimated Restorations Times

The Department requested that we provide a description of the data we are gathering related to improving estimated restoration times and requested the Company provide a summary of that data in future annual service quality reports.

A. Data Description

On a monthly basis, the Company pulls year-to-date data from its Network Management System (NMS) that itemizes each outage along with associated outage data such as: (i) time of outage; (ii) number of customers impacted, interrupting device; (iii) level of outage; (iv) estimated restoration time (ERT) pre-determined by the Company; and (v) actual restoration time.

This information is used to analyze the accuracy of our estimated restoration times when compared to the actual restoration time. The current draft metric measures actual restoration times which occurred within 90 minutes prior to the published ERT up to 0 minutes after the published ERT. The metric factors in customer impact by measuring the percentage of customers experiencing accurate ERTs where restoration occurred within the 0 to 90 minute window prior to the published ERT. The 0 to 90 minute bandwidth is internally referred to as the "*window of success.*" This metric applies to non-storm outages (i.e. when the Control Center is not in escalated operations due to high outage volumes). We expect the design of this metric could evolve as we continue to monitor and analyze the data compared to customer expectations.

B. Improvement Efforts

As part of our on-going efforts to improve the estimated outage restoration times provided to our customers, in 2015 the Company completed an analysis of our historical ERT estimate accuracy. As a result of this study, we were able to make some adjustments to the model algorithm built into our NMS system that generates estimated restoration times based on such things as: (i) level of outage; (ii) location of outage; (iii) overhead vs. underground; and (iv) time of day, day of the week, etc. In early 2016 we implemented these adjustments and results of the model updates have shown some incremental improvements achieved in our ERT accuracy during 2016 and 2017 year-to-date.

In addition to the model update, we are also working with our Control Center to reduce the number of ERT's that expire (service not yet restored by latest published ERT) by generating an "updated" ERT estimate once we know the current published ERT will not be met.

C. Future Reporting

The Company agrees to provide summary ERT data on a going forward basis as part of its annual service quality filings. We propose the data will be summarized as to the accuracy of our ERT estimates for the calendar year and will consider how to best present the information in a meaningful manner.

CONCLUSION

We appreciate the Department's review of our Report and hope the additional information we provide in these Reply Comments meets the Department's requests for further clarification and information. We respectfully request that the Commission approve our Annual Safety, Reliability, and Service Quality Reports for 2015 and 2016 as supplemented by these Reply Comments.

Dated: September 29, 2017

Northern States Power Company

Example of Impact to 2016 Results
Based on the Annual Rules criteria

Actual Results

State of Minnesota	Mainline	Tap level	Substation & Transmission	Transformer & Secondary	Total
Customer Minutes Out (CMO)	41,124,360	51,436,670	10,502,472	8,744,868	111,808,370
Sustained Customer Interruptions (SCI)	508,636	345,979	110,591	61,358	1,026,564
SAIDI = CMO/# of customers on system	32.9	41.1	8.4	7.0	89.4
SAIFI = SCI/# of customers on system	0.407	0.277	0.088	0.049	0.821
CAIDI = CMO/SCI	81	149	95	143	109
# of customers on system	1,250,205				

If FLISR were installed / ***Net Difference***

State of Minnesota	Mainline	Tap level	Substation & Transmission	Transformer & Secondary	Total	Net Difference Total
Customer Minutes Out (CMO)	24,351,695	51,436,670	10,502,472	8,744,868	95,035,705	-16,772,665
Sustained Customer Interruptions (SCI)	307,024	345,979	110,591	61,358	824,952	-201,612
SAIDI = CMO/# of customers on system	19.5	41.1	8.4	7.0	76.0	-13.4
SAIFI = SCI/# of customers on system	0.246	0.277	0.088	0.049	0.660	-0.161
CAIDI = CMO/SCI	79	149	95	143	115	6

	CAIDI by Level of Outage	CAIDI 2016	CAIDI W/FLISR	SAIFI 2016	SAIFI W/FLISR	SAIDI 2016	SAIDI W/FLISR
Transmission	Transmission Line	93.2	93.2	0.025	0.025	2.3	2.3
Transmission	Transmission Substation	132.0	132.0	0.002	0.002	0.2	0.2
Substation	Distribution Substation	94.6	94.6	0.062	0.062	5.8	5.8
Mainline	Feeder	80.9	79.3	0.407	0.246	32.9	19.5
Tap	Overhead Primary	142.2	142.2	0.186	0.186	26.5	26.5
Tap	Underground Primary	161.9	161.9	0.091	0.091	14.7	14.7
Transformer/Secondary	Overhead Transformer	132.5	132.5	0.039	0.039	5.1	5.1
Transformer/Secondary	Underground Transformer	207.4	207.4	0.005	0.005	1.1	1.1
Transformer/Secondary	Overhead Secondary	119.8	119.8	0.002	0.002	0.3	0.3
Transformer/Secondary	Underground Secondary	254.0	254.0	0.000	0.000	0.1	0.1
Transformer/Secondary	Overhead Service	167.0	167.0	0.002	0.002	0.3	0.3
Transformer/Secondary	Underground Service	153.3	153.3	0.001	0.001	0.1	0.1
Transformer/Secondary	Network	284.0	284.0	0.000	0.000	0.0	0.0
Transformer/Secondary	Part Out	168.9	168.9	0.000	0.000	0.1	0.1
		108.9	115.2	0.821	0.660	89.4	76.0
	Net Difference		6.3		-0.2		-13.4

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; or

xx by electronic filing.

MPUC Docket Nos: E002/M-16-281 and E002/M-17-249

Dated this 29th day of September 2017.

/s/

Carl Cronin

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Xcel Energy			
Docket No.:	E002/M-17-776		
Response To:	Office of the Attorney General	Information Request No.	9
Requestor:	Ryan Barlow		
Date Received:	November 9, 2017		

Question:
Reference: Page 32–33

The Report lists four assumptions made for the cost benefit analysis. What evidence or data does Xcel possess to support the reasonableness of these assumptions?

Response:
In preparing this response, we realized that Figure 5 in our Grid Modernization Report, which portrays the CMO savings calculation contains errors. It should have stated "Average Annual CMO" rather than "Average Annual CMO Saved" in the numerator. Additionally, rather than referring to "Equipment," we should have stated the calculation in terms of *sections of the feeder*. So, the references to "Equipment" in both the numerator and denominator should instead be "Sections." We provide the updated Figure 5 with the changes shown in **bold redline** as Attachment A to this response, and will also submit it in the docket.

Our Report approximates the value of FLISR in terms of expected reliability benefits for customers. As described in our Report, the FLISR devices are expected to eliminate an outage that would have occurred for a portion of customers on a feeder, and for another portion of customers, it will shorten the outage to be a momentary rather than a sustained outage. The remaining customers will experience a sustained outage, as they would presently.

Quantifying this value requires that we make assumptions about how the system will operate, which we have outlined as follows:

- All but one section of the customers on the feeder will see their power restored in less than one minute, which eliminates a sustained outage for the majority of customers on the feeder,[1]

- An improvement of at least 50 percent from historical performance,
- Efficiencies associated with sharing tie switches between two automated feeders, such that each feeder acts as the back-up for the other, and
- A 25 percent reduction in the identified benefits, to represent a conservative but realistic estimate of the percentage of time that FLISR may not be available during an outage for some reason.[2]

The FLISR System Design and Operation will Automatically Restore More Customers – and do so More Quickly. The design of the FLISR system is to restore service to all feasible customers within one minute. Today's existing automated feeders typically restore service to the customers on the non-faulted line sections within one minute. We expect the new FLISR design and equipment to exceed the existing automation in terms of speed of operation.

We made assumptions about the proportion of customers on a FLISR-enabled feeder that would not experience a sustained outage – or be counted as Customer Minutes Out (CMO). We based these assumptions on our general system design, which is typically to segment the feeder into 1,000 or fewer customers[3] – with all customers that are not on the faulted section to be automatically restored within one minute. Because the mainline portion of a feeder is often not a single straight line to the next feeder, a significant portion of feeders will require additional switches to accomplish our goal of segmenting the customers on the feeder as evenly as possible. We accounted for this by assuming one more switch per feeder.

By design and function of FLISR, the fault is 'located' then 'isolated' and then 'service is restored' to all unfaulted sections. A feeder divided into two sections would quickly restore 50 percent of the customers; three sections would quickly restore 66 percent of the customers; this improvement in the percentage of customers quickly restored would continue to increase as more sections are added. We expect to generally have three segments per feeder, consistent with our system design principles; thus our assumption that the majority of customers on the feeder will not experience a sustained outage as they would from a similar event today.

[1] A sustained outage is defined as an outage lasting five minutes or more. In many cases, we expect that half or more of the restored customers will not even see a momentary outage due to our use of electronic reclosers across the feeders, which act to limit the number of customers interrupted in an outage event.
[2] The system might not be available for switching for a variety of reasons including: construction, abnormal state of system, devices out of service for maintenance, system loading, communications failure and others.
[3] With a minimum of two sections.

Sharing Tie Switches Reduces Per-Feeder Costs. We also expect efficiencies associated with sharing tie switches. Tie switches provide the vast majority of their value to a feeder that is automated by being available to restore service to those customers from an adjacent feeder. When a tie switch is shared between two automated feeders, we gain efficiencies, because that device is able to restore service for individual events on *either* of the feeders. FLISR systems are stronger and more flexible when deployed in groups of feeders in a geographic area. By sharing tie switches between automated feeders, our per-feeder tie switch costs are therefore lower.

An Adjustment to Recognize FLISR will not Always Be Available to Operate is Necessary. In recognition that the actual FLISR system design will be complex, and there will be times when the automation is unavailable for restoration, we applied a 25 percent reduction to the "CMO savings" to derive a more conservative view of projected benefits. We based this on our experience with our present feeder automation system. While we believe that a mass FLISR rollout, controlled by ADMS and utilizing the FAN for communications will out- perform our present system, we chose to portray the expected benefits more conservatively, using our historical results as a basis.

We thought an example using our actual experience with our present automated switches would provide a helpful illustration of our assumed customer value, so we analyzed data from the large storm we experienced in Minnesota on June 11, 2017. Three circuits with automation experienced a mainline fault during the storm. Two of the events automatically restored 5,000 of the total 8,800 customers on the circuits (the remaining 3,800 experienced a sustained outage). We estimate that if we would have had to perform manual switching, the 5,025 customers that were automatically restored would have experienced a combined 1.3 million CMO.[4]

In terms of the industry, there is not a lot of information regarding specific FLISR benefits publicly available. However, Transmission & Distribution World did an article on Pittsburgh Power and Light's (PPL) FLISR implementation.[5] The article reports that PPL measured the 12-month performance of the FLISR circuits post-automation to their pre-automation state and saw a 58 percent drop in the average number of interruptions customers experience in a year. These circuits also saw a 55 percent drop in the average number of minutes customers are without service overall.

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[4] Customers affected by one of these outages would have experienced an extra 420,784 CMO (1,904 customers * 221 minutes); customers on the second circuit would have experienced an additional 889,485 CMO (3,121 customers * 285 minutes). The third mainline fault on an automated circuit was successfully isolated, and the customers were restored within one minute. However, a second fault in a different line section occurred one minute later, causing a sustained outage and all customers on the circuit had to wait for restoration until crews arrived on the scene.

[5] *See*: http://www.tdworld.com/distribution/ppl-electric-utility-reaps-smart-rewards

There are challenges in doing an apples-to-apples comparison due to factors such as weather, and the article acknowledges the long-term improvement may be somewhat less than the current rate as the effects of weather normalize over time.

We believe however, our FLISR value assumptions agree with our actual experience with our present automated switches in Minnesota, and generally with the industry.

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Date:	November 30, 2017

Figure 5: CMO Savings Calculation

$$\text{CMO Saved} = \frac{(Average\ Annual\ CMO\ \cancel{Saved}) * (Number\ Of\ \cancel{Equipment}Sections - 1)}{Number\ of\ \cancel{Equipment}Sections} * (1 - \text{Scale Factor})$$

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Xcel Energy			
Docket No.:	E002/M-17-776		
Response To:	Office of the Attorney General	Information Request No.	10
Requestor:	Ryan Barlow		
Date Received:	November 9, 2017		

<u>Question:</u>

Reference: Page 32

How did Xcel establish a "value for each CMO" of $0.76 per minute? What evidence or data was used to support the calculation?

Did Xcel calculate a different CMO value for different states?

<u>Response:</u>

The Customer Minutes Out (CMO) value we used to estimate the value of implementing FLISR on an individual feeder is based on actual Northern States Power Company – Minnesota operating company reliability and customer class data, and work completed by Lawrence Berkeley National Laboratory (LBNL). LBNL created a tool to estimate the value of an interruption from a customer viewpoint called the Interruption Cost Estimate (ICE) Calculator. It incorporates the studies, analyses, and econometric models done by Freeman, Sullivan & Co., and was designed for electric reliability planners at utilities, government organizations or other entities interested in estimating interruption costs and/or benefits associated with reliability improvements.[1]

The LBNL ICE Calculator primarily focuses on the length of outage mitigated by the reliability project, and the value different customer classes place on preventing an outage. LBNL bases the value for commercial and industrial customers on their costs due to an outage, and for residential customers, on the amount they would be willing to spend to avoid an outage.

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[1] The ICE calculator and the work to develop it are available at icecalculator.com.

We developed an in-house model that applies the ICE Calculator concepts to our customer base and actual reliability statistics to derive the per CMO value. The $0.76 per CMO is based on the average length of a mainline outage in NSPM, which is 167.5 minutes. Most utilities value a CMO from a customer view point, and the ICE Calculator is frequently cited as the tool used.

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