BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota	OAH Docket No. 22-2500-37994 MPUC Docket No. E-002/GR-21-630

DIRECT TESTIMONY AND ATTACHMENTS OF BEN HAVUMAKI

ON BEHALF OF

**THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA COMMERCE DEPARTMENT**

OCTOBER 3, 2022

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I. INTRODUCTION

Q. Please state your name, occupation, and business address?

A. My name is Ben Havumaki. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. On behalf of what party are you testifying in this proceeding?

A. I am testifying on behalf of the Minnesota Department of Commerce.

Q. What is your educational and professional background?

A. I have six years of experience in the energy field. At Synapse, I focus on grid modernization and a range of other often interrelated regulatory topics, including ratemaking, rate design, and performance-based regulation. I am also regularly engaged in benefit-cost analysis (BCA) work, including in the development of guidance for emerging areas of practice such as grid modernization, and in reviewing utility BCAs in the context of litigated proceedings. Prior to being hired by Synapse, I worked for the World Bank on a consulting team that authored a field manual on benefit-cost analysis for practitioners in the developing world. I have sponsored testimony before the Public Utilities Commission of New Hampshire, the Georgia Public Service Commission, the Illinois Commerce Commission, the West Virginia Public Service Commission, and the Rhode Island Public Utilities Commission. I hold a Master of Arts in Applied Economics from the University of Massachusetts. My resume is attached as Ex. DOC-___, BH-D-1 (Havumaki Direct).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the Xcel Energy's (Xcel or Company) proposals for Fault Location, Isolation and Service Restoration (FLISR) and Distributed Intelligence (DI), and to provide specific recommendations about cost recovery, performance measurement, and customer protection.

Q. Please summarize your findings and conclusions.

A. My findings and conclusions are as follows:

1. The Company's benefit-cost analysis indicates FLISR, as proposed, is likely to be cost-effective for commercial customers.
2. The Company's benefit-cost analysis indicates FLISR, as proposed, is not cost-effective for residential ratepayers.
3. The Company's FLISR proposal can be refined to improve the prioritization of circuits by cost-effectiveness.
4. The Company's proposal does not adequately account for the risk of not achieving the projected benefits of FLISR.
5. The Company has not fulfilled the Commission's requirements for proposing metrics and performance targets for FLISR.
6. The Company's FLISR proposal does not comply with all Commission filing requirements.

7. The Company has not demonstrated that DI is cost-effective. Its benefit-cost analysis relies on benefits based on bill savings, as opposed to benefits based on avoided costs; it assumes unreasonably optimistic participation rates; and it does not sufficiently consider alternative options.
8. The Company's DI proposal does not comply with all Commission filing requirements.
9. The current approach to grid modernization proposal and review in Minnesota is inefficient, resulting in an increased risk that grid modernization investments will not be in the public interest.

Q. Please summarize your recommendations.

A. I offer the following recommendations:

1. The Commission should approve FLISR, but it should only allow recovery of the proposed costs for the first three years of FLISR deployment, from 2022–2024.
2. The Commission should allocate 97 percent of FLISR costs to the commercial and industrial classes.
3. Xcel should prioritize deployment of FLISR by circuit according to the relative cost-effectiveness of each circuit.
4. The Commission should establish metrics and performance targets for FLISR, based upon the Company's proposed deployment plans and the anticipated benefits presented in support of this investment.

5. The Commission should make cost recovery for FLISR at least partly contingent on achievement of performance targets for FLISR.
6. The Commission should not approve DI.
7. In the event that the Commission does grant cost recovery for DI, it should establish metrics and performance targets, and it should make cost recovery for DI at least partly contingent on achievement of performance targets.
8. The Commission should seek all opportunities to improve the efficiency of the grid modernization evaluation process by consolidating dockets in order to reduce fragmentation and enhance cohesion across proposals.
9. In order to improve the efficiency of the grid modernization evaluation process, the Commission should require that each future grid modernization proposal include:
    a. A grid modernization road map with all planned and contemplated future grid modernization investments.
    b. A complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs.
    c. A table containing all Commission grid modernization proposal filing requirements and specific references to where each requirement has been met within the filing.

10. To reduce fragmentation and enhance cohesion across grid modernization proposals, the Commission should standardize its grid modernization filing requirements so that they are applicable in all instances in which utility grid modernization proposals are brought forward, including those instances in which cost recovery has not been requested.

Q. Please provide your recommendations for cost recovery for FLISR and Distributed Intelligence by year for the term of the multi-year rate plan.

A. My recommended cost recovery for FLISR and DI, along with the Company's proposed recovery, is presented in the table below.

Table 1. Cost Recovery for FLISR and DI – proposed by Xcel and recommended

	2022	2023	2024	2025	2026
				[NOT PUBLIC DATA BEGINS . . .	
FLISR – as proposed by Xcel					
Capital[1]	$3,400,000	$7,800,000	$7,800,000	[redacted]	
O&M[2]	$300,000	$300,000	$400,000		
Total	$3,700,000	$8,100,000	$8,200,000		
FLISR – as recommended					
Capital	$3,400,000	$7,800,000	$7,800,000		
O&M[3]	$300,000	$300,000	$400,000		
Total	$3,700,000	$8,100,000	$8,200,000		
DI – as proposed by Xcel					
Capital[4]	$0	$0	$23,500,000		
O&M[5]	$200,000	$2,600,000	$2,000,000		
Total	$200,000	$2,600,000	$25,500,000		
DI – as recommended					
Capital	$0	$0	$0		
O&M	$0	$0	$0		
Total	$0	$0	$0		
					. . . NOT PUBLIC DATA ENDS]

[1] Capital costs for FLISR from 2022-24 from Ex. Xcel-___ at 99 (Bloch Direct). These costs correspond to the "MN Electric Jurisdiction." Capital and O&M costs for FLISR from 2025-26 were obtained from Ex. Xcel-___, KAB-D-4 (Bloch Direct) and rounded to the nearest $100,000. This schedule (the BCA) does not appear to break out MN-specific costs from Total Company costs, so these costs are likely overstated.

[2] O&M costs for FLISR from 2022-24 were obtained from Ex. Xcel-___ at 138 (Bloch Direct). These costs are provided for NSPM.

[3] The recommended O&M budget provided in this table for 2025-26 was calculated by taking the O&M costs for 2028 and 2029 (the first two years after proposed device deployment would end) in Ex. Xcel-___, KAB-D-4 (Bloch Direct) and dividing these values by the cumulative number of devices deployed. The dollar per device values for the first and second years after the recommended end of device deployment (2025 and 2026) were then multiplied by my recommended cumulative number of devices from 2022-2024 according to the Company's deployment plan. Again, this value may be overstated as the Company did not appear to segregate MN jurisdictional costs in its BCA. The final values are rounded to the nearest $100,000.

[4] Capital costs for DI from 2022-24 were extracted from Ex. Xcel-___ at 48 (Remington Supplemental Direct). These costs are provided for NSPM. Capital costs for DI from 2025-26 were obtained from Ex. Xcel-___, MOR-SD-3 (Remington Supplemental Direct).

[5] O&M costs for DI from 2022-24 were obtained from Ex. Xcel-___ at 50 (Remington Supplemental Direct). These costs are provided for NSPM. O&M costs for DI from 2025-26 were obtained from the Ex. DOC-___, BH-D-3 (Havumaki Direct) (DOC IR No. 3) and rounded to the nearest $100,000. As stated in the Response, "At this time, the appropriate allocation of these costs to utility and jurisdiction is being developed. The Company plans to include DI costs allocated to Minnesota Electric Jurisdiction in its rebuttal testimony."

II. OVERVIEW OF THE COMPANY'S GRID MODERNIZATION PROPOSALS IN THE MYRP

Q. Please describe the Company's grid modernization program.

A. The Company's grid modernization program is termed Advanced Grid Intelligence and Security (AGIS). This is a multi-part, phased initiative that aims to "advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers."[6]

Q. What investments are included in the AGIS initiative?

A. The "core components" of the AGIS initiative include the Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), the Field Area Network (FAN), and Fault Location, Isolation, and Service Restoration (FLISR). The Company proposed additional AGIS components, including the Distributed Intelligence (DI) use cases that would leverage AMI meter technical capabilities, a time-of-use (TOU) rate pilot, and the LoadSEER planning tool.[7]

Q. Which AGIS investments has the Company included in its MYRP petition?

A. The Company has requested recovery of both capital costs and operations and maintenance (O&M) expenses for its FLISR and DI investments. Xcel also has included internal labor costs for the other AGIS components in the instant petition.

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[6] Ex. Xcel-___ at 95 (Bloch Direct).
[7] *Id.*

Q. What is the status of the Company's other AGIS investments?

A. The Commission approved recovery of ADMS costs in 2019 through the Transmission Cost Recovery (TCR) rider,[8] and this investment has been enabled at selected control centers as of 2021.[9] The Company filed its most recent TCR petition in November 2021, seeking continued recovery of ADMS costs along with recovery of AMI, FAN, TOU, and LoadSEER costs.[10] Subsequently, the Company filed a supplemental petition in support of cost recovery for AMI and FAN.[11] The Commission has yet to make a determination on this latest round of cost recovery requests.

Q. Why is the Company seeking recovery of FLISR and DI costs in this rate case?

A. The Company initially pursued cost recovery for each of these investments through the TCR pathway. In July 2020, the Commission declined to certify FLISR, thereby foreclosing on TCR rider cost recovery for this investment.[12] The Company requested certification for DI in 2021 in conjunction with its 2021 IDP filing, but then it subsequently withdrew this request before the Commission could make a determination.[13]

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[8] *In re Pet. of N. States Power Co. for Approval of Transmission Cost Recovery Rider Revenue Requirements for 2017 & 2018, & Revised Adjustment Factor*, Docket No. E-002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, & SETTING FILING REQUIREMENTS (Sept. 27, 2019) (eDocket No. 20199-156134-01).

[9] Ex. DOC-___, BH-D-2 (Havumaki Direct) (DOC IR No. 48).

[10] *In re N. States Power Co.'s Pet. for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2021-2022, & the Resulting Adjustment Factors by Customer Class*, Docket No. E-002/M-21-814, Petition & Compliance Filing (Nov. 24, 2021) (eDocket No. 202111-180141-01).

[11] *re N. States Power Co.'s Pet. for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2021-2022, & the Resulting Adjustment Factors by Customer Class*, Docket No. E-002/M-21-814, Supplement Filing (Aug. 17, 2022) (eDocket No. 20228-188420-02).

[12] *In re Xcel Energy's Integrated Distribution Plan & Advanced Grid Intelligence & Security Certification Request*, Docket No. E-002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, & CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS (July 23, 2020) (eDocket No. 20207-165209-01).

[13] *In re Xcel Energy's 2021 Integrated Distribution System Plan*, Docket No. E002/M-21-694, Letter Withdrawing Request for Distributed Intelligence Certification (Apr. 22, 2022) (eDocket No. 20224-185032-01).

Q. Does the Company plan to pursue additional grid modernization investments in the future?

A. It is not clear. In its filings in this proceeding, the Company does not definitively address whether it intends to pursue additional grid modernization investments in the future.

Q. Has the Company provided a complete picture of AGIS costs in this proceeding?

A. No. The Company has only provided a limited picture of just the subset of AGIS costs proposed for recovery in this proceeding.

Q. Do you believe that the Company should provide a comprehensive view of its past and future AGIS plans?

A. Yes. Over the years, the Company has pursued a staggered, even fragmented, approach to grid modernization investment. Unfortunately, without a comprehensive view of past and anticipated future plans and costs, it is not possible to obtain a complete picture of the Company's grid modernization initiatives or to assess whether investments proposed at any juncture, including in the instant proceeding, are the best option for the Company and its customers.

Q. Why is it necessary to evaluate the Company's current proposals within the context of past and anticipated future plans?

A. Grid modernization is a technically complex and novel undertaking that is characterized by interdependencies between component parts. Making the best decisions about how to pursue modernization requires a complete view of both grid needs and technical options. The utility thus plays a key role in providing this complete view through maximizing transparency into its past and anticipated future modernization plans.

Q. Have you estimated the total costs of Xcel's AGIS initiative?

A. Yes. I have attempted to fill in the gap in the Company's proposal by estimating the total past and projected future costs of the AGIS initiative. Based on my review of the Company's filings across the various relevant proceedings, I estimate the total cost of ADMS, AMI, FAN, TOU, LoadSEER, FLISR, and DI to be approximately $1.37 billion.[14] I note that this total represents only my best approximation, and that I am limited in my ability to estimate total AAGIS program costs by the diffuse and even disparate state of current cost information.

III. GRID MODERNIZATION PRESENTS NEW CHALLENGES

Q. What makes grid modernization investment proposals challenging to evaluate?

A. There are several features of grid modernization that may make evaluation challenging. As I just mentioned, grid modernization investments are novel, technically complex, and often expensive. Many grid modernization investments also promise to transform the

[14] *In re N. States Power Co.'s Pet. for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2021-2022, & the Resulting Adjustment Factors by Customer Class*, Docket No. E-002/M-21-814, Petition & Compliance Filing (Nov. 24, 2021) (eDocket No. 202111-180141-01); Ex. Xcel-___ (Bloch Direct); Ex. Xcel-___ (Remington Supplemental Direct); Ex. DOC-___, BH-D-3 (Havumaki Direct) (DOC IR No. 3).

grid, and they represent a new functional paradigm that is highly integrated and interdependent. Finally, in contrast with traditional investments in wires and poles, grid modernization investments are usually optional, and there may be several viable alternatives to achieving the same ends.

Q. Are there other factors in Minnesota that add to the challenge of evaluating grid modernization proposals?

A. Yes. The existence of multiple cost recovery mechanisms for grid modernization investments may compound the review challenge by encouraging a distributed approach to proposing grid modernization investments. The Company's historical approach to proposing grid modernization investments is a case in point.

Q. Has the Commission sought to address these grid modernization evaluation challenges?

A. Yes. The Commission has addressed these review challenges by promulgating filing requirements for grid modernization proposals through two key Orders – an Order in Docket No. E002/M-17-797 issued on September 27, 2019, and an Order in Docket No. E002/M-19-666 issued on July 23, 2020.

Q. Please summarize the requirements established in the Commission's September 27, 2019 Order in Docket No. E002/M-17-797.

A. In this Order, the Commission set forth a comprehensive set of requirements covering the evaluation of the costs and benefits of proposed grid modernization investments. The Commission required that future AGIS cost recovery requests from Xcel include details about investment scope, functionality, and alternatives, and that the assessment of costs and benefits be detailed and quantitative to the extent possible. This Order further included a set of evaluation principles.

Q. Please summarize the requirements established in the Commission's July 23, 2020 Order in Docket No. E002/M-19-666.

A. This Order expanded on the Commission's September 27, 2019 Order with the requirements that Xcel's future AGIS cost recovery requests include "a discussion of the mechanisms that will be employed to maximize cost reductions and minimize cost increases," and "a demonstration that the utility has thoroughly considered the feasibility, costs, and benefits of alternatives, and that the proposed approach is preferable to alternatives." The Commission specifically raised as an example the need for Xcel to "compare different types of the same technology, for example, by comparing different AMI meters."[15]

[15] *In re Xcel Energy's Integrated Distribution Plan & Advanced Grid Intelligence & Security Certification Request*, Docket No. E-002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, & CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS at 17 (July 23, 2020) (eDocket No. 20207-165209-01).

Q. Did the Commission's July 23, 2020 Order in Docket No. E002/M-19-666 expand customer protections?

A. Yes. In this Order, the Commission indicated that future AGIS cost recovery for AMI and FAN, which were certified in this Order, would be contingent on the Company's achievement of "Commission-approved metrics and performance evaluations."[16]

Q. How do these filing requirements improve the process of review?

A. These requirements, if complied with, should increase public understanding of proposed grid modernization investments and potential alternatives to promote selection of the best investment options. The Commission's filing requirements also advance customer protection and utility accountability by facilitating a better understanding of customer impacts through the requirements that metrics and performance targets be established and that cost recovery be made conditional on achievement of these performance targets.

Q. Is there a need for additional attention from the Commission to grid modernization proposal filing requirements?

A. Yes. In its petitions for AGIS cost recovery in this proceeding, it does not appear that the Company has complied with all grid modernization filing requirements. The Commission should ensure that it is holding utilities to account for compliance with applicable grid modernization filing requirements.

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[16] *Id.*

Q. What required information is missing from the Company's FLISR and DI proposals?

A. I do not believe that the Company has provided sufficient detail about the benefits of Distributed Intelligence, as required by the Commission in its Order in Docket No. E002/M-17-797.[17] Nor, in my opinion, have the Company's proposals for FLISR and DI met the requirements of the Commission's Order in Docket No. E002/M-19-666 for a "discussion" of cost reducing mechanisms and a "demonstration" that the proposed approach is preferable to alternatives.[18] Further, the Company has not sufficiently developed proposals for metrics or performance targets for DI and FLISR – a requirement established in both of the aforementioned Orders.

Q. Do you have any recommendations for the Commission to help ensure that future grid modernization proposals are compliant with Commission filing requirements?

A. Yes, I recommend that the Commission require that future filings include a table with all applicable Commission grid modernization proposal filings requirements and specific references to where each requirement has been met within the given petition. Such a table should be reasonably detailed, with references pointing to particular paragraphs, tables/figures, or other specific information within the filing rather than merely referencing general sections of the filing.

[17] *In re Pet. of N. States Power Co. for Approval of Transmission Cost Recovery Rider Revenue Requirements for 2017 & 2018, & Revised Adjustment Factor*, Docket No. E-002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, & SETTING FILING REQUIREMENTS at 12-16 (Sept. 27, 2019) (eDocket No. 20199-156134-01).

[18] *In re Xcel Energy's Integrated Distribution Plan & Advanced Grid Intelligence & Security Certification Request*, Docket No. E-002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, & CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS at 17 (July 23, 2020) (eDocket No. 20207-165209-01).

Q. Do you have other concerns about process that the Commission should seek to address?

A. Yes. As I discussed before, I am concerned about the availability of multiple cost recovery pathways for grid modernization investments, and the fact that the Company has been permitted to make grid modernization proposals in a piecemeal fashion over several years. Neither of these features is necessarily a bad thing, but together, they may make review less efficient even when proposals are otherwise fully compliant with existing filing requirements.

Q. Can you provide a specific example to illustrate your concerns about these outstanding issues that you recommend the Commission seek to address?

A. One specific example can be seen in the approach that the Company has taken to proposing AMI, FAN, and DI. The Company has separated its proposal for AMI and FAN from its proposal for DI despite the fact that DI is wholly dependent on AMI. Moreover, the value proposition for the specific DI-enabled AMI meters that the Company is in the process of installing is at least partly dependent on the benefits that can be achieved through DI. The Company has not provided a compelling rationale for this bifurcated approach.

Q. What are the implications of this bifurcated approach?

A. This approach introduces some awkwardness into the Commission’s decision-making since the Commission must consider the outcome of the TCR proceeding when considering DI in the instant proceeding. DI can only be installed with AMI meters in place, so if the Commission were not to approve AMI, then the DI program could not proceed. Meanwhile, though FLISR may not be technically dependent upon other grid modernization components under review in other dockets to the same degree that DI is, FLISR is nonetheless likely to yield benefits in part through its interactions with other grid modernization components not included in the instant proposal.

Q. What specific actions do you recommend that the Commission take concerning grid modernization filing requirements?

A. I recommend that the Commission expand on its existing filing requirements to require that every future grid modernization investment proposal include the following:

i. A grid modernization road map with all planned and contemplated future grid modernization investments.

ii. A complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs.

While the incorporation of these additional requirements would not completely ameliorate the challenges created by multiple recovery pathways and the Company's staggered approach to proposing AGIS investments, they would help to facilitate a more comprehensive understanding of the Company's overarching grid modernization strategy.

Q. Do you have any other recommendations regarding grid modernization filing requirements?

A. Yes. I recommend that the Commission standardize its grid modernization filing requirements so that they are applicable whenever a grid modernization proposal is brought forward, even if there is no associated requested for cost recovery. This should help to ensure that the Commission and other stakeholders are able to properly vet all such proposals, and that there are not differential information standards at different regulatory junctures that enable the Company to secure formal or informal approbation without making the complete case for its proposed grid modernization investments.

IV. FLISR INVESTMENT PROPOSAL AND BCA

Q. What is FLISR?

A. FLISR (Fault Location, Isolation and Service Restoration) is an automation tool that aims to reduce outages. It uses automated switching devices that can detect feeder mainline faults, isolate these faults, and restore power to unfaulted sections. FLISR relies on ADMS to provide central control, intelligent field devices to detect faults, and FAN to communicate wirelessly between devices. The application of FLISR that uses sensor data to locate faulted sections of a feeder is known as Fault Location Prediction (FLP).[19]

Q. Why is the Company proposing to invest in FLISR?

[19] Ex. Xcel-___ at 100-101 (Bloch Direct).

A. The Company states that FLISR will provide reliability improvements for customers. FLISR will allow the Company to restore power more quickly and with fewer resources after an outage. The Company projects that on feeders with FLISR installed the number of customers who experience a sustained outage as a result of a fault can be reduced by two-thirds.[20] In addition, FLISR provides more granular data for system planning. The enhanced quality and quantity of information that will be available allows for greater system visibility, which can improve reliability management, reduce employee field trips and improve the accuracy of planning models and hosting capacity analyses. According to the Company, the information collected by FLISR can also be useful for identifying potential issues and disturbances on the distribution system.[21]

Q. Does the Company provide a benefit-cost analysis for FLISR?

A. Yes. The BCA includes customer savings as well as savings due to decreased patrol times. These benefits are both linked to reductions in customer minutes out (CMO). From 2022 to 2024, the BCA estimates patrolling savings as about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** and customer savings as **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]**, totaling about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** in nominal dollars. Patrolling savings through 2041 have a net present value (NPV) of about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]**, and customer savings have

[20] *Id.* at 102-103.
[21] *Id.* at 106-107.

an NPV of about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]**, resulting in about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** in total benefits over this longer time period.[22]

Q. Please describe how the benefits included in the Company's FLISR BCA are calculated.

A. To calculate benefits of FLISR deployment, the Company estimates "the improvement in customer restoration times from our FLISR proposal in the form of reduced customer minutes out (CMO)."[23] The Company then multiplies this estimate by the value of these outage minutes according to the Lawrence Berkeley National Lab (LBNL) Interruption Cost Estimate (ICE) calculator.[24] LBNL's methodology involves a meta-analysis of customer value of service studies and a two-part regression model to estimate "customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers."[25]

Q. What are the costs of FLISR?

A. The capital costs associated with FLISR from 2022 to 2024 are equal to about $19 million, and O&M FLISR costs during this period are equal to about $1 million. The total NPV of FLISR costs through 2041 is calculated at about **[NOT PUBLIC DATA BEGINS . . .**

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[22] Ex. Xcel-___, KAB-D-4 (Bloch Direct).
[23] Ex. DOC-___, BH-D-4 (Havumaki Direct) (DOC IR No. 49).
[24] Ex. DOC-___, BH-D-5 (Havumaki Direct) (DOC IR No. 29).
[25] Michael J. Sullivan et al, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States* at 15, LAWRENCE BERKELEY NATIONAL LABORATORY (Jan. 2015), https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf.

[redacted] **. . . NOT PUBLIC DATA ENDS].**[26] This latter figure includes FLISR asset costs (specifically asset cost, installation, project management, and vendor), distribution communication, and ADMS FLISR integration and testing. These costs have an NPV of about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** through 2041. The BCA also contains O&M costs corresponding to deployment and ongoing support and communications, including project management, vendor, and network communication costs. O&M makes up about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** of the total cost NPV.

Q. What are the results of the Company's FLISR BCA?

A. Through 2041, the Company estimates an expected benefit-cost ratio of approximately **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** in net benefits on a present value basis.[27]

Q. Has the Company evaluated alternatives to FLISR?

A. The Company states that there are no comparable technologies and instead considered (1) maintaining the current system and (2) delaying FLISR deployment. The Company concludes that maintaining the current system would limit reliability improvements and that delaying deployment would only delay benefits and potentially increase costs.[28] No

[26] Ex. Xcel-___, KAB-D-4 (Bloch Direct).
[27] *Id.*
[28] Ex. Xcel-___ at 109 (Bloch Direct).

BCA or quantitative analysis was provided as justification for dismissing comparable technology options.

FLISR Cost Allocation

Q. How does the Company propose to recover FLISR costs?

A. Through base rates, allocated as shown below.

Table 2. Estimated Cost Allocation Through Base Rates[29]

Year	Residential	SCI Non-Demand	Demand	Lighting
2022	65.8%	5.2%	27.9%	1.1%
2023	68.5%	5.1%	25.2%	1.2%
2024	70.7%	5.1%	23.2%	0.9%

Q. Is the proposed cost allocation for FLISR equitable relative to the benefits?

A. No. The economic cost of outages, and thus the benefit of reducing outages, overwhelmingly benefits the commercial and industrial (C&I) classes relative to residential customers.

Q. How has the Company determined the cost of outages?

A. As discussed above, the Company uses the estimated economic value of reliability benefits published by LBNL. The following table shows the cost of an interruption by class for various time periods (momentary to 16 hours long) according to LBNL's meta-analysis of interruption cost studies and associated econometric modeling. Costs by class are shown per event, kilowatt (kW), and kilowatt hour (kWh).

[29] Ex. DOC-___, BH-D-6 at 3 (Havumaki Direct) (DOC IR No. 35) (table 4).

Table 3. Cost of Interruption per Customer, by Class ($2013)[30]

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

LBNL's analysis finds that "on both an absolute and normalized basis, residential customers experience the lowest costs as a result of power interruption."[31] As shown in the table, the cost of a one-hour outage for a residential customer in the United States is around $5, versus nearly $18,000 per hour for a medium or large C&I customer.

Q. Do these values differ for Xcel's service territory?

A. The table above shows interruption cost values for the entire United States. To evaluate results for Xcel's service territory, I used the latest version of the ICE calculator from LBNL's website and adjusted inputs to match Minnesota's recorded SAIDI/SAIFI in 2020. I also input the number of residential and commercial customers for Xcel's expected

[30] Costs are for an average customer. Michael J. Sullivan et al, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States* at xii, LAWRENCE BERKELEY NATIONAL LABORATORY (Jan. 2015), https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf.
[31] *Id.*

deployment of FLISR from the Company's BCA workpapers. The table below presents the outputs from this calculator.

Table 4. Cost of Interruption by Class for Minnesota/Xcel ($2016)[32]

[NOT PUBLIC DATA BEGINS . . .

[redacted]

. . . NOT PUBLIC DATA ENDS]

On a weighted average basis, residential customers represent about 2.5 percent of the total cost per reliability event (outage).[33] This is equivalent to the percentage of benefits received by residential customers per CMO, the methodology used by Xcel in its BCA.[34] This means that under the Company's proposal residential customers will be asked to pay 66 percent to 71 percent of FLISR costs (see above) but receive only about 2.5 percent of the benefits.

Q. Does the estimate of the share of reliability costs borne by residential customers depend on any assumptions?

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[32] SAIDI and SAIFI inputs utilizes Xcel actuals from 2020. The number of residential vs. commercial/industrial customers sourced from Xcel's BCA. Ex. DOC-___, BH-D-7 (Havumaki Direct) (EIA Reliability Data); Ex. DOC-___, BH-D-5 at 30–44 (Havumaki Direct) (DOC IR No. 29) ("CMO Feeder" Tab).

[33] The individual contribution to the weighted average cost per event shown here is calculated by multiplying the percentage of customers in each class by the cost per event.

[34] This is calculated by dividing total cost of interruptions by number of customers by the CAIDI.

A. Yes. The analysis with the ICE calculator assumes that, on average, residential customers experience the same frequency and duration of outages as do other customers. This analysis also assumes that the Company's FLISR plans will provide equal outage reduction benefits to residential customers and other customers. These assumptions appear sound, but even if residential customers were to experience a greater reduction in outage impacts due to FLISR than would other customers, the difference in the costs per hour of outage time between residential customers and commercial and industrial customers is so extreme that the large majority of benefits would almost certainly still accrue to commercial and industrial customers.

Q. What does your finding mean in terms of the cost-effectiveness of FLISR?

A. The proposal is not cost-effective for residential customers. Assuming the residential class receives 2.5 percent of benefits and pays for 66 percent of the costs, on a present value basis residential customers would receive **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** in benefits but incur **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** in costs.[35] This equates to a benefit-cost ratio of **NOT PUBLIC DATA BEGINS . .** [redacted] . . . **NOT PUBLIC DATA ENDS]**, compared with benefit-cost ratios of **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . NOT PUBLIC DATA ENDS]** for all customer classes combined.

Q. What do you recommend concerning cost allocation for FLISR?

[35] Ex. Xcel-___, KAB-D-4 (Bloch Direct) ("Ratio Out" tab).

A. I recommend that costs be allocated in proportion to benefits. For simplicity, I recommend that 97 percent of costs should be allocated to the commercial and industrial (C&I) classes and 3 percent of costs should be allocated to the residential class. Alternatively, I would not oppose that 100 percent of costs be allocated to C&I as this may be even simpler to implement. Even with the latter cost allocation, Xcel's analysis indicates C&I customers would receive a substantial net benefit from this investment, if the Company's investment performs as well as these estimates. I further ask that Xcel provide in rebuttal an updated version of Exhibit_(MAP-1), Schedule 3 attached to Mr. Michael A. Peppin's direct testimony to reflect my cost allocation recommendations.

<u>Prioritization of Circuits, Affordability, and Risk Considerations of FLISR Deployment</u>

Q. How does the Company propose to prioritize circuits?

A. Xcel proposes to prioritize circuits based on "(1) five-year reliability performance that takes into account the number of customers per feeder; (2) planned or recently completed projects that impact a feeder's reliability performance; (3) constructability."[36, 37]

Q. Why does the prioritization of circuits matter?

[36] The terms "circuit" and "feeder" are used interchangeably.
[37] Ex. Xcel-___ at 102 (Bloch Direct).

A. It is important for purposes of maximizing reliability benefits per dollar spent on FLISR deployment.

Q. How should the Company approach its prioritization of FLISR deployment?

A. The Company should aim to prioritize installation on FLISR on those circuits where it is most cost-effective, i.e., where it will deliver the greatest amount of benefits for the money spent on it.

Q. How can the Company effectively prioritize its FLISR deployment?

A. First, it is key to determine how the cost-effectiveness of FLISR investments will vary by circuit. I used the data in the Company's BCA to calculate the annual dollars of reliability benefits per device installed, as a proxy of cost-effectiveness at the circuit level since the cost of implementation generally varies directly with the number of FLISR devices installed.[38] I then sorted the circuits from highest to lowest annual dollars of reliability benefit per device. The figure below shows the results.

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[38] 97 percent of FLISR costs are capital related, and of these capital costs **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** are related to FLISR asset costs, which vary directly with the number of assets installed. In total, this means at least **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** of costs are related to the number of devices deployed, though other elements of costs likely also depend on the number of assets ultimately installed (communications, FLISR integration and testing, O&M). *See* Ex. Xcel-___, KAB-D-4 (Bloch Direct) ("SumFLISRCOSTS" tab).

Figure 1. Annual Savings per Device Sorted from Highest to Lowest

[NOT PUBLIC DATA BEGINS . . .

[redacted]

. . . NOT PUBLIC DATA ENDS]

The figure shows that reliability benefits are not proportionally distributed across Xcel's feeders.[39] In general, circuits with relatively worse historical reliability performance that also require the same or fewer FLISR devices as other feeders represent the most cost-effective investments. The first 20 percent of devices result in the greatest savings per device, while the last 50 percent provide much smaller savings per device.

Q. Does your analysis of feeder-level cost-effectiveness have implications for the utility's proposed circuit prioritization?

A. The utility's prioritization differs fairly significantly from a deployment based on the relative cost-effectiveness of circuits, according to my calculations shown above. While I understand that there may be practical constraints to deploying FLISR based strictly on

[39] This testimony uses the terms "feeder" and "circuit" synonymously.

cost-effectiveness criteria, as a general matter, deployment to circuits where the least amount of funds can be spent for the greatest reliability benefits represents the most beneficial approach for ratepayers.

Q. Are you suggesting that the Company modify its plans for deploying FLISR?

A. Yes. I suggest that the Company limit its initial deployment to the most cost-effective circuits to maximize benefits and improve overall affordability. Specifically, I recommend that the Commission only approve recovery of capital costs associated with the first three years of FLISR deployment, for 2022–2024, as proposed by the Company, along with the associated O&M costs on an ongoing basis. Over these first three years, the Company should focus on deploying FLISR on those circuits with the highest expected savings relative to costs.

Q. Are there other reasons to favor a limited initial deployment?

A. Yes. At this juncture, the benefits of FLISR are still hypothetical and projected based on numerous modeling assumptions. There is inherent risk that these benefits may not be realized. A more limited initial deployment helps to reduce the potential downside consequences of this risk. After the first two or three years of deployment, the Company can reassess the cost-effectiveness of the devices still to be installed based on actual data obtained over those years.

Q. Why do you say that the benefits of FLISR are "hypothetical?"

A. The Company's analysis is based on several assumptions, not all of which are based on historical data. For example, the Company assumes FLISR performs as intended during each and every outage, and that service will be restored to two-thirds of customers when outages occur. Yet the utility also admits "feeder characteristics vary and there may be more or less than two-thirds of the customers impacted by a fault."[40] These are major modeling assumptions that affect the realization of actual benefits.

Q. Are the costs of FLISR deployment also uncertain?

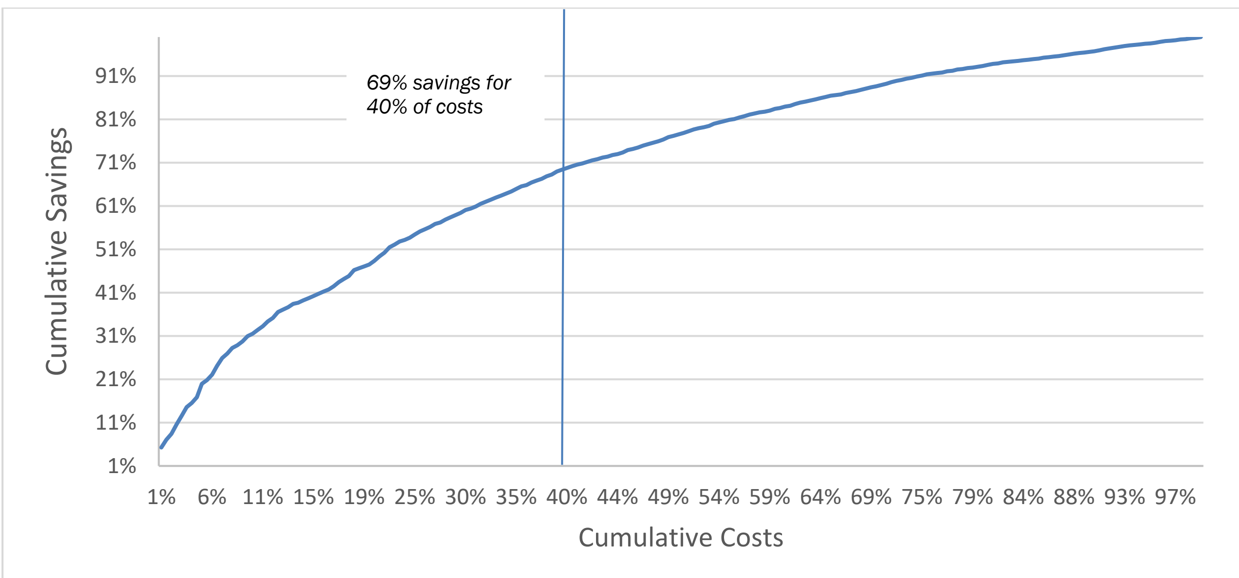
A. Yes, though they may be somewhat more certain than are the benefits because the costs are based on the Company's actual deployment of FLISR in Colorado. That said, under the Company's proposal any cost overruns would not be refunded to customers unless the Company overspends its entire forecast and adopted capital amount in this multi-year rate plan,[41] which it could avoid by reducing work on another capital cost category. I do not know if there are any differences between Minnesota and Colorado that will affect ultimate deployment costs.

Q. Have you analyzed the impacts of a more limited initial deployment over three years with enhanced prioritization of circuits?

[40] Ex. DOC-___, BH-D-8 (Havumaki Direct) (DOC IR No. 38); Ex. Xcel-___ at 103 (Bloch Direct).
[41] Ex. DOC-___, BH-D-9 (Havumaki Direct) (DOC IR No. 4).

A. Yes. If the Company were to deploy FLISR to circuits in order of each circuit's benefit-to-cost ratio over a three-year period as I describe above, I estimate based on the Company's BCA assumptions that the Company could achieve 69 percent of total FLISR program benefits at just 40 percent of total FLISR program costs. The figure below shows this potential result.

Figure 2. Cost-Effective Deployment of FLISR[42]



[42] Calculated from Ex. Xcel-___, KAB-D-4 (Bloch Direct) ("SumFLISRCOSTS" and "SUMFLISRBenefits" tabs). I first sorted feeders by cost-effectiveness (dollar savings per device) and then adjusted deployment years by assuming approximately the same number of circuits in each year as Xcel ("FLISRInputs" tab). I then calculated the Present Value (PV) of savings based on utility calculations but adjusted for the new deployment. Costs were calculated by dividing total capital and O&M costs in each year by the number of devices and taking the PV. This was then multiplied by the number of devices expected to be deployed on each circuit to determine a per-circuit cost.

Q. Under your proposed approach, could Xcel still complete its full FLISR program as proposed?

A. Yes. In Xcel's next rate case or other appropriate venue, the utility would have the opportunity to demonstrate based on *historical* performance of FLISR assets whether continued installation of FLISR would be cost-effective for the remainder of the circuits.

<u>**Performance Metrics**</u>

Q. Has Xcel proposed any performance metrics for FLISR?

A. No. This is problematic as Xcel seeks certain cost recovery for uncertain benefits.

Q. What types of metrics should the Company use to track its performance?

A. The benefits of FLISR hinge on reliability improvements for the feeders on which it is deployed. Xcel should track and report on reliability performance of circuits with FLISR installed and compare this with the previous eight-year average reliability (before FLISR was installed). This is the period length Xcel utilizes in its BCA. Specifically, Xcel should report SAIDI, SAIFI, and CAIDI metrics on an annual basis.[43] Further, Xcel should compare its forecast costs to actuals and explain any discrepancy.

Q. How should these metrics be used?

A. There are two primary purposes for which these metrics should be utilized. First, they should be used to evaluate whether any additional investment in FLISR is warranted

[43] Ex. DOC-___, BH-D-5 at 30–44 (Havumaki Direct) (DOC IR No. 29) ("CMO Feeder" tab)

past the initial three years of deployment. Second, if benefits are less than forecast, the Commission should evaluate whether all or a portion of costs should be refunded to ratepayers, consistent with the Commission's directive in its July 23, 2020 Order in Docket No. E002/M-19-666.

V. DISTRIBUTED INTELLIGENCE INVESTMENT PROPOSAL AND BCA

Q. What is DI?

A. DI is a technology that enables localized computer processing and analytics using data collected from AMI. In the context of the Company's DI proposal, AMI meters with DI capabilities can be used to directly process and analyze the data that they collect on-site and communicate with both the Company's IT infrastructure and with each other ("peer-to-peer").[44]

Q. Why is the Company proposing to make investments in DI?

A. The Company states that DI will empower customers to better understand their energy usage, encouraging behavioral change that can increase energy savings and reduce carbon emissions. DI can also extend the Company's ability to characterize the distribution system, identify issues, and actively manage grid performance.[45]

[44] Ex. Xcel-___ at 11-12 (Remington Supplemental Direct).
[45] *Id.* at 14-16.

According to the Company, DI will enhance the granularity and reduce the latency of grid data compared to AMI alone. While AMI meters may be technically capable of collecting data in intervals as small as 5 or 15 minutes, the volume of data that this would produce is not practical for broad collection and centralized processing. DI allows the Company to analyze sub-second data directly on the meter and transmit the results of this analysis to its back-end systems to be sent to customers in real-time.[46]

Q. Please describe the benefits included in the Company's DI BCA.

A. The BCA includes customer bill savings from 2024 to 2028 as benefits, resulting in an NPV of about $41 million. These benefits correspond to one of the Company's proposed initial customer-facing use cases (Energy Analysis), and assume a customer adoption rate based on current enrollments to MyAccount.[47] The Energy Analysis use case requires customers to use a smartphone application to analyze meter data and perform load disaggregation. This would lead to bill savings by encouraging participants to change their behavior in response to suggestions and notifications from this application.[48]

The Company expects to begin offering the Energy Analysis use case to customers in the second half of 2023, and there are no benefits identified in the BCA before 2024.[49]

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[46] *Id.* at 16-17.
[47] Ex. Xcel-___ at 59-60 (Remington Supplemental Direct).
[48] *Id.* at *27*.
[49] *Id.* at 29.

Q. Are other benefits and use cases included in the Company's BCA?

A. No. Other benefits and use cases discussed by Mr. Remington are not included in the BCA because the Company was unable to quantify them with sufficient certainty at this time.[50]

Q. What are the costs of DI?

A. The Company is proposing to recover about $23.5 million in capital expenses and $4.8 million in O&M costs that would be incurred between 2022 and 2024.[51] The Company has also indicated that it will seek recovery for the costs associated with certain future DI uses cases through the Conservation Investment Programs Rider.[52]

For the period from 2021 to 2028, the Company calculates the NPV of total costs for DI to be about **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]**.[53] This figure includes software architecture, grid-facing pilot development, and customer-facing pilot development capital costs. These total to an NPV of **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS].** The BCA also includes O&M costs corresponding to customer support and governance, system upgrades and maintenance, and Home Area Network (HAN). The NPV of these costs is **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS].**

50 *Id.* at 59.
51 *Id.* at 48, 50.
52 Ex. Xcel-___ at 138 (Bloch Direct); Ex. Xcel-___ at 32 (Remington Supplemental Direct).
53 Ex. Xcel-___, MOR-SD-3 (Remington Supplemental Direct).

Q. What are the results of the Company's DI BCA?

A. The Company estimates an expected benefit-cost ratio of approximately **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** in net benefits.[54]

Q. Has the Company evaluated alternatives to DI?

A. The Company was not able to identify any feasible alternatives to evaluate. In his testimony, Mr. Remington points to the installation of additional smart devices with every meter as an alternative. However, this would provide the same benefits as DI while requiring additional costs such as equipment purchase, networking, and software development. The Company made the decision to pursue DI capabilities during its AMI meter procurement process.[55]

Q. Do you have any concerns about the Company's BCA for DI?

A. Yes. Principally, I am concerned about the Company's approach to calculating the benefits of DI on the basis of bill savings. Further, I am concerned with the Company's lack of evaluation of alternatives to DI.

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[54] *Id.*

[55] Ex. Xcel-___ at 18-19 (Remington Supplemental Direct).

Q. Please explain your concern about how the Company calculates bill savings benefits for DI.

A. It is standard utility practice to value energy savings on the basis of avoided energy costs, not bill savings. Avoided energy costs reflect the utility system costs that can be avoided in the future as a result of DI or similar utility investments. Bill savings, on the other hand, are based on electricity prices that are generally based on historical, embedded costs that cannot be avoided in the future. The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* is clear on this point, and it includes a principle that benefit-cost analyses should be "forward-looking, long-term, and incremental to what would have occurred absent the DER."[56] Using bill savings as a benefit violates this principle because they are based on prices that are based on historical costs that cannot be avoided by the utility investment. Further, the Company uses future avoided costs, not bill savings, in analyzing the cost-effectiveness of its Conservation Investment Programs. DI benefits are similar to the benefits of these energy efficiency programs in that they help customers reduce their bills. There is no reason to treat the DI benefits any differently than the Conservation Investment Programs benefits.

Q. Is the DI proposal cost-effective?

A. No. Without the bill savings benefits, the DI proposal is clearly not cost-effective. If the Company were to replace the bill savings benefits with benefits based on future avoided

[56] National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* at 16 (Aug. 2020), www.nationalenergyscreeningproject.org/national-standard-practice-manual.

costs, then the DI proposal might be cost-effective. However, this is unlikely because the Company estimates the DI proposal to be marginally cost-effective using the customer bill savings and avoided energy costs tend to be significantly lower than electricity rates.

Participation Rate May Be Overstated

Q. How does Xcel estimate the number of customers that will participate in its DI programs?

A. To project the participation rate for DI, the Company starts with the percentage of customers with online MyAccount subscriptions, which is **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** of customers. The Company determines that **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** of this subset are active, and then it assumes that **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]**[57] of the active cohort will enroll in DI programs **. . . NOT PUBLIC DATA ENDS]**.[58] In total, this results in an assumption that **[NOT PUBLIC DATA BEGINS . . .** [redacted] **. . . NOT PUBLIC DATA ENDS]** of Xcel's customers with AMI will use DI.

Q. What are your concerns with this estimate?

A. First, Xcel does not present sufficient evidence to demonstrate the correlation between MyAccount usage and future DI usage will hold true. Signing into an online account once in 6 months is not the same as following and adjusting energy usage on a fairly constant

[57] Ex. Xcel-___, MOR-SD-3 (Remington Supplemental Direct) ("BenefitAssumptions" tab, cell C21).
[58] *Id.* ("BenefitAssumptions" tab, cell D20).

basis. Furthermore, the utility with which Xcel benchmarked its energy savings estimate, Detroit Energy (DTE), had 59,429 active participants in its comparable program, representing only around 2.9 percent of its total residential customers.[59]

Q. What are your conclusions with regard to the participation rate?

A. Xcel has not adequately supported its participation rate, and the actual active participation rate may be lower than the Company's assumption. The cumulative effect of this finding along with other flaws in the utility's analysis demonstrate why it should not be approved for cost recovery.

<u>Alternatives to DI</u>

Q. Please explain your concerns about the Company's evaluation of alternatives to DI.

A. The Company did not evaluate alternatives to DI.[60] First and foremost, time-of-use (TOU) rates and demand response programs can reduce energy use *at the appropriate time when costs are high* using price signals and/or load control. Given the primary quantifiable benefit of DI according to Xcel is energy savings, it is necessary and worthwhile to examine these alternatives.

Q. How do TOU rates compare with purported DI benefits?

[59] Ex. DOC-___, BH-D-10 at 9 (Havumaki Direct) (Form EIA-861 data). DTE has just over 2 million residential customers.
[60] Ex. Xcel-___ at 18 (Remington Supplemental Direct).

A. TOU rates can help shift load from peak times, which creates generation, transmission, and distribution capacity benefits as well as avoided energy costs.[61] In general, for demand response programs, the dollar values of capacity benefits are much greater than avoided energy costs. I do not know if Xcel has estimated a cost to implement TOU rates once AMI meters have been deployed. The value of on-peak reduction is generally much larger than off-peak.

Q. Can demand response programs also shift load during critical periods?

A. Absolutely. Demand response programs can target the highest cost periods when the system is most stressed to reduce load at these critical times. This can be accomplished in multiple ways using methods that the utility is actively deploying.[62]

Q. Has the Company demonstrated that its DI proposal in the public interest?

A. No. The Company has not demonstrated that the benefits of the DI proposal are likely to exceed the costs. The information provided by the Company in this docket suggests that the costs will exceed the benefits and therefore the DI proposal will not be in the public interest.

Q. What do you recommend?

[61] Represented by the delta between avoided on-peak and off-peak energy, assuming no load *reduction* occurs.
[62] *Minnesota Demand-Side Management*, Xcel Energy (last visited Sept. 30, 2022), www.xcelenergy.com/company/rates_and_regulations/filings/minnesota_demand-side_management

A. I recommend that the Commission reject the Company's request for approval of its proposed DI investments for 2022 through 2026. As explained above, the Company has not identified sufficient customers benefits to warrant the associated costs.

VI. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I offer the following recommendations:

1. The Commission should partially approve FLISR, but it should only approve costs for 2022–2025.
2. At least 97 percent of FLISR costs should be allocated to the commercial and industrial classes.
3. Xcel should prioritize deployment of FLISR by circuit according to the relative cost-effectiveness of each circuit.
4. The Commission should establish metrics and performance targets for FLISR, based upon the Company's proposed deployment plans and the anticipated benefits presented in support of this investment.
5. The Commission should make cost recovery for FLISR at least partly contingent on achievement of performance targets for FLISR.
6. The Commission should not approve DI.

7. In the event that the Commission does grant cost recovery for DI, it should establish metrics and performance targets, and it should make cost recovery for DI at least partly contingent on achievement of performance targets.

8. The Commission should seek all opportunities to improve the efficiency of the grid modernization evaluation process by consolidating dockets in order to reduce fragmentation and enhance cohesion across proposals.

9. In order to improve the efficiency of the grid modernization evaluation process, the Commission should require that each future grid modernization proposal include:

    a. A grid modernization road map with all planned and contemplated future grid modernization investments.

    b. A complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs.

    c. A table containing all Commission grid modernization proposal filing requirements and specific references to where each requirement has been met within the filing.

10. To reduce fragmentation and enhance cohesion across grid modernization proposals, the Commission should standardize its grid modernization filing requirements so that they are applicable in all instances in which utility grid modernization proposals are brought forward, including those instances in which cost recovery has not been requested.

Q. Please provide your recommendations for cost recovery for FLISR and Distributed Intelligence by year for the term of the multi-year rate plan.

A. My recommended cost recovery for FLISR and DI, along with the Company's proposed recovery, is presented in the table on the following page.

Table 5. Cost Recovery for FLISR and DI – proposed by Xcel and recommended

	2022	2023	2024	2025	2026
				[NOT PUBLIC DATA BEGINS . . .	
FLISR – as proposed by Xcel					
Capital[63]	$3,400,000	$7,800,000	$7,800,000	[redacted]	
O&M[64]	$300,000	$300,000	$400,000	[redacted]	
Total	$3,700,000	$8,100,000	$8,200,000	[redacted]	
FLISR – as recommended				[redacted]	
Capital	$3,400,000	$7,800,000	$7,800,000	[redacted]	
O&M[65]	$300,000	$300,000	$400,000	[redacted]	
Total	$3,700,000	$8,100,000	$8,200,000	[redacted]	
DI – as proposed by Xcel				[redacted]	
Capital[66]	$0	$0	$23,500,000	[redacted]	
O&M[67]	$200,000	$2,600,000	$2,000,000	[redacted]	
Total	$200,000	$2,600,000	$25,500,000	[redacted]	

[63] Capital costs for FLISR from 2022-24 from Ex. Xcel-___ at 99 (Bloch Direct). These costs correspond to the "MN Electric Jurisdiction." Capital and O&M costs for FLISR from 2025-26 were obtained from Ex. Xcel-___, KAB-D-4 (Bloch Direct) and rounded to the nearest $100,000. This schedule (the BCA) does not appear to break out MN-specific costs from Total Company costs, so these costs are likely overstated.

[64] O&M costs for FLISR from 2022-24 were obtained from Ex. Xcel-___ at 138 (Bloch Direct). These costs are provided for NSPM.

[65] The recommended O&M budget provided in this table for 2025-26 was calculated by taking the O&M costs for 2028 and 2029 (the first two years after proposed device deployment would end) in Ex. Xcel-___, KAB-D-4 (Bloch Direct) and dividing these values by the cumulative number of devices deployed. The dollar per device values for the first and second years after the recommended end of device deployment (2025 and 2026) were then multiplied by my recommended cumulative number of devices from 2022-2024 according to the Company's deployment plan. Again, this value may be overstated as the Company did not appear to segregate MN jurisdictional costs in its BCA. The final values are rounded to the nearest $100,000.

[66] Capital costs for DI from 2022-24 were extracted from Ex. Xcel-___ at 48 (Remington Supplemental Direct). These costs are provided for NSPM. Capital costs for DI from 2025-26 were obtained from Ex. Xcel-___, MOR-SD-3 (Remington Supplemental Direct).

[67] O&M costs for DI from 2022-24 were obtained from Ex. Xcel-___ at 50 (Remington Supplemental Direct). These costs are provided for NSPM. O&M costs for DI from 2025-26 were obtained from the Ex. DOC-___, BH-D-3 (Havumaki Direct) (DOC IR No. 3) and rounded to the nearest $100,000. As stated in the Response, "At this time, the appropriate allocation of these costs to utility and jurisdiction is being developed. The Company plans to include DI costs allocated to Minnesota Electric Jurisdiction in its rebuttal testimony."

DI – as recommended				
Capital	$0	$0	$0	[redacted]
O&M	$0	$0	$0	
Total	$0	$0	$0	
				. . . NOT PUBLIC DATA ENDS]

Q. Does this complete your direct testimony?

A. Yes.