Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

March 22, 2022

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: REPLY COMMENTS
INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/M-21-694

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply Comments to the Minnesota Public Utilities in response to the Comments filed by parties on February 25 and 28, 2022 on our 2021 Integrated Distribution Plan in the above-referenced proceeding.

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

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie J. Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE DISTRIBUTION SYSTEM PLANNING FOR XCEL ENERGY

DOCKET NO. E002/M-21-694

REPLY COMMENTS

INTRODUCTION

Pursuant to the Notice of Extended Comment Period issued on February 7, 2022, Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Reply Comments in response to the Comments filed by parties on February 25 and 28, 2022.

We appreciate the opportunity to provide these Reply Comments. The record contains sufficient information for the Commission to accept our Integrated Distribution System Plan (IDP) and certify our planned Distributed Intelligence (DI) projects and the Resilient Minneapolis Project (RMP). We appreciate the thoughtful approach taken by the numerous parties that submitted Comments, and the support several parties gave for the IDP, and for certification of DI and RMP.

Several months after we filed our IDP and requests for certification, however, the Department of Commerce presented a "Guidance Document" developed by its consultants at Synapse Energy Economics, Inc. (Synapse) and the Wired Group, and suggested that our IDP and certification applications, among other things, be evaluated using the criteria and proposed requirements set forth in that document. We respectfully disagree. While we welcome the opportunity to further discuss our distribution planning and the DI and RMP projects with the Commission and stakeholders, changes to the IDP process and the criteria by which the Commission reviews grid modernization proposals should be made on a prospective basis after a full record has been developed through a robust opportunity for stakeholders to engage on the proposed changes. This is especially true given the Commission already has adopted a framework for assessing grid modernization proposals, which the Department's Guidance Document, if adopted, would substantially revise.

Our IDP and certification requests should be assessed using the established frameworks specified by the Commission. Our IDP complies with the Commission's filing requirements, and we have achieved the Commission's planning objectives.[1] Similarly, our DI and RMP certification requests meet the Commission's informational requirements and provide a robust record for the Commission to make a certification decision. Both projects, while not particularly significant in terms of expenditure, are important to our ability to develop capabilities that benefit our customers, the reliability of the distribution system, and the environment. DI is a promising new technology that furthers the capabilities of our Advanced Metering Infrastructure (AMI) meters and will facilitate greater customer engagement with their energy usage, while also providing capabilities that can improve the operation of the distribution grid. Our initial DI proposal is relatively modest, but the lessons we learn and the capabilities we develop, including the experiences from working with our partners in the project, should provide a foundation for future developments using this new technology. RMP is a relatively low-cost project that will promote grid equity and resilience in the specific communities it serves, while also providing valuable experience integrating battery energy storage into the distribution system and managing it to deliver multiple benefits.

To the extent the Commission wishes to establish a prescriptive framework for evaluating grid modernization investments, or to change the purpose of the IDP from its current informational objective to be more akin to an integrated resource plan (IRP), which the Department's Guidance Document unilaterally assumes, significant, additional process is necessary. Before making such a determination, the Commission could initiate a workgroup to assess and explore the changes that would be necessary to affect such a transformation. We would be happy to participate in such an effort and to help develop any forward-looking guidance on these important topics.

The balance of this Reply focuses on four key issues: (1) whether the IDP should be accepted, (2) proposed changes to the IDP process and requirements including: (i) what role, if any, the Department's Guidance Document, should play in the evaluation of this IDP and the DI and RMP certification requests and (ii) proposed prospective changes with regard to consideration of equity; (3) whether DI should be certified, and, (4) whether RMP should be certified.

We respectfully request the Commission to:

- Accept the IDP,
- Certify the Company's DI investments,

[1] As amended by the Commission's November 2, 2020 Order in Docket No. E002/M-19-666.

- Certify the Company's planned RMP project, and
- Reject the Department's request for the Commission to: (1) adopt its Guidance Document, and (2) use it to assess the IDP and DI and RMP investments.

REPLY COMMENTS

I. THE COMMISSION SHOULD ACCEPT XCEL ENERGY'S IDP

Questions 1 and 2 from the Notice of Comment Period issued by the Commission on November 15, 2021 were whether the IDP should be accepted or rejected and whether the IDP achieves the planning objectives outlined in the Commission's filing requirements and its November 2, 2020 Order in Docket No. E002/M-19-666. To squarely answer those questions: yes, the Commission should accept our IDP; it complies with the filing requirements, including the planning objectives, and provides the Commission with the information it needs to understand our distribution system planning and our efforts in pursuit of the objectives established by the Commission.

In Comments, parties recognized the quality and value of our IDP. We have worked hard to improve the content and usability of the IDP with each iteration. Fresh Energy began its comments by stating that we have presented a "strong" IDP that "builds upon" past plans and is "responsive to Commission and stakeholder feedback."[2] In addition, Community Power, the Environmental Law & Policy Center, and Vote Solar (collectively, "CEV") recommended acceptance of the IDP,[3] and recognized that the IDP "does express a long-term vision for the distribution grid consistent with the requirements of the current planning objectives."[4] The City of Minneapolis recommended acceptance of the IDP, with modifications.[5] While the Department of Commerce requests some additional information and raises various issues, particularly related to its February 2022 Guidance Document, the Department also states that its preliminary analysis is that the IDP has sufficiently addressed each of the IDP filing requirements and Commission Orders.[6]

In summary, while various proposals have been made for changes to the process and filing requirements in the future, we have presented a strong IDP that complies with

[2] Fresh Energy Comments at 1.
[3] Contingent on acceptance of their recommendations for the next IDP, which are discussed in Attachment A.
[4] CEV Comments at 12.
[5] City of Minneapolis Comments at 3. We discuss the City's recommendations regarding changes to the IDP process in the Attachment A.
[6] Department of Commerce Comments at 11.

the relevant requirements and that presents a long-term vision for the distribution grid that is consistent with the Commission's planning objectives.

II. PROPOSED CHANGES TO THE IDP PROCESS AND REQUIREMENTS

A. The Department's Guidance Document

In the Department's Comments and the Guidance Document the Department filed in February 2022, the Department envisions substantial changes in the IDP process. These changes include the adoption of new requirements for evaluating the cost effectiveness of distribution projects, and an overall conversion of the IDP from a largely informational filing, consistent with the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, to some kind of combination of a prudency assessment, such as is done in a rate case or rider proceeding, *and* a resource planning or certificate of need assessment of distribution investments.

At minimum, the Department's Guidance Document—developed without any utility or other stakeholder input—should not be considered in this proceeding. The criteria used to evaluate our current IDP and certification requests should not be based on the retroactive application of a document filed in the midst of the proceeding. Moreover, adoption of the Department's Guidance Document's impractical standards would create a significant new regulatory burden with wide-ranging impacts as we discuss in this Reply and Attachment A. We believe it would be reasonable and appropriate for the Commission to require the Department to work with stakeholders to modify its Guidance Document to make it consistent with the Commission's objectives for IDP and practicable for utilities – then file it in a new and forward-looking all-utilities docket, subject to further stakeholder efforts and formal regulatory procedure to build a comprehensive record for the Commission to consider. That said, in addition to these comments, we reserve the right to further comment on the Department's Guidance Document in our Transmission Cost Rider (TCR) docket or other proceedings, as necessary or appropriate.

1. The Application of the Department's Guidance Document to this Proceeding Creates Process Deficiencies

We submitted our 2021 IDP, as required, on November 1, 2021, consistent with requirements that the Commission has developed over many years. Since 2015, we have been transparent about our plans for modernizing the electric grid, and over the course of several years and proceedings, outlined a comprehensive set of multi-year investments to develop the next generation energy grid. Since that time, there has been years' worth of dialogue and record development on our proposed and in-process grid modernization investments. This includes significant work by the Department to examine metrics, develop performance evaluation methods, and ensure consumer protection. In 2019, our IDP requested certification of the Company's proposed investments in AMI and FAN among other projects. In that filing, we provided comprehensive information on the proposed investments including cost-benefit analyses, as required by the Commission. And, during that proceeding, the Commission and stakeholders evaluated our requests, and the Commission ultimately granted certification of both AMI and FAN.[7]

However, apparently without regard for the Commission's precedent, the Department filed its Guidance Document on February 9, 2022 – more than three months after we filed our IDP and accompanying DI and RMP certification requests – with new proposed requirements it developed itself and stated it would apply to all distribution spending, including the grid modernization investment at issue in ongoing proceedings. The Department has since retroactively applied the "criteria" and "requirements" set forth in its Guidance Document to evaluate both the IDP generally, and the specific projects for which we have requested certification. While its final recommendations are pending and will be included in Party Reply Comments, essentially, the Department is contending that the IDP and certification requests are deficient because they do not comport with its unilaterally-developed Guidance Document that was only provided to the Company *after* our IDP was already filed.

We respectfully object to the approach the Department has taken with its Guidance Document and in this proceeding. We have spent considerable effort creating the IDP and developing the projects for which we are seeking certification. The Department's recommended approach, if adopted, would effectively deprive the Company, and other stakeholders, of required due process. While the Department states that it intends to evaluate all IDPs and grid modernization proposals using its Guidance Document issued just last month, no party, not even the Commission, has had the opportunity to comment on its findings and recommendations. New requirements should be adopted prospectively, not retroactively, and only after receiving and considering appropriate stakeholder input.

2. *Adoption of the Department's Guidance Document Without Stakeholder Input and Full Consideration Would be Contrary to Sound Public Policy*

In addition to our concerns regarding the lack of process and the fundamental unfairness of assessing the IDP and certification requests using the Department's Guidance Document in the manner suggested by the Department, we also believe that suddenly adopting detailed new requirements would not be sound public policy. If

[7] July 23, 2020 Order, Docket No. E002/M-19-666.

the Commission does determine it wishes to consider adopting a new process and methodology for evaluating IDPs and distribution projects, it should do so after building a record and careful consideration of the issues at stake, with input from stakeholders, and any resulting decision applied prospectively. Even Synapse, the Department of Commerce's own experts, previously stated in a 2021 report for the U.S. Department of Energy, "[i]deally, public utility commissions should articulate a BCA framework for grid modernization prior to the development and submission of grid modernization plans. This allows for stakeholder input and regulatory guidance in developing the framework, outside of the review of specific grid modernization proposals."[8]

If the Commission wishes to adopt a prescriptive, standard framework, Minnesota has successfully used a process like Synapse recommended in its report for DOE in the past – in developing a framework to evaluate the cost-effectiveness of Conservation Improvement Plan programs and investments. In fact, the Department has an effort currently underway to update the existing framework. An effort such as this is essential to ensure that the framework to evaluate grid modernization proposals is properly aligned with Minnesota's public policy objectives – and that the evaluation methods it prescribes fairly assess proposed initiatives and their ongoing effectiveness in a Minnesota context. Another example of just the sort of process Synapse recommended in its report for the DOE referenced above is occurring in Docket No. G999/CI-21-566, where the Commission is currently acting pursuant to Minn. Stat. § 216B.2428 (part of the Natural Gas Innovation Act or NGIA) to develop, among other things, a cost-benefit analytic framework that the Commission will use for comparing the cost effectiveness of innovative resources and innovation plans.[9] A similar process with all the impacted utilities and other stakeholders participating in a single docket (rather than addressing the Department's Guidance Document separately in each utility's docket) would be similarly appropriate for analyzing the cost effectiveness of grid modernization investments, if the Commission wishes to adopt a prescriptive, standard framework. Alternatively, the Commission could also

[8] Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations, February 2021 at 25, available at [Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations (synapse-energy.com)](); *see also* Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments; Designing Resilient Communities: A Consequence-Based Approach for Grid Investment, May, 2021, at 21 ("The regulatory perspective, and the decisions regarding how to account for policy goals in a JST [jurisdictional specific test], should be informed by robust stakeholder input to balance the interests of different parties"), available at Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments 19-007.pdf (synapse-energy.com).

[9] Notice of Comment Period on Natural Gas Innovation Act, Section 21, Docket No. G999/CI-21-566, Sept. 3, 2021.

establish a workgroup process to consider adopting such a framework and/or address how the IDP process correlates to the IRPs and certificates of need.[10]

Similarly, while the Department's Guidance Document recommends quantifying and reducing all qualitative benefits to a monetary value, there are no existing, well-established methodologies for doing this. Developing new methodologies for quantification and reduction of qualitative benefits to a monetary value will require considerable time and resources – and such unilateral efforts by the Company would undoubtedly be subject to criticism. Similarly, efforts by the Commission to evaluate new methodologies for developing quantifiable metrics or methods to assess impacts can be considerable undertakings. Two such examples are the Commission's investigation into performance-based ratemaking in Docket No. E002/CI-17-401 and its environmental cost proceeding in Docket No. E999/CI-14-643. Both of those dockets took years to reach conclusions and involved input from numerous parties. As we also noted above, the cost-effectiveness framework for energy efficiency measures and the work the Commission is currently in the midst of with its work to establish a framework for GHG emissions from natural gas use in Minnesota as part of the NGIA are good examples of the type of efforts necessary to establish thoughtful and appropriate frameworks.

If the Commission decides to initiate a proceeding to consider a standardized, prescriptive framework for grid modernization cost-effectiveness, the appropriate outcome may not be the adoption of a single required methodology. Notably, the California Public Utilities Commission declined to do so after considering the matter in 2018, stating that it "will not require a method to quantify a *cost-effectiveness* showing in order to evaluate grid modernization investments" but that careful scrutiny of "*cost reasonableness*" will continue to be required in general rate cases.[11] Moreover, as we discuss further in Attachment A, there is not a single, universally accepted methodology for assessing the cost-effectiveness of proposed grid modernization investments. In that respect (and others), the Department's Guidance Document is overly broad and overly prescriptive. Instead, there are a variety of potential approaches, some of which may be more or less appropriate in particular instances. Indeed, as Synapse itself notes in a May 2021 report for Sandia National Laboratories, different tests "provide different information about the costs and benefits of grid investments, and it is important to identify the test or tests that are most appropriate

[10] Any such workgroup effort should involve potential prospective changes, and not the retroactive application of new standards to ongoing dockets.

[11] California Public Utilities Commission, Decision 18-03-023 at 24-25 (March 22, 2018) (emphasis in the original), available at [212432689.PDF (ca.gov)](212432689.PDF (ca.gov)).

for the jurisdiction."[12] After careful consideration and with the benefit of stakeholder input, the Commission might choose to adopt a single test, multiple tests, or no specific test at all. The Department's Guidance Document deserves careful and thoughtful consideration in a proceeding or workgroup, but so do proposals and comments offered by other stakeholders, including the utilities in Minnesota that would be subject to the requirements.

3. The Proposed Application of the Department's Guidance Document is Not Consistent with the Nature of the IDP Process

Finally, the Department's proposed approach of applying its Guidance Document in a manner similar to a Certificate of Need proceeding does not comport with the established nature of the IDP process. IDPs were borne out of the Commission's grid modernization inquiry and desire to gain greater visibility into the distribution system for the benefit of the Commission and stakeholders. For example, the report on IDPs presented by ICF International to the Commission in 2016 contemplated that distribution planning would provide analyses, forecasts, and other system planning information.[13] Likewise, a Commission Staff presentation on January 23, 2018, indicated that distribution planning should provide the Commission with an understanding of the utilities' plans, provide context for investments, and ensure the utilities are proactively planning for the future.[14] In the briefing papers preceding the first IDP in 2018, Staff proposed that the Commission "accept" rather than "approve" IDPs, indicated that acceptance should not constitute a prudency determination, and stated that IDP "filings are intended to obtain a better understanding and dialogue surrounding forthcoming investments and planning considerations and to provide a forum to proactively address where additional information or planning considerations are needed."[15]

As is clear from the Commission's Order Accepting Report, and Amending Requirements in our 2018 IDP proceeding, the Commission accepted Staff's recommendation. The Order stated that the IDP is intended to "advance the Commission and customer understanding of the Company's planning" in the areas of

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[12] Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments; Designing Resilient Communities: A Consequence-Based Approach for Grid Investment Report Series, May 2021 at 21, available at [Standard_Approach_to_Benefit-Cost_Analysis_for__Electric_Grid_Resilience_Investments_19-007.pdf (synapse-energy.com)].

[13] Integrated Distribution Planning, ICF International, Aug. 2016, at 5-6, 10-12, attached to Notice of Integrated Distribution Planning Report and Stakeholder Workshop, Sept. 13, 2016, Docket No. E999/CI-15-556.

[14] January 23, 2018 Planning Meeting Slides, Docket No. E999/CI-15-556 at 16. These slides also reflect that some stakeholders did contend that IDP proceedings should address prudence in some manner, see slide 15; however, the Commission did not accept that proposal as subsequent orders cited below make clear.

[15] Staff Briefing Papers for April 19, 2018 Meeting, Docket No. E999/CI-15-556, at 12.

grid modernization and the framework for on-going distribution system planning.[16] IDPs have been and continue to be informational proceedings. In that way, they are markedly different than integrated resource plans, which – as set out in Minnesota statutes – are required to be "approve[d], reject[ed], or modif[ied]" by the Commission and result in an order that constitutes "prima facie evidence which may be rebutted by substantial evidence in all other proceedings."[17]

Consistent with their informational purpose, the Commission has made it clear that the acceptance of a utility's IDP has no bearing on cost recovery or prudence.[18] Accordingly, while the Department seeks additional information regarding our distribution system budgeting and expenses in this proceeding, and is considering recommending that we be required to provide illustrative cost-benefit analyses for projects in each budget category in our next IDP,[19] such a recommendation must be evaluated with the understanding that prudence and cost recovery are not at issue in this proceeding. Instead, cost recovery for the vast majority of distribution spending occurs in rate case proceedings where we have the burden of showing those costs were prudently incurred; the only exception is the ability to seek cost recovery through certain rate riders in narrow circumstances. Given the informational context of the IDP, it is appropriate that the budget discussion in the IDP provides more of a general overview as opposed to justifying the prudence of discrete projects or the planned expenditures in each budget category.[20]

Likewise, even certification of grid modernization projects only allows the Company to subsequently seek recovery in the TCR, and does not establish any presumption of prudence or guaranty that the investments will, in fact, be allowed to be recovered through the rider.[21] Were IDP proceedings fundamentally transformed into matters in which the prudence of the Company's expenditures were at issue, that would substantially increase the burden on participating parties and the Commission in considering IDPs. It would also upend long-established regulatory frameworks and duplicate issues that are appropriately considered and decided in other proceedings. Such a fundamental change to the IDP process is unwarranted and, at a minimum, should certainly not be implemented in the midst of an ongoing proceeding.

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[16] July 16, 2019 Order, Docket E002/CI-18-251, at 4.
[17] Minn. Stat. § 216B.2422, Subd. 2.
[18] See November 2, 2020 Order, Docket No. E002/M-19-666 at Order Point 4 (noting that Commission review "is not a prudence determination of any proposed system modifications or investments.")
[19] Department of Commerce Comments at 15-21.
[20] The Department of Commerce's budget-related comments are addressed further in Attachment A.
[21] July 23, 2020 Order, Docket No. E002/M-19-666 at 12 (stating that "certification does not constitute a pre-judgment of whether costs will be recovered through riders or base rates. Certification simply permits a utility to request rider recovery in the future, which the Commission may approve or deny based on the facts available at that time.")

The Department's Guidance Document evinces a desire to create an IDP process that mimics the IRP process in Minnesota and the MISO transmission planning processes. While we generally support aligning various planning processes, we do not believe simply porting requirements from one process to another, at least without careful consideration, is supported by statute or consistent with the Commission's direction on the purpose and objectives of the current IDP process.

Fundamentally, we disagree with the premise that the current IDP process is equivalent to current IRP and Midcontinent Independent System Operator (MISO) transmission planning processes. The IRP process is a long-term (15-year) resource planning process that has been in place for decades and is governed by established Minnesota Statutes and Rules (which result in Orders that constitute prima facie evidence in other proceedings). Similarly, transmission planning is largely governed by FERC and NERC requirements, and overseen by MISO. In contrast, as explained above, the IDP process is nascent in comparison – intended to be informational in nature, and based on a set of reporting requirements that the Commission has established on a utility-by-utility basis.

While IDP requirements may change over time, evolving it to be similar to an IRP-like process would require significant time, work, and stakeholder input – and that is only if the Commission desires to evaluate or pursue such a change.

B. Proposals Regarding Explicitly and Broadly Incorporating Equity into the IDP

Across several recent dockets, including the IDP, parties have placed an increasing emphasis on more explicitly incorporating equity broadly into energy planning and decision-making. We recognize and appreciate this focus. Most recently, this discussion of equity appears clearly in the decision options the Commission voted to approve on February 8, 2022 in connection with our IRP in Docket No. E002/RP-19-368. The Decision Option the Commission adopted, and which several parties referenced in their IDP comments, reads:[22]

> The Company shall do community outreach and establish a stakeholder group to:
>
> a. Design for the equitable delivery of electricity services and programs for energy burdened customers in the next IRP.
> b. Create new options to improve customer access to energy efficiency and renewable energy.
> c. A plan to be submitted in the next IRP to bring its workforce's racial and gender diversity in line with the utility's stated goals.
> d. Design DG Resource incentive programs that ensure distributed generation

[22] See CEV comments at 6, Fresh Energy comments at 16, and City of Minneapolis comments at 7.

programs provide equitable access to low income and Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions.

e. Adopt practices in furtherance of procedural justice, including deeper engagement with renters, affordable rental property owners, BIPOC communities, and under-resourced individuals, providing resources for engagement and participation, and providing financial support for impacted individuals to participate in dockets and decision-making processes.

f. Form an environmental justice accountability board, which would develop environmental justice-focused initiatives to be incorporated throughout the utility.

In its next IRP docket, and in a separate docket to be established by the Executive Secretary, Xcel shall file details describing stakeholder outreach and progress by January 1, 2023 and annually thereafter.[23]

In this IDP docket, various parties urge the Commission to incorporate similar equity considerations and requirements in evaluating distribution system investments.[24] Notably, the parties in question are recommending changes that would apply to the next IDP. We fully support incorporating equity broadly into energy planning and decision-making.[25] Parties also point to overlapping equity issues and considerations in the Performance-Based Ratemaking docket (Docket No. E002/CI-17-401), and the Safety, Reliability, and Service Quality docket (Docket No. E002/M-20-406). The equity discussions occurring in disparate dockets significantly overlap in some areas, and also complement one another in some areas. We see opportunity in the adopted Decision Option referenced above that anticipates a separate equity docket with annual reporting requirements. We anticipate that this new docket will provide a more holistic but central process and forum to engage stakeholders and attempt to reach consensus on how equity can be incorporated across the Company, including in our IRP, IDP, and related dockets. As such, we do not believe CEV's or the City of Minneapolis' proposed additions to the IDP planning objectives and filing requirements[26] are necessary at this time. Likewise, we believe that including a duplicate equity-focused Order Point in this docket is not necessary, but we respectfully request that this or any Order Point that the Commission chooses to adopt for the IDP be identical to that in the IRP to ensure that there is one set of clearly-stated expectations. Two sets of similar, but not identical, Order Points on the same topic could lead to confusion and duplicative efforts. Attachment A includes our full response to Parties' comments on new or revised IDP planning objectives.

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23 Decision Option E15, adopted verbally during February 8, 2022 Deliberations in Docket No. E002/RP-19-368; written Order pending.

24 City of Minneapolis Comments at 6-7, CEV Comments at 9-11, 13-16, Fresh Energy Comments at 16.

25 Parties also commented on equity aspects specific to the RMP; we address those comments in Part IV of this document and further in Attachment A.

26 CEV Comments at 13-16.

We appreciate the stakeholder interest in equity issues and look forward to engaging with a diverse set of stakeholders, intervenors, communities, and customers as we implement the equity initiatives outlined in the Commission's anticipated IRP Order Points.

III. CERTIFICATION OF FOUNDATIONAL DI CAPABILITIES AND INITIAL DI USE CASES

Distributed Intelligence (DI) is an emerging technology that can be leveraged to provide substantial benefits in the near-term, including substantial energy savings, and has even greater potential in the medium and long-term. The distribution of computer processing capabilities to the edge of the distribution grid and the communications pathways made available by Wi-Fi radio and the IEEE 2030.5 communications protocol together open up new possibilities for analyzing, transmitting, and sharing data in ways that will empower customers, give the Company greater insight into the operation of our distribution system, and benefit the environment. Certification is appropriate for this investment both because of the benefits described in our application, including the quantified predicted customer energy savings benefits, and, more importantly, because of the new technological pathways that will open up as a result of the development of foundational DI capabilities and the lessons and the capabilities that will be learned and developed as a result of our deployment of the initial use cases.

The Commission granted certification for the Company's Advanced Metering Infrastructure (AMI) meters in the last IDP;[27] we are currently seeking cost recovery in the pending TCR docket. The Itron Riva 4.2 AMI meters we have procured have DI capabilities, which means, essentially, that each meter will contain the equivalent of a small computer. We referenced DI in our prior IDP,[28] but did not seek certification for any DI capabilities at that time. Because the Department's Comments express concern regarding our decision to separately seek certification for DI, we briefly describe the background and basis for that decision – and, the distinction between the meters themselves, which we sought certification for previously, and the incremental DI investments we are seeking certification for now.

As an initial matter, it is important to take note that the timing of the Company's procurement of new AMI meters is driven by the age and obsolescence of our existing automated meter reading (AMR) meters. Landis+Gyr (Cellnet) has indicated it will no longer manufacture replacement parts for the meters we use after 2022 and we are, in fact, the last Cellnet customer using the technology. Replacement Cellnet

[27] July 23, 2020 Order in Docket No. E002/M-19-666, Order Point 7.
[28] Nov. 1, 2019 Integrated Distribution Plan (2020-2029), Docket No. E002/M-19-666 at 9, 26, 173.

parts are also not available from other vendors and so we will not be able to purchase replacement parts after 2022. Additionally, our contract with Cellnet for meter reading service and support expires at the end of 2025. The AMR meters served our Company well for nearly 30 years, but they must now be replaced.

Given the impending need to replace our existing electric meters, we began our procurement process in 2016. In March 2018, we issued a request for proposals (RFP) to select an AMI meter vendor, and responses were received from four vendors. None of the responding vendors proposed DI-enabled meters. However, later in 2018 during discussions with vendors, the Company was made aware that some manufacturers were developing DI-enabled meters (then referred to "edge" computing or "grid edge" technology). We responded by studying DI technology and then issuing a bid clarification seeking proposals for DI-enabled meters. Ultimately, we negotiated favorable pricing with Itron, which allowed us to purchase DI-enabled meters for a price within the range of those that had earlier been proposed for non-DI AMI meters. Itron was selected as a vendor in May 2019.

At the time of our 2019 IDP filing, DI technology was new to the market, and the Company had just selected its preferred meter vendor the preceding spring. While the Department suggests that we should have combined our AMI certification request with a DI certification request, it was simply not possible for us to submit such an application for DI, given the novelty of DI technology both in the industry and to the Company. We needed some time to study DI and better understand the capabilities it offers our customers and the grid, including the costs to develop those capabilities, so that our stakeholders and the Commission could evaluate the investments. We were transparent with the Commission about the fact that we had selected DI-capable meters[29] and waited to make a concrete proposal for the deployment of those incremental capabilities until we were ready to do so.

After selecting Itron as our vendor, we collaborated with Itron with regard to the design and construction of the physical and cyber infrastructure that will support the DI capabilities of the meters. Over the past two-plus years, we have made the necessary progress to be able to present a robust DI certification application with the 2021 IDP.

On a similar note, the degree of certainty the Department seeks regarding the benefits of DI deployment is not practicable given the emerging nature of the technology.[30] If

[29] Nov. 1, 2019, Integrated Distribution Plan (2020-2029), Docket No. E002/M-19-666 at 9, 26, 173.

[30] One area of complaint is the presentation of unquantified benefits. However, the Commission specifically required in Order Point 3 of its July 16, 2019 Order in Docket No. E002/CI-18-251 that Xcel Energy include a discussion of non-quantifiable benefits when it presents cost-benefit analyses for grid modernization projects.

we wait to deploy DI capabilities until numerous other utilities have gained experience with DI, we may be able to quantify more of the expected benefits. However, the AMI acquisition timing is driven by the approaching end of the service lives of our AMR meters. Given that timing, we could not simply choose to postpone AMI deployment while waiting and observing other utilities' experiences with DI-enabled meters. And, if we were to deploy the AMI meters now while postponing the development and deployment of DI applications, we would not be utilizing the meters' full capabilities and would be losing the opportunity to gain experience with DI now, which would result in years of lost benefits, including substantial customer energy savings and delay in the development of capabilities and experience that will facilitate future DI use cases.

We respectfully request that the Commission approve our certification application. The development of foundational DI capabilities and the deployment of the initial DI use cases will provide both expected financial benefits to our customers and other benefits that we are not currently able to quantify. The City of Minneapolis supports certification, with certain proposed modifications we discuss in Attachment A,[31] CEV takes no position,[32] and Fresh Energy supports certification of the customer-facing use cases, but not the grid-facing use cases.[33] Fresh Energy's position appears to be based on the fact that the estimated quantifiable benefits presented in our DI certification application all relate to the customer-facing uses, in particular, the Energy Analysis use case. Fresh Energy also references the limited number of issues that will be detected by the grid-facing uses. That analysis, however, does not consider how DI provides sub-second analytics capabilities at the final portion of the distribution grid or the grid edge – the portion of the grid that we currently cannot see or monitor. This visibility is becoming increasingly critical as more and more is happening with distributed energy resources and electric vehicles. Because we lack visibility on this final portion of our distribution grid, we are not fully aware of what is happening, and, therefore DI will enhance our planning and operations. However, as we integrate these capabilities with our planning and operations of the distribution grid we expect to better understand the quantifiable benefits and we are certain it will enhance the service we provide our customers. In addition, the initial grid-facing uses will provide a foundation for how we integrate DI into our planning and operations which will support future uses.

The first set of proposed grid-facing DI use cases use applications that are already developed and available for purchase. While the direct benefits of these specific use cases may be somewhat limited, through deploying them now, we can gain experience

[31] City of Minneapolis Comments at 21-22.
[32] CEV Comments at 27.
[33] Fresh Energy Comments at 11.

and develop capabilities that will later facilitate the deployment of more complex, and more promising, grid-facing uses. To take one example, while the Connectivity grid-facing use case will improve our hosting capacity analysis as a result of more accurate GIS data, a potential future case would involve using on-meter processing to identify whether there are local (secondary system) limitations to DER, which could further improve hosting capacity analysis. To take another example, the potential Transformer Load Monitoring use case will provide near real-time monitoring of the amount of load on an individual transformer. While it has always been important to manage these assets, as the adoption of distributed energy resources and electric vehicles increases such management is becoming increasingly critical. Being able to have the information to proactively replace transformers so they do not impact the ability for customers to charge electric vehicles, for instance, will be a priority so there are not unnecessary barriers for to the adoption of electric vehicles.

We are not seeking certification for either of those potential future Use Cases, but are seeking to certify the foundational investments and initial grid-facing Use Cases that would lay the groundwork and allow us to develop the experience and capacity to move towards those and other potential promising future grid-facing uses of DI. By moving forward with all proposed DI use cases, we will position ourselves to continue to modernize our grid in ways that benefit our customers, the distribution grid, and the environment.

IV. CERTIFICATION OF RMP

The Resilient Minneapolis Project (RMP) meets the Commission's criteria for certification and has widespread support both among the parties in this docket and those organizations who have filed letters of support with the Commission. We thank the following parties, organizations, and individuals for their support of the RMP:

- Fresh Energy,
- Community Power, the Environmental Law & Policy Center, and Vote Solar (collectively CEV),
- City of Minneapolis,
- Mayor Jacob Frey of Minneapolis,
- Minneapolis City Council President Andrea Jenkins,
- Sabathani Community Center,
- Center for Energy and Environment,
- Elevate,
- Minneapolis Climate Action,
- Minneapolis American Indian Center,
- Renewable Energy Partners, Inc.,

- University of St. Thomas - Center for Microgrid Research, and,
- Mr. Tim Wulling.

We note that these expressions of support are a result of the work done in partnership with community organizations and local government to develop this project and reflect the widespread recognition that RMP will provide significant community and equity benefits. Several also highlight its potential to generate useful lessons for BESS and other DER integration across the Company's system.

Fresh Energy suggested minor modifications to RMP, which we address in Attachment A. Although the Department did not provide a final recommendation, the Department's Comments indicated skepticism regarding the project. In particular, the Department's Comments took issue with the relatively low benefit-cost ratio and the lack of other quantified forecasted benefits. We recognize both of those potential shortcomings and clearly stated them in our certification request. However, the potential benefits, though unquantifiable, are significant for us, our partner organizations, and the communities in which the project sites are located.

These projects have already, and will continue to require considerable collaboration with our community partners. That process has and will continue to provide valuable insights into the community's needs, which can inform the developing efforts to consider and further issues of equity into utility planning. In addition, the development of microgrids and battery energy storage systems will further our understanding of how and when to facilitate the development of such systems, while also providing experience to the partner organizations, contractors, and involved community members. Moreover, we fully believe there will be cascading effects from each community's designation as a resiliency hub, including the potential to become a community gathering space and increased funding for community initiatives. The risks and costs of RMP are low – and the potential benefits, though largely qualitative, are high. Multiple stakeholders and the Commission itself have made clear the importance of embedding equity and procedural justice considerations into energy planning and decision-making. Basing a certification decision on a singular economic criterion, such as a cost-benefit result, to the exclusion of other important, but qualitative benefits that these projects will provide, would be inconsistent with the public interest and the Commission's approach to-date.

Conclusion

We appreciate the opportunity to provide these Reply Comments, including Attachment A where we provide additional detailed responses to various issues and requests from parties' Comments. We respectfully request the Commission to accept our Integrated Distribution Plan, certify our proposed Distributed Intelligence and the Resilient Minneapolis Project grid modernization investments, and reject the Department's request for the Commission to: (1) adopt its Guidance Document, and (2) use it to assess the IDP and our proposed DI and RMP investments

Dated: March 22, 2022

Northern States Power Company

This Attachment responds to certain comments from parties that are not otherwise addressed in the body of our Reply and/or expand upon certain topics.

I. THE DEPARTMENT'S GUIDANCE DOCUMENT AS APPLIED TO OUR INTEGRATED DISTRIBUTION PLAN

The body of our Reply responds generally to the Department's Guidance Document. In this Section, we respond to the Department's apparent intention to apply its Guidance Document to not just grid modernization investments – but also to the entirety of utility distribution expenditures, budgets, and associated strategies for managing the distribution grid. In addition to the due process concerns expressed in the body of our Reply, this would be a significant departure in procedure for the Integrated Distribution Plan (IDP) and for a rate case, which is the current and proper venue to assess prudence of the Company's investments and costs to customers.

We also provide additional information regarding the variety of methods that could potentially be used to measure the effectiveness of proposed grid modernization investments. We provide this information to reinforce the point that the Commission should carefully consider whether to adopt any specific required test or tests and, if so, what types of projects should be tested and how. As we discuss elsewhere in this Reply, this would require some type of formal process, including opportunities for record development and stakeholder input, which has not occurred for the Department's Guidance Document or potential alternative approaches.

We conclude our discussion of the Department's Guidance Document in this Section by addressing the recommendations it contains regarding the appropriate discount rate to use when analyzing the cost-effectiveness of proposed investments.

A. Prudence and Costs to Customers are Determined in a Rate Case

The Department appears to be applying its new Guidance Document to more than grid modernization proposals – also to evaluate our utility distribution expenditures, budgets, and associated strategies for managing the distribution grid as part of the IDP process.[1] As discussed in Section II.A of our Reply, IDPs are not the proceedings in which the Commission determines prudence or cost recovery.[2] As

[1] Department Comments at 14, 23, 25
[2] See November 2, 2020 Order, Docket No. E002/M-19-666 at Order Point 4 (noting that Commission review "is not a prudence determination of any proposed system modifications or investments.")

the Department itself recognizes in presenting its Guidance Document, the IDP process was established by the Commission as a "distribution planning process and principles that require utilities to transparently and proactively plan for the ongoing paradigm shift in technology and customer preferences."[3] Our IDPs have comported with this intent and provided significant transparency into many aspects of our distribution business, including the ways that we proactively plan our system. To date, the Commission has been clear that neither grid modernization investments nor distribution expenditures more generally are evaluated for prudence through the IDP process. Rather, prudence for the vast majority of our distribution spending is determined in rate case proceedings.

Further, the cost-benefit testing that the Department is contemplating to evaluate the prudence of all types of distribution spending would not be a meaningful analysis and would nearly always, if not always, produce results suggesting the project failed that type of assessment. Cost-benefit analyses are not intended nor suited for traditional distribution investments that are most often driven by emergent circumstances and by our obligation to serve.

Adding a detailed assessment of the prudence of our planned capital budgets would take considerable time and consume significant resources for the Company and parties to the IDP, with no meaningful benefit or contribution. The results would not inform the decisions we make about operating our system and would not be appropriate measures of the prudence of actions or plans. The IDP is currently not a forum to assess prudence, approve plans, or to grant cost recovery, nor should it be.

We have an obligation to provide reliable service to customers in our assigned service territory and accordingly must spend in certain situations, for example, to replace failing, failed, or damaged equipment – even if a cost-benefit analysis indicates that the cost-benefit ratio for the projects in question are less than 1.0. For much of our distribution spending, the focus is not on whether to perform the work, but rather on how to most effectively complete the necessary work – and in some cases, when is the most appropriate time to do so. Effectively building, maintaining, and operating a distribution system is informed by engineering analyses and engineering judgements, and cannot be reduced to a mathematical, monetized equation. The prudence of utility budgets are appropriately evaluated and resolved in rate case proceedings using traditional measures of prudence.

B. Experts Agree There is More than One Cost Effectiveness Test

[3] Department Comments, Docket No. E002/M-21-814 at 9 (February 9, 2022).

The Department's Guidance Document portrays that there is only one way to assess a project – through a cost-benefit analysis that results in a cost-benefit ratio. However, there are multiple types of cost-effectiveness tests that may be appropriate for distribution system projects (and for other kinds of projects), and different tests can be appropriate for different types of distribution projects. In Volume III of its Modern Distribution Grid Decision Guide, the U.S. Department of Energy ("DOE") identifies four broad categories of grid modernization expenditures and suggests different types of methodologies that might be appropriate for each category. For some expenditures, cost-benefit analysis is not even recommended; these include replacement of aging infrastructure, relocation projects, new customer service connections, and "core platform" expenditures to allow for reliable operations with higher levels of distributed resources. Instead, least-cost, best-fit methodologies are suggested for these types of expenditures, and other "traditional methods" are suggested for evaluating the replacement of aging infrastructure, relocations, and new customer service extensions.[4]

Even when cost-benefit analysis is recommended by the DOE Decision Guide, it refers to multiple types of cost-benefit analyses that may be appropriate in different situations.[5] The DOE also notes that both EPRI and New York have developed frameworks for cost-benefit analyses.[6] As we noted in Section II.A of the body of our Reply, the California Public Utilities Commission decided not to require a single, standardized methodology for evaluating grid modernization investments. Given the variety of distribution projects, a similar determination would be warranted in Minnesota. However, if the Commission decides to consider the possibility of a standard methodology for evaluating cost-effectiveness, it should evaluate the various possible methodologies in a Minnesota context to determine what test or tests might be most appropriate here.

Finally, with regard to the incorporation of qualitative considerations in evaluating grid modernization investments, such as equity, and conducting cost/benefit analysis, the Department's Guidance Document seems to favor and require quantification of virtually all costs and benefits. The Commission has previously recognized that some benefits are qualitative – and requires that we discuss those. Requiring quantification of qualitative benefits without an associated framework that has been vet by stakeholders and adopted for use by the Commission would be highly subjective and likely a source of disagreement among parties. We have no objection to further discussions of methods to improve quantification of qualitative benefits. Indeed, we

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[4] U.S. Department of Energy, Modern Distribution Grid Decision Guide, Volume III at 39 (2017).
[5] Id. at 39-42.
[6] Id.

believe further discussions of frameworks that aid utilities' assessments of the qualitative aspects of their grid modernization or integrated resource plans for considerations such as equity, community resilience, and the development of technological capabilities, will become increasingly important in the future – and will help align the Company's interests with those of our stakeholders.

That said, we have concerns with the approach the Department takes in its Guidance Document, and the retroactive application of that approach to the DI and RMP grid modernization investments in this IDP. With regard to equity, the Department's Guidance Document does suggest some methods for quantification. However, the City of Minneapolis in its Comments also provided a helpful review of ways various states have considered equity and incorporated equity outcomes, metrics, and procedural concerns in Commission decision making.[7] Accordingly, the Department's Guidance Document prescribes only one possible method – and adopting that approach retroactively without stakeholder input, including from community groups affected by IDP investments, would seem to violate the "procedural justice" principles embedded in the Commission's February 8, 2022 decision option in our latest Integrated Resource Plan (IRP) proceeding, and mentioned by several parties in their IDP comments.[8]

More generally, it is expected that grid modernization investments such as the RMP and DI will include benefits that are resistant to quantification, but are nonetheless important to the Commission's consideration of these investments. DI, for example, involves new technological capabilities and it is simply not feasible for the Company to quantify all the benefits when it is still learning and developing that technology. We caution against an approach that insists all benefits must be quantified, and/or that only quantified benefits are worth consideration. In addition to other things, that type of approach would tend to hamper innovation. As we discuss elsewhere in this Reply, the Commission and the Department have previously utilized workgroups combined with formal procedure to establish other frameworks to assess cost-effectiveness for subjects such as energy efficiency – and to establish methodologies to measure avoided greenhouse gases, for example, such as it is doing now with the NGIA. These approaches and the frameworks themselves could serve as models toward the development of an equity evaluation framework, for example, or a comprehensive grid modernization evaluation framework.

C. The Weighted Average Cost of Capital is an Appropriate Discount Rate for the Company's Cost-Effectiveness Tests

[7] City of Minneapolis Comments at 5-11.
[8] See for example CEV Comments at 9 and 11; City of Minneapolis Comments at 6-7.

The Department's Guidance Document opines that the weighted average cost of capital (WACC) should not be used as the discount rate in cost analyses of grid modernization investments "or any other investments in Minnesota."[9] Instead, they recommend using a "low risk or societal" discount rate for evaluating grid modernization investments.[10] The Department's Guidance Document further suggests that the same discount rate should be used for all utility investments.[11] Taken together, the Department appears to be suggesting that a societal or "low risk" discount rate be used by the Company for all its evaluations of the cost-effectiveness of proposed investments: grid modernization investments, other distribution system investments, and all other types of investments – including generation resources. This is a sweeping position to take. Consistent with the points made in the body of our Reply Comments, if the Department is truly seeking such a dramatic change in how all utility investments are analyzed, including in resource planning, it would be most appropriate to consider such a proposal in a separate proceeding with the relevant stakeholders, including other utilities.

With regard to the substance of the issue, it is worth noting that the Department's Guidance Document itself indicates three of the five states with established grid modernization evaluation procedures (New York, Massachusetts, and Rhode Island) explicitly provide for use of WACC and one (California) does not provide for a specific discount rate.[12] Accordingly, despite the strong opinion the Department's consultant expresses, their recommendation clearly does not represent a regulatory consensus. WACC has been recognized as the appropriate rate in other jurisdictions because it represents the true cost of any project to customers. If it is decided to utilize the proposed discount rate suggested in the Department's Guidance Document, which appears to be more similar to a rate of inflation rather than a true rate of cost, the final cost to customers and the analyses derived from those will be misleading.

With the exception of some specific instances when the Commission has determined another rate should be used for particular analyses, we generally use WACC as the discount rate for analyzing proposed projects of all types. Notably, WACC is what we use in resource planning, including in numerous resource plans that have been accepted over the years by the Commission and stakeholders.

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[9] Department Guidance Document at 24.
[10] Id. at 25.
[11] Id.
[12] Id. at Appendix B, Table B-6, p. B-7. The table seems to suggest that Hawaii considers grid modernization investments during rate cases and recorded depreciation accruals are determined by project.

WACC is the appropriate rate to use in evaluating the cost-effectiveness of proposed investments because it is the Company, not individual customers or society as a whole, that may be making these potential investments, and we use our capital to do so. That capital is either debt or equity and WACC represents the average cost we pay for that capital. WACC is thus an opportunity cost and, as such, is commonly used by private companies to evaluate potential investments.

II. IDP BUDGET AND FINANCIAL INFORMATION

In Comments, the Department requested additional information regarding our budgeting process for non-capacity projects, and also asked for information regarding changes in the Company's five-year budgets over time. As we discuss throughout this Reply, a rate case is the proper regulatory forum in which to assess the prudence of our expenditures; an IDP is an informational filing, and as such, provides summary level information about numerous distribution-related topics. With that said, we provide summary information responsive to the Department's questions, and direct the Department to our currently pending multi-year rate case in Docket No. E002/GR-21-630 for a more robust discussion about our budget development and the drivers for the budgets for which we are seeking approval in that case.

As we discuss in the IDP, and our pending rate case in more detail, electric and gas utilities are long-term, capital intensive businesses. Every year, we prepare a five-year financial forecast that we use to anticipate our financial needs. Key components of the five-year financial forecast are the O&M and capital expenditure five-year budgets. When a five-year budget is created and approved, the first-year budget is essentially "locked in." However, budgets for the subsequent two to five years are reevaluated in the next budgeting cycle and will necessarily change in response to new developments and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period, and forecasted expenditures are adjusted accordingly.

This is particularly true for the Distribution business area, which is responsible for the final connection to our customers – and is so distributed, that it is not practicable to have a comparable level of redundancy as exists at the transmission level. This means that distribution must constantly anticipate and respond to emergent needs from customers and external forces such as local governmental requirements and the weather to ensure safe, reliable, and adequate service to customers. With that context, we supplement the information already contained in our IDP about our overall budget process, including more detail in the specific areas requested by the Department.

A. Overall Budget Development Process

Xcel Energy's capital planning process involves a bottom-up analysis of needs and priorities on the part of the business areas, such as distribution, as they develop capital budgets for review and approval. In this process, achieving the balance of funding key strategic priorities, maintaining base operations, and minimizing impacts on customer rates is important. Once proposed, project expenditures – both capital and O&M – are identified and developed. They are then reviewed in the context of the Company's overall resources to determine how projects should be prioritized and which are ultimately included in an approved budget. We also assess overall cost levels in relation to inflation, which provides a helpful benchmark for reasonable increases. This allows us to ensure the most important priorities are met while keeping overall costs at reasonable levels.

In any budget process, there is typically more demand for O&M and capital budget dollars than there is financial capacity to fund. Therefore, financial guidance is provided to the business areas to set expectations for that area. The starting point for developing the guidance is the most recent five-year financial forecast, considering Xcel Energy's business plans and other factors. Of particular importance in this review are known and expected changes to business area O&M and capital plans. The guidance process also looks at any new legislation or regulatory requirements that may impact spending in the next five years, assesses the current portfolio of projects and how any expected changes will impact customer rates, reviews changes related to new requirements or that are necessary to maintain or improve reliability, safety, and satisfaction of regulatory requirements, and considers where there may be opportunities to mitigate risk or to work toward meeting state policy goals or advance priorities our customers or regulators have communicated.

The result of this process balances our overall budgets and thus costs to customers in alignment with all of these factors. This means that some business areas and operating companies get more or less of the overall budget, depending on the circumstances, so in certain years, Distribution's capital investments may be lower to support increased investments by other business areas of the Company. Conversely, Distribution's capital investment levels may increase in years when it is working on major initiatives, and capital additions necessarily increase when those initiatives are placed in service.

B. Business Area Budget Development

In Comments, the Department requested additional information regarding our budgeting process for non-capacity projects, which we provide in this section.[13] Please see our 2021 IDP, Appendix A1 for a description of the overall Distribution budget framework and process that coordinates and builds on the overall corporate process summarized in Part A above. In summary, Distribution uses a bottom-up approach to determine its needs over the upcoming 5-year budget period. The overwhelming majority of the Distribution budget is reactive and dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment based on customer needs – as well as reacting to external factors such as requirements from local and other units of government to relocate our facilities, aging equipment, public policy objectives and priorities, and restoring customers and our system in the wake of severe weather.

For purposes of this response, we assessed the 5-year budget information provided in our 2021 IDP for each of the IDP budget categories and determined the approximate percentage that is reactive and proactive. Setting aside our AGIS and Electric Vehicle (EV) initiatives, which we consider to be committed at this time, approximately 80 percent of the distribution budget is reactive, which means we have little to no flexibility in those areas which are largely budgeted based on historical trends and future growth rates. Proactive budget categories have some flexibility, but often, the level of flexibility depends on the risk tolerance for failure and customer impacts. We outline these categories below:

Table 1: IDP Budget Categories – Proactive/Reactive Summary

IDP Budget Category	Description	Budget Basis
Reactive		
Projects Related to Local (or other) Government-Requirements	Required to relocate our facilities as a condition of operating in the public rights of way.	Developed based on historical trends and anticipated initiatives of which we may be aware.
New Customer Projects and New Revenue	Required to serve.	Developed based on historical trends and projected customer growth.
Metering (not AGIS)	Required to serve.	Developed based on historical trends and projected customer growth.
Age-Related Replacements and Asset Renewal	Response to failure/system issues.	Based on historical trends.
System Expansion or Upgrades for Reliability and Power Quality	Criteria-based programs driven by failures, test results or	Developed based on historical trends and engineering

[13] Department Comments at 19-20.

	unfavorable performance.	analysis.
System Expansion or Upgrades for Capacity	Required to maintain adequate electrical service.	Based on an engineering-based system planning process. • Funding level is driven by overload risks, contingency risks, and high-consequence contingency risks. • A risk score is used to prioritize the identified projects
Other	Miscellaneous items that do not fall into the other categories including fleet, tools, locates, communication equipment, corporate initiatives, and transformer purchases.	Various budget development strategies depending on item, ranging from specific project plans for corporate initiatives to historical trends for locating.
Committed		
Grid modernization and Pilots	Approved or certified AGIS and other grid mod investments, approved EV programs and pilots.	Developed based on the parameters of the approved or certified initiatives.
Proactive		
System Expansion or Upgrades for Capacity	Targeted programs to prepare for electrification and expand SCADA capabilities.	Developed based on the parameters of initiative(s), using engineering analyses and judgment.
Age-Related Replacements and Asset Renewal	Targeted programs to replace assets prior to failure and otherwise address aging infrastructure	Based on engineering judgment and analyses, such as life-cycle analysis.
System Expansion or Upgrades for Reliability and Power Quality	Targeted programs to replace assets prior to failure and otherwise address aging infrastructure	Based on engineering judgment and analyses, such as life-cycle analysis.
Grid modernization and pilots	Innovative or technology-based initiatives to advance the grid and our operational service to customers.	Based on engineering judgment and analyses, with budgets developed based on the parameters of specific proposed or potential initiatives.

We believe this view is helpful to illustrate the discussion elsewhere in this Reply that a cost-benefit analysis as suggested by the Department would be misplaced on traditional distribution infrastructure investments. These are largely categories of emergent work that are budgeted based on historical spend levels and engineering analyses and judgement – with a goal of maintaining safe, reliable, and adequate electrical service. As we noted in Section I.B above, in its Modern Distribution Decision Guide, the DOE does not recommend using cost-benefit analyses for such expenditures. Similarly, a report co-authored by Synapse for DOE recognized least-cost, best-fit analysis as cost-effectiveness test appropriately used when the need for a project is already established.[14] Traditional system expenditures are budgeted based on our obligation to provide safe, reliable, and adequate service to customers, regardless of whether individual projects or components do or do not have favorable cost-benefit ratios. We must continue to provide reliable service to customers even if, for example, the monetary benefits of replacing storm-damaged infrastructure in a particular location do not outweigh the costs. As such, a cost-benefit analysis would not provide value to informing the vast majority of the work that we need to do as a distribution utility, or even the priorities of that work to fulfill our obligation to provide our customers with safe, reliable, and adequate service.

C. Distribution Budget Category Process

We summarize the drivers and process to derive the budgets for the current Distribution budget in Part B above. In this section, we summarize further information from the Direct Testimony of Company Witness Ms. Kelly A. Bloch in our currently pending rate case regarding the specific budgeted levels for which we are seeking approval in that case.

As discussed in Ms. Bloch's testimony in our pending multi-year rate case, while our historical levels of investments have been sufficient to maintain our system in the past, we are now reaching the point where many of our assets are at or are past their anticipated useful life. As a result, we have been forecasting for several years the need for greater Asset Health and Reliability investments to make sure that we are able to replace assets that are in poor condition, like our overhead poles, and that we are able to replace assets closer to their estimated useful life, like substation transformers. These investments will allow us to maintain reliable service for our customers and will also allow us to harden our system as appropriate to make it more resilient to extreme weather events, which are becoming more common as the climate changes. For instance, we are now installing larger, diameter poles to make those poles better able to withstand high winds and heavier ice loadings. We are also installing mainline underground cable in conduits to better protect these assets from the elements. In the near-term, we are also adding new subprograms to address aging equipment,

[14] Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations, February 2021 at 13, 24-25, available at [Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations (synapse-energy.com)](synapse-energy.com)

reliability issues, and to better support Distributed Energy Resources (DER) interconnection.

Distribution is also continuing work to implement our AGIS initiative, which includes commencing the mass deployment of Advanced Metering Infrastructure (AMI) meters and the associated Field Area Network (FAN) throughout Minnesota – and the installation of Fault Location Isolation and Service Restoration (FLISR) technology. Other priorities for Distribution include continued work on our existing EV programs and expanding our EV offerings. This includes work on several pilot programs that were previously approved by the Commission; the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot,[15] as well as for four new pilots and programs that are currently before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending before the Commission.[16] Our near-term budgets reflect increased investments in capacity projects, where we are completing eight discrete projects to address potential overload conditions at substations throughout our service area. This category also includes investments in our Feeder Load Monitoring Program to install Supervisory Control and Data Acquisition (SCADA) at our substations and in a Grid Reinforcement Program to replace overloaded feeders and service transformers to support additional load growth. Finally, while Tools and Equipment is a smaller category of investments for Distribution, it too is seeing increased levels of investment to build out fiber optic communications from our substations, improve our cyber security, and to enable remote monitoring of the downtown portion of our distribution system.

As also provided in Ms. Bloch's testimony, the below Tables illustrate the increased investment levels in Distribution over the recent past. We note that these Tables are in the Company's budget categories, not the categories specified for IDP.[17]

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[15] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

[16] Docket No. E002/M-20-745.

[17] As the Company previously cautioned, when IDP budget categories were established that were different from those we use for our internal and rate case purposes, the differences lead to some difficulty in reconciling the IDP and rate case views of distribution spending.

Table 2: Table 7 (Bloch Direct)
2018-2024 Distribution Capital Expenditures
(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Health & Reliability	$99.7	$95.3	$126.7	$145.7	$191.0	$205.1	$212.3
Advanced Grid Intelligence & Security (AGIS)	$0.4	$6.6	$2.7	$14.9	$92.8	$138.3	$116.6
Electric Vehicle Program (EVP)	$0.0	$0.6	$0.1	$7.7	$94.1	$63.1	$59.1
New Business	$62.2	$55.8	$59.1	$66.2	$60.7	$61.9	$61.9
Capacity	$13.6	$21.6	$47.4	$32.6	$38.9	$40.8	$50.9
Mandates	$28.9	$39.3	$33.6	$28.3	$32.4	$32.2	$36.6
Tools and Equipment	$2.7	$4.9	$4.8	$10.7	$14.7	$15.4	$14.2
Solar	($11.4)	($0.8)	$0.2	($1.4)	$0.0	$0.0	$0.0
Total	**$196.2**	**$223.4**	**$274.5**	**$304.6**	**$524.6**	**$556.9**	**$551.5**

Table 3: Table 8 (Bloch Direct)
2018-2024 Distribution Capital Additions
(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Health & Reliability	$81.6	$87.3	$122.8	$116.8	$168.9	$180.8	$205.0
Advanced Grid Intelligence & Security (AGIS)	$0.0	$4.7	$2.2	$7.7	$88.6	$118.7	$131.2
Electric Vehicle Program (EVP)	$0.0	$0.5	$0.1	$4.9	$79.1	$69.7	$60.5
New Business	$63.3	$56.3	$56.6	$61.4	$60.5	$61.3	$61.5
Capacity	$10.6	$12.2	$33.4	$59.7	$33.2	$41.4	$53.0
Mandates	$21.6	$29.2	$26.4	$42.8	$28.0	$29.2	$33.5
Tools and Equipment	$2.5	$2.5	$4.9	$8.6	$12.6	$14.1	$14.3
Solar	($13.2)	($2.1)	$24.6	($14.7)	($0.2)	($0.0)	($0.0)
Total	**$166.4**	**$190.6**	**$271.0**	**$287.3**	**$470.7**	**$515.2**	**$558.9**

These Tables also illustrate how Distribution's capital investments can vary on a year-to-year basis depending on the specific work that is necessary to meet the needs of both our customers and our business. As also noted above, in certain years, Distribution's capital investments may be lower to support increased investments by other business areas of the Company. Conversely, Distribution's capital investment levels may increase in years when we are working on major initiatives, and capital additions necessarily increase when those initiatives are placed in service.

Finally, these Tables also illustrate the incremental capital increases for 2022-2024 over previous years are the result of greater investment in the following budget categories: Asset Health and Reliability, EVs, AGIS, Capacity, and Tools and Equipment. As discussed in detail in Ms. Bloch's testimony in our pending multi-year rate case, this increase in investments is necessary to maintain the safety, reliability, and resiliency of the distribution system and to meet the requirements of a modern grid.

D. Budget Vintage Comparison

The Department requested that we reconcile and explain the budgets we have reported in our most recent three annual IDP filings (2019 IDP, 2020 Compliance, and 2021 IDP).[18] We note that in each IDP filing, we provide a discussion and bar charts that illustrate how our actual spending over a 5-year reference period compares to our 5-year forward budget by IDP category – with explanations for any significant increases or decreases over time.

As we discuss in the IDP and above in this Section, when a five-year budget is created and approved, the first-year budget is essentially "locked in." However, budgets for the subsequent two to five years are reevaluated in the next budgeting cycle and will necessarily change in response to new developments and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period, and forecasted expenditures are adjusted accordingly. This is particularly true for Distribution, which is the final connection to our customers. As such, the current forecast compared to past actuals paired with an explanation of what is driving the changes is the most meaningful information about what is going on in the business area. While we provide the reconciliation the Department requested in this Reply, it has been administratively burdensome and misplaces the focus, which should be on actuals compared to plans, as currently required.

1. Overall Summary of Budget Vintages

As also discussed above, historical levels of investments are no longer sufficient to maintain our system and we are now reaching the point where many of our assets are at or are past their anticipated useful life. As a result, we have been forecasting for several years the need for greater investments to ensure that we are able to replace assets that are in poor condition, like poles and overhead wires, and that we are able to replace assets closer to their estimated useful life, like substation transformers. We initially referred to this in our 2019 IDP as the "incremental system investment" or

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[18] Department Comments at 20-21.

ISI initiative. These investments will allow us to maintain reliable service for our customers and will also allow us to harden our system as appropriate to make it more resilient to extreme weather events. We provide a snapshot of the overall budget vintages below to illustrate the narrative that follows:

Table 4: Distribution Overall Budget Comparison
2019 – 2020 – 2021 Vintage

	IDP 5-Year Budget			YOY DELTA	
IDP Category	2019 ($M)	2020 ($M)	2021 ($M)	2020 ($M)	2021 ($M)
Age-Related Replacements and Asset Renewal	$ 406	$ 718	$ 860	$ 312	$ 142
New Customer Projects and New Revenue	$ 193	$ 188	$ 199	$ (5)	$ 11
System Expansion or Upgrades for Capacity	$ 188	$ 237	$ 241	$ 50	$ 4
Projects related to Local (or other) Government-Requirements	$ 145	$ 186	$ 182	$ 41	$ (4)
System Expansion or Upgrades for Reliability and Power Quality	$ 488	$ 238	$ 205	$ (251)	$ (33)
Other	$ 192	$ 239	$ 238	$ 47	$ (0)
Metering	$ 18	$ 30	$ 15	$ 12	$ (15)
Grid Modernization and Pilot Projects	$ 440	$ 411	$ 741	$ (29)	$ 330
TOTAL	**$ 2,069**	**$ 2,247**	**$ 2,681**	**$ 177**	**$ 434**

2. *2020 Compared to 2019*

In 2020, there is a $177 million increase in the 5-year budget over the 5-year budget established in 2019. The drivers of this increase were due to an increased focus on asset renewal, risk minimization and grid readiness (for electrification, for example), specific initiatives associated with EV programs and pilots, and Distribution's portion of corporate cyber security and fiber buildout requirements, partially offset by decreases in system expansion or upgrades for reliability and power quality, and grid modernization and pilot projects. We discuss the changes in the various categories in more detail below.

Table 5: Narrative Summary of Changes from the 2019 to 2020 5-Year Budget

IDP Budget Category and Change from 2019	Drivers
Age-Related Replacements and Asset Renewal: $312M	The ISI placeholder from 2019 was deconstructed and reallocated to existing/new programs throughout the budget. A significant portion of the ISI dollars moved to Asset Renewal, driving a $312M increase to this category.
	Funds were allocated to new and existing programs to replace aging infrastructure including substation end of life programs network end of life programs and other asset renewal programs to replace aging line equipment.
	Funds were allocated to large discrete projects targeting end of life equipment or whole substation rebuilds were also identified including projects to address issues at Daytons Bluff and Aldrich substations.
	Funds were allocated to a large discrete project to relocate St. Paul feeders out of the tunnel system -
	Storm restoration reserves were also increased based on current storm restoration trends.
New Customer Projects and New Revenue: ($5M)	Updated customer growth rates and historical trends driving a decrease in this category. Budgets are based on customer growth rates, meter set forecast, cost per meter, and current area trends. Adjusted as needed in the current year, reset annually based on previous year's results, and updated growth projections.
System Expansion or Upgrades for Capacity: $50M	The ISI placeholder was deconstructed and reallocated to existing/new programs throughout the budget. A portion of the ISI dollars moved to Capacity driving a $50M increase in this category.
	Funds were allocated to Capacity to robustly address capacity overloads and contingency risks, including high consequence contingency risks, due to an overall direction to reduce capacity risks.
	Funds were allocated to new programs geared at grid readiness for electrification including the Grid Reinforcement program.
Projects Related to Local (or other) Government-Requirements: $41M	Increasing historical trends driving a $41M increase to this category. Mandates are externally driven relocation projects. Assuming historical increasing trends would continue and given the reactionary nature of this program (no flexibility) budgets were funded at similar increasing trends.
System Expansion or Upgrades for Reliability and Power Quality: ($251M)	The ISI placeholder was deconstructed and reallocated to existing/new programs throughout the budget. A significant portion of the ISI dollars moved from Reliability to Asset Renewal and Capacity driving a significant decrease in this category.
Other: $47M	Strategic initiatives driving a $47M increase to this category including Cyber Security and Fiber Buildout. Cyber Security addresses critical infrastructure protection and Fiber Buildout upgrades communication lines inside our substations. Funds were allocated to the Network Monitoring program based on monitoring and communication needs and transformer purchases based on increasing demand and customer growth rates.
Metering: $12M	Uncertainty around the timing of AMI driving the increase to this category. Generally, meter purchases align with new business/customer growth assumptions, the uptick in this cycle was in relation to timing of AMI and impacts on meter purchases. Once the timing was solidified, the funding was adjusted to be more in line with previous trends.
Grid Modernization and Pilots: ($29M)	AGIS decreased due to the removal of initiatives that were not certified.

3. 2021 Compared to 2020

In 2021, there is a $434 million increase in the 5-year budget over the budget established in 2020. The drivers of this increase were the EV Program, AGIS and an increased focus on asset renewal, risk minimization and grid readiness, partially offset by decreases in system expansion or upgrades for reliability and power quality, and metering expenses. We discuss the changes in the various categories in more detail below.

Table 6: Narrative Summary of Changes from the 2020 to 2021 5-Year Budget

IDP Budget Category and Change from 2020	Drivers
Age-Related Replacements and Asset Renewal: $142M	A combination of increasing historical trends, increasing failure rates in the pole replacement program and increased focus on Asset Renewal (reallocation from Reliability) driving the increase in this category.
	Funds were allocated to routines and failure reserves due to increasing historical trends and the assumption trends would continue.
	Funds were allocated to pole replacements based on current failure rates, testing schedules and cost per unit.
	Funds were allocated to asset renewal programs targeted at replacing assets prior to failure including substation ELR programs targeting substation equipment and line ELR programs targeting line equipment. Increasing funds based on current life cycle analysis and desire to minimize reliability concerns.
New Customer Projects and New Revenue: $11M	Current customer growth rates, meter set forecast, cost per meter, and current area trends drove the decrease in this category. Adjusted as needed in the current year, reset annually based on previous year's results. Fluctuations in this category can be driven by customer driven projects (not always known at the time of budget create)
System Expansion or Upgrades for Capacity: $4M	Continued strong focus to minimize risk associated with overloads, contingencies and high-consequence contingencies drove an increase to this category.
Projects Related to Local (or other) Government-Requirements: $4M	Historical trends drove an increase to this category.
System Expansion or Upgrades for Reliability and Power Quality: ($32M)	Increased focus on overhead asset renewal driving a ($32M) decrease in the category. Funds were reallocated from reliability to Asset Renewal.
Other: $0M	Consistent with previous IDP – no changes.
Metering: ($15M)	Uncertainty around the timing of AMI deployment drove a decrease to this category. Generally, meter purchases align with new business/customer growth assumptions; the downtick in this cycle was in relation to timing of AMI and impacts on meter purchases. Once the timing was solidified, the funding was adjusted to be more in line with previous trends.
Grid Modernization and Pilots: $330M	EV programs primarily drove the $330M increase to this category. EV increased by $278M due to planned expenditures for approved and proposed programs and rebates, including Residential EV Charging, Residential EV Service Pilot, Fleet EV Service and Public Charging Infrastructure Pilots, Residential EV Subscription Service Pilot, EV Accelerate At Home, and Multi-Dwelling Unit (MDU) EV Service Pilot.[19] AGIS increased by $51M due to the addition of FLISR back into the current 5-year plan and aligning the FAN budget with the latest deployment plan.

III. SUGGESTED CHANGES TO THE IDP CONTENT

[19] As some of these programs have a term of less than the 5-year budget period, the budget reflects some assumptions about the continuation of those programs.

A. Information to Assess Prudence of Distribution Investment Strategies and Expenditures

As part of its assessment of the Commission's planning objectives, the Department references the need to assess the reasonableness of the Company's investment strategies and decisions as part of its IDP evaluation – and that additional information is necessary to accomplish that goal.[20]

As we discuss in Section I above and the body of our Reply, the IDP is not a cost recovery proceeding and not the proper regulatory forum to assess prudency of distribution system management costs. Further, the Department implies that a CBA is necessary to any evaluation, which is not the case. We have an obligation to serve our customers, and that means that some investments are necessary and will not have corresponding benefits of the kind that are typically considered in a CBA. Further, distribution maintenance and operations costs are assessed for prudence in a rate case. As the Department recognizes,[21] the Annual Electric Service Quality Report provides the proper forum for reliability and resilience assessment; the parallel holds true with respect to a rate case or rider proceeding and prudence evaluations.

Relatedly, as part of its review of Planning Objective #2, the Department recommends the Commission require the Company to provide information to assess reasonableness of proposed costs related to customer-facing programs:

> The Department recommends that in future filings the Commission require Xcel to provide the following information that will allow for an independent verification of the reasonableness of the proposed incurred costs related to customer-facing utility offerings and programs:
>
> - Xcel's internal benefit-cost analyses for reference and investment case scenarios, including reasonably known and analyzed alternatives;
> - Assumptions and data supporting the projected customer participation rates; Sensitivity analysis for varying rates of adoption of proposed programs; and
> - Discussion of how the proposed customer-facing utility offerings and programs may interact with existing or proposed Conservation Improvement Plan or Next Generation Energy Act programs.[22]

We do not object to providing this information on projects for which we are seeking certification and have identified specific planned customer products or services to accompany the investment, and that are included in a cost-benefit assessment. Because the outcome of an IDP is not cost recovery or prudency determination,

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[20] Department Comments at 14.
[21] *Id.*
[22] *Id.* at 15.

broad application of these recommended requirements would be misplaced.

B. Rate Impact Analysis

CEV recommended that the Commission require Xcel Energy to provide a detailed analysis of projected bill impacts and affordability of all its planned distribution system investments over time.[23]

First, IDPs provide a view of capital expenditures – not revenue requirements, which would be necessary to perform an analysis of customer bill impacts. Development of revenue requirements and customer bill impacts is done in a rate case or other cost recovery proceeding such as a Rider. Second, conducting individual analyses on different project costs would be overly burdensome and provide limited value. Any class-based rate impact analysis is imperfect and decreases in value as we move out in time because these analyses apply current jurisdiction and class allocations to future revenue requirements and does not account for any allocation shifts that may occur through future class cost of service studies. Because any rate or bill impact analysis is illustrative at best outside the context of a rate recovery proceeding, such analyses in the IDP would, inherently, provide little "actionable and transparent information to those who do not have energy and regulatory expertise." That said and as CEV notes, we did provide an estimated bill impact of Distributed Intelligence as part of our request for certification, and we are committed to providing a similar analysis for certification requests in the future.

C. Incorporating Equity into the IDP

CEV and the City of Minneapolis discussed equity broadly in their comments, and suggested additions and modifications to the Commission's filing requirements and planning objectives to explicitly incorporate equity considerations. We appreciate these comments and the support expressed for equity-informed planning and equity initiatives broadly. As we discuss below, we believe any changes to IDP planning objectives or filing requirements should be an outcome of the forthcoming equity docket that will explore with stakeholders how we best incorporate equity into planning, analysis, and reporting.

CEV proposes that the Commission's principles for incorporating grid equity into distribution planning should be based on "proactive listening to and acting upon the needs of communities" who have been most impacted by past pollution and high energy burden, are likely to be most impacted by climate change, and suffer legacies of

[23] CEV Comments at 17-19.

economic and social marginalization. CEV further proposes that a grid equity approach should direct energy system investments in a way that generates wealth, shares decision-making power, and generates resilience from disruption for these communities.[24] Indeed, this is an apt description of the approach the Company has taken in designing the RMP in partnership with the three project hosts. The neighborhoods served by the North Minneapolis Community Resiliency Hub, Sabathani Community Center, and the Minneapolis American Indian Center fit the above description, having been impacted by past and present disparities in wealth, pollution, and decision-making power.[25] The RMP seeks to address these patterns, build these communities' resilience in view of their expected greater vulnerability to future climate change and other emergencies, and ensure that the communities themselves are designing the effort and defining their own best interest. We discuss the RMP further in Section IV of this Attachment.

The City of Minneapolis suggests that equity be centered in the distribution planning process and suggests that the Commission require community engagement and stakeholder workshops to this effect, and document and incorporate feedback in the next IDP. The City also suggests that the Company include equity-focused metrics in NWA and hosting capacity analyses.[26] Minneapolis commends the incorporation of equity objectives in designing the RMP:

> As Xcel details in their Resilient Minneapolis Project section, there are several equity objectives in selecting potential host sites, such as reducing energy burden, increasing equitable access to renewable energy, providing workforce training, and addressing environmental justice concerns. That process is an excellent example of this type of assessment and inclusion of metrics that we would like to see expanded to all NWA analysis.[27]

We find the recommendations from CEV and the City of Minneapolis consistent with new equity requirements included in the verbal approval of an equity-focused Decision Option E15 during the Commission's February 8, 2022 deliberations on our IRP in Docket No. E002/RP-19-368, as discussed in the body of this Reply.

We are confident that we and our stakeholders can work to address these important issues in the forthcoming equity docket, and we will seek to reach a consensus with stakeholders regarding how we incorporate equity into planning, analysis, and reporting. As such, we do not believe CEV's or the City of Minneapolis' proposed

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[24] CEV comments at 9-10.
[25] See Fresh Energy's comments at 15 for an analysis of how the neighborhoods surrounding the RMP host sites meet criteria for high proportion People of Color and low median incomes.
[26] City of Minneapolis comments at 6-8.
[27] City of Minneapolis comments at 9.

additions to the planning objectives are necessary or appropriate at this time.[28]

1. Defining Grid Equity

CEV offers definitions of *energy equity* ("the fair distribution of the benefits and burdens of energy production and consumption")[29] and *energy justice* ("the distribution of costs and benefits from the generation, distribution, and consumption of energy; the process of energy decision making; the recognition of unequal historical energy system impacts; and the need for the energy system to move towards a restorative justice frame")[30] to inform a potential Commission definition of *grid equity*. CEV also suggests criteria that are "key prerequisites" for grid equity.[31]

The Company appreciates these proposed definitions and examples. Indeed, the desire to improve energy equity has been a key driver of the RMP – both in relation to outcomes (access to solar, batteries, and microgrids to improve resiliency) and process (active engagement with BIPOC-led organizations at every step in the design of this proposed initiative). We see an opportunity to incorporate such considerations and "prerequisites" in other parts of our distribution planning as well, and the equity-driven process the Company will shortly be launching as an outcome of our IRP docket, as discussed above and in the body of our Reply Comments, will serve as an appropriate forum to further discuss and formulate these considerations.

2. Equity in IDP Filing Requirements

In addition, CEV recommends changes to the IDP filing requirements that would:[32]

- Add insights gained from locational reliability/equity analysis to the 5-year Action Plan and 10-year long-term plan,
- Require a locational reliability/equity analysis, i.e., an analysis of the extent to which planned investments will advance the goals of ensuring affordable, equitable service quality, reliability and capacity in disadvantaged communities, and

[28] CEV comments at 13-16.
[29] Chandra Farley et al, *Advancing Equity in Utility Regulation*, U.S. Department of Energy Grid Modernization Laboratory Consortium (Nov. 2021).
[30] Gabriel Chan and Alexandra Klass, *Regulating for Energy Justice*, New York University Law Review (forthcoming 2022), at p. 7 (available at https://ssrn.com/abstract=4032969) (advance copy used with authors' permission).
[31] CEV comments at 11.
[32] CEV Comments at 15-16.

- Require an overview of steps taken to promote grid equity based on input from community stakeholders, and the extent to which planned investments are responsive to stakeholder feedback and community-specific energy-specific plans.

While we appreciate and support CEV's – and many other parties' – interest in equity, we do not support these additional filing requirements in the IDP, because the locational reliability work is occurring in other regulatory forums – namely, in the Safety, Reliability, and Service Quality docket (Docket No. E002/M-20-406) and the Performance-Based Ratemaking docket (Docket No. E002/CI-17-401). We also expect these issues to be discussed and reported on in the forthcoming equity docket discussed above. That said, we are happy to include a summary of those efforts in our 2023 IDP.

D. Integration of Distributed Energy Resources

In this Section, we address comments regarding DER.

1. Alignment of DER Forecasting and Modeling

In Comments, CEV recommends the Company be required to use consistent DER forecasting, modeling, and planning for DER in both IRP and IDP cases.[33] The Department makes a similar suggestion regarding alignment between IDP and IRP planning processes, especially related to forecasting of DER.[34]

In response, we note that the Commission adopted Decision Option E3 during its recent IRP deliberations, which already addresses several of the topics raised by CEV and the Department, including alignment between IDP and IRP forecasting. While the written Order is forthcoming, we anticipate it to read:

> E3. Require Xcel to take the following steps to better align distribution and resource planning, including:
>
> a. Set DER forecasts consistently in the IRP and IDP.
> b. Conduct advanced forecasting to better project the levels of DER deployment at a feeder level, using Xcel's advanced planning tool.
> c. Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and EV additions consistent with the DER forecast.
> d. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of DERs to address discrete distribution system costs.

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[33] CEV Comments at 24-25.
[34] Department Comments at 22.

e. Plan for aggregated DERs to provide system value including energy/capacity during peak hours.

We see no need for the Commission to duplicate this adopted Decision Option in this docket, because the Company will already have the obligation through the IRP outcome. However, should the Commission find it necessary to include the same requirements in this docket, we request that the language in any Ordering Point be identical to that in the forthcoming IRP Order, to ensure clarity for parties and the Company.

2. DER Integration

Fresh Energy suggests that the Company be directed to provide various information on policies governing cost allocation of system upgrades caused by DER integration and details on proactive planning for grid investments in its next IDP.[35] CEV also suggests two new filing requirements related to DER integration and benefits:

> Provide a narrative description of programs and policies that will be implemented to mitigate barriers to DER integration. The Plan should describe how these programs and policies are tailored to promote opportunities for enhanced system benefits associated with wider deployment of DER technologies, including behind the meter energy efficiency measures, and
>
> Provide a discussion of how the Company is pursuing opportunities to capture system-wide benefits through broad adoption of DER, including the use of DER to manage local capacity constraints.[36]

In response, we clarify that an IDP is an informational filing, and as such, any programs or policies such as those noted by Fresh Energy and CEV would be developed in a separate proceeding. To the extent that occurs, we would be happy to report on the status of that proceeding in our next IDP.

3. Hosting Capacity Analysis

Although Fresh Energy acknowledges there is a separate docket dedicated to Hosting Capacity Analysis (HCA), Fresh Energy requests the Company to provide further explanation in our IDP Reply of our treatment of Reverse Power Flow and

[35] Fresh Energy Comments at 6-7.
[36] CEV comments at 21-22.

Unintentional Islanding thresholds in our HCA.[37].

Our understanding of Fresh Energy's request is that they are concerned about the number of feeders where Reverse Power Flow and Unintentional Islanding are limiting factors, and about how this aligns with the Company's interconnection requirements. As Fresh Energy noted in Comments, Reverse Power Flow becomes problematic when it leads to unacceptable voltage, thermal, or system protection violations. It should also be noted that Reverse Power Flow is also a concern in regard to the capacity rating of substation transformers. When Reverse Power Flow is stated as the maximum hosting capacity limit, it is indeed because of the voltage, thermal, or protective issues that can be caused during these conditions.

Part of the improvement to our HCA process that considers these thresholds in relation to where we have Voltage Supervisory Reclosing (VSR) on our system, is only accounting for unintentional islanding violations where VSR is *not present*. Fresh Energy mistakenly states that the interconnection process does not address the issue of unintentional islanding, when we in fact require all grid-connected inverters to not only provide anti-islanding protection – but to also undergo testing prior to interconnection. That said, the HCA indeed aligns with the interconnection process as it: (1) is only considered where VSR is not present, and is therefore a legitimate safety concern, and (2) aligns with our interconnection study practice that requires VSR protection be added at the interconnection customers expense if the study identifies a risk for Unintentional Islanding, and (3) screens every affected feeder and identifies potential violations in advance of interconnection applications being submitted. Our synchronization of the HCA with this aspect of the interconnection process was intentional, and that the HCA provide that initial screening for potential Unintentional Islanding violations prior to in-depth interconnection studies being performed.

4. IEEE Standard 1547-2018

In addition, Fresh Energy recommends adoption of the IEEE Std 1547-2018 default inverter settings for volt-var with reactive power priority, and requests that we include our smart inverter roadmap with this Reply.

We are wrapping up an engagement with ICF on this topic. In addition, EPRI is

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[37] As Fresh Energy notes in its Comments, our most recent Hosting Capacity Analysis in Docket No. E002/M-21-767 will provide parties and the Company an opportunity to comment on these issues. The Commission has issued its Notice of Comment Period and we will respond further in our Reply in that proceeding. Fresh Energy Comments at 5-6.

currently working with several utilities to study various conditions to support recommended operating settings for inverters. Based on this, we anticipate being in a position to share our roadmap for utilizing inverters that support IEEE 1547-2018 (smart inverters) in the third quarter of 2022. The actual usage of IEEE 1547-2018 inverters, however, will be dependent on when tested and certified inverters are readily available which has been delayed into 2023.

E. Possible Synergies Between Planned Infrastructure Investments and DER Project-Driven Upgrades

Fresh Energy requests that the Company explain whether there is coordination between our planned infrastructure projects and DER interconnection project-driven upgrades resulting from interconnection application studies and any synergies from such coordination.[38]

Any planned upgrades within the next two years and projects already in construction are considered during an interconnection Facilities Study. Planned capital investments such as reconductoring and feeder capacity and substation upgrades could provide benefits to DER systems interconnecting to the grid. We have not estimated the extent of potential synergies from this and are not able to do so in the timeline for these Reply Comments; however, we are open to estimating those synergies in future IDPs.

F. Forecasting and Planning

In this section, we respond to questions, issues, and requests for additional information related to aspects of our forecasting and planning.

1. Integrated Forecasting

In Comments, CEV, the City of Minneapolis, and Fresh Energy provided recommendations regarding our forecasting and planning. Generally, these recommendations are related to consistency between the IRP and IDP, including the consideration of local clean energy goals in our forecasting and planning. In making these recommendations, parties acknowledged that the Commission verbally approved an IRP Decision Option as part of its February 8, 2022 consideration of our IRP that requires such alignment of forecasting and planning in the IRP and IDP.[39]

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[38] Fresh Energy Comments at 8. CEV Comments at 22-23, Fresh Energy at 2, City of Minneapolis at 16-18
[39] Fresh Energy Comments at 2; CEV comments at 23.

We clarify that the Commission previously required the Company to align its forecasts as much as practicable and to consider local clean energy goals in the IDP – and the Commission's verbal decision in the IRP on this topic was based on that that existing IDP requirement. As such, we believe our existing IDP requirements and those in the forthcoming IRP Order will fully address the Commission's expectations regarding integrated planning – and therefore, it is not necessary to repeat the requirements for the IDP. That said, if the Commission determines it is necessary to also memorialize these requirements in the IDP, we request that they be stated identical to the IRP to ensure clarity for the Company and parties. For clarity, we outline the specific, verbal IRP Decision Options that we believe fully address these topics:

> [D6.] Require Xcel to account for local clean energy goals, in aggregate, in forecasting and modeling for the IRP. In particular, distributed generation in the plan should include consideration of local community generation goals.
>
> [D11.] Require Xcel to account for anticipated effects of advanced rate design, demand response, and any other efforts to shift customer demand in its next IRP.
>
> [D13.] Require Xcel to develop and/or improve base case adoption forecasts of the following technologies to include in its overall demand forecast for its next IRP filing, either through its Integrated Distribution System Plan proceedings, or through another stakeholder process.
>
> a. Light, medium, and heavy-duty electric vehicle adoption
> b. Electric space heating adoption
> c. Electric water heating adoption
> d. Electrification of other end uses
> e. Increased potential for demand response and load flexibility from an increase in electrification of the technologies in a – d
> f. Distributed solar adoption, including customer sited, community solar gardens, and non-customer sited/non-CSG distributed solar

Finally we note CEV's comments that suggest Minnesota does not have a transmission planning process that is analogous to the IRP or IDP, and the Commission should encourage discussion of transmission planning in the IRP and IDP processes.[40] We note that we heavily participate in the planning processes overseen by the Midcontinent Independent System Operator (MISO), and report biennially on our transmission projects, most recently in Docket No. E999/M-21-111, as required under Minn. Stat. § 216B.2425. Transmission planning and considerations are also discussed in our IRP as it relates to the NSP System and our long-term IRP planning horizon. In the IDP, we discuss transmission planning in the context of distribution system impacts on the transmission system and how we are coordinating

[40] CEV comments at 23.

our planning at all levels of the system – bulk system resource level, the transmission system, and the distribution system as required by existing IDP requirement 3.A.5. No further requirements are necessary or appropriate.

2. *Use of LoadSEER Capabilities*

In this Section, we respond to Fresh Energy's recommendations regarding our use of LoadSEER and the incorporation of net load, beneficial electrification, and demand-side management (DSM) into distribution planning and forecasting.[41]

Before we address these specific topics however, we note that LoadSEER is a new advanced planning tool for Xcel Energy and in the industry. As such, as we expand our use of LoadSEER, we anticipate that it will be an iterative process because our initial attempts to incorporate planning inputs that are novel for distribution system planning, such as net load, demand-side management (DSM), and electrification will be challenging and require refinement over time. As such, we expect our reliance on planning results that include these assumptions will be an evolution, rather than a bright line implementation on a date certain.

i. Use of Net and Native Load in Distribution System Planning

Fresh Energy recommends the prioritization of net load in our forecasts and system planning for the 2023 IDP, including presentation of a proposed methodology.[42] We are currently assessing the best approach to incorporate net load into our forecasting and risk analysis. Specifically, we are working toward being able to create a net load forecast in addition to the native load forecast we currently use for each of our feeders and banks within LoadSEER. We intend to include the results of this broader analysis in our 2023 IDP. We are also working toward determining the methodology for appropriately using net load forecast information in our planning process and risk analysis. This is a very important consideration. We must remain mindful of the Company's operational practices while creating our forecasting and risk analysis methodologies, and be careful that we are not planning the system based on conditions that do not and/or could not exist operationally. Similarly, we must continue to be sure that our plans adequately ensure our provision of safe and reliable electric service to our customers.

We note that Fresh Energy included with their Comments, a Southern California Edison (SCE) methodology for how they use net load forecasts in their planning

[41] Fresh Energy Comments at 2-5.
[42] Fresh Energy Comments at 2-4.

process. We note that every utility's system is different, every utility's risk tolerance is different, and there is currently no broadly accepted industry standard methodology or set of assumptions. So, while SCE's assumptions and methodology work for their system, we need to determine what assumptions and what risk tolerance is most appropriate for our system. Similarly, various utilities have their own methodologies to forecast net load, but the industry lacks a well-accepted, standardized method for net load forecasting.

ii. Load-Modifying Impacts of DSM

Fresh Energy suggested that the Commission require the Company to incorporate the load-modifying impacts of DSM in its system-wide, substation, and feeder-level forecasts.[43] CEV suggested that the Commission ensure DER modeling, forecasting, and program planning functions are treated consistently in the Company's distribution and resource plans.[44] As we discuss below, we have done some of the foundational work to prepare for a future where we will be able to factor DSM into our feeder and substation-level planning, but there is more work to do before we can incorporate it with any sense of certainty into our planning process.

At the system-wide level, we currently develop a Base System Peak Demand forecast that includes the peak hour impacts of energy efficiency and distributed solar. We use this forecast in distribution system planning. We also create a Net System Peak Demand forecast, which equals the Base System Peak Demand forecast, less all demand response (Saver's Switch and Interruptible/Peak Control programs, for example). At a system level, we reduce the energy forecast by expected energy efficiency achievements, but not demand response because the impact is too small to affect total energy at the system-wide level, due to the relatively few hours in which demand response is called.

At the substation and feeder levels, we intend to incorporate the load modifying impacts of DSM into our planning process using LoadSEER. As an initial matter, we note that energy efficiency is embedded in our Base System Peak Demand forecast and therefore our distribution forecasts. So, in this case, this discussion of incorporating DSM impacts into forecasting effectively – for now – means incorporating demand response impacts.

We have taken initial steps with LoadSEER toward this future capability by integrating customer demand response program enrollment data (i.e., Savers Switch,

[43] Fresh Energy Comments at 4.
[44] CEV Comments at 24-26.

AC Rewards, etc.) with our initial implementation of LoadSEER; this data is also updated on an ongoing basis through an integration with Salesforce. As is the case with the system-wide forecast, the nature of demand response is a challenge, because it is not a permanent reduction in load, and it is often behaviorally dependent. Also, we traditionally have utilized demand response at an NSP System level, with specified agreements to control for MISO during system events. So, properly reflecting it in our system planning analysis at the distribution feeder and substation level is challenging. To illustrate, if we were to simply incorporate demand response into our forecasts at the substation and feeder levels, we would be assuming that demand response could be specifically only targeted to a feeder or group of feeders based on distribution need, which is not at all the case.

There are also further challenges with how to properly reflect and use DSM data for distribution system planning. Some of the additional considerations and challenges we are currently assessing, and that will take ongoing work to solve and develop include: (1) forecasts for customer enrollment in DSM programs into the future; this could potentially be derived from a system-wide DSM impact forecast, but we would have to develop assumptions or a methodology to forecast its geographic dispersion; (2) we will need hourly load shapes by customer type and program that show how much we should expect the loading of a customer to be reduced upon activation of specific DR programs; we expect our implementation of AMI to be very helpful to this end; and, (3) energy efficiency is already embedded in the corporate forecast, from which we derive projected year-over-year load growth.

As we noted above, we have done some of the foundational necessary to prepare for a future that factors DSM into our distribution-level planning, but there is more work to do before we can more fully incorporate and rely on the planning results to meet our customers' energy needs every hour of every day.

iii. Electrification Scenarios

Fresh Energy suggested that the Commission direct the Company to incorporate building, transportation, and industrial electrification scenarios into its system-wide, substation, and feeder-level forecasts.[45] CEV suggested that the Commission ensure DER modeling, forecasting, and program planning functions are treated consistently in the Company's distribution and resource plans.[46]

As noted above, the Commission-adopted Decision Options in the IRP docket

[45] Fresh Energy Comments at 5.
[46] CEV Comments at 24-26.

already aligns with these recommendations. We fully expect to engage with stakeholders on these issues and align these forecasts, and we do not object to Fresh Energy's suggestion that we host two stakeholder workgroup meetings by December 1, 2022, as this suggestion also aligns with the anticipated IRP Order.[47]

That said, we are currently working to more fully incorporate the impacts of transportation electrification and building electrification into our system-wide forecasts. For EVs, we can create system-level forecasts for various vehicle segments (light duty, medium duty, and heavy duty), although light-duty vehicles account for the majority of EVs currently. As we further develop these system-level forecasts, LoadSEER's capabilities can help us incorporate them in future distribution planning forecasts. We are working through the complexities associated with how we properly apply the inputs in a substation- and feeder-level forecast.

With respect to building and industrial electrification, we are actively laying the groundwork for new programs to enable electrification under both the Energy Conservation and Optimization ("ECO") Act and NGIA – both of which will allow new electrification programs and measures if certain criteria are met. We recognize that these types of electrification have the ability to significantly impact the loading on the distribution system in the long term – including the possibility of shifting the feeders from summer peaking to winter peaking. At the system-wide level, we are beginning to develop forecast methodologies for building-electrification and expect to include those in our next IDP. However, for distribution system planning purposes, we will also need to develop a methodology to incorporate those impacts into LoadSEER. We expect this to be a topic for discussion with stakeholders as we implement the Commission's forthcoming IRP Order Points related to electrification, forecasting, and IDP-IRP alignment.

We confirm that we understand the need and importance of incorporating EVs and other electrification into our forecasting, and have already been and will continue to work on finding ways to do so.

G. Non-Wires Alternatives Analysis

In Comments, the City of Minneapolis made several recommendations with regard to the methodology used to consider non-wires alternatives ("NWA").[48] We proposed a significant shift in the way that we evaluate NWAs beginning with our 2022 analysis that is more wholistic in that it better recognizes a broader set of potential benefits

[47] Fresh Energy Comments at 5.
[48] City of Minneapolis Comments at 12-16.

from NWA – and that more closely mirrors what we expect an NWA procurement process might look like. We welcome the City's feedback.

1. *Energy Efficiency and Load Forecasts*

With regard to inclusion of energy efficiency, we note that energy efficiency trends are already incorporated in the load forecast, and so the load reduction benefit from energy efficiency is already accounted for in our risk assessment. However, incremental energy efficiency gains beyond the current trends are not included in our initial NWA screening process. This is a simplifying assumption we use, because risks can generally be solved in a more cost-effective and timely manner with other DER types such as BESS, solar, and demand response/load flexibility. Even so, this does not exclude energy efficiency from being considered for inclusion in NWAs. Our proposed methodology includes an assumption that there would be an open solicitation process that is technology agnostic. Therefore, any bid that can solve the projects risks cost-effectively can be a viable alternative and will be considered, regardless of DER type(s). The initial NWA screening process is a coarse filter that serves to exclude projects that are either infeasible from an engineering perspective or that have costs vastly outweighing the benefits. Projects that are close in terms of costs and benefits will not be excluded by the initial screening.

2. *Wider Range of Grid Constraints*

With regard to the recommendation that NWAs be considered for a wider range of grid constraints, we clarify that reliability and resilience issues are caused by a broad range of hazards and conditions – the most common of which are wildlife and vegetation contact, weather, human error, aging equipment, and overloads. NWAs have no effect on nearly all of these outage causes, with the exception of overloads. However, potential overloads are already captured in our annual planning cycle and are already accounted for and considered for NWAs. In some cases, an NWA may be able to supply power to customers in the case of an extended outage. However, this benefit would be reflected in an NWA cost-benefit analysis, but would not directly be a reason for considering an NWA. Again, this is also captured in our annual system planning cycle. The risk of an extended outage would be captured as an N-1 risk and the NWA would be considered as a potential mitigation.

3. *Ten-Year Timeline*

With regard to the ten-year timeline, we clarify that ten years is the anticipated contract term for load relief services that would be provided by an NWA. This does not mean that the Company would not consider NWAs for near-term planning needs (e.g., needs 3-5 years out), provided there is adequate time to evaluate, solicit, and place the NWA into operation. However, there are several factors that led us to a standard term of ten years instead of a shorter term for load relief services.

First, one of the key drivers of NWA value is the deferral value of the project, which is related to the concept of time value of money. In simple terms, the longer a traditional project can be deferred, the greater potential benefit that can accrue to the NWA project through the application of the time value of money. In other words, projects that have shorter deferral periods would be comparatively more costly in relation to their benefits than projects with a longer deferral period such as the 10-year period included in our analysis.

Second, a longer project timeline results in a more efficient engineering and regulatory process. The time committed to identify, screen, and propose NWAs is significant. It will take approximately 1.5 years to perform the initial NWA cost screening and conduct a technology-neutral solicitation. In addition, we expect it would take at least one year for third-parties to develop and commission NWAs. Repeating this approximate three-year process on a cadence of less than a 10-year deferral period is inefficient.

Third, both developers and their investors prefer long-term, stable cash flows. It can be difficult to finance and sell projects that have shorter contract terms. In addition, the useful asset lives of many projects such as those we expect may be proposed for NWAs (e.g. batteries, solar PV) are a minimum of ten years.

4. Dollar Value Threshold

With regard to the current $2 million threshold contained in the IDP requirements, we agree with the City that some threshold is necessary. We have discussed in past IDPs the reasons we believe $2 million is the right threshold at this time, and we continue to believe those same reasons continue to be relevant and pertinent. There is practical limitation to how many potential NWAs can be analyzed during a given period. Further, it continues to be is less likely that there will be viable NWAs for smaller distribution projects given the costs of the possible NWA infrastructure at this time.

5. Discount Rate

We used the WACC as the discount rate for the reasons discussed above in Section I.C. As we have discussed, we generally use WACC to analyze the cost-effectiveness of proposed projects. We acknowledge however, in some specific instances it may be appropriate to use a different rate for particular analyses – and that there may be merit in further exploring the use of other discount rates in the specific context of NWA analysis in our next NWA analysis. Ultimately, the discount rate(s) used in NWA analysis should be consistent with the value stream assessed (e.g., utility costs, society, customer). The matter is not binary as some comments suggest. To the extent the Commission decides to establish a prescriptive framework for NWA analysis or prescriptive aspects of such an analysis, the issue of discount rate should be carefully considered in the context of its effect on the analysis and the outcomes on all customers.

With regard to the specific suggestion to use the same discount rate for NWAs that is used in the referenced Conservation Improvement Program (CIP) customer-funded programs, we clarify that there are two primary discount rates that were set in the February 11, 2020 Order in Docket No. E999/CIP-18-783. A Societal Discount Rate of 3.02% was required for use by all electric utilities in the Societal Cost Test, which is used to determine which individual technologies may be allowed in the electric CIP portfolio. This rate is based on the 2018 average of the United States Department of Treasury's 20-year Constant Maturity Rate. This test includes all costs and benefits of customer-funded programs, including the cost of the equipment installed by customers and environmental externalities. The breadth of the costs and benefits included in this test is the rationale for the use of a more general, economy-wide discount rate to be used. The Order also established a Utility Discount Rate of 5.38% that is required for the Utility Cost test, which considers only the program costs of the electric utilities and excludes environmental externalities. This rate was based on a combination of the utility WACC and the Societal Discount Rate.

As we note above, there may be merit in further exploring the use of other discount rates in the specific context of NWA analysis. However, caution is warranted in merely adopting a rate established for a different purpose, and without fully vetting the details and implications. Ultimately, the discount rate(s) used in NWA analysis needs be consistent with the value stream being assessed. To the extent the Commission wants to consider setting a prescriptive discount rate for NWA analysis, the record in this IDP is not fully developed and ripe for a determination. We are happy to engage in further dialogue or record development on this issue that will contribute to the Commission's careful consideration, and we welcome input from other stakeholders who have not yet addressed the subject.

H. Other Items

As part of its assessment of the Company's responsiveness to the Commission's planning objectives, the Department suggests more specificity in our descriptions of locations where certain topics are discussed; for example, safety.[49] The Commission's planning objectives are broad and may be addressed directly or indirectly in many places throughout the IDP report, so correlating specific content to the planning objectives as currently required by the Commission's July 16, 2019 Order which stated that the Company is to provide an analysis of how the information presented in the IDP relates to each planning objective and the location of such information in the IDP is subjective.[50] Indeed, safety is central to everything that we do – and the word "safety" appears 61 times in our filing. That said, the most relevant or informative details about safety (or any given topic) may be different for each party or stakeholder. Listing and citing to every statement that is related to safety and safe operation of our system (or other topics contained in the Commission's planning objectives) would be administratively onerous and provide little value in exchange. That said, we recognize that our IDP is voluminous, so we are open to replacing the current planning objective to content mapping requirement with a keyword index of the Commission's planning objective topics in future IDPs. Such an index would be more administratively streamlined and significantly lesson the subjectivity of creating the connections between the planning objectives and the content – and, it would provide users with a comprehensive tool to view related content.

We also note here, as discussed in more detail elsewhere in this Reply, we believe the Department is measuring the content of our IDP in relation to the Commission's planning objectives and specific IDP requirements to a higher and different standard than is intended for an IDP.

Finally, we note that we agree with recommendation by CEV and the Department that the Commission consolidate all relevant requirements for our next IDP into a single document that will help stakeholders understand the structure and context of the IDP more easily and ensure the Company complies with all of the requirements.

IV. CERTIFICATION OF DISTRIBUTED INTELLIGENCE FOUNDATIONAL INVESTMENTS AND INITIAL USE CASES

We respond to comments from the Department and Fresh Energy regarding certification of our proposed DI investments in Section III of the body of our Reply Comments. In this section, we respond to other recommendations and questions.

A. Requested Information Related to Customer and Third-Party Data

[49] Department Comments at 13.
[50] *See* Order Accepting Report, and Amending Requirements, Docket No. E002/CI-18-215, at Order Point 5 (July 16, 2019).

Access

Fresh Energy noted in its Comments that the Company's Xcel Energy affiliate operating company, Public Service Company of Colorado (PSCo) entered into a Settlement Agreement, and asked the Company to explain in Reply whether the customer and third party customer data access provisions of the Settlement will be handled the same in Minnesota.[51] In summary, these issues will be implemented in Minnesota generally consistent with how they will be addressed in PSCo, pending the outcome of the Settlement Agreement.

On February 18, 2022, PSCo and the other parties in Proceeding No. 21A-0279E filed a unanimous Settlement Agreement (Settlement). On March 7, 2022, the Administrative Law Judge in that matter issued a Recommended Decision that recommends approval of the Settlement. Unless exceptions are filed, or the Colorado Commission issues a stay on its own motion in the interim, the Recommended Decision will become the final decision of the Colorado Commission on March 28, 2022. The discussion below outlines the customer and third-party data provisions of the Settlement and is based on the premise that it will be approved. If the Settlement is not approved in Colorado, some issues might have to be revisited.

That said, we note that the Settlement is not binding on the Company in Minnesota – and many of the provisions it contains, such as those addressing cost recovery in Colorado, a Colorado pilot program regarding electric vehicles, or reporting to the Colorado Commission, are simply not relevant to the deployment of DI in Minnesota. However, issues of customer and customer-authorized third-party access to data and the manner in which connectivity between meters and the Home Area Network (HAN) is deployed are relevant in both Minnesota and Colorado; we plan on addressing those issues in Minnesota generally consistent with how they will be addressed in Colorado if the Settlement is approved.

With regard to HAN, the Company plans to first roll out its HAN mobile application, which will initially have limited functionality, and then subsequently enable Bring Your Own Device (BYOD) functionality that will allow Wi-Fi compatible devices using the IEEE 2030.5 compatible devices to access the meter and obtain one-second power (kW) and five-second energy (kWh) consumption data, with customer consent (verified using a two-step authentication process). The HAN software development kit provided to third parties pursuant to the Settlement will facilitate third-party development of applications that can also be deployed in Minnesota. As in Colorado, however, we cannot guarantee any particular customer's ability to successfully connect

[51] Fresh Energy Comments at 12-13.

with a meter via Wi-Fi as the distance between meter locations and Wi-Fi routers can differ, as can the quality of customers' internet connectivity and home Wi-Fi networks.

The Settlement also provides for a second software development kit to developers. This will facilitate the ability for customer-authorized third parties to remotely connect to customer meters via the internet and customers' Wi-Fi, and obtain one-second data using the IEEE 2030.5 protocol. This second kit will also function with the Company's Minnesota meters. As with HAN connectivity, the Company cannot guarantee the success of any particular connection given our lack of control over customer Wi-Fi and internet connectivity and variances in meter locations.

In summary, the DI capabilities of the meters will be deployed in a manner that facilitates the development of third-party services using customer energy usage data, with customer consent, to provide insights and services. The software development kits issued by the Company pursuant to the Settlement will help third-party developers create relevant products and services.

We further note that the Settlement does not require PSCo to install customer-chosen third-party applications on its electric meters, and Xcel Energy does not plan on allowing such functionality in either jurisdiction. The meters are crucial portions of the Company's electric distribution system and they are connected to our back-end systems, including the secure Operational Technology zone. In order to maintain cybersecurity and avoid potential operational issues, the only software installed on the meters will be programs Xcel Energy itself selects after conducting appropriate due diligence.

B. City of Minneapolis Recommendations

In response to recommendations from the City of Minneapolis in its Comments that the Company be required to provide an annual report regarding data sharing,[52] we note that issues of customer privacy, data release, and reporting regarding utility customer data practices are already being addressed in Docket Nos. E999/CI-12-1344 and E,G999/M-19-505. To avoid duplication, any proposed new requirements should be addressed in those dockets. We note that the Commission issued a Notice for Comments in that proceeding, with initial Comments due April 1, 2022.

The City of Minneapolis also recommends that there be "an option to opt out of data sharing" and that if the Company receives any income from "data sharing," it offer a

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[52] City of Minneapolis Comments at 26.

small bill credit to customers who share data. In response, we note that customer consent and control are central tenets of our customer data practices, and therefore, just as other data we maintain today, with DI, customers will have to affirmatively consent to share their data with third parties. Customers will also have the option of opting out of having an AMI meter installed at their premises.[53] We further note that we do not plan on generating income by selling customer data.

V. CERTIFICATION OF THE RESILIENT MINNEAPOLIS PROJECT

We outlined the robust support for our Resilient Minneapolis Project (RMP) and responded to the Department's Comments regarding RMP in Section IV of our Reply Comments. We address additional comments from other parties here.

A. Preference for Local Union Labor

In its comments, Fresh Energy suggested that a preference for local union labor be used in the procurement and bid evaluation process for the project.[54] The Company has no objection to this recommendation; though we note this preference will need to be balanced with our intention to apply supplier diversity criteria and give preference to women- and minority-owned businesses in the RFP(s) for BESS equipment and associated services.

B. Additional Reporting Requirements

Fresh Energy suggested that the Company be required to provide the following in the Annual RMP reports the Company offered to submit as part of its RMP proposal:

a. Optional feedback from site hosts and community partners, using a form Xcel distributes on an annual (or more frequent) basis, which invites partners to discuss their experience participating in the project, its impact on the organization or community, or other information partners wish to share with the Commission.

b. Updates on the status of HVAC upgrades, building envelope upgrades, energy efficiency measures, and/or demand response programs undertaken at any of the RMP sites, to be provided in consultation with site hosts.

c. A discussion of the RMP program in comparison to battery and microgrid programs/projects in Xcel's other service territories, and how Xcel is

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[53] There are one-time and recurring charges associated with this service. *See* Order in Docket No. E002/M-20-592 (July 21, 2021).
[54] Fresh Energy Comments at 18.

identifying and applying lessons learned across territories.

We have no objection to this recommendation. We clarify however, with respect to item 2.b, we will only be able to provide updates as long as the RMP host(s) consent to our release of information about their participation in Xcel Energy programs. In the case of one of the hosts, Sabathani Community Center, we have worked with Sabathani over the past year to identify existing programs and sources of funding for its planned HVAC and building efficiency upgrades. We assisted Sabathani to complete its LED lighting retrofit in 2021, leveraging CIP rebates, City of Minneapolis cost share funds, and other resources to finance a lighting project that will provide an estimated $28,000 in annual cost savings at no up-front cost to Sabathani. We are providing funding assistance and partner connections to support Sabathani's evaluation of potential HVAC system retrofits and will continue to support that effort going forward.

C. City of Minneapolis Requests

The City of Minneapolis recommends the Commission approve certification of the RMP and asks that the Company continue to work collaboratively with the community hosts in the final development and implementation of the projects, including working with the hosts to identify building loads that are most critical for the resiliency hub during an outage as well as non-critical loads that could be curtailed to extend battery capacity and sustain critical services.[55] The Company supports these requests. We have worked closely with Renewable Energy Partners, Sabathani Community Center, and the Minneapolis American Indian Center since mid-2021 on the design of the RMP, and intend to continue doing so as we move into the engineering, construction, and operational phases, should the Commission approve the RMP. A key part of the design phase will be, as Minneapolis suggests, to identify critical and non-critical loads within each of the RMP host buildings in order to ensure the microgrids could support resiliency during an extended outage if necessary.

Minneapolis also commends several aspects of the RMP design, some of which echo the equity and "procedural justice" requirements expected to be part of the Commission's forthcoming order in Docket No. E002/RP-19-368:

- Expanded consideration of community resilience as part of the project value. Minneapolis does not suggest all benefits of community resilience need to be quantified to have value,
- Supporting communities to determine their own needs, identify how to meet

[55] City of Minneapolis Comments at 23-25.

those needs, and support partnerships that empower the community,

- Leverage internal and external funds for energy efficiency and rooftop solar – including building and HVAC improvements that, while not included in the RMP budget, are equally important goals for the hosts,
- Increase investments in under-resourced and marginalized communities through needed grid upgrades that improve resilient infrastructure, reduce energy burden, and allow for more community-based generation,
- Provide an opportunity for utilities to develop projects that are responsive to the community through focused stakeholder engagement, include equity considerations as part of the criteria's last selection process, and consider the full range of DERs that could comprise a true non-wires alternative,
- Maximize opportunity for women-and minority-owned small businesses to build and maintain these systems.[56]

We thank the City of Minneapolis for these comments and intend to continue working with both the City and the RMP hosts to ensure the project meets these aspirations if the Commission certifies it.

C. Other Questions

CEV Comments include recommendations that we consider adding training and education to this and future related projects.[57] We thank CEV for its support for certification, and note these recommendations are already part of the RMP project plan. Two of our RMP partners, Renewable Energy Partners and Sabathani Community Center, are already active in workforce training and development to promote BIPOC careers in clean energy. We intend to work with these partners to provide new educational and workforce development/career pipeline opportunities connected to the RMP investments.

In Section IV of its Comments, the City of Minneapolis seems to suggest that RMP is an NWA project. We clarify that RMP is not an NWA project. However, the RMP deploys some of the same technologies as – and we believe will provide learning opportunities in the design and operation of those technologies to inform future NWA projects.

Fresh Energy included in their comments several questions they request the Company address in Reply Comments.[58] We address these briefly below, and note that we will

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[56] City of Minneapolis Comments at 24-25.
[57] CEV Comments at 27.
[58] Fresh Energy Comments at 17-20.

address them more fully in RMP Annual Reports, should the Commission certify the RMP.

Question	**Response**
How does Xcel anticipate using these learnings [from managing BESS for resiliency and other use cases] for future programs and offerings to their customers?	The RMP will demonstrate whether this type of partnership can be a viable solution to extending resilience services to at-risk portions of the population where increased resilience is deemed to provide a public good, yet faces funding challenges. This may provide a way to offer resilience services to customers/partners where the forthcoming "Resiliency as a Service" program is not an option.
How will this project help reduce costs for future projects or streamline execution of future BESS or microgrid projects?	RMP will provide lessons on how the Company can integrate these systems more quickly and efficiently, which should translate into lower costs for design, construction, installation, and integration with our ADMS on future projects.
What has Xcel learned so far about BESS and/or microgrid deployment from both the Resiliency as a Service program in Wisconsin and the Energy Future Collaboration in Colorado?	<u>Wisconsin</u> – *Resiliency Service Assets* – Company ownership and operation of Resiliency Service Assets (RaaS) will provide valuable experience to the Company on the benefits of behind-the-meter technologies that can aid the Company in evaluation of alternatives to traditional utility distribution investments. As proposed, the Wisconsin pilot is voluntary for customers and exists to meet customer resiliency needs. The data and experience from the pilot may be valuable for evaluating non-wires alternatives in the future. We currently have no projects in service yet. The Wisconsin RaaS product officially launched summer 2021. Microgrid projects have a long lead time due to the intensive engineering and financial analysis required to implement a project in partnership with a potential customer. We are finding that each project is highly customized and the costs and benefits of each microgrid deployment is highly situational. *Community Critical Infrastructure Support* – This pilot will result in the additional deployment of microgrids and green energy infrastructure which could help achieve carbon emissions goals for individual customers, communities, and the state of Wisconsin. Community microgrid projects supported by the pilot will enable communities to provide support to the most vulnerable

groups during a disaster.

Additionally, as discussed above, the pilot will also provide the Company with experience with potential non-wires alternatives and can enable communities to increase resiliency for critical infrastructure, thereby increasing support for vulnerable populations.

Colorado –
In the *Community Resiliency Initiative* (CRI), the Company is installing six microgrids with similar scale and objectives to the RMP. Projects are currently in various stages of design/construction, so no operational learnings are yet available. However, the CRI projects have provided learnings on design and construction, fire safety precautions, permitting complexities, and vendor limitations. We expect these to help streamline the design, permitting and construction process for the RMP sites.

What specifically has Xcel learned about managing BESS for grid services or peak reduction on the feeder level, and about integrating battery and microgrid software with its distribution management systems?

Since the CRI projects are still in design/construction, the Company has no operational learnings yet. If it is of interest, there are status reports to the Colorado PUC for the Panasonic Battery Demonstration Project, which (while larger and installed at a commercial customer site) shares some common elements with the RMP.[59] The status reports were submitted as compliance filings in Docket No. E002/M-17-776.

What lessons from these projects are being or could be applied to the RMP?

The CRI projects have provided lessons learned on design and construction, fire safety precautions, permitting complexities, and vendor limitations, which will help streamline the design, permitting and construction process for the RMP sites. Operational learnings from the Panasonic project will also be applied in the design and operation of RMP.

What lessons has the Company learned from these procurements [from the Wisconsin and

These procurements have indicated the need for realistic timelines due to supply chain issues and long lead times

[59] *See* CO-Panasonic-Fact-Sheet.pdf (xcelenergy.com). Located at Panasonic's Denver operations hub at Peña Station NEXT, this 1 MW/2 MWh battery and solar (1.3 MW at a carport plus 200 kW on Panasonic's facility) project is evaluating several benefits to the grid: renewable energy integration (voltage regulation and ramp rate control on a distribution feeder with high solar penetration), peak demand reduction (feeder and system level), energy arbitrage (using time of charging and discharging to take advantage of fluctuations in wholesale energy prices), regulation services (responding to low frequency events), and islanding (automated isolation of the system from the larger grid in the case of an outage to function as a microgrid providing power to Panasonic).

Colorado resiliency projects], and how are these informing the MN process?	for BESS. Many BESS vendors are moving toward large utility-scale projects only.
What has Xcel's experience been like with the selected vendors? Discuss any challenges in design, construction, and operations.	As these are active projects, what the Company can disclose here is limited. However, for CRI, the Company submits semi-annual status reports to the Colorado Public Utilities Commission in Docket 19A-0225E.[60]

[60] *See* Public Service Company of Colorado CRI Reports submitted December 2020, June 2021, and December 2021. Access DORA for proceeding 19A-0225E at: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search.

CERTIFICATE OF SERVICE

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

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

xx electronic filing

DOCKET NO. E002/M-21-694
Cover Letter, Reply Comments and Attachment A to Reply Comments

Dated this 22nd day of March 2022

/s/ Mustafa Adam

Mustafa Adam
Regulatory Administrator

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-694_21-694
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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