COMMERCE DEPARTMENT

October 17, 2022

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket Nos. E002/M-20-680 and E002/M-21-814

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2021 and 2022, Tracker True-up and Revised Adjustment Factors

The Petition was filed on November 24, 2021 by:

> Holly Hinman
> Regulatory Manager
> Xcel Energy
> 414 Nicollet Mall, 401 – 7th Floor
> Minneapolis, MN 55401

The Department recommends that the Minnesota Public Utilities Commission (Commission) approve Xcel's Transmission Cost Recovery Rider Revenue Requirements for 2021-2022 subject to the recommendations made by the Department and Synapse Energy Economics, Inc. (Synapse). The Department and Synapse are available to answer any questions the Commission may have.

Sincerely,

/s/ MATTHEW LANDI
Rates Analyst

/s/ NANCY CAMPBELL
Financial Analyst, CPA

ML/NC/ja
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket Nos. E002/M-20-680 and E002/M-21-814

I. PROCEDURAL HISTORY AND BACKGROUND

On October 30, 2015, Northern States Power Company d/b/a Xcel Energy (Xcel, or the Company) filed its 2015 Biennial Distribution Grid-Modernization Report under Minn. Stat. §216B.2425 (the Grid Modernization Statute).[1] Under the Grid Modernization Statute, subdivision 2 requires that a utility operating under a multi-year rate plan[2] identify investments that it considers necessary to modernize its transmission and distribution grid by enhancing reliability, improving security against cyber and physical threats, and increasing opportunities for energy conservation. Subdivision 3 of the Grid Modernization Statute requires the Minnesota Public Utilities Commission (Commission) to certify, certify as modified, or deny certification of the investments identified by a utility under subdivision 2. As part of its 2015 Biennial Distribution Grid-Modernization Report, the Company proposed an Advanced Distribution Management System (ADMS) project and requested that the Commission certify the ADMS project. On June 28, 2016, the Commission certified the ADMS project.[3]

Minn. Stat. §216B.16, subd. 7b authorizes the Commission to approve the automatic adjustment of charges for the Minnesota jurisdictional costs associated with a utility's new transmission facilities through a utility's Transmission Cost Recovery (TCR) Rider, and subd. 7b(b)(5) specifically "allows the utility to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the commission under Minn. Stat. §216B.2425" (the TCR Rider Statute). [4]

Xcel's two most recent TCR Rider petitions, in Docket Nos. E002/M-17-797 (Xcel's 2017-2018 TCR Rider Petition) and E002/M-19-721 (Xcel's 2019-2020 TCR Rider Petition), respectively, included the ADMS project as part of its cost recovery request. Subsequent Commission Orders in both proceedings have

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[1] Minn. Stat. §216B.2425, accessed at: https://www.revisor.mn.gov/statutes/cite/216B.2425.

[2] Minn. Stat. §216B.16, subd. 19. Accessed at: https://www.revisor.mn.gov/statutes/cite/216B.16#stat.216B.16.19.

[3] *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report, Docket No. E-002/M-15-962*, ORDER CERTIFYING ADVANCED DISTRIBUTION-MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. § 216B.2425 AND REQUIRING DISTRIBUTION STUDY (June 28, 2016). Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={6ACF016C-3E0E-4CA7-A52A-35FD0E28D7FB}&documentTitle=20166-122702-01.

[4] Minn. Stat. §216B.16, subd. 7b(b)(5), accessed at: https://www.revisor.mn.gov/statutes/cite/216B.16#stat.216B.16.7b.

allowed the Company to recover the Company's revenue requirements associated with the ADMS project through its TCR Rider.[5,6]

On November 1, 2017, Xcel filed its Petition for approval of a Residential Time of Use (TOU) Rate Design Pilot Program (TOU Rider Pilot) in Docket No. E002/M-17-775, and did so in conjunction with the Company's Grid Modernization Report in Docket No. E002/M-17-776. Xcel requested certification of its TOU Rider Pilot pursuant to the Grid Modernization Statute. On August 7, 2018, the Commission certified the TOU Rider Pilot.[7] Until the instant TCR Rider petition, Xcel has not requested cost recovery of any of the costs associated with implementing the TOU Rider Pilot.

On November 1, 2019, Xcel filed its 2019 Integrated Distribution Plan (2019 IDP) in Docket No. E002/M-19-666. The Company's 2019 IDP included the Company's certification request of its proposed Advanced Grid Intelligence and Security (AGIS) Initiative and an Advanced Distribution Planning Tool (APT, now known as the LoadSEER tool) pursuant to Minn. Stat. §216B.2425.[8] The AGIS Initiative includes Advanced Metering Infrastructure (AMI), a Field Area Network (FAN), Fault Location and Isolation Service Restoration (FLISR), and an Integrated Volt-Var Optimization (IVVO) project.

On July 23, 2020, the Commission issued its Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects (Certification Order) in Xcel's 2019 IDP proceeding and certified the AMI, FAN, and APT/LoadSEER projects, and declined to certify the FLISR and IVVO projects.[9]

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[5] *In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor,* Docket No. E002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (September 27, 2019) (2017-2018 TCR Rider Order). Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90C2736D-0000-C01D-9089-5F9E7FB89DA6}&documentTitle=20199-156134-01.

[6] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2019 and 2020 and Revised Adjustment Factors,* Docket No. E002/M-19-721, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (December 10, 2021) (Xcel's 2019-2020 TCR Rider Order). Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={3092A57D-0000-CC11-9CCC-621D818F8CBB}&documentTitle=202112-180572-01.

[7] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program,* Docket No. E002/M-17-775, and *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report,* Docket No. E002/M-17-776, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST (August 7, 2018). Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={103F1565-0000-C21D-B43D-24C097C567A3}&documentTitle=20188-145582-01.

[8] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666, Xcel Energy Integrated Distribution Plan (2020 – 2029), dated November 1, 2019. Accessed at (PUBLIC): https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={90E1276E-0000-C617-9E33-75094BC2422E}&documentTitle=201911-157133-01.

[9] In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS (Certification Order) (July 23, 2020). Accessed at:

On August 20, 2020, the Department initiated a stakeholder process and investigative proceeding in Docket No. E999/DI-20-627 (Department Investigation)[10] in response to the Commission's Certification Order, specifically Order Point No. 9, which requested the following:

> 9. The Commission Requests that the Department file a report by November 1, 2020, including recommendations on specific metrics, detailed methods for evaluating performance, and consumer protections or other conditions, including cost caps, that should be applied to the certified projects. The report should be informed by a stakeholder process and will be made part of the record for any future cost recovery proceedings. Xcel must participate in the stakeholder process, which must be open to all interested parties, and fully cooperate with the Department.

The Department's Notice of Solicitation of Stakeholder Input and Comments (Department Notice) requested comments on numerous topics under four broad areas: (1) the content of Xcel's cost recovery petition (filing requirements); (2) metrics accompanying Xcel's cost recovery request for the AMI and FAN projects; (3) methods for evaluation of performance of Xcel's AMI and FAN projects; and (4) consumer protections. Several parties filed comments in response to the Department's Notice between September 18, 2020 and October 16, 2020.

The Department convened a stakeholder workshop on Friday, October 23, 2020 regarding Xcel's AMI and FAN projects. Xcel also held a workshop on November 20, 2020 providing a detailed overview of its FAN and AMI projects. After receiving valuable stakeholder feedback and recommendations, the Department's Investigation culminated in a report filed on December 1, 2020 called *Methods for Performance Evaluations, Metrics, and Consumer Protections for AMI and FAN* (Department Report).

During the time the Department's Investigation was ongoing, another proceeding was initiated in Docket No. E002/M-20-680 on August 28, 2020 to consider the procedural paths for the processing and review of Xcel's expected TCR Rider petition. Xcel filed a compliance filing in which it discussed these procedural paths (Procedural Paths Proceeding)[11], and explained that it would file its TCR Rider petition containing a cost recovery request for the then-recently certified AMI, FAN, and APT/LoadSEER

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https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={F00E7D73-0000-CD15-B6E0-EA73F0AC037E}&documentTitle=20207-165209-01.

[10] *In the Matter of the Department Stakeholder Process Informing the Report on the Metrics, Performance Evaluation Methods, and Consumer Protection Conditions to be applied to Xcel Energy's Advanced Metering Infrastructure and Field Area Network Projects Certified in Docket No. E002/M-19-666,* Docket No. E999/DI-20-627, Notice of Solicitation of Stakeholder Input and Comments, August 20, 2020. Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={C0AC1174-0000-CF1E-937E-B1525931BB6F}&documentTitle=20208-166087-01.

[11] *In the Matter of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2021 and Revised Adjustment Factors,* Docket No. E002/M-20-680, Compliance – Procedural Paths Forward: Integrated Distribution Plan and AGIS Certification Request & Transmission Cost Recovery Rider (Procedural Paths Proceeding, Xcel's Compliance Filing), August 28, 2020. Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D0F33674-0000-CA1C-BF4E-78D8FD2371B2}&documentTitle=20208-166259-01.

projects on or about November 6, 2020.[12] Xcel's Procedural Paths Proceeding Compliance Filing was required by Order Point No. 13 of the Commission's Certification Order, which states:[13]

> 13. 60 days prior to a petition to seek rider recovery for AGIS costs, Xcel Energy shall file preferred procedural paths forward with one option being a contested case. The Commission will make a procedural and scoping decision prior to the consideration of a rider recovery determination. The Executive Secretary is authorized to establish a comment and reply schedule prior to the procedural and scoping hearing.

On September 23, 2020, the Commission issued a Notice for Comment on Xcel's Procedural Paths Compliance Filing (Procedural Paths Proceeding Notice). On October 16, 2020, the following parties submitted Comments in response to the Commission's Procedural Paths Proceeding Notice:

- The Department;
- The Office of Attorney General – Residential Utilities Division (OAG-RUD);
- The Citizens Utility Board of Minnesota (CUB); and
- Xcel Large Industrials (XLI).

Again, at the time, Xcel was expected to file its TCR Rider petition on or about November 6, 2020, but declined to do so. To ascertain the timing of Xcel's TCR Rider petition, the Department was in periodic dialogue with the Company throughout 2021. The Company's plans to file its TCR Rider petition shifted throughout the year, and ultimately, Xcel did not file its TCR Rider petition until November 24, 2021 in the instant proceeding (Docket No. E002/M-21-814). On February 7, 2022, the Commission issued a Notice of Comment Period for Xcel's 2021-2022 TCR Rider Petition (TCR Rider Notice) and the related Procedural Paths Proceeding.

On February 9, 2022, the Department submitted a letter in the instant proceeding (Department's Letter), as well as several other related distribution system planning and grid modernization proceedings.[14] The Department's Letter explains that the Department retained Synapse Energy Economics, Inc. (Synapse) in response to the Commission's September 27, 2019 Order in Docket No. E002/M-17-797 requesting that the Department secure specialized technical professional investigative services to investigate the potential costs and benefits of grid modernization investments proposed by Xcel in its next rate case or Transmission Cost Recovery filing and to assist the Department in providing recommendations to the Commission regarding any such investments.[15]

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[12] Procedural Paths Proceeding, Xcel's Compliance Filing, at 2.
[13] Certification Order, Order Point No. 13, at 17.
[14] Department's Letter. February 9, 2022. Accessed at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D09BE07E-0000-C153-AEF1-6251101796D1}&documentTitle=20222-182633-03.
[15] 2017-2018 TCR Rider Order, Order Point No. 10.

Through this engagement and in service of the Commission's request, Synapse developed a document, attached to the Department's Letter, titled *Review and Assessment of Grid Modernization Plans: Guidance for Regulators, Utilities, and Other Stakeholders* (Guidance Document). The Guidance Document was developed to support the analysis of grid modernization investments in Minnesota.

The Commission's February 7, 2022 TCR Rider Notice contains two separate comment periods, one for the AGIS Related Scoping & Procedures, and the other for the Transmission Cost Recovery (TCR) Rider Petition. The Commission's TCR Rider Notice contains two separate comment periods, one for the *AGIS Related Scoping & Procedures*, and the other for the *Transmission Cost Recovery (TCR) Petition*. After comment period extensions, initial comments for the *AGIS Related Scoping & Procedures* comment period were submitted on March 30, 2022 by the following parties: (1) the Citizens Utility Board of Minnesota (CUB); (2) the Department; and (3) Xcel.

The Department originally recommended that the Commission bifurcate Xcel's 2021-2022 TCR Rider petition into the AGIS-related costs and non-AGIS costs and refer the AGIS-related costs of Xcel's 2021-2022 TCR Rider Petition to the Office of Administrative Hearings (OAH) for a contested case proceeding pursuant to Minn. R. 7829.1000. CUB also recommended that the Commission bifurcate the costs of Xcel's 2021-2022 TCR Rider petition and refer the AGIS-related costs to the OAH, citing the complexity and significance of Xcel's AGIS investments. Xcel recommended that the Commission rely on the miscellaneous filing procedures to evaluate the merits of Xcel's 2021-2022 TCR Rider Petition, arguing that a bifurcation is not warranted.

Separately, on March 24, 2022, the Department requested that the Commission suspend the Transmission Cost Recovery (TCR) Comment periods of April 5 and 15 until after the Commission receives comments and reply comments in response to the AGIS Related Scoping & Procedures comment period and determines the procedural path for the review of the AGIS-related costs of Xcel's 2021-2022 TCR Rider Petition. On April 4, 2022, the Commission suspended the Transmission Cost Recovery (TCR) Comment periods.

On April 8, 2022, the Department requested an extension of the AGIS Related Scoping & Procedures reply comment period of April 11 to May 2. The Department's extension request letter explained that preliminary discussions between the Department and Xcel were ongoing regarding an alternative approach to the procedural review of Xcel's 2021-2022 TCR Rider Petition, and that further time was needed to determine whether the Department and Xcel could come to an agreement.

In the intervening time, both the Department and Xcel engaged in good-faith and constructive dialogue regarding the procedural review of the Xcel's 2021-2022 TCR Rider Petition. The Department and Xcel agreed to an alternative approach relying on the Commission's comment and reply comment process in conjunction with ongoing dialogue regarding the Department's Letter, technical workshops for stakeholders, and a supplemental filing that is intended to provide additional information necessary to understand and evaluate the Company's investments (Procedural Agreement).[16]

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[16] Department Reply Comments and Procedural Agreement (PUBLIC). Docket Nos. E002/M-20-680 and E002/M-21-814. May 2, 2022. Accessed at:

The Commission adopted the Department and Xcel's Procedural Agreement in its June 2, 2022 Order.[17] Per the Procedural Agreement, Xcel met with the Department and Synapse on July 20, 2022

Additionally, as per the Procedural Agreement, Xcel hosted three technical workshops on July 19, 2022, July 25, 2022, and September 7, 2022:

- Workshop 1: Industry Landscape and Technology Selection, Capabilities, and Implementation
- Workshop 2: Customer Strategy and Products and Services Roadmap[18]
- Workshop 3: AMI and FAN Financials, Cost-Benefit Analysis, and Reporting[19]

Additionally, per the Procedural Agreement, Xcel, the Department, and Synapse held several informal and formal meetings, including one between Xcel's subject matter experts and Synapse on July 20, 2022 to discuss Synapse's Guidance Document, compliance with previous Commission Orders regarding Xcel's AMI and FAN investments, and the additional information Synapse indicated is necessary to conduct a full evaluation of Xcel's cost recovery request. Subsequently, also per the Procedural Agreement, Xcel submitted its TCR Rider Petition Supplement on August 17, 2022 (Supplement).[20]

On August 22, 2022, the Commission issued a Notice of Comment Period for the TCR Rider Petition and Supplement (August 22 Notice). The following topics are open for comment:

- Does Xcel Energy's AGIS-related cost recovery request in the instant TCR Petition including what is found in the Company's August 17, 2022 Supplemental filing comply with:
  - the Commission's July 23, 2020 Order in Docket No. E-002/M-19-666; and
  - the Commission's September 27, 2019 [Order] in Docket No. E-002/M-17-797?
- Should the Commission approve, modify, or reject Xcel Energy's 2021-2022 TCR revenue requirement and resulting adjustment factors?
- Are there other issues or concerns related to this matter?

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https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={70E58680-0000-C327-A561-D9ADA0186F3C}&documentTitle=20225-185474-03.

[17] Commission June 2, 2022 Order. Docket Nos. E002/M-20-680 and E002/M-21-814. Accessed at: https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={50F82581-0000-CC17-8C2C-45B2E0CE10F7}&documentTitle=20226-186333-01.

[18] Xcel Letter. AMI and FAN Technical Workshop Series – Workshops #1 and #2 Recordings and Presentation. Docket Nos. E002/M-20-680 and E002/M-21-814. August 4, 2022. Accessed at: https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={60976A82-0000-C431-AD21-B4ACB3846652}&documentTitle=20228-188114-02.

[19] Xcel Letter. AMI and FAN Technical Workshop Series – Workshop 3 Recording and Presentation. Docket Nos. E002/M-20-680 and E002/M-21-814. September 14, 2022. Accessed at: https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={C0563D83-0000-CB12-885B-17B0095C1AFE}&documentTitle=20229-189064-01.

[20] Xcel Supplement Filing (Supplement). Dockets Nos. E002/M-20-680 and E002/M-21-814. Accessed at (PUBLIC): https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={2056AD82-0000-C935-9831-9C640FAA4300}&documentTitle=20228-188420-02.

Xcel's 2021-2022 TCR Rider petition and Supplement are seeking approval of its 2021-2022 TCR Rider revenue requirements and resulting rate classes' adjustment factors. Xcel proposed a 2022 TCR Rider revenue requirement of approximately $104.5 million, an increase of approximately $22.6 million over 2020 revenue requirements of approximately $81.9 million.[21] Xcel's proposed revenue requirements and the resulting adjustment factors were calculated with an assumed implementation date of June 1, 2022, and the Company is proposing to recalculate the adjustment factors for implementation in compliance based on the timing of a Commission decision.

Through Xcel's 2021-2022 TCR Rider, the Company is proposing to recover the following:[22]

- Costs associated with distribution-grid modernization projects previously certified by the Commission and eligible for TCR cost recovery, as follows:
  - The ADMS Project;
  - The AMI Project;
  - The FAN Project;
  - The TOU Rider Pilot; and
  - The APT/LoadSEER project.
- Costs associated with transmission projects previously approved for TCR Rider recovery, including:[23]
  - CapX2020 Fargo – Twin Cities;
  - CapX2020 La Crosse;
  - CapX2020 Brookings – Twin Cities;
  - La Crosse – Madison (also referred to as Badger – Coulee);
  - Big Stone-Brookings 345 kV Line; and
  - Huntley-Wilmarth 345 kV Transmission Line.

The Department provides these Initial Comments in response to the Commission's August 22 Notice regarding Xcel Energy's 2021-2022 TCR revenue requirement and resulting adjustment factors.

II. DEPARTMENT ANALYSIS

A. AUGUST 22 NOTICE – TOPIC #1

The first topic under the August 22 Notice of Comment Period is as follows:

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[21] *In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2021 and 2022, Tracker True-up, and Revised Adjustment Factors,* Xcel's Transmission Cost Recovery Rider Petition (Xcel's 2021-2022 TCR Rider Petition), Docket No. E002/M-21-814, November 24, 2021. Accessed at (PUBLIC): https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D031537D-0000-C911-9323-7302B00603AD}&documentTitle=202111-180141-01.

[22] Xcel's 2021-2022 TCR Rider Petition, at 1-2.

[23] Xcel's 2021-2022 TCR Rider Petition, Attachment 1.

- Does Xcel Energy's AGIS-related cost recovery request in the instant TCR Petition including what is found in the Company's August 17, 2022 Supplemental filing comply with:
  - the Commission's July 23, 2020 Order in Docket No. E-002/M-19-666; and
  - the Commission's September 27, 2019 [Order] in Docket No. E-002/M-17-797?

As mentioned before, the Department retained Synapse to review Xcel's AGIS-related cost recovery request in the instant TCR Petition. Attached to the Department's Initial Comments is a report from Synapse regarding its analysis and recommendations regarding Xcel's distribution-grid modernization projects.[24]

The Department recommends that the Commission adopt the recommendations made by Synapse regarding Xcel's AGIS-related cost recovery request.

B. AUGUST 22 NOTICE – TOPIC #2

The second topic under the August 22 Notice of Comment Period is as follows:

- Should the Commission approve, modify, or reject Xcel Energy's 2021-2022 TCR revenue requirement and resulting adjustment factors?

Here the Department's analysis focuses on the transmission-related components of Xcel Energy's 2021-2022 TCR revenue requirement.

1. SUMMARY OF TCR RIDER REVENUE REQUIREMENTS

Xcel requested approval of its 2022 revenue requirements, tracker balance, and updated TCR adjustment factors for the Minnesota jurisdiction. A summary of Xcel's proposed projects and related revenue requirements for the period is included in Table 1 below:[25]

[24] Synapse Report, *Comments on Xcel Energy's 2021-2022 TCR Rider Petition.* Department Attachment 1.
[25] Xcel's 2021-2022 TCR Rider Petition, Attachment 8. Annual Revenue Requirements.

Table 1. Proposed MN Revenue Requirements ($)

Project	2019 Actual	2020 Actual	2021 Mixed	2022 Forecast	2023 Forecast
AGIS – ADMS	$1,979,777	$2,799,047	$5,185,468	$5,895,245	$5,940,888
AGIS – AMI	-	$1,210,039	$4,639,342	$15,708,542	$35,101,489
AGIS – FAN	-	$234,981	$1,239,549	$1,925,235	$3,185,952
AGIS – LoadSeer	-	$230,108	$740,129	$672,353	$625,508
AGIS – TOU Pilot	-	-	-	$699,701	$667,758
Big Stone-Brookings	$4,095,135	$3,973,954	$3,850,967	$3,752,627	$3,664,659
CapX2020- Brookings	$32,887,354	$32,127,705	$31,300,336	$30,662,824	$29,949,570
CapX2020-LaCrosse Local	$4,139,767	$4,156,103	$3,992,695	$3,957,322	$3,858,452
CapX2020-LaCrosse MISO	$5,397,139	$5,255,055	$5,119,584	$5,015,570	$4,898,618
CapX2020-LaCrosse MISO-WI	$10,043,647	$9,741,083	$9,458,162	$9,229,727	$8,977,953
CapX2020-Fargo	$14,818,201	$14,355,718	$13,929,370	$13,589,185	$13,215,609
Huntley-Wilmarth HVTL	$200,312	$1,106,219	$2,990,627	$4,843,143	$4,759,949
LaCrosse-Madison	$14,923,365	$14,915,964	$14,288,700	$13,845,072	$13,488,580
MISO RECB Sch. 26/26a	($8,497,508)	$510,576	($3,995,005)	($9,607,189)	($10,858,596)
Transmission Projects	$79,987,189	$90,616,552	$92,739,924	$100,189,357	$117,476,389
Rev. Reqm't in Base Rates	($1,937,000)	($1,937,000)	($1,937 ,000)	-	-
TCR True-Up Carryover	$1,036,546	($7,482,299)	($3,753,258)	$4,346,913	$7,956,886
Revenue Requirements (RR)	$79,086,735	$81,197,253	$87,049,666	$104,536,270	$125,433,275
Revenue Collections (RC)	$86,569,032	$84,950,512	$82,702,754	$96,579,384	$105,286,448
Carry Over Balance	**($7,482,297)**	**($3,753,259)**	**$4,346,912**	**$7,956,886**	**$20,146,827**

Xcel has requested approval of 2021-2022 revenue requirements of approximately $104.5 million. This represents an increase of $22.6 million compared to the 2020 revenue requirement of approximately $81.9 million.

Xcel proposed to allocate the revenue requirements within the TCR to Minnesota and its various customer classes based on the same jurisdictional and demand allocators used in Company's last electric rate case in Docket No. E002/GR-15-826. Xcel proposed to charge its residential and commercial non-demand customers using an energy-only rate (per kWh) and its demand billed customers using a demand rate (per kW).

Xcel's prior and provisionally approved (proposed) TCR rate adjustment factors are shown in Table 2 below:

Table 2. Xcel's Prior and Proposed TCR Rate Adjustment Factors

Customer Class	2019-2020 Provisionally Implemented Charge per kWh	2019-2020 Provisionally Implemented Charge per kW	2021-2022 Proposed[26] Charge per kWh	2021-2022 Proposed[26] Charge per kW
Residential	$0.003607	N/A	$0.005905	N/A
Commercial (Non-Demand)	$0.003185	N/A	$0.004649	N/A
Demand Billed	N/A	$0.982	N/A	$1.11
Total Revenue Requirements	$81,883,541		105,691,660	

Xcel stated that the monthly bill of an average residential customer using 675 kWh of electricity per month would increase by $1.47 per month under its proposed rates, from a bill impact of $2.43 (675 kWh*$0.003607) to $3.90 per month (675 kWh*$0.005783) for residential customers. This increase further increases to $3.99 per month (675 kWh*$0.005905) using the Company's updated TCR Adjustment Factors provided in its September 12, 2022 response to Department IR No. 76.

Xcel's proposed rate factors are calculated assuming an implementation date of June 1, 2022. Xcel proposed to recalculate its rates based on the authorized rates and actual implementation date to recover its full 2021-2022 revenue requirement over the 12 months subsequent to the Commission Order. The Commission authorized similar treatment in past TCR orders.

2. *STATUTORY REQUIREMENTS*

The TCR Statute, Minn. Stat. §216B.16, subd 7b, states the following:

> Subd. 7b. Transmission cost adjustment. (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues of:
>
> **(1) new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 [Certificate of Need Statute] or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425 [State Transmission Plan Statute]**;
>
> (1) new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that

[26] Xcel response to Department IR No. 76. Attachment A – Att 11 Adj Factor Calc. September 12, 2022. Department Attachment 2.

state, and determined by the Midcontinent Independent System Operator [MISO] to benefit the utility or integrated transmission system; and

(2) charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system.

(b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243;

(2) allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;

(3) allows the utility to recover on a timely basis the costs net of revenues of facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system;

(4) allows the utility to recover costs associated with distribution planning required under section 216B.2425;

(5) allows the utility to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the commission under section 216B.2425;

(6) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(7) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(8) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(9) allocates project costs appropriately between wholesale and retail customers;

(10) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(11) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

(c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b). In its filing, the public utility shall provide:

(1) a description of and context for the facilities included for recovery;

(2) a schedule for implementation of applicable projects;

(3) the utility's costs for these projects;

(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and

(5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

(d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are

> expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers. [emphasis added]

Based on the above, the Department understands that in order for an in-state transmission project to be eligible for recovery under the TCR Statute, the project must either be approved under the Certificate of Need Statute, exempt from the Certificate of Need Statute, or certified as or deemed to be a priority project under the State Transmission Plan Statute.

Regarding eligibility for out-of-state transmission projects, the Department understands that the projects must be for new transmission facilities approved by the regulatory commission of the state in which the new transmission faciliti.es are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator (MISO) to benefit the utility or the integrated transmission system.

With respect to distribution projects, the Department understands that in order for a distribution project to be eligible for recovery under the TCR Statute, the project must certified by the Commission under Minn. Stat. §216B.2425.

3. PROJECT ELIGIBLITY

The projects for which Xcel has requested cost recovery in its Petition were determined to be eligible by the Commission in prior TCR proceedings. Moreover, as of the time of filing these comments, all projects included in the Petition are in-service.[27]

The Department notes that the Company's Petition, filed November 24, 2021, indicated that the eligibility of the Huntley-Wilmarth Project was pending a Commission Order that affirmed rider eligibility. The Commission's December 10, 2021 Order in Docket No. E002/M-19-721 indeed affirmed the Huntley-Wilmarth Project's eligibility.[28] Xcel's revised response to Department IR No. 73 indicated that the Huntley-Wilmarth Project was placed in-service in November 2021.[29]

The Department otherwise notes that there has been no change in the eligibility status of any of the existing transmission projects and concludes that they remain eligible for cost recovery under the TCR Statute.[30]

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[27] Xcel's 2021-2022 TCR Rider Petition, Attachment 6. The Company's Petition, filed November 24, 2021, indicated that the Huntley-Wilmarth Project was estimated to be in-service in December 2021. The Department assumes that the project is now in service at the time of these comments.
[28] Xcel's 2019-2020 TCR Rider Order, Order Point No. 1A.
[29] Xcel revised response to Department IR No. 73. Revised October 5, 2022. Department Attachment 2.
[30] Xcel's 2021-2022 TCR Rider Petition, Attachment 1.

4. REASONABLENESS OF PROJECT REVENUE REQUIREMENTS

The Commission set a standard for evaluating TCR Rider project costs going forward in Xcel Energy's TCR Rider filing in Docket No. E002/M-09-1048. The Commission stated in its April 27, 2010 Order that:

In setting guidelines for evaluating project costs going forward, the TCR project cost recovered through the rider should be limited to the amounts of the initial estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought forward for Commission review only if unforeseen and extraordinary circumstances arise on the project.

The Commission applied this same approach to Otter Tail Power Company in its 2013 TCR Rider in Docket No. E017/M-13-103. The Commission stated in its March 10, 2014 Order that:

Accordingly, the Commission continues to believe that project costs included in the TCR rider should be capped at certificate of need levels, and concurs with the Department that the appropriate cap for the Bemidji project is $74 million. The TCR rider mechanism gives Otter Tail the extraordinary ability to charge its ratepayers for facilities prior to the ordinary timing (the first rate case after the project goes into service) and without undergoing the full scrutiny of a rate case. Holding the Company to its initial estimate is an important tool to enforce fiscal discipline.

Further, imposition of a cap protects the integrity of the certificate of need process, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. And, capping costs at the certificate of need levels is consistent with the Commission's actions in similar cases involving other utilities' riders.

The Company is recovering the cost of these transmission facilities through a rider, a unique regulatory tool essentially designed to enable utilities to begin recovering the prudent and reasonable costs of critically needed capital investments between rate cases. The rate case remains the primary vehicle for determining prudence and reasonableness.

In the absence of a rate case, the best available proxy for determining prudence and reasonableness is the cost determination made on the record of a certificate of need or cost recovery eligibility proceeding. Here, the relevant proceeding is a certificate of need case. Otter Tail should continue recovering the costs it sponsored in its certificate of need case unless and until it demonstrates in a rate case that higher costs are prudent and reasonable. [emphasis added] [footnotes omitted]

i. Transmission Projects

Table 3 below summarizes the Company's initial transmission project cost estimates, escalated cost estimates, current investments, and estimated investments through 2024.

Table 3. Transmission Project Costs and Cost Caps (in millions)[31]

Project	Initial Cost Estimate		Initial Cost Estimate Escalated		Project Investment Through 2022		Estimated Project Investment Through 2024	
	(a)		(b)		(c)		(d)	
In-State Projects								
CAPX2020 Brookings	523.9	[1]	625.6	[2]	484.1	[3]	484.1	[4]
CAPX2020 La Crosse Local					80.1	[3]	80.1	[4]
CAPX2020 La Crosse MISO					81.4	[3]	81.4	[4]
CAPX2020 La Crosse MISO – WI					147.5	[3]	147.5	[4]
CAPX2020 La Crosse	276.5	[1]	330.3	[2]	309	[3]	309	[4]
CAPX2020 Fargo	231.0	[1]	275.9	[2]	225.2	[3]	225.2	[4]
Huntley-Wilmarth HVTL	70.1	[5]	77.9	[6]	56.2	[7]	56.2	[7]
Out of State Projects								
Big Stone – Brookings	92.2	[1]			63.9	[3]	63.9	[4]
La Crosse – Madison	179.1	[1]			175.6	[3]	176.3	[4]

Sources:
[1] Department's October 16, 2020 Comments in the 2019-2020 TCR Rider.
[2] Department's October 16, 2020 Comments in the 2019-2020 TCR Rider, escalated through 2015.
[3] Petition, Attachment 7B, sum of costs through 2022.
[4] Petition, Attachment 7B.
[5] $140.1 million / 2 = $70.1 million.
[6] $155.8 million / 2 = $77.9 million.
[7] Xcel revised response to Department IR No. 73. October 5, 2022. Department Attachment 2.

The Department reviewed Xcel's actual and forecasted capital expenditures for each transmission project included in the 2021-2022 TCR Rider. As shown in the above table, all transmission projects are below their initial estimates or escalated initial estimates. As a result, the Department recommends that the Commission approve recovery of the proposed transmission capital costs in this proceeding.

5. NET REGIONAL EXPANSION AND COST BENEFIT (RECB) CHARGES (MISO SCHEDULES 26/26A, 37 & 38)

During the 2008 Minnesota Legislative Session, Minn. Stat. 216B.16, Subd, 7(b) (2) was amended to allow utilities providing transmission service to recover "the charges incurred by a utility that accrue from other transmission owners' regionally planned transmission projects that have been determined by MISO to benefit the utility, as provided for under a federally approved tariff," upon Commission approval. The Statute further requires any recovery to "be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset."

[31] Includes internal labor. Actual costs included in TCR revenue requirement calculations exclude internal labor as shown in Attachment 7A and Attachment 15 of the Petition.

MISO's regionally planned transmission projects are also referred to as Regional Expansion and Cost Benefit (RECB) projects. Moreover, RECB charges and revenues are generally reflected under MISO Schedules 26/26A. MISO Schedule 26 includes other regionally shared projects such as Market Efficiency Projects and Generation Interconnection Projects. MISO Schedule 26A includes projects that have been deemed to be Multi-Value Projects (MVPs).

In addition to MISO Schedules 26/26A, utilities also receive revenues related to regionally-shared projects under MISO Schedules 37 and 38. MISO Schedule 37 revenues represent a utility's share of contributions MISO receives from American Transmission Systems, Inc., which left MISO on June 1, 2011 to integrate with PJM. Likewise, MISO Schedule 38 revenues represent a utility's share of payments from Duke-Ohio and Duke-Kentucky, which left MISO on December 31, 2011, but have an ongoing obligation to pay for MISO projects due to their previous membership.

Similar to previous TCR filings, Xcel proposed to recover the net charges it pays other electric utilities through MISO Schedules 26/26A in its TCR Rider. Under Xcel's proposal, it would recover the estimated amount of payments it makes under MISO Schedules 26/26A net of the estimated amount of revenues it receives from other utilities under MISO Schedules 26/26A. Specifically, Xcel proposed to include its estimated 2021 and 2022 MISO Schedule 26/26A net revenues of -$3,995,005 and -$9,607,189, respectively, in its TCR Rider. However, in response to Department IR Nos. 76 and 78, Xcel provided updated RECB actuals through July 31, 2022. Xcel's revenue requirements for MISO Schedules 26/26A increased $1,499,497 to -$2,495,508) for 2021 and $1,604,732 to -$8,005,746 for 2022.[32]

Order Point No. 12 of the Commission's December 10, 2021 Order in Xcel's 2019-2020 TCR Rider required Xcel to specifically identify Auction Revenue Rights for multi-value projects in Schedules 26 and 26A, including forecasted revenue. According to Xcel, this also includes MVP Auction Revenue Rights (MVP ARR).[33] Xcel's MISO Schedule 26/26A and MVP ARR calculations are provided in Attachment 14 of the Petition.

The Department concludes that Xcel specifically identified the MVP ARR amounts in Attachment 14 of the Petition.

6. OTHER WHOLESALE TRANSMISSION REVENUES (NON-RECB)

The Department notes that the bulk of Minnesota regulated electric utilities' transmission assets over 100 kilovolts are considered to be non-RECB projects for MISO purposes and are included in the utilities' base rates rather than a transmission rider. Similar to RECB charges that are reflected in MISO Schedules 26/26A, these non-RECB charges (wholesale transmission revenues and expenses) are reflected in MISO Schedule 9 revenues for the party that owns the transmission assets and in MISO Schedule 9 expenses for any party that uses the transmission assets (including the owner of the assets). As such, any wholesale transmission revenues and expenses (MISO Schedule 9 revenues and

[32] Xcel responses to Department IR Nos. 76 and 78. September 12, 2022. Department Attachment 2.
[33] Xcel's 2021-2022 TCR Rider Petition, at 16.

expenses) associated with these facilities are generally reflected in base rates. These MISO Schedule 9 charges are determined under each utility's open-access transmission tariff (OATT) approved by the Federal Energy Regulatory Commission (FERC).

While most of these costs and revenues are reflected in utilities' base rates, sometimes Minnesota rate-regulated utilities have non-RECB transmission projects that qualify for TCR Rider recovery. In those instances, the utility provides a net credit (commonly referred to at the OATT credit) in its TCR Rider to account for the amount of revenues it expects to receive from MISO for other utilities' use of the transmission asset. This net credit reflects the difference between what the utility pays MISO for using its own non-RECB transmission asset and what the utility receives from MISO for other utilities' use of the asset.

For example, if FERC determined that annual revenue requirements for a specific non-RECB project totaled $100 and Xcel were the owner, the $100 would be allocated and charged to all utilities located in Xcel's transmission pricing zone, based on their respective loads in that zone. If Xcel makes up approximately 80 percent of the load in its own transmission pricing zone, Xcel would be required to pay MISO $80 in Schedule 9 expenses (paying MISO for Xcel's use of its own facilities). The remaining $20 in MISO Schedule 9 expenses would be paid to MISO by the other utilities with load in Xcel's transmission pricing zone to reflect their reliance on Xcel's facilities. MISO would then pay Xcel the entire $100 in MISO Schedule 9 revenues for its ownership of the project. The difference between what Xcel pays and receives for its ownership of the non-RECB project is the $20 net OATT credit.

As shown in Attachment 12 of the Petition, Xcel calculated its net OATT credits in percentage terms for years 2019 – 2023. Xcel used these net OATT credit percentages to determine the dollar amount of the OATT credit reflected in the annual revenue requirement calculations shown in Attachment 13 of the Petition.

Department IR No. 77 requested that Xcel update Xcel's Annual OATT Credit Factor in Attachment 13 using actual information through July 31, 2022, for 2021, 2022, and 2023. Xcel's response to Department IR No. 77 indicated that the impact of this update will be reflected in the next TCR Filing when actuals and a new forecast will be provided.[34]

The Department agrees with this approach and concludes that Xcel's net OATT credit calculations appear reasonable and consistent with previous TCR filings.

7. FERC ISSUES

i. FERC Return on Equity Interest Adjustment

Xcel indicated that the FERC's 2019 and 2020 Orders on two ROE complain proceedings were on appeal at the D.C. Circuit Court, but that for the calculation of the 2021-2022 TCR revenue requirements, Xcel applied the currently authorized 10.52 percent MISO ROE, which includes an RTO adder of 50 basis

[34] Xcel response to Department IR No. 77. September 12, 2022. Department Attachment 2.

points, for 2022 activity.[35] Xcel indicated that future adjustments to the TCR Tracker may be necessary pending the appeals at the D.C. Circuit Court or any other FERC actions. Xcel committed to keeping the Commission informed of any additional outcomes in those proceedings.

Based on the above, the Department concludes that Xcel's filing appears consistent with the requirements established in previous TCR Rider Orders.

ii. FERC Transmission Audit Refund

Order Point 15 of the Commission's December 10, 2021 Order in Xcel's 2019-2020 TCR Rider required Xcel to explain precisely how the transmission audit refund required by FERC effects MISO Schedules 26 and 26A.

In Xcel's 2021-2022 TCR Rider petition, the Company explained that it had identified FERC audit revenues and expenses in 2021 in Attachment 14 of the Petition.

The Department reviewed Attachment 14 of the Petition and the Company's September 13, 2022 response to Department IR No. 1137 in the Company's multi-year rate plan (Docket No. E002/GR-21-630).[36] Xcel provided separate amounts for the FERC Audit Adjustment in Attachment 14,[37] and further explained in response to Department IR No. 1137 that the audit refund was issued in 2021 and not during the MYRP period for 2022-2024.[38]

The Department concludes that Xcel complied with Order Point 15.

8. RATE OF RETURN ON INVESTMENT

Minn. Stat. §216B.16, subd. 7b (2) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest.

In its 2019-2020 TCR Rider Order, the Commission required Xcel to use a 9.06 return on equity (ROE) for all proceedings until a new ROE has been established in Xcel's next rate case.

In the instant Petition, Xcel used the 9.06 ROE to calculate its annual revenue requirements. The Department concludes that Xcel's ROE is consistent with the Commission's 2019-2020 TCR Rider Order.

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[35] Xcel's 2021-2022 TCR Rider Petition, at 19-20.
[36] Xcel response to Department IR No. 1137. Docket No. E002/GR-21-630. September 13, 2022. Department Attachment 2.
[37] Xcel's 2021-2022 TCR Rider Petition, Attachment 14. See lines 3 (Sch 26 – NSPM FERC Audit Adjustment) and 6 (Sch 26(a) – NSPM FERC Audit Adjustment) for Revenue amounts, and lines 11 (Sch 26 – NSPM FERC Audit Adjustment) and 13 (Sch 26(a) – NSPM FERC Audit Adjustment) for Expense amounts. Note that there are figures for only 2019 – 2021, consistent with the Company's explanation in response to Department IR No. 1137.
[38] Xcel response to Department IR No. 1137. Docket No. E002/GR-21-630. September 13, 2022. Department Attachment 2.

9. INTERNAL CAPITALIZED LABOR

Consistent with the Commission's decisions in prior TCR proceedings, the Company removed internal capitalized labor costs in its revenue requirements calculations. The Department agrees with this approach.

10. PRORATED ACCUMULATED DEFERRED INCOME TAXES

Xcel stated the following on page 22 of its Petition regarding prorated accumulated deferred income taxes (ADIT):

> The Company calculated the 2022 revenue requirements using the alternative ADIT treatment discussed in our May 25, 2018 Supplemental Reply Comments in Docket No. E002/M-17-797, which conforms to our understanding of the proration formula in IRS regulation section 1.167(1)-1(h)(6). Under this treatment we have:
>
> 1. Treated each forecast month as a test period since the revenue requirements in riders are calculated monthly. This allows the monthly ADIT balance to be reset to its un-prorated beginning balance and only the monthly activity receives the proration.
> 2. Then applied a mid-month convention for the proration factors in each month.
> 3. Removed ADIT from the beginning-of-month and end-of-month rate base average, since the proration is itself a form of averaging. These treatments reduce the proration impact to the ratepayers in these rider mechanisms significantly.
>
> We believe that this treatment minimizes customer impact while still maintaining the significant deferred tax benefits provided to our customers. This treatment requires the ADIT prorate to be embedded in the rate base calculation rather than separated as a line item. However, we provide Attachment 16 to show how ADIT proration impacts the total revenue requirement for 2021 and 2022. Since we do not propose to implement the 2021-2022 adjustment factors until June 2022, the ADIT prorate is only included for June – December 2022.
>
> As can be seen from Attachment 16, the impact on customers of our proposed ADIT treatment is de minimis. The total impact of ADIT proration on the TCR Rider under this methodology is $208 of $104.5 million in total revenue requirements for the 2022 calendar year.

Overall the Department agrees with Xcel's approach for calculating prorated accumulated deferred income taxes.

11. ALLOCATION OF COSTS

Northern States Power Minnesota (NSPM) and Northern States Power Wisconsin (NSPW) operate as a single, integrated system, and therefore costs are initially calculated at the total system level. The allocation of costs from the total system level to the Minnesota jurisdictional customer groups is a three-step process. First, the Company allocates total system costs between NSPM and NSPW. Second, NSPM allocates its share of total system costs to each of its three state jurisdictions (Minnesota, North Dakota, and South Dakota). Third, the Company allocates its Minnesota jurisdictional costs among its customer classes.

To allocate total system costs between NSPM and NSPW, the Company uses a demand allocator which reflects the sharing of costs between NSPM and NSPW pursuant to its Interchange Agreement. Xcel stated that it used its budgeted Interchange Agreement allocators for 2021 and 2022.[39] Xcel stated that that any future over- or under-recovery due to the use of its budgeted allocators will be reflected in their next TCR Rider filing that will use actual allocators as they are available.

The Interchange Agreement demand allocator, reported on Attachment 12, line 21 of the Petition, is based on 36-month coincident peak demand. NSPM proposed to use allocation factors of 83.6786 percent, and 83.7474 percent, in 2021 and 2022, respectively. Xcel indicated the 2022 allocator is

83.6779 percent, but that it was approved on May 30, 2022 after the instant Petition was filed.[40] The Company's proposed cost allocation between NSPM and NSPW is consistent with the methodology used in previous TCR filings, and the Department concludes that it is reasonable.

To allocate NSPM's share of total system costs between NSPM's three state jurisdictions, the Company proposed to use demand allocators based on 12-month coincident peak demand, as shown in the Petition, Attachment 12, line 20. The allocator proposed, 87.3461 percent, is consistent with the jurisdictional allocator the Company proposed in its most recent rate case, Docket No. E002/GR-15-826 (the 2016 Rate Case), and is consistent with the allocator the Department used in its Direct Testimony in the 2016 Rate Case, which served as the basis for the settlement of that case. The Department concludes that the Company's proposed jurisdictional allocator is reasonable.

To allocate NSPM's Minnesota jurisdictional costs among the Company's various rate classes within the Minnesota jurisdiction, the Company used its D10S allocator from the 2016 Rate Case, which is based on the Company's system peak coincident with the MISO system peak. This approach is consistent with past practice, and the Department concludes that it is reasonable.

ii. Recovery from Minnesota Customer Classes and Applicable Recovery Rates

NSPM's Minnesota jurisdictional customer classes include Residential, Commercial Non-Demand, and Demand. The Company proposed to recover costs allocated to its Residential and Non-Demand

[39] Xcel's 2021-2022 TCR Rider Petition, at 20-21.
[40] Xcel response to Department IR No. 77. September 12, 2022. Department Attachment 2f.

customers on an energy-only basis (i.e. via a per kWh charge), and to recover costs allocated to its Demand customer class on a demand-only basis (i.e. via a per kW charge). This recovery method is consistent with the method used in prior TCR Rider filings; thus, the Department concludes that it is reasonable.

12. CONCLUSION

The Department recommends that the Commission approve recovery of the proposed transmission capital costs in this proceeding.

C. AUGUST 22 NOTICE – TOPIC #3

The third topic under the August 22 Notice of Comment Period is as follows:

- Are there other issues or concerns related to this matter?

The Department has not identified other issues nor has any other concerns related to this matter at this time.

III. DEPARTMENT RECOMMENDATIONS

The Department appreciates the opportunity to comment on the Commission's August 22, 2022 Notice of Comment period. The Department makes the following recommendations:

- **The Department recommends that the Commission adopt the recommendations made by Synapse regarding Xcel's AGIS-related cost recovery request.**

- **The Department recommends that the Commission approve recovery of the proposed transmission capital costs in this proceeding.**

The Department and Synapse are available for any questions that the Commission may have.

Comments on Xcel Energy's 2021-2022 TCR Rider Petition

In Response to the Notice of Comment in Docket Nos. E002/M-21-814 and E002/M-20-680

Prepared for Minnesota Department of Commerce

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CONTENTS

1. OVERVIEW

Synapse Energy Economics, Inc. (Synapse) submits these comments on behalf of the Minnesota Department of Commerce, Division of Energy Resources in response to the Minnesota Public Utilities Commission's (Commission) Notice of Comment (Notice) in Docket Nos. E-002/M-21-814 and E002/M-20-680 dated August 22, 2022. In this Notice, the Commission put forward three topics for respondents to address: the Company's compliance with filing requirements for its AGIS cost recovery requests; whether cost recovery for the proposed AGIS investments should be granted; and any other related issues. In these comments, Synapse responds to all three of these topics. We focus particularly on the proposals for cost recovery for AMI and FAN in the Company's TCR petition, and on broader process issues associated with current grid modernization practices and standards in Minnesota.

While Synapse finds that Xcel's cost recovery request is not fully compliant with the Commission's filing requirements, we nonetheless recommend that the Commission approve the AGIS-related components of Xcel Energy's 2021–2022 TCR revenue requirement and resulting adjustment factors.[1] These components include the AMI, FAN, LoadSEER, ADMS, and TOU Pilot investments and expenditures. However, we stress that the Commission should also establish robust consumer protective measures to ensure that the eventual investments yield the greatest benefits, at the lowest cost, for customers in Minnesota.

2. COMPLIANCE WITH COMMISSION FILING REQUIREMENTS

The first topic in the Notice of Comment concerns Xcel's compliance with the Commission's filing requirements for AGIS cost recovery requests, which are contained in two Orders:

- The Commission's July 23, 2020 Order in Docket No. E-002/M-19-666;
- The Commission's September 27, 2019 Order in Docket No. E-002/M-17-797.

Overall, Synapse finds that the Company has only partially satisfied the Commission's filing requirements. We review these requirements and then discuss key areas of compliance and non-compliance in the following sections.

[1] Separately, the Department is focusing its review on the transmission-related components of Xcel Energy's 2021–2022 TCR revenue requirements and resulting adjustment factors.

2.1. Overview of Commission's Filing Requirements

The Notice references two Orders that together set a robust standard for grid modernization information requirements. In the first Order, dated September 27, 2019 in Docket No. E-002/M-17-797 (First Order), the Commission established a comprehensive set of requirements for economic evaluation of grid modernization investments, including required information on the costs and benefits of these investments, plus details about investment scope, functionality, and alternatives. This Order also included a set of evaluation principles that future evaluations were meant to follow.

The second Order, dated July 23, 2020 in Docket E-002/M-19-666 (Second Order), expanded on the First Order with the requirements that Xcel's future AGIS cost recovery requests include "a discussion of the mechanisms that will be employed to maximize cost reductions and minimize cost increases," and "a demonstration that the utility has thoroughly considered the feasibility, costs, and benefits of alternatives, and that the proposed approach is preferable to alternatives." In addressing the need for comparison between alternatives, the Commission specifically instanced the need for Xcel to "compare different types of the same technology, for example, by comparing different AMI meters."

2.2. Past Evaluations of Completeness and Procedural Agreement

Synapse previously addressed the completeness of the Company's initial TCR filing in comments that were attached to the Department's filing in this docket, dated March 30, 2022. In its assessment of completeness for this earlier filing, Synapse applied its recommended filing requirements from its "Guidance Document," which was also included with that March 30, 2022 submission. In Synapse's view, these filing requirements represent a consolidation of the relevant parts of the aforementioned Commission Orders rather than any expansion in the scope of these original requirements.

Subsequently, the Company and Synapse entered into a voluntary engagement, established through a procedural agreement in this docket dated June 2, 2022, wherein the Company agreed to work with Synapse to remedy gaps in its proposal for AMI and FAN cost recovery. While the terms of this agreement committed the Company to attempting to bring its petition into compliance with the filing requirements per the Guidance Document, in so doing, the Company would necessarily bring its filing into compliance with the Commission's requirements.

The Company filed its supplemental petition for AMI and FAN cost recovery on August 17, 2022. In the sections that follow, we consider this updated filing in addressing the completeness of the Company's AMI and FAN proposals.

2.3. Filing Requirements that Have Been Satisfied

The Company has met some of the Commission's filing requirements for AGIS cost recovery requests. Key required items that the Company has provided include the following:

- A benefit-cost analysis[2]
- Technical and functional information about the proposed investments[3]
- Cost details about the proposed investments[4]
- Descriptions of both quantitative and qualitative benefits[5]

While the Supplement did not feature any major modifications to the Company's evaluation methods or its conclusions, the Company did shore up some informational deficiencies through the Supplement. Namely, the Supplement provided the following requirement information that had not been included in the earlier TCR petition:

- Details about bids received for alternative meters[6]
- Evaluation of sensitivities[7]

While Synapse commends the Company for engaging in the voluntary process to address information deficiencies, Synapse remains concerned about some lingering gaps in the Company's filing. We address these remaining deficiencies in the next section.

2.4. Filing Requirements that Have Not Been Satisfied

At the heart of any benefit-cost analysis is the comparison of alternatives. Without this comparison, there is little insight to be gleaned from benefit-cost analysis for the decision-making process. It is clear that the Commission shares this view, as it included a mandate in the Second Order specifically calling for grid modernization benefit-cost analyses to include comparisons across alternatives and demonstration that the proposed investments are superior:

> When Xcel makes any future cost recovery proposal, in addition to requirements from previous orders, it must include….a demonstration that the utility has thoroughly considered the feasibility, costs, and benefits of alternatives, and that the proposed approach is preferable to alternatives. In discussing the alternatives, Xcel should compare different types of the same technology, for example by *comparing different AMI meters* (emphasis added).[8]

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[2] Required by Order Point 9 from the First Order.

[3] Required by Order Point 9.A.1 from the First Order.

[4] Required by Order Point 9.A.3 and Order Point 9.B.2 from the First Order.

[5] Required by Order Point 9.B.2 from the First Order.

[6] Required by Order Point 9.A.2 from the First Order.

[7] Required by Order Point 9.B.2 from the First Order.

[8] Order Point 10.B from the Second Order.

This direction in the Second Order builds on the imperative in the First Order to compare proposed modernization solutions against traditional options.[9] In the First Order, the Commission also expressed the need for Xcel to evaluate options within the chosen portfolio of investment (i.e., through evaluating "bundles").[10]

Unfortunately, the Company has not sufficiently evaluated alternatives—neither in its initial filing, nor in its supplemental filing. In both cases, the Company simply compares its selected combination of AMI meter and FAN against an alternative, Automated Meter Reading (AMR) case. The failure of the Company to compare its chosen AMI solution against alternatives is particularly conspicuous in light of the Commission's specific reference to the need to compare "different AMI meters."

In Synapse's judgement, and in the interest of providing the Company with the benefit of the doubt, it appears that the Company did not remedy the lack of comparison across alternatives in its supplemental filing because it could not. The Company had already completed its decision-making, and assessing the benefits of alternatives not selected had become impracticable. This problem indicates a potential incongruity between the Company's approach to decision-making, and the Commission's requirements for benefit-cost analysis. In other words, at least in this case, it does not appear that the Company has rigorously and quantitatively accounted for the benefits of alternatives to its selected AMI and FAN solutions en route to making its choice.

In its supplemental filing, the Company addresses its approach to decision-making by stating, "[a]s a practical matter, it is not feasible to keep all options open through a complex procurement process such as was required for AMI and FAN. Instead, decisions are made along the way that impact what options are then subsequently available."[11] Synapse acknowledges that the utility's decision-making may be more complex and multifaceted; the utility may face a range of constraints, logistical and otherwise, which cannot be completely translated into the framework of benefit-cost analysis. However, in future filings, to comply with the First and Second Order, the Company must provide the Commission with the requisite comparison across alternatives. This will require the Company changing its decision-making process so that documenting alternatives at the stage of benefit-cost analysis is feasible and not simply a pro forma exercise in retrospective guessing.

In summary, in its application for cost recovery, the Company should have considered multiple alternatives to its proposed investments as required by the Commission. Merely comparing its selected pairing of AMI and FAN with a reference case does not suffice. Moreover, the Company should have included both options with Distributed Intelligence (DI) capabilities, as its proposed meters feature, and AMI alternatives without DI capabilities. Furthermore, to the extent that the Company included DI-enabled meters, the benefits and costs associated with utilizing this DI functionality should have been

[9] Order Point 9.B.2.d.i from the First Order.

[10] Order Point 9.B.2.d.x from the First Order and Order Point 9.B from the First Order.

[11] Xcel Supplement, at 31.

included in the benefit-cost analysis since this functionality is central to the value proposition for these meters. Not including this potential benefit stream suggests a lack of clarity about how this new functionality could be leveraged at the time of investment decision-making.

While the Company has reported a benefit-cost ratio for its joint AMI-FAN investments exceeding 1.0, this result does not signify that this particular set of investments is the optimal use of customer funds. Rather, the result only shows that the proposed AMI and FAN pairing are superior to the alternative of AMR. By considering multiple alternatives, the Company could come closer to justifying that its proposed investments are optimal.

3. Cost Recovery and Consumer Protections

The second question in the Notice concerns whether to grant cost recovery for the various AGIS investments included in the TCR rider petition. In this section, we provide overall recommendations about cost recovery, and then we address in detail two related issues with customer protection implications—performance tracking and cost caps.

3.1. Overall Cost Recovery Recommendations

Synapse recommends that the Commission approve the AGIS-related components of Xcel Energy's 2021–2022 TCR revenue requirement and resulting adjustment factors (AMI, FAN, LoadSEER, ADMS, and the TOU Pilot). In this section, we focus specifically on the requested approval for AMI and FAN. While Synapse does support cost recovery for AMI and FAN as requested by the Company, we recommend that this approval be made conditional on performance tracking and achievement of performance targets. The following sections provide more details on these conditions.

While Synapse did not find that Xcel had fully complied with the Commission's filing requirements, in our view, the balance of factors at play in the instant proceeding weighs in favor of allowing the Company to move ahead with the proposed AMI and FAN investments. Critically, the Company's existing stock of meters requires replacement, which diminishes somewhat the controversy associated with the Company's proposed investments since these investments are *somewhat* necessary. While the advanced functionality of the Company's selected solutions may be elective, the core functions of the investments (in metering and transmitting data) meet a clear need.

The Company's benefit-cost analysis for AMI and FAN provide some additional, if somewhat flimsy, support for these investments. The benefit-cost analysis yielded a benefit-cost ratio exceeding 1.0, which suggests that the proposed investments are superior to the alternative in AMR.

Taken together, these two factors—the need for meters and the benefit-cost ratio exceeding 1.0—provide moderate support for the proposed investments but leave open the question of whether an alternative solution might be better. We do not think that this ambiguity merits rejection of the

Company's proposal, all things considered, but we stress that the gaps in the Company's petition indicate a particular need for robust consumer protection measures.

3.2. Cost Recovery Should Be Partly Contingent on Utility Performance

Our recommendation that cost recovery be conditional on performance is based in part on our understanding of previous Commission Orders. In the Second Order, the Commission articulated a vision that connected performance, performance tracking, and cost recovery:

> Certification of the projects in ordering paragraph 7 [AMI and FAN] is made with the recognition, and acceptance from Xcel, that all future cost recovery will be based upon the Company accomplishing Commission-approved metrics and performance evaluations for the certified projects. Any future proposals for cost recovery of investments certified in this Order must be accompanied by a proposal for specific metrics and evaluation methods, and a detailed plan describing how the Company will maximize the benefits of the AGIS investments for ratepayers.[12]

On the basis of the Second Order, it is clear that the Commission envisions making cost recovery for AMI and FAN contingent on Company performance. In Synapse's view, the accountability that would result from making cost recovery conditional on achievement of performance targets would provide a key lever to "maximize the benefits of the AGIS investments for ratepayers."

3.3. Contingent Cost Recovery Mechanisms Should Be Treated Like Performance Incentive Mechanisms

While we stress the importance of making cost recovery contingent on performance, we also acknowledge that implementing new metrics and targets is not simple; determining how to correlate cost recovery and performance may be even more difficult. Another confounding factor is the lack of baseline performance data. While the Company has provided projections of anticipated benefits in its benefit-cost analysis that should inform future target-setting, these projections alone may not be adequate for setting targets.

To help structure the process of developing and deploying these new mechanisms that will effectuate contingent cost recovery, Synapse recommends that the Commission follow the general processes and principles that it established concerning performance incentive mechanisms (PIM) in Docket No. E-002/CI-17-401. While there are likely some distinctions between the PIMs contemplated in that Commission Investigation proceeding and the cost recovery mechanisms that would established here, there are also key similarities. (For simplicity, for the remainder of these comments, we will simply refer to these mechanisms for contingent cost recovery as PIMs.)

---

[12] Order Point 8 from the Second Order.

In its January 8, 2019 Order in Docket No. E-002/CI-17-401, the Commission endorsed the process for developing PIMs proposed by the Office of the Attorney General (OAG), which included separate stages for determining goals, determining outcomes, and establishing metrics. For present purposes, we do not believe it necessary to separate out these tasks. The key goals and outcomes associated with the AMI and FAN investments have already been identified by the Company in its petitions. However, we endorse a robust, participatory process for vetting the set of metrics to be developed. We also recommend that the development of metrics precede the development of performance targets and determination of potential financial penalties to be associated with these PIMs. We provide a more detailed set of recommendations for this staged approach to developing PIMs in the following section.

3.4. Recommendations for a Staged Approach to Contingent Cost Recovery

In this section, we provide recommendations for establishing metrics and PIMs. The recommended steps are divided into two categories. The first category covers the near-term actions that the Company and Commission can take to develop metrics and begin tracking performance. The second category covers later steps required to implement PIMs. We defer to the Commission to determine the appropriate venue for facilitating this process.

Near-Term Actions to Develop Metrics

Develop proposal for metrics and PIMs

Should the Company receive approval for AMI and FAN, it should next turn to developing a proposal for a set of metrics, which should include several mechanisms that will ultimately be converted to PIMs. We recommend that this proposal include approximately 15 metrics for AMI and FAN, with at least five of the metrics designated to become PIMs.

In its Supplement, Xcel states that it already fulfilled the requirement by proposing metrics in its November 24, 2021 TCR Rider Petition. However, we find that Xcel's proposed metrics do not adequately capture the full set of purported quantifiable outcomes of its investments in AMI and FAN.[13]

In its set of metrics, Xcel should include metrics related to deployment of AMI and FAN, costs, and customer satisfaction. In its set of PIMs, it should include measures of key benefits associated with AMI and FAN per the Company's benefit-cost analysis. Xcel should also include a PIM to gauge whether cost savings achieved through AMI and FAN are passed on as benefits to customers.

We recommend the Commission require that the Company provide this proposal by August 1, 2023, which is three months in advance of Xcel's next TCR Rider petition.

[13] Xcel Supplement, at 4.

Provide straw performance targets

While we acknowledge that it may be premature for the Company to *commit* to specific goals, we recommend that the Company be required to provide straw goals for each of the PIMs included in its proposal. These goals would be based upon projected benefits in the Company's benefit-cost analysis and any other pertinent information, and they would represent the Company's best estimate of achievable performance outcomes.[14]

Provide timelines

The Company should also specify in its proposal when it expects to be able to begin tracking performance for each of its proposed metrics. For the metrics designated to become PIMs, the Company should indicate when it expects to be able to establish a performance target.

Commission action to finalize reporting

Once the Company has provided its proposal for metrics and PIMs, the Commission can facilitate a process to finalize this set. During this process, other intervenors should be afforded the option to critique the Company's proposal and to make modifications or recommend entirely different proposals. Once the Commission has determined the final set of metrics, the Company should be required to immediately begin tracking performance to the extent practicable.

The Commission may wish to make the process of establishing the Company's required reporting for AMI and FAN a part of the TCR rider proceeding to commence in 2023, or alternatively, the Commission may elect to launch a separate proceeding to finalize reporting.

We recommend that the Commission establish as a requirement that the Company provide annual performance reporting. In the annual report, the Company should provide outcomes for all metrics for which performance tracking is feasible; for metrics for which performance may not yet be tracked, the Company should specify when it expects to be able to begin tracking performance. Eventually, PIMs performance could also be reported in the same filing.

Longer-Term Actions to Implement PIMs

Once the preliminary set of metrics has been established, the Commission can next turn to designing the PIMs for AMI and FAN. The PIM design process should cover the following:

[14] We note that in Docket No. E002/M-19-666, several parties recommended the Commission require Xcel to track and report on the savings it claims in its benefit-cost analysis. In response to these comments, Xcel stated that the issue of conditions on cost recovery and specific performance metrics should be addressed in in a cost-recovery proceeding, whether that be a TCR rider or general rate case. See Docket No. E002/M-19-666, Reply Comments of Xcel Energy, April 10, 2020, Attachment A, at 28.

i. Determination of the performance baselines for the PIMs: these baselines may reflect data collected since inception of the reporting regime, or the baselines may simply reflect the benefits projected in petition for AMI and FAN.

ii. Determination of PIM structure: whether these PIMs include dead-bands, how penalties will be structured, and other PIM design issues.[15]

iii. Determination of when PIMs will take effect, and, if relevant, when they will cease to be in effect.

iv. Determination of the penalty values to be associated with each PIM.

v. Determination of the specific mechanisms for effectuating a penalty on the Company.

In our opinion, these PIMs should be formulated on a penalty-only basis since the Company already has an incentive in achieving its return on capital investments. These PIMs will function to hold the Company accountable to the expected performance and benefits indicated by the Company in its petition for these investments.

Since it is the incremental costs of the Company's proposed AMI and FAN solution relative to the least-cost alternative that is at issue here, we suggest that the Commission cap the total penalty potential associated with these PIMs to either the value of the incremental costs of the proposed investments over the least-cost alternatives, or just the value of the *return* on these incremental costs.

While we anticipate that the process of developing and deploying these PIMs will be somewhat intensive, we expect that allowing for stakeholder participation will yield a more effective process. Ultimately, these PIMs should help to ensure that the Company delivers on the considerable promise of its AMI and FAN investments. Last, once the PIMs for Xcel's AMI and FAN investments are determined, the Commission may wish to eventually merge them with the PIMs established in Docket No. E-002/CI-17-401.

3.5. Cost Caps

In the Second Order, the Commission expressed its intention to apply cost caps to Xcel's future grid modernization investments, directing the Department of Commerce to file a report with recommendations on "specific metrics, detailed methods for evaluating performance, and consumer protections and other conditions, including cost caps, that should be applied to certified projects." On the basis of this language and with an eye to better integrating the certification and cost recovery

[15] Dead-bands refer to a range of performance outcomes around a performance target in which no incentive (positive or negative) is incurred. Dead-bands are included in PIMs to provide some allowance for "noise" and other non-significant variation in performance. For more detail on PIM design, see Whited, et al. "Utility Performance Incentive Mechanisms: a Handbook for Regulators." 2015. Prepared for the Western Interstate Energy Board. Accessed at: https://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

processes, Synapse recommended in the Guidance Document that cost caps be set based on the budgets provided at the certification stage.

Synapse recommends a different approach in this instance. Given the complex and protracted process that has led up to the instant request for cost recovery from the Company, and given the nascent state of practices surrounding performance measurement and consumer protections for grid modernization investments, we recommend that the Commission set a cost cap for AMI and FAN cost recovery based upon the cost information provided by the Company in its TCR petition. We recommend the Commission set a cost cap for AMI and FAN based upon the total budget, inclusive of capital investments and operations and maintenance expenses, which the Company reports to be $563.7 million for the period 2022–2026.[16] In the future, we recommend the Commission set cost caps based upon cost information provided by the Company at the certification stage.

Under our proposed approach, the Company would be required to seek Commission approval for any spending above its proposed budget including contingencies. This is consistent with the Second Order's imposition of a $4 million cost cap on the Advanced Planning Tool (APT)/LoadSEER project as well as the $9 million cost cap the Commission created in its July 26, 2022 Order for the Resilient Minneapolis Project in the Company's 2021 Integrated Distribution Plan (Docket No. E002/M-21-694). In those instances, the Commission created cost caps based on the total estimated budget of the project unless Xcel can show by clear and convincing evidence that the costs incurred were reasonable, prudent, and beyond its control.[17] We do understand that the constellation of current issues related to supply chain constraints and other inflationary pressures may create price increases that the Company cannot foresee. However, the Company must demonstrate good cause to support its request for an increase in budget and file this request to the Commission and any parties to this docket.

4. Other Recommendations

Synapse encourages the Commission to continue to seek improvements in the grid modernization proposal and review process. In our view, there are two distinct dimensions that the Commission might target for additional improvement: (1) grid modernization investment proposal filing requirements and compliance thereof, and (2) the phenomenon of piecemeal and staggered proposals across multiple proceedings.

Concerning grid modernization filing requirements and the Company's compliance with them, while we do understand that it would be difficult to remedy the major, structural issues in the Company's benefit-

[16] Xcel TCR Rider Petition, Attachment 4, at 55.

[17] Order Point 14 from the Second Order. See also Order Point 7 from the Commission's July 26, 2022 Order in Docket No. E002/M-21-694.

cost analysis for AMI and FAN at the current juncture, we encourage the Commission to be stringent with the Company going forward about its compliance.

We further recommend that the Commission incorporate some additional filing requirements to help ensure that necessary information is available in the review of new investment proposals. Specifically, Synapse recommends that the Commission expand on its existing filing requirements to require that every future grid modernization investment proposal include the following:

- A grid modernization road map with all planned and contemplated future grid modernization investments.[18]
- A complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs.
- A table containing all Commission grid modernization proposal filing requirements and specific references to where each requirement has been met within the filing.

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

While we recognize that the regulatory framework governing grid modernization proposal is complex, with multiple alternative cost recovery pathways, we nonetheless recommend that the Commission aim to rationalize this process. Specifically, we recommend that the Commission seek all opportunities to improve the efficiency of the grid modernization evaluation process by consolidating dockets in order to reduce fragmentation and enhance consistency across proposals.

[18] This is consistent with Order Point 9.A.1.d from the First Order.

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Xcel Energy		Information Request No.	1137
Docket No.:	E002/GR-21-630		
Response To:	Minnesota Department of Commerce		
Requestor:	Holly Soderbeck		
Date Received:	August 30, 2022		

Question:
Topic: Transmission Audit
Reference(s): Commission Order dated December 10, 2021, Docket No. E-002/M-19-721
Order Points 15 and 16 in Commission Order dated December 10, 2021 (Docket No. E-002/M-19-721) required, in part:

> In its next TCR Rider filing, Xcel shall explain precisely how the transmission audit refund required by the Federal Energy Regulatory Commission effects MISO Schedules 26 and 26A.
>
> In its next multi-year rate plan, Xcel shall explain precisely how the transmission audit refund required by the Federal Energy Regulatory Commission effects all other rate components.

Request:

A. For Xcel's most recent FERC transmission audit, please explain each audit finding and how each finding was addressed in Xcel's TCR Rider filing in Docket No. E-002/M-21-814 and in the current MYRP in Docket No. E-002/GR-21-630. Please show the resulting adjustments in Docket Nos. E002/M21-814 and E-002/GR-21-630.
B. If Xcel did not include the impacts of the most recent FERC transmission audit in Docket Nos. E002/M-21-814 and E-002/GR-21-630, please list each audit finding and calculate adjustments to implement FERC transmission audit findings in Docket Nos. E-002/M-21-814 and E-002/GR-21-630. Please explain how these adjustments reflect and make correction required by FERC transmission audit report.

Response:

A. Please see 21-0630 DOC-1137_Attachment A - FA17-5 Refund Report - As Filed, which summarizes the impact of the finding for each of the applicable MISO Attachments. Please note, this attachment did not include additional interest for 2020 which was included in the final refund amount. The table below details the earnings impact in 2021 along with the additional 2020 interest.

Impact of FERC Audit Refund on NSPM

	Audit Findings	+	Addition of 2020 Interest	=	2021 Refund
Impact on TCR - RECB					
Revenue - Increase / (Decrease)					**NSPM**
Sch 26 - NSPM FERC Audit Adjustment	(518,367)		(35,015)		(553,382)
Sch 26(a) - NSPM FERC Audit Adjustment	(475,526)		(31,909)		(507,435)
Total - Revenue	(993,893)		(66,923)		(1,060,817)
Expense - Increase / (Decrease)					
Sch 26 - NSPM FERC Audit Adjustment	186,819		12,619		199,439
Sch 26(a) - NSPM FERC Audit Adjustment	33,666		2,259		35,925
Total - Revenue	220,485		14,878		235,364
Margin Impact in RECB - Sch 26/26a					**(1,296,181)**
Impact to TCR Revenue Requiremet - Increase / (Decrease)					**1,296,181**
Earnings Impact of FERC Audit Refund in Sch 26/26a					-
Impact of Attachment O					
Revenue - Increase / (Decrease)					
Att O - Audit Adjustment*	(2,881,246)		(150,250)		**(3,031,496)**

*No impact to retail customers since reduction of revenue not part of rate case

The topic of the FERC audit refund was addressed in the current MYRP in Docket No. E-002/GR-21-630 in the Direct Testimony of Company witness Mr. Benjamin Halama, BCH-1 starting on page 139:

> In accordance with the Commission's recent hearing on the Company's Transmission Cost Recovery Rider adjustment in Docket No. E002/M-19-721, I address how the FERC Transmission Audit refund impacts all components other than Schedule 26/26A. The FERC audit resulted in refunds to NSP Transmission Formula Rate customers. The refunds were included in the 2019 annual true up and are currently being refunded as part of the 2021 transmission formula rate. These refunds would have resulted in an increased cost to retail customers; however, with no rate case filing for 2021 there is no impact on retail customers.

The topic of the FERC audit refund was addressed in the TCR Rider filing in Docket No. E-002/M-21-814, filed November 24, 2021, page 17, "In addition, we have identified the Federal Energy Regulatory Commission (FERC) audit revenues and expenses in 2021. See Attachment 14." The 2021 numbers from Attachment 14 in the TCR Rider filing has been included as part of this response, see 21-0630 DOC-1137_Attachment B.

B. As noted in response A, the RECB impacts were reflected in the TCR Rider filing and an adjustment was not required for the MYRP as the audit refund was issued in 2021 and not during the MYRP period for 2022-2024.

Witness:	Benjamin Halama
Preparer:	Christopher Franks
Title:	Principal Rate Analysis
Department:	Revenue Requirement North
Telephone:	612-337-2007
Date:	September 13, 2022

414 Nicollet Mall
Minneapolis, MN 55401

March 27, 2020

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

RE: Docket No. FA17-5-000
Refund Report of Northern States Power Company (Minnesota)

Dear Secretary Bose:

The Division of Audits and Accounting ("DAA") within the Office of Enforcement ("OE") of the Federal Energy Regulatory Commission (the "Commission") issued a letter order dated July 31, 2019 ("Letter Order") in the above-captioned docket. The Letter Order approved the Audit Report ("Audit Report") for the audit of the FERC Form 1 and Transmission Formula Rate of Northern States Power Company (Minnesota) ("NSPM"), a utility operating company subsidiary of Xcel Energy Inc. ("Xcel Energy"). The attached Refund Report summarizes the refunds being made in compliance with the Audit Report's Finding #1 (Recommendation #3), Finding #2 (Recommendation #10), and Finding #3 (Recommendation #14).

The Audit Report made six findings and recommended certain corrective actions. NSPM was directed to submit a Refund Analysis within 60 days of receipt of the Audit Report allowing for the DAA to assess the company's calculation of refunds. Refunds were required in response to three findings: Finding #1 – Income Tax Receivables; Finding #2 – Accounting for Prepayments; and Finding #3 – Accounting for Miscellaneous Expenses. A Refund Analysis was prepared and provided to the DAA on Sept. 30, 2019. On Jan. 30, 2020, the DAA indicated they had assessed NSPM's Refund Analysis and found it to be acceptable.

NSPM was directed to file a Refund Report with the Commission after receiving DAA's assessment of the Refund Analysis and to refund the amounts disclosed in the Refund Report to wholesale customers, with interest calculated in accordance with section 35.19a of the Commission's regulations, 18 C.F.R. § 35.19a (2019). As discussed in NSPM's Implementation Plan submitted Aug. 30, 2019, the refund, including interest, will be incorporated into the 2019 annual transmission formula rate true-up, which is calculated in mid-2020, and then included in MISO rates effective January 1, 2021. NSPM will continue to refund the $3,875,139, inclusive of $822,624 of interest, throughout the 2021 rate year. Interest was calculated and compounded quarterly using the Commission's quarterly interest rates in effect for each period from Jan. 1, 2013 through Dec. 31, 2019. NSPM will also continue to apply interest to the refund amount though 2020 pursuant to NSPM's Annual True-up, Information Exchange and Challenge Procedures set forth in Attachment O-NSP of the MISO Open Access Transmission Tariff.

Please contact Karen Everson (715-737-2417) with any questions or concerns regarding this Refund Report.

Sincerely,

/s/ Jeffrey S. Savage

Jeffrey S. Savage
Senior Vice President & Controller
Xcel Energy Services Inc., on behalf of
Northern States Power Company (Minnesota)

Attachments

cc: Greg Chamberlain, Regional Vice President, Rates & Regulatory, NSPM
Chris Haworth, Associate Vice President, Revenue Requirements
Frank Prager, Vice President, Policy & Federal Affairs/FERC Compliance Officer
Terri K. Eaton, Senior Director, Federal Regulatory Affairs
Mike Rodriguez, Senior Director, Utility Accounting
David E. Pettit, Assistant General Counsel

Docket Nos. E002/M-20-680 and E002/M-21-814
Department Attachment 2
Page 5 of 129

Docket No. FA17-5-000 **Attachment A**
Northern States Power Company (Minnesota) **Page 1 of 1**
Refund Report

	FY2013	FY2014	FY2015	FY2016	FY2017	Total Refund	Interest	Total Refund with Interest
Audit Findings:								
Finding 1: Income Tax Receivable								
Attachment O	($612,650)	$0	$0	$0	$0	($612,650)	($193,869)	($806,519)
Attachment GG	(75,978)	-	-	-	-	(75,978)	(24,043)	(100,021)
Attachment MM	(77,776)	-	-	-	-	(77,776)	(24,612)	(102,388)
	($766,404)	$0	$0	$0	$0	($766,404)	($242,523)	($1,008,927)
Finding 2: Accounting for Prepayments								
Prepaid Capital for Joint Ventures								
Attachment O	($438,099)	($394,411)	($271,392)	($136,769)	($61,518)	($1,302,188)	($346,343)	($1,648,531)
Attachment GG	(54,331)	(85,352)	(69,122)	(34,311)	(14,381)	(257,497)	(65,651)	(323,148)
Attachment MM	(55,617)	(82,005)	(57,035)	(26,309)	(11,574)	(232,540)	(60,329)	(292,870)
	($548,046)	($561,769)	($397,549)	($197,389)	($87,473)	($1,792,226)	($472,323)	($2,264,549)

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	FY2013	FY2014	FY2015	FY2016	FY2017	Total Refund	Interest	Total Refund with Interest
Insurance Premium Refunds								
Attachment O	($37,265)	($48,748)	($62,048)	($64,879)	($94,207)	($307,147)	($66,697)	($373,844)
Attachment GG	(4,621)	(10,549)	(15,803)	(16,275)	(22,023)	(69,272)	(14,584)	(83,856)
Attachment MM	(4,731)	(10,136)	(13,040)	(12,480)	(17,724)	(58,111)	(12,464)	(70,575)
	($46,617)	($69,433)	($90,891)	($93,634)	($133,954)	($434,529)	($93,746)	($528,275)
Miscellaneous Prepayments								
Attachment O	($5,648)	($9,396)	($7,722)	($6,530)	($1,884)	($31,180)	($7,728)	($38,908)
Attachment GG	(700)	(2,049)	(2,100)	(1,848)	(581)	(7,278)	(1,723)	(9,001)
Attachment MM	(717)	(1,969)	(1,734)	(1,418)	(469)	(6,307)	(1,520)	(7,827)
	($7,065)	($13,414)	($11,556)	($9,796)	($2,934)	($44,765)	($10,971)	($55,736)
Finding 3: Accounting for Miscellaneous Expenses								
Expenditures Related to Discriminatory Employment Practices								
Attachment O	($215)	($1,916)	$0	($8,977)	$0	($11,108)	($2,336)	($13,444)
Attachment GG	(18)	(288)	-	(1,634)	-	(1,940)	(402)	(2,342)
Attachment MM	(18)	(273)	-	(1,252)	-	(1,543)	(324)	(1,867)
	($252)	($2,477)	$0	($11,863)	$0	($14,591)	($3,061)	($17,652)
Summary By Recovery Method:								
Attachment O Total (1)	($1,093,876)	($454,472)	($341,162)	($217,155)	($157,608)	($2,264,273)	($616,973)	($2,881,246)
Attachment GG Total (2)	(135,649)	(98,238)	(87,025)	(54,068)	(36,985)	(411,965)	(106,402)	(518,367)
Attachment MM Total (3)	(138,859)	(94,383)	(71,809)	(41,459)	(29,768)	(376,277)	(99,249)	(475,526)
	($1,368,384)	($647,093)	($499,996)	($312,682)	($224,360)	($3,052,515)	($822,624)	($3,875,139)

(1) The total Attachment O refund with interest of $2,881,246 will be included in Line 6a of the Transmission Formula Template for Attachment O for the projected test period January 1, 2021 through December 31, 2021.

(2) The total Attachment GG refund with interest of $518,367 will be included in True-Up Adjustment section (Column 11) of the Transmission Formula Template for Attachment GG for the projected test period January 1, 2021 through December 31, 2021.

(3) The total Attachment MM refund with interest of $475,526 will be included in True-Up Adjustment section (Column 15) of the Transmission Formula Template for Attachment GG for the projected test period January 1, 2021 through December 31, 2021.

Document Content(s)

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Docket No. E002/M-21-____

Attachment 14

Line No:		Jan - 2021 Actual	Feb - 2021 Actual	Mar - 2021 Actual	Apr - 2021 Actual	May - 2021 Actual	Jun - 2021 Actual	Jul - 2021 Forecast	Aug - 2021 Forecast	Sep - 2021 Forecast	Oct - 2021 Forecast	Nov - 2021 Forecast	Dec - 2021 Forecast	2021 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,972,057	4,364,568	3,606,957	5,248,824	5,251,540	5,902,168	6,435,889	6,198,821	5,499,630	4,776,499	4,608,070	4,879,780	62,744,801
3	Sch 26 - NSPM FERC Audit Adjustment	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(553,382)
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	135,701	122,722	122,722	125,298	107,836	122,749	124,056	124,056	124,056	124,056	124,056	124,056	1,481,362
5	Schedule 26(a)	7,634,901	5,773,733	5,964,980	5,208,179	5,059,226	6,632,124	8,197,975	7,600,887	6,257,490	6,411,306	6,706,205	7,022,098	78,469,103
6	Sch 26(a) - NSPM FERC Audit Adjustment	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(507,435)
7	**Total Revenue**	13,654,257	10,172,622	9,606,258	10,493,898	10,330,201	12,568,640	14,669,517	13,835,362	11,792,774	11,223,458	11,349,929	11,937,532	141,634,449
8														
9	**Expense**													
10	Schedule 26	5,537,318	4,851,002	4,782,241	4,488,649	5,762,858	7,484,759	7,785,520	7,289,041	6,147,398	4,748,120	4,705,074	5,332,050	68,914,030
11	Sch 26 - NSPM FERC Audit Adjustment	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	199,439
12	Schedule 26(a)	6,012,998	5,295,334	5,197,510	4,586,113	4,642,459	6,299,824	6,845,173	6,343,810	5,215,787	5,344,943	5,592,564	5,857,813	67,234,327
13	Sch 26(a) - NSPM FERC Audit Adjustment	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	35,925
14	Sch 26(a) - RT MVP DIST	(33,879)	(33,896)	(25,880)	(27,026)	(26,300)	(5,702)	(7,451)	(7,438)	(9,109)	(9,062)	(9,215)	(20,185)	(215,143)
15	**Total Expense**	11,536,051	10,132,053	9,973,485	9,067,349	10,398,631	13,798,494	14,642,855	13,645,027	11,373,690	10,103,615	10,308,036	11,189,291	136,168,578
16														
17	**Net Revenue/Expense**	(2,118,206)	(40,569)	367,227	(1,426,549)	68,431	1,229,854	(26,662)	(190,335)	(419,084)	(1,119,843)	(1,041,893)	(748,241)	(5,465,871)
18	Demand Allocator - State of MN Jur	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%
19	**Net RECB Revenue Requirements**	**(1,548,197)**	**(29,652)**	**268,406**	**(1,042,665)**	**50,016**	**898,900**	**(19,488)**	**(139,116)**	**(306,308)**	**(818,493)**	**(761,519)**	**(546,889)**	**(3,995,005)**

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Xcel Energy		Information Request No. 73
Docket No.:	E002/M-21-814	REVISED
Response To:	Minnesota Department of Commerce	
Requestor:	Nancy Campbell and Matt Landi	
Date Received:	September 2, 2022	

<u>Question:</u>
Topic: Huntley-Wilmarth transmission project
Reference(s): Chamberlain Direct, pages 23-24

Request:

A. Xcel forecasted Huntley-Wilmarth transmission project to be in-service in December 2021. What was the actual in-service date for Huntley-Wilmarth transmission project? If the actual in-service date was different than the forecasted in-service date, please recalculate the impact on rate base, depreciation expense, taxes, and any other rate impact, and provide the overall revenue requirement impact.
B. Please provide the actual final cost of Huntley-Wilmarth transmission project and show how that compares to the $140.1 million Certificate of Need costs in 2016 dollars and $155.8 million in escalated dollars ($77.9 million for 50 percent ownership share). Please include calculations to support the $155.8 million in escalated dollars. Please provide support for any cost overrun amounts.
C. Please provide the forecasted and actual MISO charges (including but not limited to MISO Schedules 26, 26A, 37 and 38) for Huntley-Wilmarth transmission project through both July 31, 2022

<u>Response:</u>

A. At the time of our Petition, the forecasted in-service date for the Huntley-Wilmarth transmission project was December 2021; however, the project was placed in-service in November 2021. As discussed with DOC Staff, the impact of this one month change in the in-service date will be reflected in the next TCR filing when actuals for 2021 are trued-up.

B. In its August 5, 2019 Order in Docket No. E002/M-17-184, the Commission approved a 345 kV transmission line route and expansion of the Wilmarth and

Huntley substations. The combined cost was estimated at $140.1 million (2016$) and $155.8 million (escalated or actual dollars.)

The final cost for the project is as follows, in actual dollars:

	Total	Xcel Energy Share	ITCM Share
Transmission Line and Right of Way	$105,495,598	$52,747799	$52,747,799
Wilmarth Substation Expansion	$3,441,939	$3,441,939	
Huntley Substation Expansion	$2,451,000		$2,451,000
Total	**$111,388,537**	**$56,189,738**	**$55,198,799**

At the time of our initial TCR filing, as discussed beginning on page 23 of the Petition, the Company was forecasting "an approximate reduction in total capital costs of 22 percent or $15.8 million, excluding internal labor, for the Huntley–Wilmarth project. This reduction is primarily related to an overall reduction in Company overhead costs to the project. Forecasted estimates were originally based on 2017 estimates; however, the realized actual cost of these overhead rates during the construction of the project are significantly less than estimated. Additionally, we reduced the budget for the remainder of the construction schedule as we experienced savings in contractor bids, route alignment adjustments during the permitting process that reduced costs, and efficient outage coordination. Finally, the reduction can also be attributed to overall construction savings in easement costs, actual materials cost, strategic competitive contractor bidding, and construction oversight."

We also noted in the Petition that "in the Certificate of Need (CON) proceeding, we showed project costs in both 2016 dollars and escalated dollars. The CON Order notes a final project cost of $140.1 million in 2016 dollars, which equates to $155.8 million in escalated dollars. Since the Company's share of the Huntley–Wilmarth project is 50 percent, the final cost benchmark for the purposes of TCR cost recovery is $77.9 million. The Company's current forecast is significantly less than this amount."

C. The impact of updated actuals is reflected in our responses to IRs DOC-076, Attachment A and DOC-078 in this docket.

<u>Revised Response:</u>
Since submitting our response to this information request, we discovered a reporting error impacting the Huntley Wilmarth project. Project costs were correctly accounted

for in our systems; this error impacted only the reporting accessed for the response to this IR. We provide the corrected Huntley Wilmarth costs in redline below.

	Total	Xcel Energy Share	ITCM Share
Transmission Line and Right of Way	~~$105,495,598~~ $111,157,389	~~$52,747799~~ $55,578,695	~~$52,747,799~~ $55,578,695
Wilmarth Substation Expansion	$3,441,939	$3,441,939	
Huntley Substation Expansion	$2,451,000		$2,451,000
Total	**~~$111,388,537~~ $117,050,328**	**~~$56,189,738~~ $59,020,634**	**~~$55,198,799~~ $58,029,695**

With this revision, the project was still completed well under both the escalated and non-escalated cost estimates.

Preparer:	Christopher Franks	Grant Stevenson
Title:	Principal Rate Analyst	Project Manager
Department:	Revenue Requirement North	Transmission Project
Telephone:	612-337-2007	612-330-6330
Date:	September 12, 2022	REVISED: October 5, 2022

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Xcel Energy		Information Request No. 74
Docket No.:	E002/M-21-814	
Response To:	Minnesota Department of Commerce	
Requestor:	Nancy Campbell and Matt Landi	
Date Received:	September 2, 2022	

Question:
Topic: Revenue Requirement for 21-630 & TCR Rider
Reference(s): Page 2 of Xcel's Petition

A. Starting with Xcel's forecasted 2023 TCR Rider revenue requirements for 2023, please show a breakout of projects 1) that will remain in the TCR Rider, and 2) that will be rolled into the rate case in Docket No. E002/GR-21-630 assuming an 8/31/23 roll in date, and for each project provide the revenue requirement impact.

Response:
A. Please see Attachment A to this response.

Preparer:	Christopher Franks
Title:	Principal Rate Analyst
Department:	Revenue Requirements North
Telephone:	612-337-2007
Date:	September 12, 2022

Docket No. E002/M-21-814
DOC IR No. 74
Attachment A - Page 1 of 2

Monthly Revenue Requirement Filing Summary

Line #		Jan - 2023 Forecast	Feb - 2023 Forecast	Mar - 2023 Forecast	Apr - 2023 Forecast	May - 2023 Forecast	Jun - 2023 Forecast	Jul - 2023 Forecast	Aug - 2023 Forecast	Sep - 2023 Forecast	Oct - 2023 Forecast	Nov - 2023 Forecast	Dec - 2023 Forecast	2023 Forecast
		2023 Monthly Details with Rider Roll-in												
1	AGIS - ADMS	502,225	500,568	498,923	497,400	496,022	494,632	493,254	492,377	492,000	491,636	491,094	490,758	5,940,888
2	AGIS - AMI	2,275,418	2,397,402	2,535,619	2,665,007	2,775,988	2,885,083	2,995,519	3,105,668	3,213,943	3,323,559	3,418,384	3,509,901	35,101,489
3	AGIS - FAN	231,686	238,005	242,943	248,555	254,573	260,859	267,159	273,123	279,060	286,712	294,665	308,612	3,185,952
4	AGIS - LoadSeer	53,707	53,419	53,132	52,844	52,557	52,269	51,982	51,694	51,407	51,120	50,832	50,545	625,508
5	AGIS - TOU Pilot	56,504	56,348	56,192	56,036	55,880	55,724	55,569	55,413	55,257	55,101	54,945	54,789	667,758
6	Big Stone-Brookings	308,293	307,765	307,237	306,709	306,181	305,652	305,124	304,596	-	-	-	-	2,451,557
7	CAPX2020 - Brookings	2,521,086	2,516,483	2,511,891	2,507,288	2,502,696	2,498,093	2,493,501	2,488,904	-	-	-	-	20,039,941
8	CAPX2020 - Fargo	1,114,705	1,112,263	1,109,832	1,107,390	1,104,958	1,102,516	1,100,085	1,097,648	-	-	-	-	8,849,397
9	CAPX2020 - La Crosse Local	325,062	324,421	323,781	323,139	322,499	321,858	321,218	320,577	-	-	-	-	2,582,554
10	CAPX2020 - La Crosse MISO	412,368	411,613	410,859	410,104	409,350	408,595	407,841	407,087	-	-	-	-	3,277,818
11	CAPX2020 - La Crosse MISO - WI	757,195	755,552	753,911	752,268	750,626	748,984	747,342	745,700	-	-	-	-	6,011,578
12	Huntley - Wilmarth	401,850	400,901	399,965	399,015	398,079	397,130	396,194	395,251	-	-	-	-	3,188,385
13	LaCrosse - Madison	1,136,754	1,134,435	1,132,136	1,129,816	1,127,517	1,125,197	1,122,898	1,120,588	-	-	-	-	9,029,341
14	**Projects**	10,096,854	10,209,175	10,336,419	10,455,571	10,556,926	10,656,592	10,757,684	10,858,625	4,091,667	4,208,127	4,309,921	4,414,605	100,952,166
15	MISO RECB Sch.26/26a	(1,334,217)	(1,284,564)	(1,000,131)	(896,263)	(916,490)	(428,821)	(403,566)	(542,700)	(728,975)	(1,211,233)	(1,151,817)	(959,819)	(10,858,596)
16	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	
17	TCR True-up Carryover	7,956,886												7,956,886
18	**Revenue Requirement (RR)**	**16,719,523**	**8,924,611**	**9,336,288**	**9,559,308**	**9,640,436**	**10,227,771**	**10,354,118**	**10,315,925**	**3,362,693**	**2,996,894**	**3,158,104**	**3,454,786**	**98,050,456**
19	**Revenue Collections (RC)**	9,318,460	7,825,489	8,734,339	7,512,998	8,062,126	9,211,114	10,690,999	10,363,021	8,420,800	8,102,118	8,039,313	9,005,670	105,286,448
20	Monthly RR - RC	7,401,063	1,099,122	601,949	2,046,309	1,578,310	1,016,657	(336,881)	(47,095)	(5,058,108)	(5,105,225)	(4,881,209)	(5,550,884)	
21	Balance (RR - RC + Cumulative CC)	7,401,063	8,500,185	9,102,135	11,148,444	12,726,754	13,743,411	13,406,530	13,359,434	8,301,326	3,196,102	(1,685,108)	(7,235,991)	(7,235,991)
22														
23														
24		**2023 Monthly Details - As Filed**												
25	AGIS - ADMS	502,225	500,568	498,923	497,400	496,022	494,632	493,254	492,377	492,000	491,636	491,094	490,758	5,940,888
26	AGIS - AMI	2,275,418	2,397,402	2,535,619	2,665,007	2,775,988	2,885,083	2,995,519	3,105,668	3,213,943	3,323,559	3,418,384	3,509,901	35,101,489
27	AGIS - FAN	231,686	238,005	242,943	248,555	254,573	260,859	267,159	273,123	279,060	286,712	294,665	308,612	3,185,952
28	AGIS - LoadSeer	53,707	53,419	53,132	52,844	52,557	52,269	51,982	51,694	51,407	51,120	50,832	50,545	625,508
29	AGIS - TOU Pilot	56,504	56,348	56,192	56,036	55,880	55,724	55,569	55,413	55,257	55,101	54,945	54,789	667,758
30	Big Stone-Brookings	308,293	307,765	307,237	306,709	306,181	305,652	305,124	304,596	304,068	303,540	303,011	302,483	3,664,659
31	CAPX2020 - Brookings	2,521,086	2,516,483	2,511,891	2,507,288	2,502,696	2,498,093	2,493,501	2,488,904	2,484,301	2,479,709	2,475,106	2,470,514	29,949,570
32	CAPX2020 - Fargo	1,114,705	1,112,263	1,109,832	1,107,390	1,104,958	1,102,516	1,100,085	1,097,648	1,095,206	1,092,774	1,090,332	1,087,900	13,215,609
33	CAPX2020 - La Crosse Local	325,062	324,421	323,781	323,139	322,499	321,858	321,218	320,577	319,935	319,295	318,654	318,014	3,858,452
34	CAPX2020 - La Crosse MISO	412,368	411,613	410,859	410,104	409,350	408,595	407,841	407,087	406,331	405,578	404,822	404,069	4,898,618
35	CAPX2020 - La Crosse MISO - WI	757,195	755,552	753,911	752,268	750,626	748,984	747,342	745,700	744,057	742,415	740,772	739,131	8,977,953
36	Huntley - Wilmarth	401,850	400,901	399,965	399,015	398,079	397,130	396,194	395,251	394,302	393,366	392,416	391,480	4,759,949
37	LaCrosse - Madison	1,136,754	1,134,435	1,132,136	1,129,816	1,127,517	1,125,197	1,122,898	1,120,588	1,118,269	1,115,969	1,113,650	1,111,350	13,488,580
38	**Projects**	10,096,854	10,209,175	10,336,419	10,455,571	10,556,926	10,656,592	10,757,684	10,858,625	10,958,135	11,060,773	11,148,684	11,239,547	128,334,985
39	MISO RECB Sch.26/26a	(1,334,217)	(1,284,564)	(1,000,131)	(896,263)	(916,490)	(428,821)	(403,566)	(542,700)	(728,975)	(1,211,233)	(1,151,817)	(959,819)	(10,858,596)
40	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
41	TCR True-up Carryover	7,956,886												7,956,886
42	**Revenue Requirement (RR)**	**16,719,523**	**8,924,611**	**9,336,288**	**9,559,308**	**9,640,436**	**10,227,771**	**10,354,118**	**10,315,925**	**10,229,160**	**9,849,540**	**9,996,867**	**10,279,728**	**125,433,275**
43	**Revenue Collections (RC)**	9,318,460	7,825,489	8,734,339	7,512,998	8,062,126	9,211,114	10,690,999	10,363,021	8,420,800	8,102,118	8,039,313	9,005,670	105,286,448
44	Monthly RR - RC	7,401,063	1,099,122	601,949	2,046,309	1,578,310	1,016,657	(336,881)	(47,095)	1,808,360	1,747,421	1,957,554	1,274,058	
45	Balance (RR - RC + Cumulative CC)	7,401,063	8,500,185	9,102,135	11,148,444	12,726,754	13,743,411	13,406,530	13,359,434	15,167,794	16,915,215	18,872,770	20,146,828	20,146,828

46														
47														
48		**Delta**												
49	AGIS - ADMS	-	-	-	-	-	-	-	-	-	-	-	-	-
50	AGIS - AMI	-	-	-	-	-	-	-	-	-	-	-	-	-
51	AGIS - FAN	-	-	-	-	-	-	-	-	-	-	-	-	-
52	AGIS - LoadSeer	-	-	-	-	-	-	-	-	-	-	-	-	-
53	AGIS - TOU Pilot	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Big Stone-Brookings	-	-	-	-	-	-	-	-	(304,068)	(303,540)	(303,011)	(302,483)	(1,213,102)
55	CAPX2020 - Brookings	-	-	-	-	-	-	-	-	(2,484,301)	(2,479,709)	(2,475,106)	(2,470,514)	(9,909,629)
56	CAPX2020 - Fargo	-	-	-	-	-	-	-	-	(1,095,206)	(1,092,774)	(1,090,332)	(1,087,900)	(4,366,212)
57	CAPX2020 - La Crosse Local	-	-	-	-	-	-	-	-	(319,935)	(319,295)	(318,654)	(318,014)	(1,275,898)
58	CAPX2020 - La Crosse MISO	-	-	-	-	-	-	-	-	(406,331)	(405,578)	(404,822)	(404,069)	(1,620,800)
59	CAPX2020 - La Crosse MISO - WI	-	-	-	-	-	-	-	-	(744,057)	(742,415)	(740,772)	(739,131)	(2,966,375)
60	Huntley - Wilmarth	-	-	-	-	-	-	-	-	(394,302)	(393,366)	(392,416)	(391,480)	(1,571,564)
61	LaCrosse - Madison	-	-	-	-	-	-	-	-	(1,118,269)	(1,115,969)	(1,113,650)	(1,111,350)	(4,459,239)
62	**Projects**	-	-	-	-	-	-	-	-	(6,866,468)	(6,852,646)	(6,838,763)	(6,824,942)	(27,382,819)
63	MISO RECB Sch.26/26a	-	-	-	-	-	-	-	-	-	-	-	-	-
64	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
65	TCR True-up Carryover	-	-	-	-	-	-	-	-	-	-	-	-	-
66	**Revenue Requirement (RR)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(6,866,468)**	**(6,852,646)**	**(6,838,763)**	**(6,824,942)**	**(27,382,819)**
67	**Revenue Collections (RC)**	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Monthly RR - RC	-	-	-	-	-	-	-	-	(6,866,468)	(6,852,646)	(6,838,763)	(6,824,942)	-
69	Balance (RR - RC + Cumulative CC)	-	-	-	-	-	-	-	-	(6,866,468)	(13,719,114)	(20,557,877)	(27,382,819)	(27,382,819)

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Xcel Energy		Information Request No. 75
Docket No.:	E002/M-21-814	
Response To:	Minnesota Department of Commerce	
Requestor:	Nancy Campbell and Matt Landi	
Date Received:	September 2, 2022	

Question:
Topic: Updated Attachments
Reference(s): Attachments 8 and 9, Revenue Requirements

Request:

A. Please update Attachments 8 and 9 revenue requirements with actuals through July 31, 2022. Please provide a table comparing Attachments 8 and 9 forecasted revenue requirements as filed by Xcel, with actuals through July 31, 2022 (resulting in actuals for 2021, actuals through July 31, 2022 and forecasted for the rest of 2022, and forecasted for 2023) and explain any differences between 1) forecasted revenue requirement by Xcel and 2) actual/forecasted revenue requirements requested by the Department, of 5 percent or more.
B. On Attachment 8, please provide support documentation, contracts, etc. that support the AGIS AMI costs of $4.6 million for 2021, $15.7 million for 2022, and $35.1 million for 2023.
C. Does Xcel receive any benefits/revenues (including non-regulated) that were not included in the AMI and FAN cost/benefit analysis in Xcel's Attachment 4? If yes, please list these benefits/revenues and explain why they are not passed back to ratepayers.
D. For Part (A) please show how you removed all Prorated ADIT through July 31, 2022 since amounts are now actual and not forecasted amounts. Please show all Prorated ADIT amounts that remain in forecasted TCR Rider Factors.

Response:

A. As discussed with DOC Staff, the impact of updated actuals will be reflected in the next TCR filing. However, the impact of updates on amounts billed to customers and RECB actuals through July 31, 2022 are addressed separately in our responses to IRs DOC-076 and DOC-078 in this docket.

B. The AMI costs of $4.6 million for 2021, $15.7 million for 2022, and $35.1 million for 2023 shown in Attachment 8 are the revenue requirement for those years based on the forecasted capital costs shown in Attachment 7A. Attachment 15 supports the derivation of the revenue requirement by breaking out the components that make up the revenue requirement for each project, including AMI. Support for the forecasted AMI capital costs shown in Attachment 7A is provided in Attachment 4. As described in Attachment 4 beginning at page 47, meter-related AMI cost estimate assumptions are as follows:

- *AMI meter cost* - Based on blended weighted average cost across multiple residential and commercial type meters plus estimates for taxes and overheads for items such as minor materials e.g. rings, seals, etc.
- *AMI meter installation costs* are based on a weighted blended average cost across multiple residential and commercial type meters plus overheads.
    - We estimate the meter install vendor (MIV) will install approximately 97 percent of AMI meters and 3 percent would be installed by internal employees or a non-MIV contractor. We further estimate the 3 percent of exchanges would cost twice as much as the cost of the MIV to account for possible return to utility (RTU) jobs and higher costs for non-MIV resources completing the work.
- Costs for *vendor project management* were based on total costs provided by the meter vendor as per the contract. These costs are spread out across the deployment years.
- *AMI operations* (internal and external labor) labor costs were developed based on role and number of personnel required to perform tasks to enable installation and deployment of AMI meters. The necessary positions include but are not limited to project managers, engineers, analysts, field deployment supervisors, office contractors, schedulers, etc.
- Estimates for *Lab equipment* were based on quotes obtained and purchases made from our existing vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and we leveraged our relationships with our existing vendors to obtain the best cost.
- Estimates for *small claims* were developed based on input from industry peers.

The AMI project team also estimated additional costs for repairs that would be required to be performed by the Company to support safe installation of the AMI meters. These are repairs that are ordinarily performed by the Company (e.g., repair of stressed or tight wires at the service) on an as-needed basis.

C. No, the Company does not receive nor anticipate monetary benefits/revenues from AMI and FAN that are not reflected in the cost-benefit analysis. See also our response to DOC-035, which explains that any reductions in business area budgets resulting from AMI/FAN benefits would be reflected as part of a rate case outcome.

D. As noted on page 22 of our initial Petition and as shown in Attachment 16, ADIT was prorated only for the months of June through December 2022 because we proposed an implementation date of June 1, 2022 for the 2022 TCR Rider rate. The total 2022 ADIT proration for those months is $208 out of the requested $104.5 million revenue requirement. We expect implementation of the TCR rate to occur after 2022 has concluded. Therefore, as discussed with DOC Staff, removal of ADIT proration will be reflected in the next TCR filing when actuals and a new forecast are updated. The removal of the *de minimus* ADIT proration of $208 in 2022 will not change the rate.

Preparer:	Karin Haas	Christopher Franks
Title:	Regulatory Policy Specialist	Principal Rate Analyst
Department:	Regulatory Affairs	Revenue Requirements North
Telephone:	612-321-3116	612-337-2007
Date:	September 12, 2022	

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☐ **Public Document – Not Public Data Has Been Excised**
☒ **Public Document**

Xcel Energy		Information Request No. 76
Docket No.:	E002/M-21-814	
Response To:	Minnesota Department of Commerce	
Requestor:	Nancy Campbell and Matt Landi	
Date Received:	September 2, 2022	

Question:
Topic: Updated Attachments
Reference(s): Attachments 10 and 11, Forecasted Revenues and TCR Rider Factors

Request:

A. Please updated Attachment 10 forecasted revenues by customer class through July 31, 2022. Please provide a table comparing Attachment 10 forecasted revenues filed by Xcel, with actuals through July 31, 2022 (resulting in actuals for 2021, actuals through July 31, 2022 and forecasted for the rest of 2022, and forecasted for 2023) and explain any differences between 1) forecasted revenues by Xcel and 2) actual/forecasted revenues requested by the Department, of 5 percent or more.
B. Please updated Attachment 11 TCR Rider Factor by customer class through July 31, 2022. Please provide a table comparing Attachment 11 forecasted TCR Rider Factors filed by Xcel, with actuals through July 31, 2022 (resulting in actuals for 2021, actuals through July 31, 2022 and forecasted for the rest of 2022, and forecasted for 2023) and explain any differences between 1) forecasted TCR Rider Factors by Xcel and 2) actual/forecasted TCR Rider Factors requested by the Department, of 5 percent or more.
C. For Parts (A and B) please show how you removed all Prorated ADIT through July 31, 2022 since amounts are now actual and not forecasted amounts. Please include all Prorated ADIT amounts that remain in forecasted TCR Rider Factors.

Response:

A. Please see our response to IR DOC-076 Attachment A which reflects updated actual billings to customers through July 31, 2022. This attachment also incorporates the impact of updating RECB actuals through July 31, 2022 which was in response to IR DOC-078.

B. Please see our response to IR DOC-076 Attachment A. Since the original filing reflected new rates starting June 2022 which has now passed, a new starting date for new rates is assumed to be January 1, 2023.

C. As noted on page 22 of our initial Petition and as shown in Attachment 16, ADIT was prorated only for the months of June through December 2022 because we proposed an implementation date of June 1, 2022 for the 2022 TCR Rider rate. The total 2022 ADIT proration for those months is $208 out of the requested $104.5 million revenue requirement. We expect implementation of the TCR rate to occur after 2022 has concluded. Therefore, as discussed with DOC Staff, removal of ADIT proration will be reflected in the next TCR filing when actuals and a new forecast are updated. The removal of the *de minimus* ADIT proration of $208 in 2022 will not change the rate.

Preparer:	Christopher Franks
Title:	Principal Rate Analyst
Department:	Revenue Requirements North
Telephone:	612-337-2007
Date:	September 12, 2022

Docket No. E002/M-21-814
DOC IR No. 76
Attachment A - Att 8 Annual RR

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Annual Revenue Requirements

		Rev Requirement w updated Revenue Collection & RECB					Original TCR Filing					DELTA after Updated Revenue Collection & RECB				
	Amounts in dollars	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
Line No:		Actual	Actual	Mixed	Forecast	Forecast	Actual	Actual	Mixed	Forecast	Forecast	Actual	Actual	Mixed	Forecast	Forecast
1	AGIS - ADMS	1,979,777	2,799,047	5,185,468	5,895,245	5,940,888	1,979,777	2,799,047	5,185,468	5,895,245	5,940,888	-	-	-	-	-
2	AGIS - AMI	-	1,210,039	4,639,342	15,708,542	35,101,489	-	1,210,039	4,639,342	15,708,542	35,101,489	-	-	-	-	-
3	AGIS - FAN	-	234,981	1,239,549	1,925,235	3,185,952	-	234,981	1,239,549	1,925,235	3,185,952	-	-	-	-	-
4	AGIS - LoadSeer	-	230,108	740,129	672,353	625,508	-	230,108	740,129	672,353	625,508	-	-	-	-	-
5	AGIS - TOU Pilot	-	-	-	699,701	667,758	-	-	-	699,701	667,758	-	-	-	-	-
6	Big Stone-Brookings	4,095,135	3,973,954	3,850,967	3,752,627	3,664,659	4,095,135	3,973,954	3,850,967	3,752,627	3,664,659	-	-	-	-	-
7	CAPX2020 - Brookings	32,887,354	32,127,705	31,300,336	30,662,824	29,949,570	32,887,354	32,127,705	31,300,336	30,662,824	29,949,570	-	-	-	-	-
8	CAPX2020 - Fargo	14,818,201	14,355,718	13,929,370	13,589,185	13,215,609	14,818,201	14,355,718	13,929,370	13,589,185	13,215,609	-	-	-	-	-
9	CAPX2020 - La Crosse Local	4,139,767	4,156,103	3,992,695	3,957,322	3,858,452	4,139,767	4,156,103	3,992,695	3,957,322	3,858,452	-	-	-	-	-
10	CAPX2020 - La Crosse MISO	5,397,139	5,255,055	5,119,584	5,015,570	4,898,618	5,397,139	5,255,055	5,119,584	5,015,570	4,898,618	-	-	-	-	-
11	CAPX2020 - La Crosse MISO - WI	10,043,647	9,741,083	9,458,162	9,229,727	8,977,953	10,043,647	9,741,083	9,458,162	9,229,727	8,977,953	-	-	-	-	-
12	Huntley - Wilmarth	200,312	1,106,219	2,990,627	4,843,143	4,759,949	200,312	1,106,219	2,990,627	4,843,143	4,759,949	-	-	-	-	-
13	LaCrosse - Madison	14,923,365	14,915,964	14,288,700	13,845,072	13,488,580	14,923,365	14,915,964	14,288,700	13,845,072	13,488,580	-	-	-	-	-
14	**Projects**	88,484,696	90,105,977	96,734,930	109,796,546	128,334,985	88,484,696	90,105,977	96,734,930	109,796,546	128,334,985	-	-	-	-	-
15	MISO RECB Sch.26/26a	(8,497,508)	510,576	(2,495,508)	(8,005,746)	(10,858,596)	(8,497,508)	510,576	(3,995,005)	(9,607,189)	(10,858,596)	-	-	1,499,497	1,601,443	-
16	Base Rates	(1,937,000)	(1,937,000)	(1,937,000)	-	-	(1,937,000)	(1,937,000)	(1,937,000)	-	-	-	-	-	-	-
17	TCR True-up Carryover	1,036,546	(7,482,299)	(3,753,258)	3,900,860	22,084,391	1,036,546	(7,482,299)	(3,753,258)	4,346,913	7,956,886	-	-	-	(446,053)	14,127,505
18	**Revenue Requirement (RR)**	**79,086,734**	**81,197,254**	**88,549,163**	**105,691,660**	**139,560,781**	**79,086,734**	**81,197,254**	**87,049,667**	**104,536,270**	**125,433,275**	**-**	**-**	**1,499,497**	**1,155,390**	**14,127,505**
19	**Revenue Collections (RC)**	86,569,032	84,950,513	84,648,303	83,607,269	107,809,774	86,569,032	84,950,513	82,702,754	96,579,384	105,286,448	-	-	1,945,549	(12,972,116)	2,523,326
20	Monthly RR - RC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Balance (RR - RC + Cumulative CC)	(7,482,299)	(3,753,258)	3,900,860	22,084,391	31,751,007	(7,482,299)	(3,753,258)	4,346,913	7,956,886	20,146,828	-	-	(446,053)	14,127,505	11,604,179

Docket No. E002/M-21-814
DOC IR No. 76
Attachment A - Att 9 Monthly RR

Monthly Revenue Requirement Filing Summary

Line #	Amounts in dollars	2018 Carryover	2019 Monthly Details Jan - 2019 Actual	Feb - 2019 Actual	Mar - 2019 Actual	Apr - 2019 Actual	May - 2019 Actual	Jun - 2019 Actual	Jul - 2019 Actual	Aug - 2019 Actual	Sep - 2019 Actual	Oct - 2019 Actual	Nov - 2019 Actual	Dec - 2019 Actual	2019 Actual
1	AGIS - ADMS		123,802	128,696	133,436	138,584	155,182	146,256	223,022	176,285	179,794	183,462	186,616	204,641	1,979,777
2	AGIS - AMI		-	-	-	-	-	-	-	-	-	-	-	-	-
3	AGIS - FAN		-	-	-	-	-	-	-	-	-	-	-	-	-
4	AGIS - LoadSeer		-	-	-	-	-	-	-	-	-	-	-	-	-
5	AGIS - TOU Pilot		-	-	-	-	-	-	-	-	-	-	-	-	-
6	Big Stone-Brookings		345,155	344,421	343,672	342,921	342,133	341,589	341,098	340,362	339,596	338,829	338,063	337,296	4,095,135
7	CAPX2020 - Brookings		2,751,523	2,769,044	2,763,160	2,757,276	2,751,393	2,745,509	2,739,625	2,733,742	2,727,851	2,721,960	2,716,077	2,710,193	32,887,354
8	CAPX2020 - Fargo		1,250,597	1,248,030	1,245,465	1,242,468	1,239,465	1,236,462	1,233,459	1,230,457	1,227,454	1,224,451	1,221,448	1,218,445	14,818,201
9	CAPX2020 - La Crosse Local		349,592	348,173	347,341	346,510	345,679	344,848	344,017	343,185	342,354	341,524	342,579	343,965	4,139,767
10	CAPX2020 - La Crosse MISO		455,270	454,180	453,187	452,194	451,201	450,207	449,214	448,221	447,228	446,235	445,241	444,761	5,397,139
11	CAPX2020 - La Crosse MISO - WI		847,102	845,086	843,115	841,087	839,028	837,445	836,444	835,122	833,084	830,883	828,793	826,456	10,043,647
12	Huntley - Wilmarth		13,603	16,792	(8,757)	17,090	17,828	18,220	18,641	19,275	19,873	20,733	22,398	24,617	200,312
13	LaCrosse - Madison		1,260,378	1,268,282	1,262,799	1,256,927	1,251,638	1,246,080	1,241,429	1,236,487	1,230,094	1,223,655	1,223,307	1,222,290	14,923,365
14	**Projects**		7,397,021	7,422,705	7,383,417	7,395,058	7,393,548	7,366,616	7,426,950	7,363,136	7,347,328	7,331,733	7,324,522	7,332,662	88,484,696
15	MISO RECB Sch.26/26a		(1,048,965)	(609,927)	(865,791)	(612,104)	(546,251)	(609,730)	(580,000)	(431,486)	(371,812)	(1,325,457)	(807,180)	(688,807)	(8,497,508)
16	Base Rates		(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(1,937,000)
17	TCR True-up Carryover		1,036,546												1,036,546
18	**Revenue Requirement (RR)**		**7,223,185**	**6,651,362**	**6,356,210**	**6,621,538**	**6,685,879**	**6,595,469**	**6,685,534**	**6,770,234**	**6,814,100**	**5,844,860**	**6,355,926**	**6,482,438**	**79,086,734**
19	**Revenue Collections (RC)**		7,294,988	6,484,043	7,315,226	6,610,227	6,560,614	6,823,629	8,438,921	8,481,413	7,095,489	7,595,978	6,402,255	7,466,251	86,569,032
20	Monthly RR - RC		(71,803)	167,319	(959,016)	11,310	125,266	(228,160)	(1,753,387)	(1,711,179)	(281,389)	(1,751,118)	(46,329)	(983,813)	
21	Balance (RR - RC + Cumulative CC)	1,036,546	(71,803)	95,516	(863,500)	(852,190)	(726,924)	(955,084)	(2,708,471)	(4,419,649)	(4,701,039)	(6,452,157)	(6,498,486)	(7,482,299)	(7,482,299)

Monthly Revenue Requirement Filing Summary

		2020 Monthly Details												
	Amounts in dollars	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
Line #:		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
1	AGIS - ADMS	199,410	217,224	217,974	232,610	207,934	220,197	236,244	245,169	272,455	253,358	259,847	236,624	2,799,047
2	AGIS - AMI	38,246	72,917	87,828	140,658	72,019	104,114	63,923	75,072	101,547	92,035	197,950	163,730	1,210,039
3	AGIS - FAN	12,773	15,838	23,464	17,356	12,944	15,638	18,013	18,824	23,482	20,791	24,977	30,880	234,981
4	AGIS - LoadSeer	1,160	5,631	13,185	13,447	11,965	12,220	13,329	22,889	36,322	30,803	23,315	45,843	230,108
5	AGIS - TOU Pilot	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Big Stone-Brookings	335,262	334,405	333,778	333,030	332,290	331,542	330,802	330,058	329,311	328,571	327,823	327,083	3,973,954
7	CAPX2020 - Brookings	2,704,548	2,699,255	2,694,662	2,689,703	2,684,765	2,679,806	2,674,869	2,669,921	2,664,961	2,660,024	2,655,064	2,650,127	32,127,705
8	CAPX2020 - Fargo	1,211,369	1,208,328	1,205,911	1,203,166	1,200,442	1,197,698	1,194,973	1,192,239	1,189,495	1,186,770	1,184,026	1,181,302	14,355,718
9	CAPX2020 - La Crosse Local	350,669	349,751	349,058	348,247	347,450	346,748	346,048	345,241	344,431	343,628	342,817	342,014	4,156,103
10	CAPX2020 - La Crosse MISO	442,871	441,870	441,077	440,175	439,279	438,377	437,482	436,583	435,682	434,786	433,884	432,989	5,255,055
11	CAPX2020 - La Crosse MISO - WI	822,207	820,585	818,793	816,750	814,732	812,748	810,801	808,848	806,883	804,910	802,913	800,913	9,741,083
12	Huntley - Wilmarth	13,089	15,845	18,447	22,473	30,936	55,482	89,490	125,756	155,733	176,165	194,075	208,727	1,106,219
13	LaCrosse - Madison	1,255,605	1,253,358	1,251,748	1,248,948	1,246,403	1,243,835	1,241,446	1,239,031	1,236,780	1,235,078	1,233,043	1,230,690	14,915,964
14	**Projects**	7,387,208	7,435,007	7,455,924	7,506,562	7,401,158	7,458,405	7,457,421	7,509,633	7,597,083	7,566,918	7,679,735	7,650,921	90,105,977
15	MISO RECB Sch.26/26a	(68,517)	(295,282)	(247,066)	344,063	(184,050)	232,100	1,290,395	299,554	(378,241)	(71,596)	(104,417)	(306,367)	510,576
16	Base Rates	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(1,937,000)
17	TCR True-up Carryover	(7,482,299)												(7,482,299)
18	**Revenue Requirement (RR)**	**(325,024)**	**6,978,308**	**7,047,442**	**7,689,208**	**7,055,692**	**7,529,088**	**8,586,400**	**7,647,770**	**7,057,426**	**7,333,906**	**7,413,902**	**7,183,137**	**81,197,254**
19	**Revenue Collections (RC)**	7,995,677	6,809,306	7,231,038	6,235,727	5,694,281	7,263,408	8,714,843	8,026,844	7,502,125	6,701,121	6,009,199	6,766,944	84,950,513
20	Monthly RR - RC	(8,320,701)	169,002	(183,596)	1,453,481	1,361,411	265,680	(128,443)	(379,074)	(444,700)	632,784	1,404,703	416,193	
21	Balance (RR - RC + Cumulative CC)	(8,320,701)	(8,151,699)	(8,335,295)	(6,881,814)	(5,520,403)	(5,254,722)	(5,383,165)	(5,762,240)	(6,206,939)	(5,574,155)	(4,169,451)	(3,753,258)	(3,753,258)

Monthly Revenue Requirement Filing Summary

		2021 Monthly Details												
	Amounts in dollars	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
		Mixed	Mixed	Mixed	Mixed	Mixed	Mixed	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Line #:														
1	AGIS - ADMS	157,549	173,414	173,608	342,611	501,771	481,345	554,869	553,695	556,348	559,257	560,950	570,051	5,185,468
2	AGIS - AMI	146,580	202,187	145,274	197,413	136,428	145,970	545,305	542,563	556,299	695,668	633,644	692,012	4,639,342
3	AGIS - FAN	12,454	26,868	26,883	30,161	45,616	55,629	155,074	159,473	165,666	176,030	185,186	200,509	1,239,549
4	AGIS - LoadSeer	59,544	237,521	(107,692)	61,621	61,383	59,137	62,790	61,999	61,333	61,056	60,744	60,693	740,129
5	AGIS - TOU Pilot	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Big Stone-Brookings	324,880	324,159	323,438	322,717	321,996	321,274	320,553	319,832	319,111	318,390	317,669	316,947	3,850,967
7	CAPX2020 - Brookings	2,633,680	2,629,077	2,624,473	2,619,870	2,615,266	2,610,663	2,606,060	2,601,456	2,596,853	2,592,250	2,587,646	2,583,043	31,300,336
8	CAPX2020 - Fargo	1,174,205	1,171,765	1,169,324	1,166,883	1,164,442	1,162,001	1,159,560	1,157,119	1,154,679	1,152,238	1,149,797	1,147,356	13,929,370
9	CAPX2020 - La Crosse Local	337,468	336,695	335,923	335,150	334,378	333,147	331,917	331,146	330,375	329,603	328,832	328,061	3,992,695
10	CAPX2020 - La Crosse MISO	430,754	430,005	429,255	428,506	427,756	427,007	426,257	425,508	424,758	424,009	423,259	422,510	5,119,584
11	CAPX2020 - La Crosse MISO - WI	797,019	795,472	793,933	792,298	790,680	789,051	787,404	785,756	784,109	782,461	780,814	779,166	9,458,162
12	Huntley - Wilmarth	197,398	192,037	211,325	223,624	234,007	246,134	255,760	266,386	276,381	283,759	289,297	314,518	2,990,627
13	LaCrosse - Madison	1,226,257	1,213,651	1,198,709	1,196,770	1,194,048	1,191,309	1,188,568	1,185,852	1,179,352	1,173,437	1,171,578	1,169,169	14,288,700
14	**Projects**	7,497,790	7,732,851	7,324,452	7,717,623	7,827,771	7,822,668	8,394,118	8,390,785	8,405,263	8,548,158	8,489,416	8,584,035	96,734,930
15	MISO RECB Sch.26/26a	(1,548,197)	(29,652)	268,406	(1,042,665)	50,016	898,900	(53,823)	303,423	142,511	(317,618)	(811,837)	(354,973)	(2,495,508)
16	Base Rates	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(1,937,000)
17	TCR True-up Carryover	(3,753,258)												(3,753,258)
18	**Revenue Requirement (RR)**	**2,034,918**	**7,541,782**	**7,431,442**	**6,513,542**	**7,716,370**	**8,560,151**	**8,178,879**	**8,532,791**	**8,386,357**	**8,069,124**	**7,516,162**	**8,067,645**	**88,549,163**
19	**Revenue Collections (RC)**	6,727,066	6,144,110	7,113,200	6,266,166	5,925,856	8,045,828	8,544,174	8,754,892	7,665,933	6,829,934	6,105,653	6,525,492	84,648,303
20	Monthly RR - RC	(4,692,148)	1,397,672	318,242	247,376	1,790,515	514,324	(365,295)	(222,101)	720,424	1,239,190	1,410,509	1,542,153	
21	Balance (RR - RC + Cumulative CC)	(4,692,148)	(3,294,476)	(2,976,234)	(2,728,858)	(938,344)	(424,020)	(789,315)	(1,011,416)	(290,992)	948,198	2,358,707	3,900,860	3,900,860

Docket No. E002/M-21-814
DOC IR No. 76
Attachment A - Att 9 Monthly RR

Monthly Revenue Requirement Filing Summary

		2022 Monthly Details												
	Amounts in dollars	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Line #:														
1	AGIS - ADMS	475,788	474,621	488,477	502,602	501,177	499,266	497,366	495,321	493,132	491,104	489,166	487,224	5,895,245
2	AGIS - AMI	832,104	939,582	1,031,849	1,119,797	1,193,063	1,280,099	1,368,496	1,441,123	1,511,985	1,584,271	1,662,147	1,744,025	15,708,542
3	AGIS - FAN	135,226	138,923	142,607	146,374	151,500	157,330	161,786	166,194	171,798	178,005	184,808	190,683	1,925,235
4	AGIS - LoadSeer	57,969	57,617	57,264	56,911	56,558	56,206	55,854	55,501	55,147	54,795	54,442	54,090	672,353
5	AGIS - TOU Pilot	59,231	59,063	58,896	58,728	58,560	58,392	58,225	58,057	57,889	57,722	57,553	57,386	699,701
6	Big Stone-Brookings	316,585	315,882	315,179	314,476	313,773	313,069	312,369	311,666	310,960	310,260	309,554	308,854	3,752,627
7	CAPX2020 - Brookings	2,580,574	2,575,966	2,571,359	2,566,752	2,562,144	2,557,537	2,552,936	2,548,328	2,543,715	2,539,114	2,534,501	2,529,899	30,662,824
8	CAPX2020 - Fargo	1,145,861	1,143,419	1,140,977	1,138,535	1,136,093	1,133,651	1,131,215	1,128,773	1,126,326	1,123,889	1,121,442	1,119,005	13,589,185
9	CAPX2020 - La Crosse Local	333,301	332,660	332,019	331,379	330,738	330,097	329,457	328,816	328,175	327,535	326,893	326,253	3,957,322
10	CAPX2020 - La Crosse MISO	422,098	421,347	420,595	419,843	419,091	418,340	417,589	416,837	416,084	415,334	414,581	413,830	5,015,570
11	CAPX2020 - La Crosse MISO - WI	778,193	776,548	774,903	773,257	771,612	769,966	768,322	766,676	765,030	763,385	761,739	760,095	9,229,727
12	Huntley - Wilmarth	395,336	400,730	406,119	408,435	407,558	406,559	405,568	404,569	403,562	402,571	401,564	400,573	4,843,143
13	LaCrosse - Madison	1,166,722	1,164,859	1,162,516	1,160,172	1,157,828	1,155,484	1,153,152	1,150,808	1,147,554	1,144,336	1,141,989	1,139,652	13,845,072
14	**Projects**	8,698,988	8,801,218	8,902,759	8,997,261	9,059,695	9,135,997	9,212,333	9,272,670	9,331,358	9,392,320	9,460,379	9,531,568	109,796,546
15	MISO RECB Sch.26/26a	(639,805)	(1,018,777)	(624,785)	(652,695)	(642,415)	(333,094)	(92,729)	(444,148)	(623,102)	(1,093,700)	(1,020,458)	(820,039)	(8,005,746)
16	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
17	TCR True-up Carryover	3,900,860												3,900,860
18	**Revenue Requirement (RR)**	**11,960,044**	**7,782,440**	**8,277,974**	**8,344,565**	**8,417,280**	**8,802,902**	**9,119,604**	**8,828,522**	**8,708,256**	**8,298,621**	**8,439,921**	**8,711,529**	**105,691,660**
19	**Revenue Collections (RC)**	7,436,527	6,443,494	7,270,737	6,226,662	6,312,018	7,272,802	8,292,183	8,020,951	6,645,296	6,434,918	6,295,968	6,955,713	83,607,269
20	Monthly RR - RC	4,523,517	1,338,947	1,007,237	2,117,903	2,105,263	1,530,100	827,421	807,571	2,062,961	1,863,702	2,143,953	1,755,816	
21	Balance (RR - RC + Cumulative CC)	4,523,517	5,862,464	6,869,701	8,987,604	11,092,867	12,622,967	13,450,388	14,257,959	16,320,920	18,184,622	20,328,575	22,084,391	22,084,391

Monthly Revenue Requirement Filing Summary

	Amounts in dollars	2023 Monthly Details												
		Jan - 2023	Feb - 2023	Mar - 2023	Apr - 2023	May - 2023	Jun - 2023	Jul - 2023	Aug - 2023	Sep - 2023	Oct - 2023	Nov - 2023	Dec - 2023	2023
Line #:		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
1	AGIS - ADMS	502,225	500,568	498,923	497,400	496,022	494,632	493,254	492,377	492,000	491,636	491,094	490,758	5,940,888
2	AGIS - AMI	2,275,418	2,397,402	2,535,619	2,665,007	2,775,988	2,885,083	2,995,519	3,105,668	3,213,943	3,323,559	3,418,384	3,509,901	35,101,489
3	AGIS - FAN	231,686	238,005	242,943	248,555	254,573	260,859	267,159	273,123	279,060	286,712	294,665	308,612	3,185,952
4	AGIS - LoadSeer	53,707	53,419	53,132	52,844	52,557	52,269	51,982	51,694	51,407	51,120	50,832	50,545	625,508
5	AGIS - TOU Pilot	56,504	56,348	56,192	56,036	55,880	55,724	55,569	55,413	55,257	55,101	54,945	54,789	667,758
6	Big Stone-Brookings	308,293	307,765	307,237	306,709	306,181	305,652	305,124	304,596	304,068	303,540	303,011	302,483	3,664,659
7	CAPX2020 - Brookings	2,521,086	2,516,483	2,511,891	2,507,288	2,502,696	2,498,093	2,493,501	2,488,904	2,484,301	2,479,709	2,475,106	2,470,514	29,949,570
8	CAPX2020 - Fargo	1,114,705	1,112,263	1,109,832	1,107,390	1,104,958	1,102,516	1,100,085	1,097,648	1,095,206	1,092,774	1,090,332	1,087,900	13,215,609
9	CAPX2020 - La Crosse Local	325,062	324,421	323,781	323,139	322,499	321,858	321,218	320,577	319,935	319,295	318,654	318,014	3,858,452
10	CAPX2020 - La Crosse MISO	412,368	411,613	410,859	410,104	409,350	408,595	407,841	407,087	406,331	405,578	404,822	404,069	4,898,618
11	CAPX2020 - La Crosse MISO - WI	757,195	755,552	753,911	752,268	750,626	748,984	747,342	745,700	744,057	742,415	740,772	739,131	8,977,953
12	Huntley - Wilmarth	401,850	400,901	399,965	399,015	398,079	397,130	396,194	395,251	394,302	393,366	392,416	391,480	4,759,949
13	LaCrosse - Madison	1,136,754	1,134,435	1,132,136	1,129,816	1,127,517	1,125,197	1,122,898	1,120,588	1,118,269	1,115,969	1,113,650	1,111,350	13,488,580
14	**Projects**	10,096,854	10,209,175	10,336,419	10,455,571	10,556,926	10,656,592	10,757,684	10,858,625	10,958,135	11,060,773	11,148,684	11,239,547	128,334,985
15	MISO RECB Sch.26/26a	(1,334,217)	(1,284,564)	(1,000,131)	(896,263)	(916,490)	(428,821)	(403,566)	(542,700)	(728,975)	(1,211,233)	(1,151,817)	(959,819)	(10,858,596)
16	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
17	TCR True-up Carryover	22,084,391												22,084,391
18	**Revenue Requirement (RR)**	**30,847,029**	**8,924,611**	**9,336,288**	**9,559,308**	**9,640,436**	**10,227,771**	**10,354,118**	**10,315,925**	**10,229,160**	**9,849,540**	**9,996,867**	**10,279,728**	**139,560,781**
19	**Revenue Collections (RC)**	9,540,113	8,012,519	8,944,995	7,694,648	8,257,143	9,431,177	10,945,083	10,610,086	8,623,608	8,297,987	8,232,454	9,219,962	107,809,774
20	Monthly RR - RC	21,306,915	912,092	391,293	1,864,660	1,383,293	796,594	(590,964)	(294,160)	1,605,553	1,551,552	1,764,413	1,059,765	
21	Balance (RR - RC + Cumulative CC)	21,306,915	22,219,008	22,610,301	24,474,961	25,858,254	26,654,848	26,063,884	25,769,724	27,375,276	28,926,829	30,691,242	31,751,007	31,751,007

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Sales and Revenue Calculation

	Forecast Revenue (2)					Sales by Customer Group (3)					kW Demand
		Customer Groups					Customer Groups				
	Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors											
2019-2020 TCR Rates - Provisional Rates		**$ 0.003607**	**$ 0.003185**	**$ 0.982000**	**$ -**						
2022 TCR Rates - Proposed Rates		**$ 0.005905**	**$ 0.004649**	**$ 1.110000**	**$ -**						
Jul 2021											
Aug 2021											
Sep 2021											
Oct 2021											
Nov 2021											
Dec 2021											
Jan 2022											
Feb 2022											
Mar 2022											
Apr 2022											
May 2022											
Jun 2022											
Jul 2022											
Aug 2022	8,020,951	3,235,145	231,698	4,554,108	-	2,764,910,903	896,907,487	72,746,745	1,788,001,598	7,255,073	4,637,584
Sep 2022	6,645,296	2,401,942	197,762	4,045,592	-	2,324,887,415	665,911,324	62,091,567	1,588,351,743	8,532,782	4,119,747
Oct 2022	6,434,918	2,223,315	194,267	4,017,336	-	2,265,198,325	616,389,023	60,994,350	1,577,258,195	10,556,757	4,090,974
Nov 2022	6,295,968	2,325,805	208,459	3,761,704	-	2,199,339,185	644,803,138	65,450,184	1,476,893,631	12,192,231	3,830,656
Dec 2022	6,955,713	2,831,434	230,490	3,893,789	-	2,400,121,716	784,982,978	72,367,343	1,528,752,077	14,019,317	3,965,162
Jan 2023	9,540,113	4,799,058	362,877	4,378,178	-	2,426,358,015	812,710,961	78,054,801	1,520,710,523	14,881,730	3,944,305
Feb 2023	8,012,519	3,864,279	315,599	3,832,642	-	2,065,502,843	654,407,887	67,885,277	1,331,224,567	11,985,112	3,452,830
Mar 2023	8,944,995	3,965,764	363,904	4,615,326	-	2,364,784,795	671,594,200	78,275,840	1,603,081,293	11,833,461	4,157,952
Apr 2023	7,694,648	3,341,052	298,459	4,055,136	-	2,048,253,891	565,800,574	64,198,619	1,408,505,469	9,749,229	3,653,276
May 2023	8,257,143	3,576,597	309,370	4,371,176	-	2,198,911,187	605,689,516	66,545,586	1,518,278,423	8,397,662	3,937,996
Jun 2023	9,431,177	4,608,535	305,858	4,516,783	-	2,422,209,610	780,446,292	65,790,066	1,568,853,457	7,119,795	4,069,174
Jul 2023	10,945,083	5,598,409	338,191	5,008,482	-	2,766,963,043	948,079,502	72,744,873	1,739,639,446	6,499,223	4,512,146
Aug 2023	10,610,086	5,290,120	325,250	4,994,715	-	2,707,938,461	895,871,377	69,961,276	1,734,857,681	7,248,127	4,499,743
Sep 2023	8,623,608	3,925,577	276,498	4,421,533	-	2,268,547,641	664,788,651	59,474,694	1,535,769,236	8,515,061	3,983,363
Oct 2023	8,297,987	3,643,186	269,616	4,385,186	-	2,208,612,074	616,966,273	57,994,427	1,523,144,441	10,506,932	3,950,618
Nov 2023	8,232,454	3,813,376	292,508	4,126,570	-	2,154,176,487	645,787,640	62,918,398	1,433,317,303	12,153,146	3,717,631
Dec 2023	9,219,962	4,643,620	321,801	4,254,542	-	2,347,334,038	786,387,763	69,219,361	1,477,766,867	13,960,048	3,832,921
Total June'22 thru May '23	**$ 76,802,264**	**$ 32,564,391**	**$ 2,712,885**	**$ 41,524,987**	**$ -**	**23,058,268,276**	**6,919,197,090**	**688,610,313**	**15,341,057,521**	**109,403,353**	**39,790,482**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
TCR Adjustment Factor Calculation

				Customer Groups				
		2022 Customer Group Weighting*	Retail % Weighting	Residential	Commercial Non-Demand	Demand	Street Lighting	Total
Transmission Demand Allocator	D10S	76,889,723	75.54%	36.14%	3.28%	60.59%	0.00%	100.00%
Distribution Allocator without Lighting	P60 W/O Lighting	24,901,077	24.46%	70.33%	4.59%	25.08%	0.00%	100.00%
Combined Average Allocation		101,790,800	100.00%	44.50%	3.60%	51.90%	0.00%	100.00%
Sales Allocator	E99		100.00%	28.47%	2.92%	68.06%	0.55%	100.00%
Group Weighting Factor (1)	**Fixed Ratio**		**1.0000**	**1.5633**	**1.2306**	**0.7625**	**-**	**1.0000**
	MN kWh retail Sales		**27,979,592,086**	8,648,530,638	813,063,217	18,395,148,706	122,849,525	27,979,592,086
	MN kW Demand					47,711,954		
State of Mn Cost per kWh	**Total Sales/Costs**	$	**0.0037775**					
	MN retail Cost		**105,691,660**	51,069,573	3,779,931	52,978,028	-	107,827,533
TCR Adjustment Factor (2)			**per kWh**	**0.005905**	**0.004649**		**0.00000**	
			per kW			**1.11**		

*excludes over/under carryover

Notes:

1) The Group Weighting Factors are calculated by dividing the combined average allocation percentage for each customer group, by the corresponding sales allocation percentage for the same customer group. The transmission demand, distribution, and sales allocation percentages were established in Xcel Energy's last approved electric rate case, Docket No. E002/GR-15-826.

2) The TCR Adjustment Factors by customer group are determined by multiplying each Group Weighting Factor by the average retail cost per kWh. The average retail cost per kWh is calculated by using the Minnesota electric retail cost divided by the annual Minnesota Retail Sales.

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2019 Actual	Feb - 2019 Actual	Mar - 2019 Actual	Apr - 2019 Actual	May - 2019 Actual	Jun - 2019 Actual	Jul - 2019 Actual	Aug - 2019 Actual	Sep - 2019 Actual	Oct - 2019 Actual	Nov - 2019 Actual	Dec - 2019 Actual	2019 Actual
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,698,504	4,906,016	5,421,233	4,591,660	5,008,429	5,909,885	6,988,361	6,558,217	5,828,231	5,398,125	5,067,931	5,336,017	66,712,610
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	133,655	133,655	133,655	133,655	133,655	133,164	133,164	133,164	133,183	133,225	133,225	133,225	1,600,624
5	Schedule 26(a)	7,060,681	5,976,809	6,200,839	5,686,399	6,263,776	6,663,610	7,138,756	7,100,624	6,157,706	5,804,531	5,822,383	6,549,457	76,425,571
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	12,892,840	11,016,480	11,755,727	10,411,714	11,405,860	12,706,659	14,260,281	13,792,005	12,119,120	11,335,881	11,023,539	12,018,699	144,738,805
8														
9	**Expense**													
10	Schedule 26	5,903,561	5,256,383	5,603,719	4,822,119	5,664,449	6,333,309	7,599,450	7,358,212	6,607,752	4,814,424	5,296,008	5,657,620	70,917,005
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	5,674,109	4,986,415	4,996,380	4,778,197	5,021,064	5,549,991	5,878,324	5,852,215	5,005,748	4,714,273	4,627,797	5,475,969	62,560,481
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(116,444)	(58,738)	(25,992)	(23,992)	(25,169)	(8,793)	(9,070)	(7,308)	(1,824)	(1,781)	(1,895)	(54,964)	(335,971)
15	**Total Expense**	11,461,226	10,184,060	10,574,107	9,576,323	10,660,344	11,874,507	13,468,705	13,203,119	11,611,676	9,526,915	9,921,909	11,078,624	133,141,515
16														
17	**Net Revenue/Expense**	(1,431,614)	(832,420)	(1,181,620)	(835,391)	(745,516)	(832,152)	(791,576)	(588,886)	(507,444)	(1,808,966)	(1,101,629)	(940,075)	(11,597,290)
18	Demand Allocator - State of MN Jur	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%
19	**Net RECB Revenue Requirements**	**(1,048,965)**	**(609,927)**	**(865,791)**	**(612,103)**	**(546,251)**	**(609,730)**	**(580,000)**	**(431,486)**	**(371,812)**	**(1,325,456)**	**(807,180)**	**(688,807)**	**(8,497,508)**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2020 Actual	Feb - 2020 Actual	Mar - 2020 Actual	Apr - 2020 Actual	May - 2020 Actual	Jun - 2020 Actual	Jul - 2020 Actual	Aug - 2020 Actual	Sep - 2020 Actual	Oct - 2020 Actual	Nov - 2020 Actual	Dec - 2020 Actual	2020 Actual
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	4,603,237	3,957,680	4,112,358	1,620,207	4,676,029	5,371,963	6,125,893	5,232,116	4,897,596	4,086,318	4,120,516	4,507,502	53,311,415
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recover	117,103	113,589	117,101	68,949	117,101	117,104	116,299	98,794	120,337	116,317	116,317	116,317	1,335,327
5	Schedule 26(a)	6,283,428	5,595,137	5,726,287	4,999,049	5,187,547	5,512,746	4,824,063	5,325,976	5,832,262	5,395,455	5,592,901	5,847,191	66,122,041
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	11,003,769	9,666,405	9,955,745	6,688,205	9,980,677	11,001,813	11,066,255	10,656,886	10,850,194	9,598,090	9,829,734	10,471,010	120,768,783
8														
9	**Expense**													
10	Schedule 26	4,769,194	4,096,496	4,202,088	2,225,049	4,639,686	5,915,930	6,745,276	5,752,031	4,939,109	4,182,809	4,260,468	4,563,515	56,291,650
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	6,194,047	5,222,596	5,422,846	4,941,012	5,098,049	5,406,505	6,086,464	5,317,541	5,398,930	5,321,467	5,430,982	5,524,648	65,365,087
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(53,020)	(55,839)	(6,509)	(8,104)	(8,344)	(3,733)	(3,696)	(3,702)	(4,261)	(3,936)	(4,276)	(35,440)	(190,859)
15	**Total Expense**	10,910,222	9,263,254	9,618,425	7,157,958	9,729,391	11,318,701	12,828,044	11,065,869	10,333,778	9,500,340	9,687,173	10,052,724	121,465,877
16														
17	**Net Revenue/Expense**	(93,548)	(403,151)	(337,320)	469,752	(251,286)	316,888	1,761,789	408,984	(516,416)	(97,750)	(142,561)	(418,286)	697,095
18	Demand Allocator - State of MN Jur	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%
19	**Net RECB Revenue Requirements**	**(68,518)**	**(295,282)**	**(247,065)**	**344,063**	**(184,050)**	**232,100**	**1,290,395**	**299,554**	**(378,241)**	**(71,596)**	**(104,417)**	**(306,367)**	**510,576**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2021 Actual	Feb - 2021 Actual	Mar - 2021 Actual	Apr - 2021 Actual	May - 2021 Actual	Jun - 2021 Actual	Jul - 2021 Forecast	Aug - 2021 Forecast	Sep - 2021 Forecast	Oct - 2021 Forecast	Nov - 2021 Forecast	Dec - 2021 Forecast	2021 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,972,057	4,364,568	3,606,957	5,248,824	5,251,540	5,902,168	6,818,906	5,370,685	4,328,928	5,048,774	4,948,752	5,120,075	61,982,232
3	Sch 26 - NSPM FERC Audit Adjustment	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(553,382)
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recover	135,701	122,722	122,722	125,298	107,836	122,749	122,749	76,648	81,325	122,749	127,625	122,749	1,390,876
5	Schedule 26(a)	7,634,901	5,773,733	5,964,980	5,208,179	5,059,226	6,632,124	7,622,638	6,068,134	4,956,307	5,967,846	6,212,619	6,583,792	73,684,480
6	Sch 26(a) - NSPM FERC Audit Adjustment	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(507,435)
7	**Total Revenue**	13,654,257	10,172,622	9,606,258	10,493,898	10,330,201	12,568,640	14,475,892	11,427,067	9,278,158	11,050,968	11,200,595	11,738,214	135,996,771
8														
9	**Expense**													
10	Schedule 26	5,537,318	4,851,002	4,782,241	4,488,649	5,762,858	7,484,759	7,419,151	6,235,812	5,322,615	5,213,309	4,682,861	5,304,227	67,084,803
11	Sch 26 - NSPM FERC Audit Adjustment	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	199,439
12	Schedule 26(a)	6,012,998	5,295,334	5,197,510	4,586,113	4,642,459	6,299,824	6,970,897	5,594,427	4,139,755	5,392,322	5,396,533	5,948,280	65,476,453
13	Sch 26(a) - NSPM FERC Audit Adjustment	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	35,925
14	Sch 26(a) - RT MVP DIST	(33,879)	(33,896)	(25,880)	(27,026)	(26,300)	(5,702)	(7,410)	(7,650)	(8,846)	(8,834)	(9,149)	(19,573)	(214,145)
15	**Total Expense**	11,536,051	10,132,053	9,973,485	9,067,349	10,398,631	13,798,494	14,402,253	11,842,202	9,473,138	10,616,411	10,089,859	11,252,548	132,582,475
16														
17	**Net Revenue/Expense**	(2,118,206)	(40,569)	367,227	(1,426,549)	68,431	1,229,854	(73,639)	415,136	194,980	(434,557)	(1,110,736)	(485,666)	(3,414,295)
18	Demand Allocator - State of MN Jur	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%
19	**Net RECB Revenue Requirements**	**(1,548,197)**	**(29,652)**	**268,406**	**(1,042,665)**	**50,016**	**898,900**	**(53,823)**	**303,423**	**142,511**	**(317,618)**	**(811,837)**	**(354,973)**	**(2,495,508)**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2022 Forecast	Feb - 2022 Forecast	Mar - 2022 Forecast	Apr - 2022 Forecast	May - 2022 Forecast	Jun - 2022 Forecast	Jul - 2022 Forecast	Aug - 2022 Forecast	Sep - 2022 Forecast	Oct - 2022 Forecast	Nov - 2022 Forecast	Dec - 2022 Forecast	2022 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,585,549	5,226,215	5,023,301	4,720,576	5,749,300	7,480,605	7,432,104	7,017,135	6,221,651	5,398,931	5,207,307	5,516,437	70,579,112
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recover	141,413	124,672	124,517	124,517	124,517	122,839	121,154	124,056	124,056	124,056	124,056	124,056	1,503,908
5	Schedule 26(a)	6,261,875	6,217,293	5,702,068	5,339,058	5,631,459	6,679,675	7,014,688	7,143,285	5,873,702	6,019,066	6,297,762	6,596,298	74,776,231
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	11,988,838	11,568,180	10,849,887	10,184,152	11,505,277	14,283,119	14,567,946	14,284,475	12,219,409	11,542,053	11,629,125	12,236,791	146,859,251
8														
9	**Expense**													
10	Schedule 26	5,778,082	4,983,577	5,079,486	4,785,605	5,908,004	7,962,158	7,975,964	7,537,355	6,321,901	4,876,069	4,823,577	5,459,282	71,491,060
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	5,356,256	5,210,932	4,945,638	4,536,691	4,748,012	5,863,648	6,553,267	6,147,384	5,054,804	5,179,902	5,419,743	5,676,657	64,692,935
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(20,146)	(19,051)	(29,351)	(30,414)	(28,954)	1,956	(88,050)	(7,438)	(9,109)	(9,062)	(9,215)	(20,185)	(269,018)
15	**Total Expense**	11,114,191	10,175,458	9,995,773	9,291,883	10,627,062	13,827,762	14,441,181	13,677,301	11,367,596	10,046,909	10,234,105	11,115,755	135,914,976
16														
17	**Net Revenue/Expense**	(874,646)	(1,392,722)	(854,113)	(892,269)	(878,214)	(455,357)	(126,765)	(607,174)	(851,813)	(1,495,145)	(1,395,020)	(1,121,036)	(10,944,274)
18	Demand Allocator - State of MN Jur	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%
19	**Net RECB Revenue Requirements**	**(639,805)**	**(1,018,777)**	**(624,785)**	**(652,695)**	**(642,415)**	**(333,094)**	**(92,729)**	**(444,148)**	**(623,102)**	**(1,093,700)**	**(1,020,458)**	**(820,039)**	**(8,005,746)**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2023 Forecast	Feb - 2023 Forecast	Mar - 2023 Forecast	Apr - 2023 Forecast	May - 2023 Forecast	Jun - 2023 Forecast	Jul - 2023 Forecast	Aug - 2023 Forecast	Sep - 2023 Forecast	Oct - 2023 Forecast	Nov - 2023 Forecast	Dec - 2023 Forecast	2023 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,931,452	5,186,576	5,149,147	4,628,628	5,769,749	6,450,117	7,129,040	6,865,067	6,086,523	5,281,323	5,093,779	5,396,326	68,967,728
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recover	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	1,488,667
5	Schedule 26(a)	6,661,309	6,164,987	5,911,574	5,064,391	5,290,183	6,464,108	7,596,849	7,040,674	5,789,329	5,932,605	6,207,297	6,501,545	74,624,850
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	12,716,817	11,475,618	11,184,777	9,817,075	11,183,988	13,038,280	14,849,944	14,029,797	11,999,908	11,337,983	11,425,132	12,021,926	145,081,244
8														
9	**Expense**													
10	Schedule 26	5,355,805	4,596,597	4,916,814	4,398,597	5,549,011	7,069,069	7,970,680	7,423,725	6,183,780	4,741,974	4,681,603	5,306,940	68,194,593
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	5,554,064	5,140,241	4,928,950	4,222,586	4,410,847	5,389,642	6,334,098	5,870,371	4,827,025	4,946,485	5,175,519	5,420,856	62,220,685
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(20,045)	(20,219)	(30,503)	(31,393)	(30,854)	(7,631)	(7,451)	(7,438)	(9,109)	(9,062)	(9,215)	(20,185)	(203,105)
15	**Total Expense**	10,889,824	9,716,619	9,815,261	8,589,789	9,929,004	12,451,080	14,297,327	13,286,658	11,001,696	9,679,397	9,847,906	10,707,611	130,212,172
16														
17	**Net Revenue/Expense**	(1,826,992)	(1,759,000)	(1,369,516)	(1,227,285)	(1,254,984)	(587,200)	(552,618)	(743,139)	(998,212)	(1,658,586)	(1,577,225)	(1,314,315)	(14,869,072)
18	Demand Allocator - State of MN Jur	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%
19	**Net RECB Revenue Requirements**	**(1,334,217)**	**(1,284,564)**	**(1,000,131)**	**(896,263)**	**(916,490)**	**(428,821)**	**(403,566)**	**(542,700)**	**(728,975)**	**(1,211,233)**	**(1,151,817)**	**(959,819)**	**(10,858,596)**

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Xcel Energy	Information Request No. 77
Docket No.:	E002/M-21-814
Response To:	Minnesota Department of Commerce
Requestor:	Nancy Campbell and Matt Landi
Date Received:	September 2, 2022

Question:
Topic: Key Inputs
Reference(s): Attachment 12, Key Inputs & Attachment 13, OATT Credit Factor

Request:

A. Please update Xcel's "Annual OATT Credit Factor" on Attachment 13 using actual information through July 31, 2022, for 2021, 2022 and 2023. If actual "Annual OATT Credit Factor" has changed from Xcel's forecast by 5 percent or more, please explain why. Please include revenue requirement impact of updating to actuals.
B. For MN 12-month CP Demand (Electric Demand) allocator, please provide support for 2021, 2022, and 2023 allocators. Please include actual allocator for 2021, and actuals through July 31, 2022 for 2022 allocator, and 2023 forecasted allocator, and explain any differences of more than 5 percent or more from Xcel's requested MN 12-month CP Electric Demand allocator. Please include revenue requirement impact of updating to actuals.
C. For the NSPM 36-month CP Demand (Interchange Electric) allocator, please provide support for 2021, 2022, and 2023 allocators. Please include applicable pages for 2021 and 2022 and 2023 FERC filed and/or accepted CP Demand Interchange Electric allocators, and explain any differences of 5 percent or more from Xcel's requested 36-month CP Demand Interchange Electric allocator. Please include revenue requirement impact of updating to actuals.

Response:

A. The OATT credit factor for 2021 updated for actuals is 24.6287%. As discussed with DOC staff, the impact of an updated "Annual OATT Credit Factor" for 2021 thru 2023 will be reflected in the next TCR filing when actuals and a new forecast will be provided.
B. The MN 12-month CP Demand allocator is not updated for actuals or an updated forecast; instead it is based on the last authorized MN 12-month CP

Electric Demand allocator, which was approved in Docket E002/GR-15-826. This is consistent with the Order in Docket No. E002/M-13-1179, which requires the Company to use the MN 12-month CP Demand allocator approved in the Company's last electric rate case in the TCR tracker. If applicable, the MN 12-month CP Demand allocator will be updated for the years included in this TCR proceeding, but that will depend on the timing and instructions included in the pending rate case final Order (Docket No. E002/GR-21-678). As discussed with DOC staff, the impact of this potential update will be reflected in the next TCR filing when actuals are trued-up.

C. The 2021 NSPM 36-month CP Demand (Interchange Electric) allocator reflects what was approved in the 2021 Interchange Agreement proceeding (FERC Docket No. ER21-1401; Order issued June 22, 2021) and thus there will be no update for actuals. The 2022 Interchange filing was filed after the TCR Rider Petition was submitted, and the approved 2022 allocator is 83.6779% (FERC Docket No. ER22-1234; Order issued May 30, 2022). As discussed with DOC staff, the impact of this updated allocation will be reflected in the next TCR filing when actuals are trued-up.

Preparer:	Christopher Franks
Title:	Principal Rate Analyst
Department:	Revenue Requirements North
Telephone:	612-337-2007
Date:	September 12, 2022

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Xcel Energy		Information Request No. 78
Docket No.:	E002/M-21-814	
Response To:	Minnesota Department of Commerce	
Requestor:	Nancy Campbell and Matt Landi	
Date Received:	September 2, 2022	

Question:
Topic: Regional Expansion Costs and Benefits (RECB)
Reference(s): Attachment 14, RECB

Request:

A. Please update Xcel's RECB revenues and expenses on Attachment 14 using actual information through July 31, 2022, for 2021, 2022 and 2023. If actual RECB revenues and expense has changed from Xcel's forecast by 5 percent or more, please explain why. Please include revenue requirement impact of updating to actuals.

Response:

A. Please see 21-0814 DOC-076 Attachment A which reflects updated RECB actuals through July 31, 2022. As discussed with DOC staff, an updated forecast and additional months of actuals for the period after August 2022 will be provided in the next TCR filing. The annual impact is as follows:

DELTA - Updated RECB Actuals through July 2022

Line No:	Amounts in dollars	2019 Actual	2020 Actual	2021 Mixed	2022 Forecast	2023 Forecast
1	AGIS - ADMS	-	-	-	-	-
2	AGIS - AMI	-	-	-	-	-
3	AGIS - FAN	-	-	-	-	-
4	AGIS - LoadSeer	-	-	-	-	-
5	AGIS - TOU Pilot	-	-	-	-	-
6	Big Stone-Brookings	-	-	-	-	-
7	CAPX2020 - Brookings	-	-	-	-	-
8	CAPX2020 - Fargo	-	-	-	-	-
9	CAPX2020 - La Crosse Local	-	-	-	-	-
10	CAPX2020 - La Crosse MISO	-	-	-	-	-
11	CAPX2020 - La Crosse MISO - WI	-	-	-	-	-
12	Huntley - Wilmarth	-	-	-	-	-
13	LaCrosse - Madison	-	-	-	-	-
14	**Projects**	-	-	-	-	-
15	MISO RECB Sch.26/26a	-	-	1,499,497	1,604,732	-
16	Base Rates	-	-	-	-	-
17	TCR True-up Carryover	-	-	-	1,499,497	3,104,229
18	**Revenue Requirement (RR)**	**-**	**-**	**1,499,497**	**3,104,229**	**3,104,229**

The primary drivers of the change from forecast is related to MISO ROE resettlements that were resettled during that time period. We do not forecast resettlement impact so that would not be included within the forecast. The remaining change is due to weather due to increased cooling and heating degree days. These came in stronger for this time period compared to forecast.

Preparer:	Christopher Franks
Title:	Principal Rate Analyst
Department:	Revenue Requirements North
Telephone:	612-337-2007
Date:	September 12, 2022

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Xcel Energy		Information Request No.	80
Docket No.:	E002/M-21-814		
Response To:	Minnesota Department of Commerce		
Requestor:	Matthew Landi and Ben Havumaki		
Date Received:	October 5, 2022		

<u>Question:</u>
Topic: Load flexibility benefits
Reference(s): Xcel's 2021-2022 TCRR Petition – Supplement Filing

Request:
1. Refer to the $225 million load flexibility benefits presented in Figure 5.
    a. What does the Company assume are the annual participation rates in (1) critical peak pricing and (2) TOU rates?
    b. How do these assumed participation rates compare to participation rates at other utilities?
    c. Does DI increase these load flexibility benefits, or would these benefits be equally achievable with AMI meters that did not have DI functionality? Please explain in detail.
    d. Has the Company assessed the impact on the benefit-cost ratio for AMI-FAN if fewer customers than planned enroll in CPP and TOU? Please explain in detail and provide any associated sensitivity results that are available.

<u>Response:</u>
a. The Company engaged The Brattle Group (Brattle) to model likely customer response to Time of Use (TOU) and Critical Peak Pricing (CPP) rates. The Brattle Group produced a study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory" (the Brattle Study). The Study was included as Appendix G2 to our July 1, 2019 Integrated Resource Plan filing in Docket No. E002/RP-19-368 and is provided as Attachment A to this response. Table 12 of the Brattle Study summarizes the TOU and CPP (among others) participation rate assumptions for residential, small, medium, and large C&I, both Opt-in and Opt-out. These participation rates informed the technical potential as outlined in Appendix D of the Brattle Study, which we used directly in the cost-benefit analysis (CBA).
b. We do not know how the participation rates in the Brattle Study compare to participation rates at other utilities. We note that on page 69 of its Study, Brattle explains that "the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S."

c. Yes, Distributed Intelligence (DI) increases these load flexibility benefits; the $225 million benefit does not rely on incremental DI capabilities. See our response to DOC-81 for details in the incremental benefits of DI.
d. The Company assessed the impact on the Benefit-Cost Ratio (BCR) resulting from lower (and higher) load flexibility benefits through Monte Carlo simulation. The resulting scatter plot on page 53 of our Supplement filing shows that if load flexibility benefits are lower than assumed in our base case, the BCR is likely to be lower (and vice versa if load flexibility benefits are higher).

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Telephone:	303-571-7639
Date:	October 12, 2022

The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

PREPARED FOR

Xcel Energy

PREPARED BY

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Tony Lee

June 2019

THE Brattle GROUP

Notice

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The authors would like to thank Jessie Peterson of Xcel Energy for valuable project leadership. They would also like to thank Brattle colleagues Mariko Geronimo Aydin, Colin McIntyre, and John Palfreyman for excellent research and modeling assistance.

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Executive Summary

Highlights:

- This study estimates the amount of cost-effective demand response available in Xcel Energy's Northern States Power (NSP) service territory, including an assessment of emerging "load flexibility" programs that can capture advanced sources of value such as geo-targeted distribution investment deferral and grid balancing services.
- Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and relatively high costs of emerging DR technologies.
- In later years of the study horizon, and under conditions that are more favorable to the economics of DR, cost-effective DR potential increases significantly, exceeding the PUC's 400 MW DR procurement requirement.
- New, emerging load flexibility programs account for around 30% of the 2030 incremental DR potential estimates in this study.

Background

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030.[1] The study addresses the Minnesota PUC's requirement that NSP "acquire no less than 400 MW of additional demand response by 2023" and "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

The scope of this study extends significantly beyond those of prior studies. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock

[1] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

"load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

The Brattle Group's Load*Flex* model is used to assess NSP's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.
- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and NSP's estimates of the capability of its existing DR programs.
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.
- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary tradeoffs when pursuing multiple value streams.
- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings, a review of experience and studies in other jurisdictions, and conversations with vendors.

Findings

Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

There is an opportunity to tap into latent interest in the current NSP programs and grow participation in those existing programs through new marketing efforts and refinements to program design. According to our analysis, doing so could provide 293 MW of incremental cost-effective potential by 2023. The majority of this growth could come from increased enrollment in a redesigned interruptible tariff program for the medium and large C&I segments, and from the transition to a residential air-conditioning DLC program that more heavily utilizes smart thermostat technology.

NSP's DR portfolio could also be expanded to include new programs that are not currently offered by the company. Our analysis considered eight new programs, including time-of-use (TOU) rates, critical peak pricing (CPP), home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral DR, ice-based thermal storage, and automated DR for lighting and HVAC of commercial and industrial customers. Some of these programs could provide ancillary services and geo-targeted distribution deferral benefits, in addition to the conventional DR value streams.

Based on current expectations about the future characteristics of the NSP market, smart water heating is the only new program that we find to be cost-effective in 2023 among the emerging options described above, providing an additional 13 MW of incremental cost-effective potential. Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and frequency regulation, and relatively high costs of emerging DR technologies.

This expanded portfolio, which reflects all cost-effective DR options available to NSP across a broad range of potential use cases, would fall short of the PUC's 2023 procurement requirement. In 2023, the current portfolio plus the incremental cost-effective DR identified in this study would equate to 1,156 MW of total peak reduction capability, 154 MW short of the procurement requirement.[2]

In 2025, the potential in the expanded portfolio increases. This increase is driven primarily by the ability to begin offering time-varying rates once smart meters are fully deployed in 2024. However, it is likely that several years will be needed for smart metering-based programs to ramp up to full participation, so the incremental potential associated with these programs is still somewhat constrained in 2025. The current portfolio plus the incremental DR in the expanded portfolio equate to 1,243 MW of cost-effective DR potential in 2025.

By 2030, NSP's cost-effective DR potential will increase further. This increase is driven primarily by the maturation of smart metering-based DR programs. Other factors contributing to the increase in cost-effective potential include a continued transition to air-conditioning load control through smart thermostats, an expansion of the smart water heating program through ongoing

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[2] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when additionally accounting for line losses.

voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

High Sensitivity Case

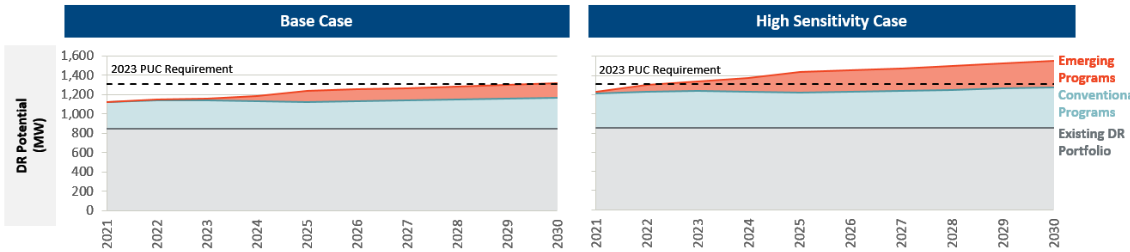
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the costs of emerging DR technologies may decline significantly, or the cost of competing resources (e.g., peaking capacity) may be higher than expected. To understand how these alternative conditions would impact DR potential, we analyzed a sensitivity case. The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. The case is not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative assumptions of the High Sensitivity Case there is significantly more cost-effective incremental potential. In 2023 there is a total of 484 MW of incremental cost effective potential, which would satisfy the PUC's procurement requirement. By 2030, the total portfolio of DR programs, including the existing programs, could reach 705 MW.

The mix of cost-effective programs in the High Sensitivity case is essentially the same as in the Base Case. However, larger program benefits justify higher incentive payments, which leads to higher participation and overall potential in these programs. Auto-DR for C&I customers also presents an opportunity to increase load flexibility in the High Sensitivity Case, though the potential in this program is subject to uncertainty in technology cost and customer adoption.

Under both the Base Case and the High Sensitivity Case assumptions, avoided generation capacity costs are the primary benefit of the DR portfolio. In the High Sensitivity Case, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Figure ES-1 summarizes the DR potential estimates and benefits of the DR portfolio under Base Case and High Sensitivity Case assumptions.

Figure ES-1: NSP's DR Potential and Annual Portfolio Benefits



2030 Avoided Cost ($M/yr)

Base Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$1.7	$15.5	$0.9	$0.0	$0.0	$18.1
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$7.4	$22.9	$1.3	$0.0	$1.2	$32.8

High Sensitivity Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$3.1	$26.8	$1.1	$0.0	$0.0	$31.0
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$22.7	$46.3	$1.9	$0.7	$4.6	$76.2

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

An expanded portfolio of DR programs will have operational flexibility beyond the capabilities of conventional existing programs. For instance, load flexibility programs could be dispatched to reduce the system peak, but also to address local peaks on the distribution system which may occur during later hours of the day. Off-peak load building through electric water heating could help to mitigate wind curtailments and take advantage of negative energy prices. The provision of frequency regulation from electric water heaters could further contribute to renewables integration value.

Specific recommendations for acting on the findings of this study including the following:

- Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.
- Pilot and deploy a smart water heating program. As a complementary activity, evaluate the impacts of switching from gas to electric heating, accounting for the grid reliability benefits associated with this flexible source of load.
- Prior to the smart metering rollout, build the foundation for a robust offering of time-varying rates, including identifying rate options that could be offered on an opt-out basis.
- Develop measurement & verification (M&V) 2.0 protocols to ensure that program impacts are dependable and can be integrated meaningfully into resource planning efforts.
- Design programs with peak period flexibility, to be able to respond to changes such as a shifts in the net peak due to solar PV adoption, or a shift in the planning emphasis from a focus on the MISO peak to a focus on more local peaks, for instance.

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I. Introduction

Purpose

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory.[3] Xcel Energy commissioned this study to satisfy the requirements of the Minnesota Public Utilities Commission (PUC) Order in Docket No. E-002/RP-15-21. That Order, established in January 2017, required NSP to "acquire no less than 400 MW of additional demand response by 2023" and to "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

Background

The Brattle Group conducted an assessment of NSP's DR potential in 2014.[4] That study specifically addressed opportunities to reduce NSP's system peak demand. As such, the assessment had a primary focus on "conventional" DR programs that are utilized infrequently to mitigate system reliability concerns. The study also included price-based DR options that would be enabled by the eventual deployment of smart meters.

The scope of this 2018 study extends significantly beyond that of the 2014 study. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions. The Brattle Group's Load*Flex* model is used to assess these emerging opportunities.

3 Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

4 Ryan Hledik, Ahmad Faruqui, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, April 2014.

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This 2018 study also extends beyond the scope of the 2014 study by evaluating the cost-effectiveness of each DR option.[5] While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A utility with significant market penetration of solar PV may find the most value in advanced load shifting capabilities that address evening generation ramping issues on a daily basis, whereas a system with a near-term need for peaking capacity may find more value in the types of conventional DR programs that reduce the system peak during only a limited number of hours per year. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

This report summarizes the key findings of The Brattle Group's assessment of NSP's DR market potential. Additional detail on methodology and results is provided in the appendices.

NSP's Existing DR Portfolio

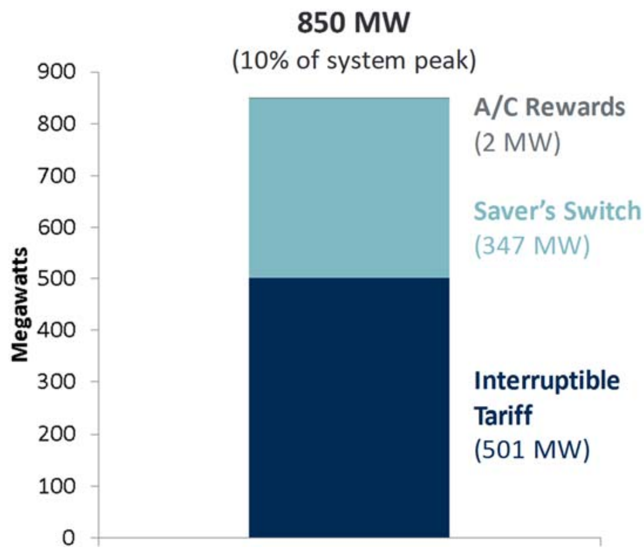
The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed as a percentage of peak demand.

As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with energy bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 11 percent of the peak-coincident demand of medium and large C&I customers is enrolled in this program.

The second program is NSP's Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit or the heating element of an electric resistance water heater is temporarily cycled off to reduce electricity demand during DR events. Saver's Switch is one of the largest such programs in the country. Roughly 52 percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around 29% of all of NSP's residential customers. Saver's Switch is gradually being transitioned to a program based on newer smart thermostat technology, called "A/C Rewards." A/C Rewards contributes an additional 2 MW to NSP's existing DR capability, though this is expected to grow significantly in coming years. A summary of NSP's DR portfolio is provided in Figure 1.

5 The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

Figure 1: NSP 2017 DR Capability



Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

Important Considerations

The focus of this study is on quantifying the amount of cost-effective DR capability that can be achieved above and beyond NSP's current 850 MW DR portfolio. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. **Incremental:** All quantified DR potential is incremental to NSP's existing 850 MW DR portfolio.[6]

2. **Cost-effective:** The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

3. **Achievable:** Program enrollment rates are based on primary market research in NSP's service territory and supplemented with information about utility experience in other jurisdictions.

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6 For the purposes of this analysis, all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon. Existing DR participants are excluded from the estimates of incremental potential.

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The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to NSP. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to NSP and its customers when deployed on a full scale basis.

II. Methodology

This study analyzes three ways to increase the capability of NSP's existing DR portfolio. First, we assess the potential to increase enrollment in existing programs. Increased enrollment could be achieved through targeted program marketing efforts, for example. Second, the menu of DR programs offered to customers could be expanded to include new, non-conventional options. These non-conventional options include emerging "load flexibility" programs which go beyond peak shaving to provide around-the-clock decreases and increases in system load. Third, consistent with the introduction of more flexible DR programs, we consider a broadened list of potential benefits in the cost-effectiveness screening process, such as ancillary services and geographically-targeted deferral of distribution capacity upgrades.

Conventional DR Programs

Our analysis considers conventional DR programs that have been offered by utilities for many years, including in some cases by NSP.

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on NSP's Savers Switch program.

- **Smart thermostats:** An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. The modeled program is based on NSP's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from NSP's online store, or use a NSP-installed thermostat. Smart thermostat programs are based on newer technology than the other "conventional" DR programs in this list, but included here as the program is already offered by NSP.

- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty. While a conventional option, demand bidding is not currently offered by NSP.

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Non-conventional DR Programs

Pricing programs are one type of non-conventional DR option. We consider two specific time-varying rate options which generally span the range of impacts that can be achieved through pricing programs: A static time-of-use rate and a dynamic critical peak pricing rate.

- **Time-of-use (TOU) rate:** Currently being piloted by NSP for residential customers and offered on a full-scale basis to C&I customers. Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled as being offered on an opt-in and an opt-out (default) basis. The study also includes an optional TOU rate for EV charging.

- **Critical peak pricing (CPP) rate:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year. CPP rates are modeled as being offered on both an opt-in and an opt-out (default) basis.

The second category of non-conventional DR programs relies on a variety of advanced behavioral and technological tools for managing customer electricity demand.

- **Behavioral DR:** Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- **EV managed charging:** Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive. The managed EV charging program was modeled on three recent pilots: PG&E (with BMW), United Energy (Australia), and SMUD. Allows curtailment of charging load for up to three hours per day, fifteen days per year. Impacts were modeled for both home charging and workplace charging programs.

- **Timed water heating:** The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

- **Smart water heating:** Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy

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price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- **Ice-based thermal storage:** Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

- **C&I Auto-DR:** Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

DR Benefits

This study accounts for value streams that are commonly included in assessments of DR potential:

- **Avoided generation capacity costs:** The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- **Reduced peak energy costs:** Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses. Our analysis does not include the effect of any potential change in energy market prices that may result from changes in load patterns (sometimes referred to as the "demand response induced price effect," or DRIPE). It is simply a calculation of reduced resource costs.

- **System-wide deferral of transmission and distribution (T&D) capacity costs.** System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this potential value using methods that were established in a recent Minnesota PUC proceeding.[7]

This study also accounts for value streams that can be captured through more advanced DR programs:

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7 Minnesota PUC Docket No. E999/CIP-16-541.

- **Geo-targeted distribution capacity investment deferral:** DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. NSP's 5-year distribution plan was used to identify candidate deferral projects, and qualifying DR programs were evaluated based on their ability to contribute to the deferral.[8]

- **Ancillary services:** The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service (albeit with limited system need).

- **Load building / valley filling:** Load can be shifted to off-peak hours to reduce wind curtailments or take advantage of low or negatively priced hours. DR was dispatched against hourly energy price series to capture the economic incentive that energy prices provide for this service.

Figure 2 summarizes the ways in which this assessment of DR potential extends the scope of prior studies in Minnesota and other jurisdictions. In the figure, "X" indicates the value streams that each DR program is assumed to provide.

Figure 2: Options for Expanding the Existing DR Portfolio

1 Increase enrollment in the conventional portfolio

2 Extend DR value streams

3 Include non-traditional DR options

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted distribution capacity deferral	Valley filling/ Load building	Ancillary services
Direct load control (DLC)	X	X	X			
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Smart thermostat	X	X	X			
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

Notes: "X" indicates the value streams that each DR option is assumed to be able to provide.

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8 The distribution plan was in-development at the time of our analysis. Distribution data was provided to Brattle in March 2018.

Defining DR Potential

We use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to determine the cost-effectiveness of the incremental DR portfolio. The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement. This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process.[9] Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective. Major categories of benefits and costs included in the UCT are summarized Table 1.

Table 1: Categories of Benefits and Costs included in the Utility Cost Test

Benefits	Costs
Avoided generation capacity	Incentive payments
Avoided peak energy costs	Utility equipment & installation
Avoided transmission capacity	Administration/overhead
Avoided distribution capacity	Marketing/promotion
Ancillary services	

Throughout this study, we quantify DR potential in two different ways:

Technical Potential: Represents achievable potential without consideration for cost-effectiveness. In other words, this is a measure of DR capability that could be achieved from anticipated enrollment associated with a moderate participation incentive payment, regardless of whether or not the incentive payment and other program costs exceed the program benefits. As it is used here, the term "technical potential" differs from its use in energy efficiency studies. Technical potential in energy efficiency studies assumes 100% participation, whereas we assume an achievable level of participation in this assessment of DR potential.

Cost-effective Potential: Represents the portion of technical potential that can be obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

[9] According to the National Action Plan for Energy Efficiency: "The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements."

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The Load*Flex* Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to NSP's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

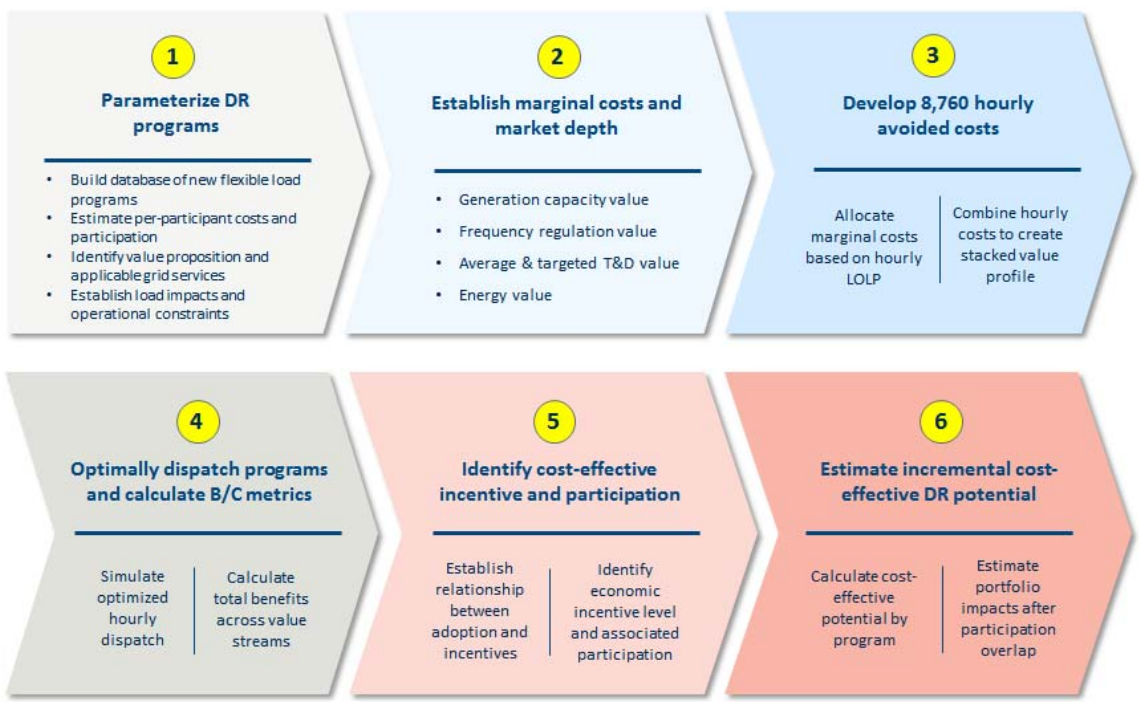
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 3. Appendix A provides detail on the methodology behind each of these steps.

Figure 3: The Load*Flex* Modeling Framework



Modeling Scenarios

The value that DR will provide depends on the underlying conditions of the utility system in which it is deployed. Generation capacity costs, the anticipated need for new transmission and distribution (T&D) assets, and energy price volatility are a few of the factors that will determine DR value and potential. To account for uncertainty in NSP's future system conditions, we considered two modeling scenarios: A "Base Case" and a "High Sensitivity Case."

The **Base Case** most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon.

The **High Sensitivity Case** was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics. The High Sensitivity Case is not intended to be the most likely future state of the NSP system. Relative to the Base Case, the High Sensitivity Case consists of a higher assumed generation capacity cost, more volatile energy prices due to greater market penetration of renewable generation, a significant reduction in emerging DR technology costs, and an increase in the need for frequency regulation.

Defining features of the two cases are summarized in Table 2. Appendix A includes more detail on assumptions and data sources behind the two cases.

Table 2: Defining Features of Base Case and High Sensitivity Case

	Base Case	High Sensitivity Case
Generation capacity (Net CONE)	\$64/kW-yr (2018 NSP IRP)	\$93/kW-yr (2018 EIA Annual Energy Outlook)
Hourly energy price	Based on MISO MTEP "Continued Fleet Change" case (15% wind+solar by 2032)	Based on MISO MTEP "Accelerated Fleet Change" case (30% wind+solar by 2032)
Frequency regulation	Price varies, 25 MW average need by 2030	Price same as Base Case, 50 MW average need by 2030
System average T&D deferral	Transmission: \$3.6/kW-yr, Distribution: \$9.5/kW-yr (2017 NSP Avoided T&D Study)	Same as Base Case
Geo-targeted T&D deferral	Value varies by distribution project, 90 MW eligible for deferral by 2030	Same as Base Case
DR technology cost	10% reduction from current levels by 2030 (in real terms)	30% reduction from current levels by 2030 (in real terms)

Notes: Unless otherwise specified, values shown are for year 2030 and in nominal dollars.

Modeling results are summarized for the years 2023 and 2030. 2023 is the year by which NSP must procure additional DR capability according to the Minnesota PUC's Order in Docket No. E-002/RP-15-21. The 2030 snapshot captures the potential for significant future changes in system conditions and their implications for DR value, and is consistent with the longer-term perspective of NSP's IRP study horizon. A summary of annual results, including intermediate years, is provided in Appendix D.

Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from NSP's experience with DR programs in its service territory. We also utilized the results of primary market research that was conducted directly with customers in NSP's service territory in order to better understand their preferences for various DR program options. Where NSP-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 4 summarizes data availability for each of the DR program types analyzed in this study.

Figure 4: Data Availability by DR Program Type

	Participation	Costs	Peak Impacts	Advanced Impacts
Residential				
Air-conditioning DLC	●	●	●	N/A
Smart thermostat	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Behavioral DR	◑	◑	◑	N/A
Smart water heating	◔	◔	◑	◔
Timed water heating	◔	◔	◑	◔
EV managed charging (home)	○	○	◔	N/A
EV charging TOU (home)	○	○	◔	N/A
C&I				
Interruptible tariff	●	●	●	N/A
Demand bidding	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Ice-based thermal storage	◔	◔	◔	◔
EV workplace charging	○	○	◔	N/A
Automated DR	○	◔	◔	○

Notes:

● NSP-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to NSP conditions

"Advanced impacts" refers to load flexibilty capability beyond conventional peak period reductions (e.g., frequency regulation)

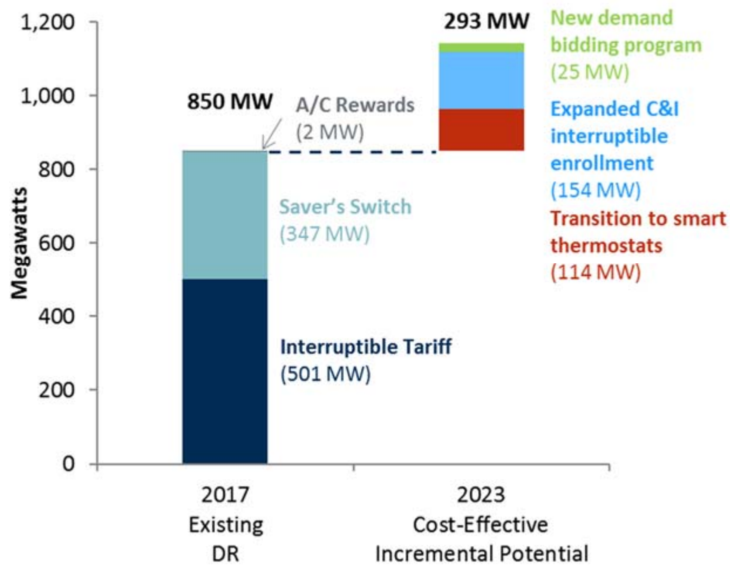
III. Conventional DR Potential in 2023

As an initial step in the assessment of NSP's cost-effective DR potential, we analyzed the potential if NSP were to deploy a portfolio of conventional DR programs. As defined for this study, conventional programs include interruptible tariffs, air-conditioning DLC, smart thermostats, and demand bidding. These program types are currently offered by NSP, with the exception of demand bidding. Therefore, the assessment of conventional programs is largely an assessment of the potential to grow the current DR portfolio through options such as new marketing initiatives or targeted marketing toward specific customer segments. We initially focus on the year 2023, as that is the year by which the Minnesota PUC has required NSP to procure additional DR capability.[10]

Figure 5 summarizes the cost-effective potential in a conventional DR portfolio in 2023. There is 293 MW of cost-effective incremental potential. Drivers of this potential include the expanded enrollment in NSP's interruptible tariff program, greater per-participant impacts that will be achieved as NSP continues to transition from a switch-based air-conditioning DLC program to a smart thermostat-based program, overall growth in NSP's customer base between 2017 and 2023, and a modest amount of potential in a new demand bidding program.

[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

Figure 5: Total DR Potential in 2023 (Conventional Portfolio)



The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. The curve also captures the different costs and potential associated with each conventional DR program and applicable customer segment. Cost-effective DR capability is identified with the blue dotted line. There is roughly 293 MW of incremental DR potential available at a cost of less than $59/kW-year. That cost equates to the value of avoided system costs after accounting for the operational constraints of DR programs.

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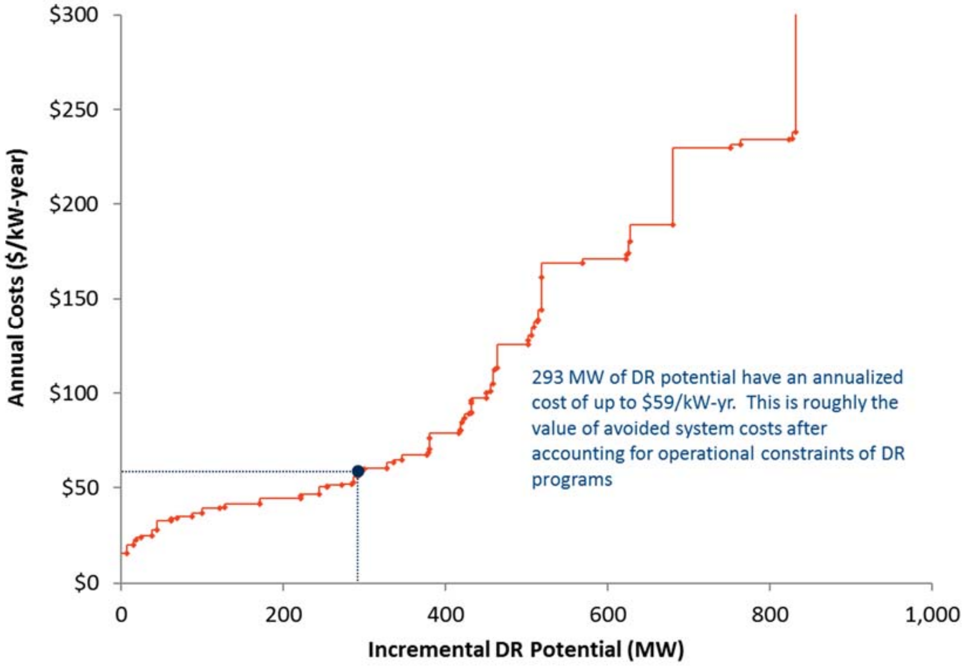
Figure 6: NSP's Incremental DR Supply Curve in 2023 (Conventional Portfolio)



Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

As discussed previously in this report, the Minnesota PUC has established a DR procurement requirement of 400 MW by 2023. It is important to clarify whether this 400 MW is a capacity-equivalent value, a generator-level value, or a meter-level value. Specifically, 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.

NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR. This equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses. These values are summarized in Table 3. Throughout this report, DR values are reported at the generator level. Thus, for consistency, we refer to the procurement requirement as a 391 MW generator-level value unless otherwise specified.

Table 3: NSP's 2023 DR Procurement Requirement

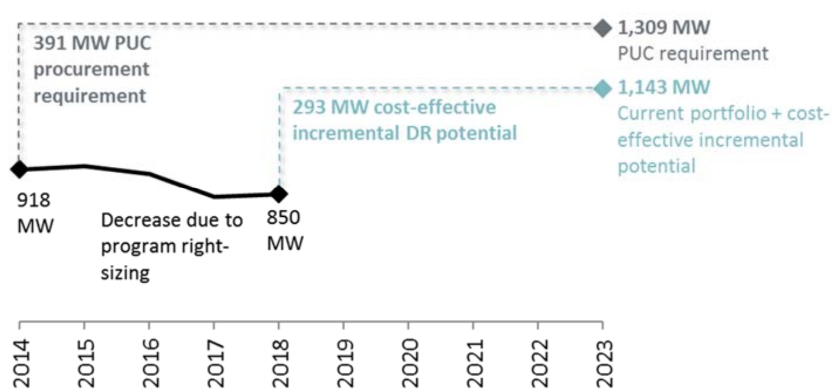
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

Source: Calculations provided by NSP.

Our interpretation of the PUC's Order is that the required DR procurement is incremental to NSP's DR capability as it existed in 2014.[11] NSP had 918 MW of DR capability in 2014, leading to a total DR capability requirement of 1,309 MW in 2023. NSP's DR capability decreased between 2014 and 2017 largely due to an effort to ensure that enrolled load would be available for curtailment when called upon, thus leading to an incremental DR requirement that is larger than 391 MW (at the generator level).[12]

Combined with current capability of 850 MW, the incremental cost-effective DR potential in 2023 would result in a total portfolio of 1,143 MW. This estimate of cost-effective potential is 166 MW short of the PUC's DR procurement requirement. Figure 7 illustrates the gap between NSP's conventional DR potential and the DR procurement requirement.

Figure 7: NSP DR Capability (Conventional Portfolio)



Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

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[11] 2014 is the year of NSP's prior DR potential study, which was used to inform the Minnesota PUC's establishment of the DR procurement requirement.

[12] For instance, some customers did not realize that they were participating in the program and dropped out when notified, or otherwise elected to reduce their enrolled load level.

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IV. Expanded DR Potential in 2023

Given the shortfall of the conventional DR portfolio relative to the 2023 procurement target, it is relevant to consider if an expanded portfolio of DR options could mitigate the shortfall. We analyzed eight additional emerging DR programs that could be offered to up to four different customer segments (if applicable). As described in Section II, these emerging DR options include both price based programs (e.g., TOU and CPP rate designs) and technology-based programs (e.g., Auto-DR and smart water heating).

Base Case

Among the individual measures with the most *technical potential* in 2023 are HVAC Auto-DR for Medium C&I customers and thermal storage for commercial customers. Each of these programs has technical potential in excess of 100 MW.

Pricing programs and lighting Auto-DR for C&I customers, timed water heating programs, and behavioral DR compose the next tier of opportunities, with technical potential in each ranging between 50 and 100 MW. These programs generally have the potential to reach significant levels of enrollment or, alternatively, to provide deep load reductions among a smaller share of customers.

The Small C&I segment accounts for many of the DR programs with the lowest technical potential, as there is a relatively small share of load in this segment and these customers have historically demonstrated a lower willingness to participate in DR programs.

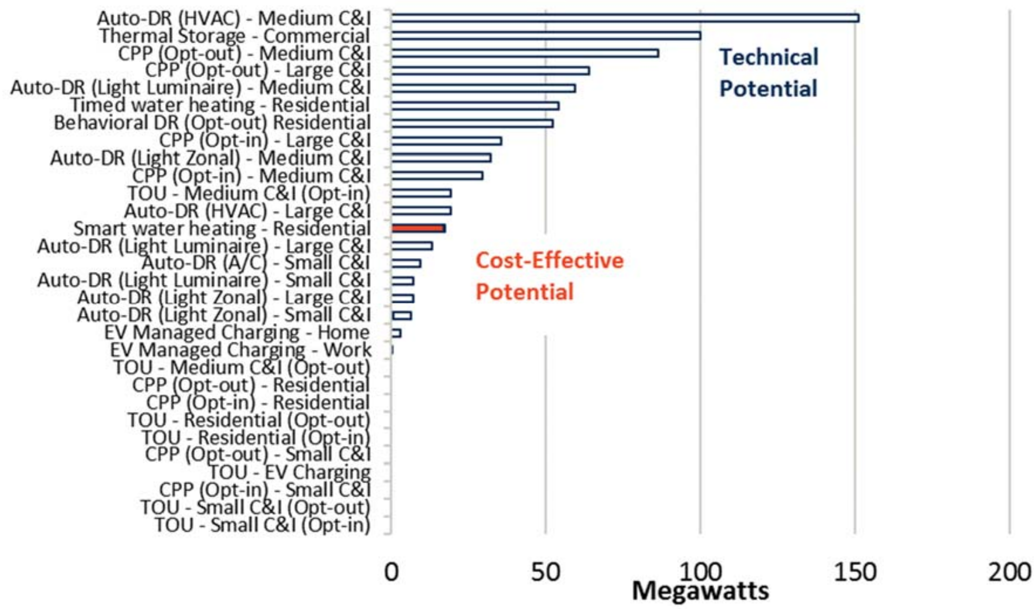
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

Pricing programs (i.e., TOU, CPP) cannot be offered on a full scale basis in 2023 to residential and small C&I customers, as AMI will not yet be fully deployed. Therefore, pricing programs have not been included in the potential estimates for 2023. Rollout of the programs is assumed to begin in 2024, upon NSP's projected completion of the AMI rollout.

Programs with significant *technical potential* do not necessarily have significant *cost-effective potential*. After accounting for cost-effectiveness under Base Case market conditions as well as technical constraints, the potential in DR programs is limited in 2023. Individually, only smart water heating and a modest amount of automated load control for C&I customers pass the cost-effectiveness screen. These programs pass the cost-effectiveness screen largely because they are capable of providing an expanded array of value streams, such as frequency regulation and geo-targeted T&D deferral.

Figure 8 summarizes the technical and cost-effective potential in each of the new DR program options. Potential is first shown for DR programs as if they were each offered in isolation.

Figure 8: New DR Program Potential in 2023 (Base Case)

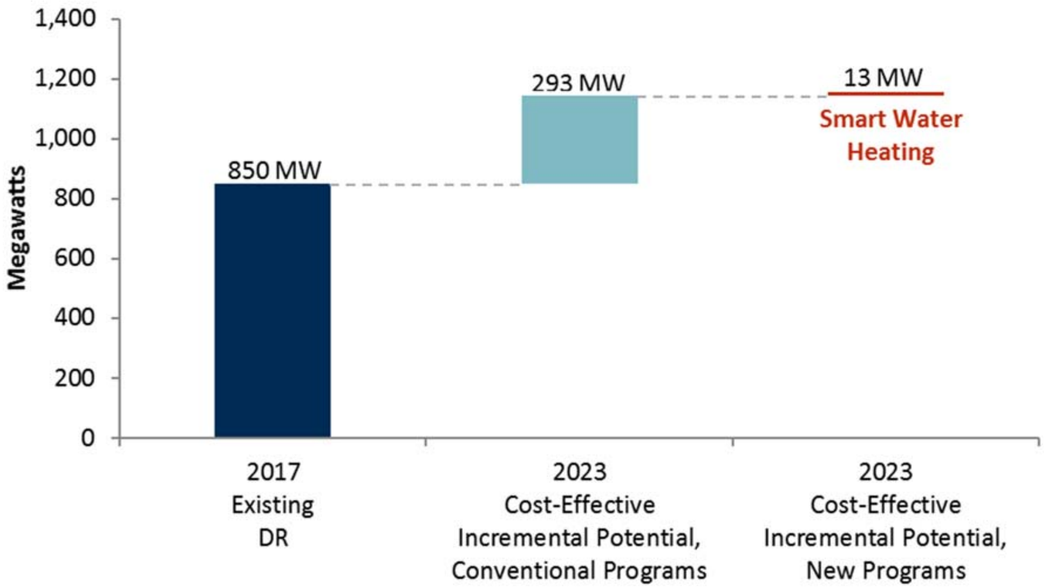


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The program-level DR impacts shown above cannot be added together to arrive at the potential capability of a DR portfolio. Adjustments must be made to account for double-counting of impacts when customers are enrolled in more than one program, and for limits on the need for certain value streams such as frequency regulation. Thus, combining the cost-effective programs into a portfolio can result in lower total potential DR capability than if the individual impacts shown above were simply summed.

In the 2023 scenario described above, the smart water heating program alone could satisfy NSP's need for frequency regulation. With that value stream no longer available to the Auto-DR program, the Auto-DR program fails the cost-effectiveness screen. **With the addition of the smart water heating program, NSP's cost-effective DR portfolio would increase by 13 MW. Achievement of all cost-effective DR potential would amount to total system-wide DR capability of 1,156 MW, but would still fall short of the PUC's procurement target by 154 MW.** The expanded capability in 2023 is illustrated in Figure 9.

Figure 9: Total DR Potential in 2023 (Expanded Portfolio)



Near-term Limitations on DR Value

The value of DR is very dependent on the characteristics of the system in which it is deployed. Several factors limit NSP's cost-effective DR in 2023, relative to other jurisdictions.

- **Low capacity prices:** NSP has access to low-cost peaking capacity, primarily due to the presence of brownfield sites that significantly reduce development costs. For instance, the all-in cost of a new combustion turbine in NSP's IRP is $63/kW-year, which is 23 percent lower than the cost of a CT assumed by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO). Similarly, a recent study approved by the Minnesota PUC determined that the average value of T&D capacity deferral achieved through reductions in customer consumption is approximately $11/kW-year in NSP's service territory.[13] This value, which was determined through a detailed bottom-up engineering assessment, is significantly lower than that of T&D deferral benefits observed in other studies, which can commonly reach values of $30/kW-year.[14] The value of T&D deferral is dependent on characteristics of the utility system and drivers of the investment need, and therefore varies significantly across utilities.

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13 Xcel Energy, "Minnesota Transmission and Distribution Avoided Cost Study," submitted to the Minnesota Department of Commerce, Division of Energy Resources (Department), July 31, 2017

14 Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

- **Metering technology limitations:** NSP has not yet deployed AMI, with an estimated forecast that system-wide AMI installation will be completed in 2024. AMI-based DR programs, such as time-varying rates and behavioral DR, cannot be offered to customers until deployment is complete. This effectively excludes the possibility of introducing any AMI-based programs in the year 2023.

- **High DR technology costs:** Some emerging DR programs depend on new technologies that have not yet experienced the cost declines that could be achieved at scale. While these technology costs could decrease over time, those reductions are not achieved in the early years of the study horizon.

- **Limited need for additional DR value streams:** While certain DR value streams potentially can be very valuable, these value streams can also be limited in need. For instance, our analysis of NSP's five-year distribution plan identified only 38 MW of projects that were potential candidates for geo-targeted capacity investment deferral. Those projects accounted for roughly 10 percent of the total value of NSP's plan. To qualify, projects need to satisfy criteria such as being driven by growth in demand and being of a certain size.[15] Similarly, while frequency regulation is often a highly-valued ancillary service and can be provided by certain types of DR, the need for frequency regulation across most markets is significantly less than one percent of system peak demand. This limits the amount of that value stream that can be provided by DR.

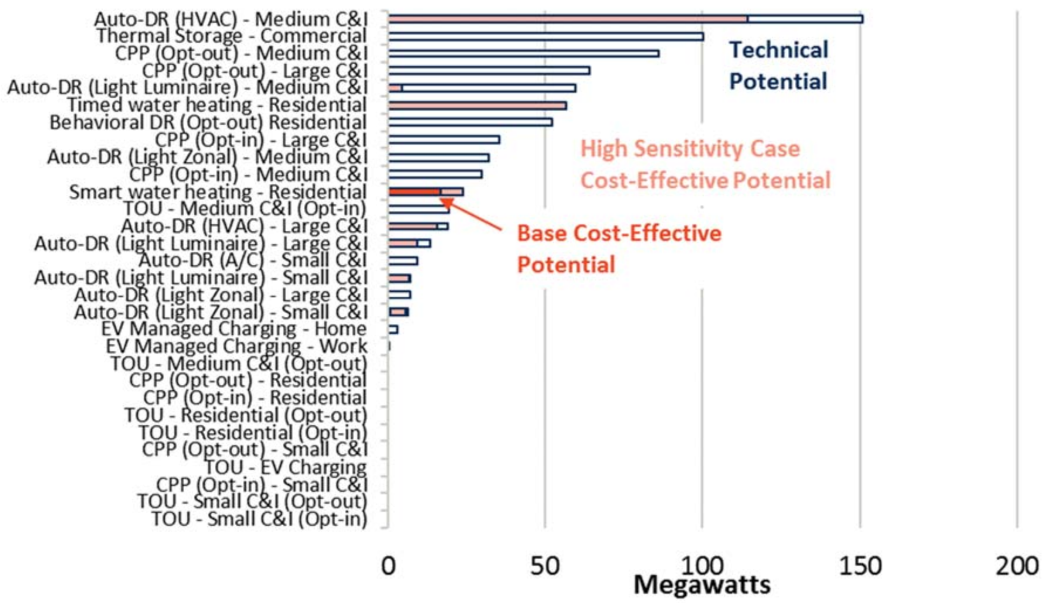
High Sensitivity Case

The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative High Sensitivity Case assumptions, cost-effective DR potential increases significantly. Several programs that were not previously passing the cost-effectiveness screen, such as medium C&I HVAC-based Auto DR, residential timed water heating, and a small amount of lighting-based Auto-DR do pass the screen under the more favorable assumptions in this case. Figure 10 summarizes the increase in cost-effective potential at the individual program level.

15 Details of the geo-targeted T&D deferral analysis are included in Appendix A.

Figure 10: New DR Program Potential in 2023 (High Sensitivity Case)



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

A DR portfolio constructed from cost-effective programs in the High Sensitivity Case would produce total incremental DR potential of 484 MW in 2023. Under the illustrative assumptions in this case, the cost-effective incremental portfolio would consist of 393 MW of conventional DR programs, and 91 MW of new DR programs. The portfolio of new DR programs includes residential smart water heating [16] (24 MW) and C&I HVAC-based Auto-DR (67 MW). Achievement of all cost-effective DR potential under the High Sensitivity Case would amount to total system-wide DR capability of 1,334 MW.

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[16] Smart water heating has lower cost-effective potential in 2023 than timed water heating. However, the smart water heating program provides more value and more significant per-participant impacts as participation ramps up in the later years of the study horizon, so it is the water heating program that was included in the portfolio.

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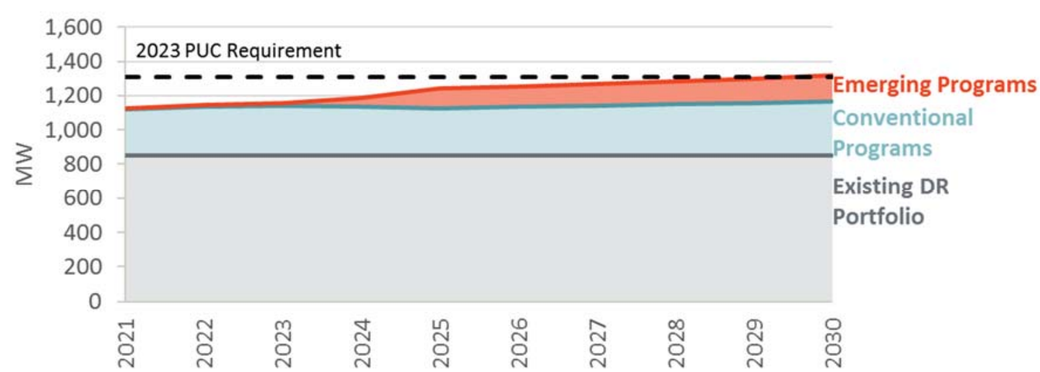
V. Expanded DR Potential in 2030

Base Case

Opportunities to expand cost-effective DR portfolio will grow beyond 2023. Most significantly, time-varying rates (such as TOU and CPP rates) can be offered to customers following completion of the AMI rollout in 2024. Additionally, the customer base is projected to grow over the study horizon, expanding the population of customers eligible to participation in DR programs. Growth in the market penetration of renewable generation will likely lead to more volatility in energy costs, further creating opportunities for DR to provide value. Additionally, current participants in the Savers Switch program are expected to transition to the smart thermostat-based A/C Reward program over time. Smart thermostats provide a greater per-participant demand reduction than the technology in the Savers Switch program, therefore further increasing DR potential.

Figure 11 summarizes growth in DR potential under Base Case assumptions for the portfolio of cost-effective DR programs. The majority of the post-2023 growth comes from the introduction of time-varying pricing programs.

Figure 11: Cost-Effective DR Potential, Base Case



Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low avoided costs in the Base Case scenario tend to favor conventional DR programs which are primarily constrained to reducing the system peak, but have lower costs as a result of this somewhat limited functionality. Table 4 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the Base Case.

Table 4: Annual Avoided Costs from 2030 DR Portfolio, Base Case ($ million/year)

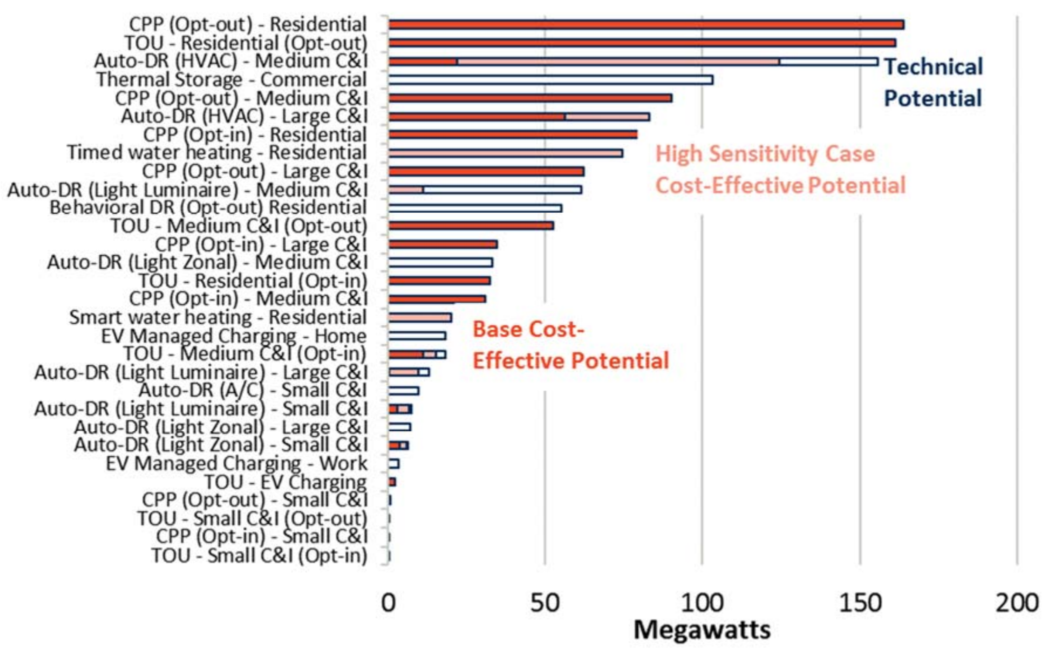
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

High Sensitivity Case

Drivers of growth over time under the illustrative High Sensitivity Case conditions are similar to growth drivers under Base Case conditions, with AMI-enabled time-varying rates accounting for the majority of new opportunities after 2023. Figure 12 summarizes the 2030 incremental measure-level potential for both the Base Case and the High Sensitivity Case.

Figure 12: New DR Program Potential in 2030



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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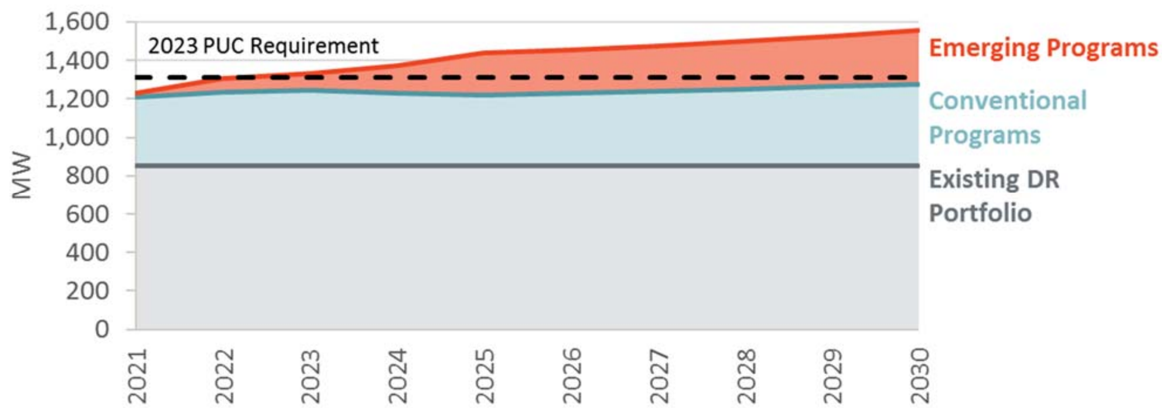
The capability of the cost-effective DR portfolio for the High Sensitivity Case is summarized in Figure 13.

Figure 13: Cost-Effective DR Potential, High Sensitivity Case



Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control technologies to connect to appliances through a standard port or socket. While widespread adoption of this standard is not considered to be imminent, it could potentially have positive implications for DR adoption in the longer term. See the Sidebar at the end of this section for further discussion of the outlook for CTA-2045.

The benefits of DR under the High Sensitivity Case assumptions continue to be driven primarily by avoided generation capacity costs. However, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Table 5 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the High Sensitivity Case.

Table 5: Annual Avoided Costs from 2030 DR Portfolio, High Sensitivity Case ($ million/year)

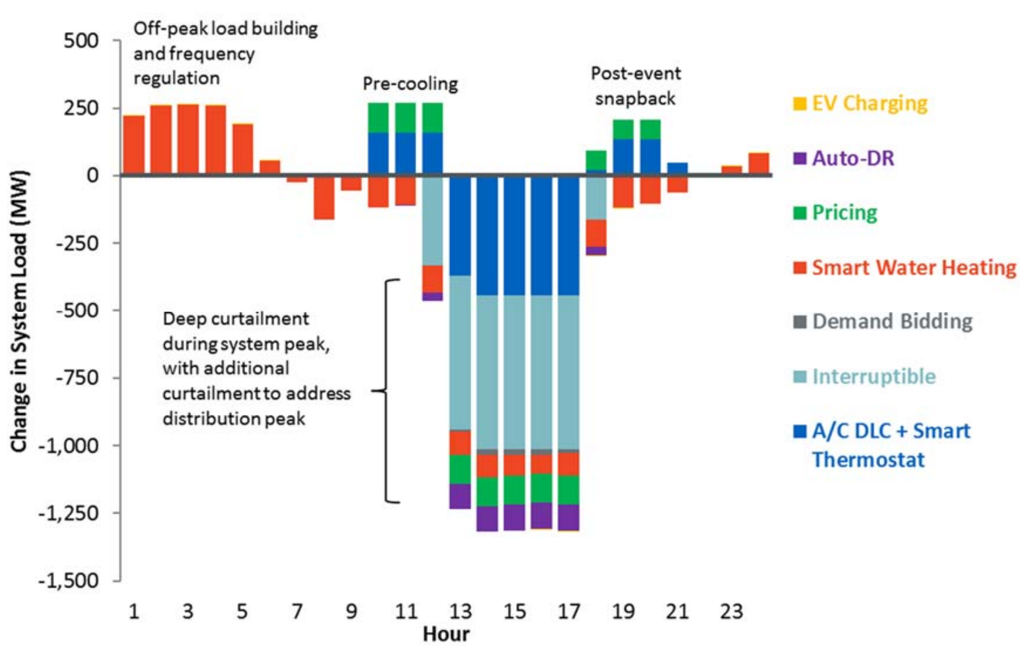
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

DR Portfolio Operation

The addition of emerging programs to NSP's DR portfolio will improve operational flexibility across NSP's system. Figure 14 illustrates how the cost-effective DR portfolio from the High Sensitivity Case could operate on an hourly basis during the days of the year with the highest system peak demand. The profile shown maximizes avoided costs relative to the system cost assumptions used in this study.

Figure 14: Average Load Impacts of the 2030 Cost-Effective DR Portfolio on Top 10 Load Days (High Sensitivity Case)



Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

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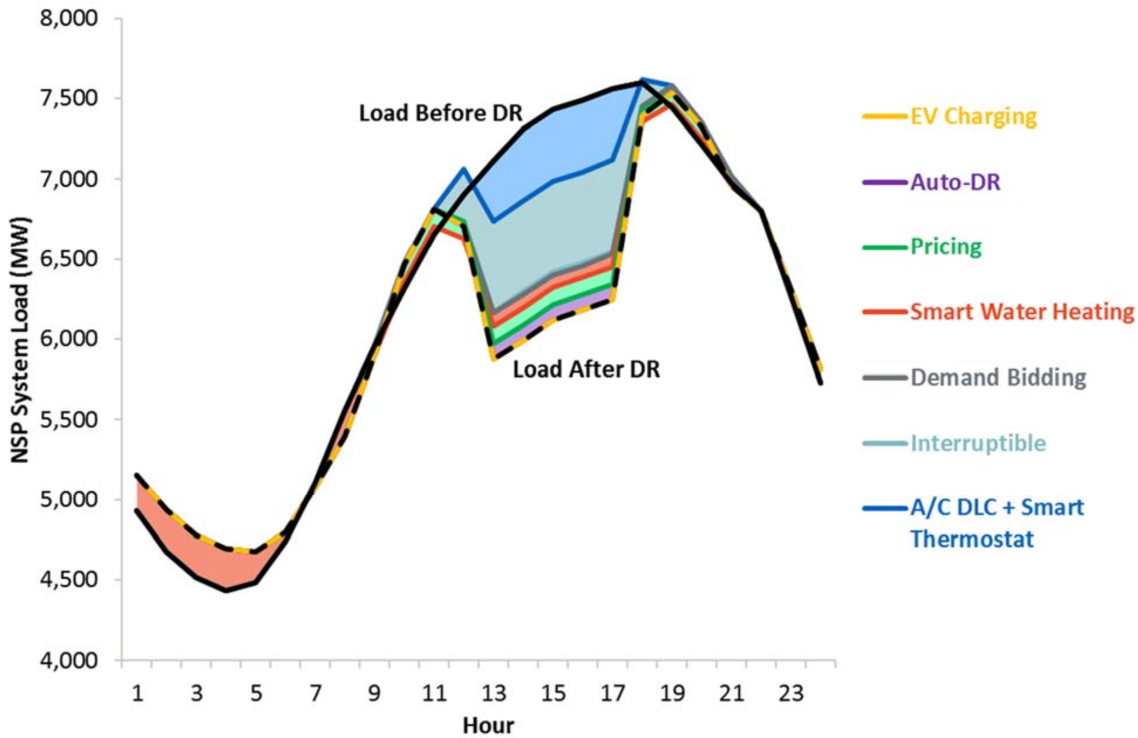
A deep curtailment of load during system peak hours is utilized to capture significant generation and T&D capacity deferral benefits. These also tend to be hours when energy costs are highest, leading to additional energy value. The duration of the peak load curtailment spans a fairly broad period of time – seven hours – in order to account for the lack of coincidence of the system and local peak demand that drive capacity needs. Load curtailment can be staggered across DR programs – and across participants in a given DR program – in order to achieve this duration of demand reduction.

Load increases are observed immediately before and after the peak load reduction. This is driven mostly by the need to maintain and restore building temperatures to desired levels around DR events. The smart water heating program builds load during nighttime hours, shifting heating load to the lowest cost hours and potentially reducing the curtailment of renewable generation.

Figure 15 illustrates how NSP's system load shape changes as a result of the impacts shown in Figure 14 above. The figure shows a steep reduction in load during hours of the MISO system peak, while NSP's later peak is only modestly reduced. This is primarily due to NSP's planning needs being driven by MISO coincident peak demand. If the MISO peak shifts later in the day due to solar PV adoption, or if NSP transitions to an increased focus on its own peak demand in planning activities, then the dispatch of the DR programs would need to be modified accordingly. In particular, it may become necessary to stagger the utilization of DR programs across a broader window of hours in order to "flatten" peak demand across the hours of the day.

Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)



Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

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Sidebar: The Outlook for CTA-2045

CTA-2045 is a standard which specifies a low-cost communications "socket" that would be embedded in electric appliances and other consumer products. If consumers wished to make an appliance capable of participating in a demand response program, they could simply plug a communications receiver into the socket, thus allowing the appliance to be controlled by themselves or a third party. CTA-2045 has the potential to establish a low-cost option for two-way communications capability in appliances, thus reducing the cost and hassle of consumer enrollment in DR programs that would otherwise require on-site installation of more costly equipment.

Development of CTA-2045 began in 2011, through work by the Consumer Technology Association (CTA) and the Electric Power Research Institute (EPRI). Refinements to the standard are ongoing. To assess the outlook for CTA-2045 and its potential implications for future DR efforts, we conducted phone and email interviews with subject matter experts from utilities, appliance manufacturers, and DR software platforms.

There is a shared view that CTA-2045 is facing a chicken-and-egg problem. Manufacturers have been hesitant to incorporate the standard into their products, because there is a cost associated with doing so and they have not yet observed demand in the market for the communications functionality. At the same time, a barrier preventing increased adoption of DR technologies could be some of the costs and installation challenges that CTA-2045 would ultimately address.

Products with CTA-2045 functionality have not yet been deployed at scale, and where available are sold at a price premium that is significantly higher than the unit costs that could ultimately be achieved at scale. The relative lack of enthusiasm among manufacturers for rolling out CTA-2045 compliant products has led to a slow pace of development of the standard itself. Progress is being made incrementally, though technical issues still remain to be resolved.

Looking forward, some in the industry feel that the mandating CTA-2045 through a new state appliance standard could be the catalyst that is needed for adoption to become broadly widespread. Aggressive support for CTA-2045 by large utilities is also considered to be the type of activity that would facilitate adoption.

If compliance with CTA-2045 ultimately were to accelerate through activities like those described above, electric water heaters are poised to become the first such commercial application, as they have been the most common test case for proving the technical concept and are an attractive source of load flexibility. Particularly in the context of water heaters, CTA-2045 would help to overcome the challenge of enrolling customers in a DR program during the very narrow window of time during which their existing water heater expires and must be replaced. Other controllable end-uses, such as thermostats or even electric vehicle chargers could be candidates for the standard, though these technologies sometimes already come pre-equipped with communications capabilities.

VI. Conclusions and Recommendations

NSP's sizeable existing DR portfolio has the potential to be expanded by tapping into latent demand for existing programs and also by rolling out a new portfolio of emerging DR programs. Specific recommendations for acting on the findings of this study including the following:

Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into a redesigned Interruptible program. NSP's relatively low avoided costs mean that lower cost, established DR programs are the most economically attractive options in the near term. Smart thermostats and a modernized Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

Pilot and deploy a smart water heating program. There is significant experience with advanced water heating load control in the Upper Midwest, and the technology is rapidly advancing. The thermal storage capabilities of water heaters provide a high degree of load flexibility that can be adapted to a range of system needs.

As a complementary activity to the development of a smart water heating program, also evaluate the economics and environmental impacts of switching from gas to electric heating, factoring in the grid reliability benefits associated with this flexible source of load. Doing so would require revisiting existing state policies that prohibit utility-incentivized fuel switching.

Build the foundation for a robust offering of time-varying rates. As a first step, prepare a strategy for rolling out innovative rates soon after AMI is deployed. This should include exploring rate offerings that could be deployed to customers on a default (opt-out) basis, as default rate offerings maximize the overall economic benefit for the program.

Develop measurement & verification (M&V) 2.0 protocols to ensure that the impacts of the program are dependable and can be integrated meaningfully into resource planning efforts. Included in this initiative could be the development of a data collection plan to enhance the quality of future market potential studies. Further, detailed customer segmentation and geographically granular load data at the distribution system level will provide an improved base from which to develop a cost-effective DR strategy.

Design programs with peak period flexibility. From a planning standpoint, the timing of the peak period could change for a variety of reasons (e.g., DR flattens the peak, solar PV shifts the net peak, or the planning emphasis shifts from a focus on the MISO peak to a focus on more local peaks). DR programs will need to be designed with the flexibility to adjust the timing of curtailments in response to these changes.

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Appendix A: Load*Flex* Modeling Methodology and Assumptions

The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction

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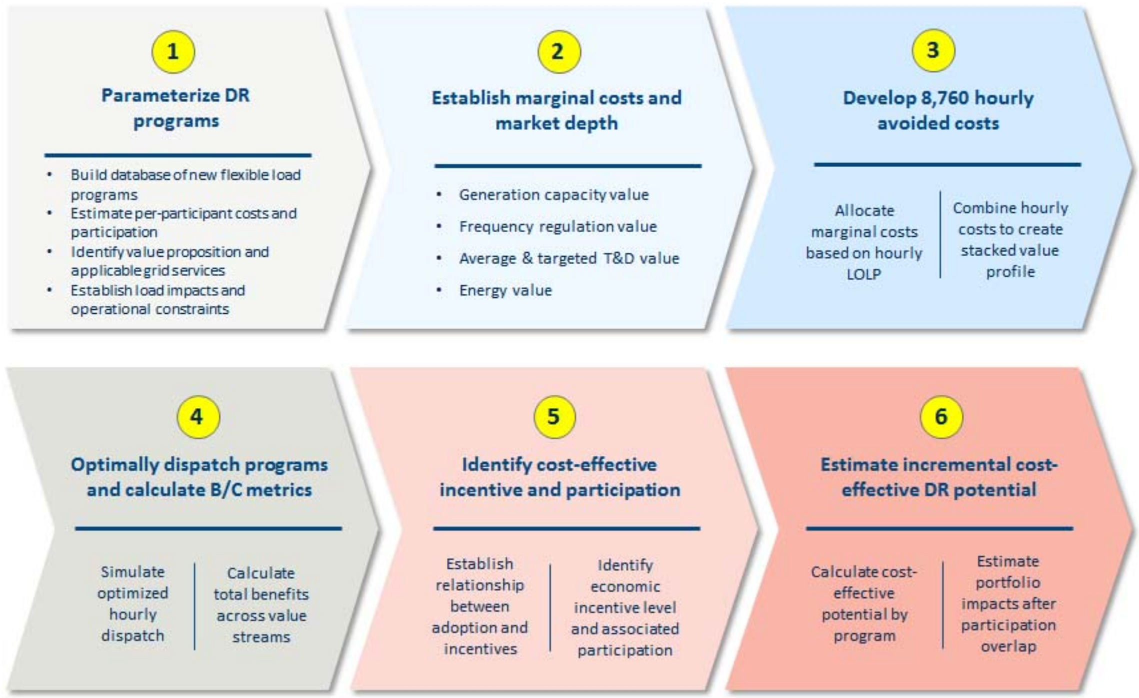
opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 16. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

Figure 16: The Load*Flex* Modeling Framework



Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

Load impact profiles

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from NSP's experience with its existing DR programs and pilots. NSP's experience directly informed the impact estimates for direct load control, smart thermostat, and interruptible rates programs. For emerging non-pricing DR programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to NSP's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- *C&I Auto-DR:* The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[17], a 2013 LBNL study of DR capability[18], and electricity load patterns representative of C&I buildings in Minneapolis developed by the Department of Energy.[19] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the NSP service territory based on assumptions about NSP's mix of C&I customers. Impacts were scaled as necessary for consistency with NSP's prior experience with C&I DR programs.

- *Water heating load control:* Assumptions for the water heating load control programs – both grid interactive water heating and static timed water heating - are derived from a 2016 study on the value of various water heating load control strategies.[20] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- *Behavioral DR:* Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[21] Based on these findings, we assumed that a

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17 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

18 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Laboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

19 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

20 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

21 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower,

behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- *EV managed charging:* Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes provided by Xcel Energy. The ability to curtail this charging load is based on a review of recent utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[22]

- *Ice-based thermal energy storage:* Estimates of load curtailment capability are estimated based on charging and discharging (freezing and cooling) information from Ice Bear[23] and adapted to mirror building use patterns in Minnesota based on load profiles from the U.S. Department of Energy.[24]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings. The database includes the results of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs.[25] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 17.

"Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

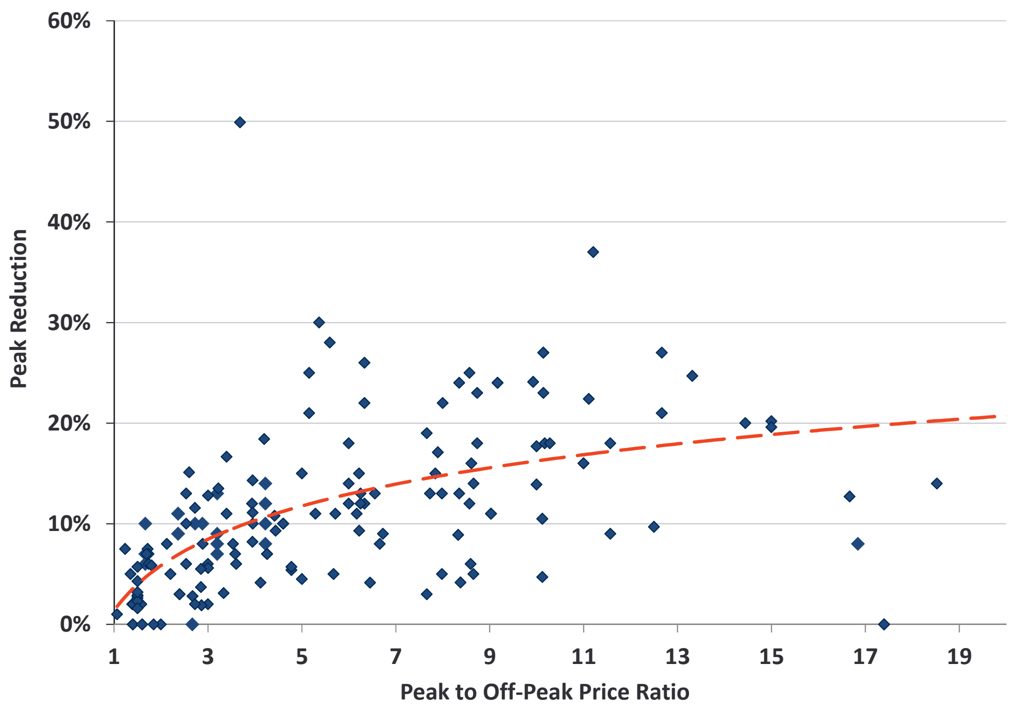
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

23 Ice Energy, "Ice Bear 20 Case Study," November 2016. Available: https://www.ice-energy.com/wp-content/uploads/2016/12/SantaYnez_CaseStudy_Nov2016.pdf

24 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

25 Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal*, 2017.

Figure 17: Relationship between Price Ratio and Price Response in Residential Pricing Pilots



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

Daily relationship between load reduction and load increase

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above. Otherwise, these impacts are derived from assumptions that were developed for FERC's 2009 *A National Assessment of Demand Response Potential*.

Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with

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allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

Ancillary services availability

If a DR program has the advanced control and communications technology necessary to provide ancillary services, Load*Flex* accounts for the capacity that is available to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. In this study, smart water heating and Auto-DR are assumed to be able to offer ancillary services. Specifically, we model frequency regulation as it is the most valuable ancillary services product. Capability is based on the same data sources described above.

Table 6 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

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Table 6: DR Program Performance Characteristics

Segment	Program	Peak-coincident curtailment capability (kW/participant)	Hours of Curtailment (hours)	Average regulation up provided (kW/participant)	Average regulation down provided (kW/participant)	Load shifting capability?
Residential	A/C DLC - SFH	0.62	75	0.00	0.00	No
Residential	Behavioral DR (Opt-out)	0.06	40	0.00	0.00	No
Residential	CPP (Opt-in)	0.34	75	0.00	0.00	No
Residential	CPP (Opt-out)	0.17	75	0.00	0.00	No
Residential	EV Managed Charging - Home	0.46	45	0.00	0.00	Yes
Residential	EV Managed Charging - Work	0.09	45	0.00	0.00	Yes
Residential	Smart thermostat - MDU	0.86	75	0.00	0.00	No
Residential	Smart thermostat - SFH	1.15	75	0.00	0.00	No
Residential	Smart water heating	0.46	4,745	0.37	0.38	Yes
Residential	Timed water heating	0.43	1,825	0.00	0.00	Yes
Residential	TOU - EV Charging (Opt-in)	0.05	1,460	0.00	0.00	Yes
Residential	TOU (Opt-in)	0.17	1,284	0.00	0.00	No
Residential	TOU (Opt-out)	0.08	1,284	0.00	0.00	No
Small C&I	A/C DLC	1.93	75	0.00	0.00	No
Small C&I	Auto-DR (A/C)	1.37	200	0.37	0.49	Yes
Small C&I	Auto-DR (Light Luminaire)	1.07	300	0.52	0.57	Yes
Small C&I	Auto-DR (Light Zonal)	0.92	300	0.44	0.49	Yes
Small C&I	CPP (Opt-in)	0.02	75	0.00	0.00	No
Small C&I	CPP (Opt-out)	0.01	75	0.00	0.00	No
Small C&I	Demand Bidding	0.02	200	0.00	0.00	No
Small C&I	Interruptible	1.98	90	0.00	0.00	No
Small C&I	TOU (Opt-in)	0.01	1,281	0.00	0.00	No
Small C&I	TOU (Opt-out)	0.00	1,281	0.00	0.00	No
Medium C&I	A/C DLC	3.92	75	0.00	0.00	No
Medium C&I	Auto-DR (HVAC)	46.17	430	14.61	14.09	Yes
Medium C&I	Auto-DR (Light Luminaire)	18.22	300	8.62	8.83	Yes
Medium C&I	Auto-DR (Light Zonal)	9.81	300	5.47	5.78	Yes
Medium C&I	CPP (Opt-in)	4.83	75	0.00	0.00	No
Medium C&I	CPP (Opt-out)	2.42	75	0.00	0.00	No
Medium C&I	Demand Bidding	4.43	200	0.00	0.00	No
Medium C&I	Interruptible	27.45	90	0.00	0.00	No
Medium C&I	Thermal Storage	50.97	644	0.00	0.00	Yes
Medium C&I	TOU (Opt-in)	2.31	1,281	0.00	0.00	No
Medium C&I	TOU (Opt-out)	1.39	1,281	0.00	0.00	No
Large C&I	Auto-DR (HVAC)	592.09	430	151.57	207.60	Yes
Large C&I	Auto-DR (Light Luminaire)	416.95	120	191.67	200.74	Yes
Large C&I	Auto-DR (Light Zonal)	224.51	120	103.21	108.09	Yes
Large C&I	CPP (Opt-in)	283.92	75	0.00	0.00	No
Large C&I	CPP (Opt-out)	141.67	75	0.00	0.00	No
Large C&I	Demand Bidding	260.28	200	0.00	0.00	No
Large C&I	Interruptible	483.62	90	0.00	0.00	No

Notes:
Program impacts shown reflect impacts for new participants. Impacts shown assume each program is offered independently.

Program Cost Characteristics

The costs of each program include startup costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.[26]

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26 The Utility Cost Test (UCT) is the cost-effectiveness screen used in this study, which calls for including incentive payments as a cost.

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Cost assumptions are based on NSP's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with NSP's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the *incremental* cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost that is likely to be justified by a broad range of benefits that the new digital infrastructure will provides to customers and to NSP. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 7 summarizes Base Case cost assumptions for 2023 and Table 8 summarizes High Sensitivity Case cost assumptions for 2030. The 2030 assumptions reflect an assumed 25% reduction in the cost (in real terms) of emerging technologies. Costs in both tables are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by NSP and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

Table 7: 2023 Base Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$172	$92	$0	$13	$59	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$4	$0	15
Residential	CPP (Opt-in)	$223,208	$0	$80	$83,703	$2	$0	15
Residential	CPP (Opt-out)	$223,208	$0	$40	$83,703	$2	$0	15
Residential	EV Managed Charging - Home	$0	$229	$0	$0	$17	$45	15
Residential	EV Managed Charging - Work	$0	$229	$0	$0	$17	$45	15
Residential	Smart thermostat - MDU	$0	$126	$92	$0	$11	$28	10
Residential	Smart thermostat - SFH	$0	$126	$92	$0	$11	$28	10
Residential	Smart water heating	$0	$686	$34	$0	$0	$28	10
Residential	Timed water heating	$0	$458	$34	$0	$0	$11	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$83,703	$0	$0	15
Residential	TOU (Opt-in)	$223,208	$0	$57	$83,703	$1	$0	15
Residential	TOU (Opt-out)	$223,208	$0	$29	$83,703	$0	$0	15
Small C&I	A/C DLC	$0	$172	$92	$0	$13	$237	15
Small C&I	Auto-DR (A/C)	$0	$0	$2,218	$0	$22	$112	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,328	$0	$22	$112	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$1,001	$0	$22	$112	15
Small C&I	CPP (Opt-in)	$74,403	$0	$80	$27,901	$0	$0	15
Small C&I	CPP (Opt-out)	$74,403	$0	$40	$27,901	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$691,944	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$280,126	$0	$259	15
Small C&I	TOU (Opt-in)	$74,403	$0	$57	$20,926	$0	$0	15
Small C&I	TOU (Opt-out)	$74,403	$0	$29	$20,926	$0	$0	15
Medium C&I	A/C DLC	$0	$343	$92	$0	$13	$481	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$26,820	$0	$22	$9,444	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$33,220	$0	$22	$4,351	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$24,719	$0	$22	$4,351	15
Medium C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Medium C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$280,126	$0	$249	15
Medium C&I	Interruptible	$0	$0	$0	$280,126	$0	$5,627	15
Medium C&I	Thermal Storage	$0	$120,114	$34	$0	$382	$0	20
Medium C&I	TOU (Opt-in)	$74,403	$0	$1,144	$20,926	$22	$0	15
Medium C&I	TOU (Opt-out)	$74,403	$0	$572	$20,926	$22	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$306,980	$0	$22	$108,307	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$495,047	$0	$22	$86,691	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$367,510	$0	$22	$86,691	15
Large C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Large C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$315,839	$0	$14,651	15
Large C&I	Interruptible	$0	$0	$0	$315,839	$0	$90,997	15

Notes:

All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Table 8: 2030 High Sensitivity Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/part.-yr)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$140	$75	$0	$16	$69	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$5	$0	15
Residential	CPP (Opt-in)	$182,204	$0	$65	$97,609	$2	$0	15
Residential	CPP (Opt-out)	$182,204	$0	$33	$97,609	$2	$0	15
Residential	EV Managed Charging - Home	$0	$187	$0	$0	$20	$52	15
Residential	EV Managed Charging - Work	$0	$187	$0	$0	$20	$52	15
Residential	Smart thermostat - MDU	$0	$103	$75	$0	$13	$33	10
Residential	Smart thermostat - SFH	$0	$103	$75	$0	$13	$33	10
Residential	Smart water heating	$0	$560	$28	$0	$0	$33	10
Residential	Timed water heating	$0	$374	$28	$0	$0	$13	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$97,609	$0	$0	15
Residential	TOU (Opt-in)	$182,204	$0	$47	$97,609	$1	$0	15
Residential	TOU (Opt-out)	$182,204	$0	$23	$97,609	$1	$0	15
Small C&I	A/C DLC	$0	$140	$75	$0	$16	$277	15
Small C&I	Auto-DR (A/C)	$0	$0	$1,810	$0	$26	$130	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,084	$0	$26	$130	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$817	$0	$26	$130	15
Small C&I	CPP (Opt-in)	$60,735	$0	$65	$32,536	$0	$0	15
Small C&I	CPP (Opt-out)	$60,735	$0	$33	$32,536	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$806,905	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$326,666	$0	$302	15
Small C&I	TOU (Opt-in)	$60,735	$0	$47	$24,402	$0	$0	15
Small C&I	TOU (Opt-out)	$60,735	$0	$23	$24,402	$0	$0	15
Medium C&I	A/C DLC	$0	$280	$75	$0	$16	$561	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$21,893	$0	$26	$11,013	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$27,117	$0	$26	$5,074	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$20,178	$0	$26	$5,074	15
Medium C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Medium C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$326,666	$0	$291	15
Medium C&I	Interruptible	$0	$0	$0	$326,666	$0	$6,562	15
Medium C&I	Thermal Storage	$0	$98,049	$28	$0	$445	$0	20
Medium C&I	TOU (Opt-in)	$60,735	$0	$934	$24,402	$26	$0	15
Medium C&I	TOU (Opt-out)	$60,735	$0	$467	$24,402	$26	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$250,588	$0	$26	$126,301	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$404,107	$0	$26	$101,093	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$299,998	$0	$26	$101,093	15
Large C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Large C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$368,313	$0	$17,085	15
Large C&I	Interruptible	$0	$0	$0	$368,313	$0	$106,116	15

Notes:

2030 one-time costs assumed to be 30% lower than 2023 one-time costs (in real terms), reflecting assumed declines in technology costs. All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, additional avoided distribution costs from geo-targeted deployment of the DR programs, frequency regulation, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to NSP's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below, for both the Base Case and the High Sensitivity Case.

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Avoided generation capacity costs

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 100 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore could run for thousands of hours per year. The DR programs considered in this study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year. Energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours.

In the Base Case, the installed cost of new CT capacity is based on data provided directly by NSP and consistent with the assumptions in NSP's 2019 IRP for a brownfield CT. The total cost amounts to $60.60/kW-year; this is sometimes referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services value that would otherwise be provided by that unit. Based on simulated unit profit data provided by NSP, we have estimated the annual energy and ancillary services value to be roughly $5.50/kW-year. The resulting net CONE value is $55.20/kW-year. This calculation is described further in Table 9 below.

This same approach is used to establish the capacity cost for the High Sensitivity Case. Rather than using the CT cost from NSP's IRP, we relied on the U.S. Energy Information Administration's (EIA's) estimate of the installed cost of an Advanced CT from the 2018 Annual Energy Outlook. For the Midwest Reliability Organization West region, this amounts to a gross CONE of $76.80/kW-year. Reducing this value by the same energy and ancillary services value described above leads to a net CONE of $71.40/kW-year.

Table 9: Combustion Turbine Cost of New Entry Calculation

Variable		NSP 2019 IRP Brownfield CT	NSP 2019 IRP Greenfield CT	AEO 2018 Advanced CT
Overnight Capital Cost ($/kW)	[1]	$467	$617	$698
Effective Charge Rate (%)	[2]	10%	10%	10%
Levelized Capital Cost ($/kW-yr)	[3]=[1]x[2]	$46.7	$61.7	$69.8
Annual Fixed Costs ($/kW-yr)	[4]	$13.9	$13.9	$7.0
Gross Cost of New Entry ($/kW-yr)	[5]=[3]+[4]	$60.6	$75.6	$76.8
E&AS Margins ($/kW-yr)	[6]	$5.5	$5.5	$5.5
Net Cost of New Entry ($/kW-yr)	[7]=[5]-[6]	$55.2	$70.2	$71.4

Notes: All costs shown in 2018 dollars. Assumes that overnight capital costs are recovered at 10% effective charge rate. AEO 2018 advanced CT costs shown for the Midwest Reliability Organization West region. Capacity costs are held constant in real terms throughout the period of study.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 8% percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise.[27] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, NSP incorporates a planning reserve margin of 2.4% percent into its capacity investment decisions.[28] This effectively means NSP will plan to have enough capacity available to meet its projected peak demand plus 2.4% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.024 kW of capacity. Including the 2.4% reserve margin adjustment increases the net CONE value described above from $55.2 and $71.4/kW-year to $56.5 and $73.1/kW-year, for the Base and High Sensitivity Cases respectively. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

Avoided transmission capacity costs

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to move electricity to where it is needed during peak times while maintaining a sufficient level of

27 8% represents an average line loss across NSP territories and customer segments. Actual line losses range from 2 to 10%.

28 NSP's planning reserve margin target is 7.8% of load during the MISO peak, which translates into a margin of 2.4% during its own system peak.

reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of NSP's 2017 T&D Avoided Cost Study for energy efficiency programs, we have assumed an avoidable transmission cost of $3.10/kW-year in 2023, rising to $3.60/kW-year in 2030.[29]

Avoided system-wide distribution capacity costs

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the NSP system. For programs that do not provide the higher-value distribution benefits from geo-targeted deployment, as described below, we have assumed that peak demand reductions can produce avoided distribution costs of $8.10/kW-year in 2023, rising to $9.50/kW-year in 2030, based on NSP's 2017 T&D Avoided Cost Study.

Geo-targeted distribution capacity costs

DR participants may be recruited in locations on the distribution system where load reductions would defer the need for local capacity upgrades. This local deployment of the DR program can be targeted at specifically locations where distribution upgrades are expected to be costly.

DR cannot serve as a substitute for distribution upgrades in all cases, such as adding new circuit breakers, telemetry upgrades, or adding distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that DR can be used to reduce local peak loads, the loading on the distribution system is reduced, which means otherwise necessary distribution upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

To quantify geo-targeted distribution capacity deferral value in Load*Flex*, we began with a list of all distribution capacity projects in NSP's five-year plan. Brattle worked with NSP staff to reduce this list to a subset of projects that are likely candidates for deferral through DR. Four criteria were applied to identify the list of candidate deferral projects:

1. The need for the distribution project must be driven by load growth. DR could not be used to avoid the need to simply replace aging equipment, for example.

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[29] Xcel Energy, Minnesota Power, Otter Tail Power Company, Mendota Group & Environmental Economics, "Minnesota Transmission and Distribution Avoided Cost Study," July 31, 2017.

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2. The project must have a meaningful overall cost on a per-kilowatt basis. In our analysis, we required that the cost of the project equate to a value of at least $100,000 per megawatt of reduced demand in order to be considered.[30] This is the equivalent of roughly $7/kW-year on an annualized basis. Projects below this cost threshold were excluded from the geo-targeted deferral analysis.

3. There must be sufficient local customer load in order for the upgrade to be deferrable through the use of DR. For instance, if a 20 MW load reduction would be needed to avoid a specific distribution upgrade, and there was only 25 MW of total load at that location in the system, then DR would not be a useful candidate because it is unlikely that DR could consistently and reliably produce an 80% load reduction. In establishing this criterion, projects with more than 6 MVA of "load at risk"[31] were excluded, as 6 MVA represents about half of the load on a typical feeder.

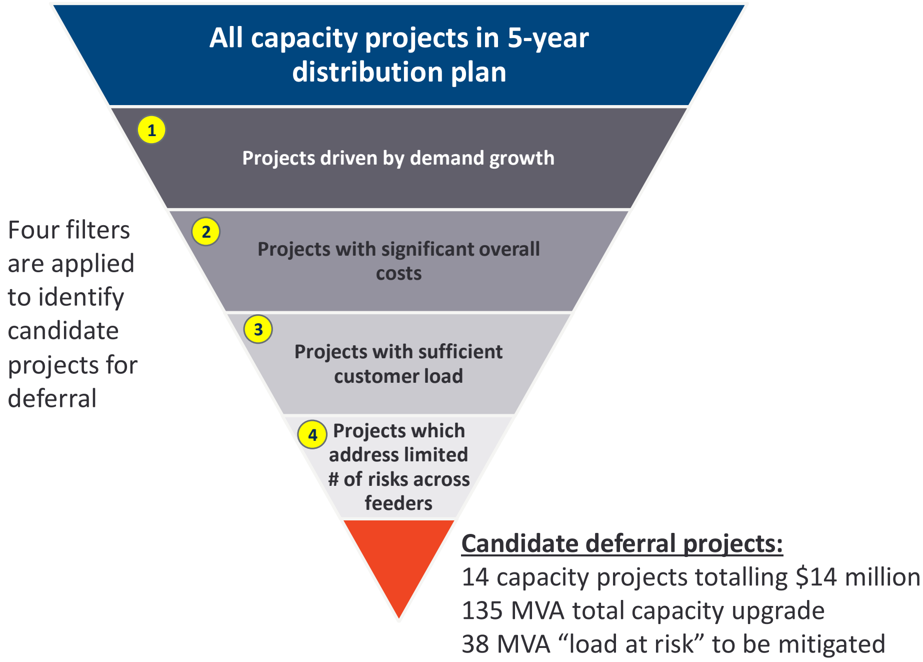
4. The project should not be needed to simultaneously address many risks across feeders. In some cases, distribution upgrades are needed to mitigate a number of different contingencies. There are significant operational challenges associated with using DR in a similar manner. Projects were screened out based on the number and severity of risks that they were intended to address.

After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every five years over the forecast horizon. Figure 17 summarizes the process for identifying geo-targeted distribution deferral opportunities.

30 For simplicity, we assumed 1 MVA = 1 MW.

31 "Load at risk" effectively represents the load reduction that would need to be achieved to defer the capacity upgrade.

Figure 18: Identification of Candidates for Geo-targeted Distribution Investment Deferral



Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system.[32] Hourly energy costs in this study are based on the 2018 MISO Transmission Expansion Plan (MTEP18) modeled day-ahead prices for the NSP hub. These modeled prices were used to capture evolving future system conditions that would not be reflected in historical prices. MTEP18 presents four "futures" that represent broadly different long-term views of MISO energy system, enabling the evaluation of the avoided energy value of DR under different market conditions.

For the Base Case, we relied on prices from MTEP18's Continued Fleet Change (CFC) future. This future assumes a continuation of trends in the MISO market from the past decade: persistent low gas prices, limited demand growth, continued economic coal retirements, and gradual growth in renewables above state requirements.[33] Figure 19 below shows that 2022 energy prices under the

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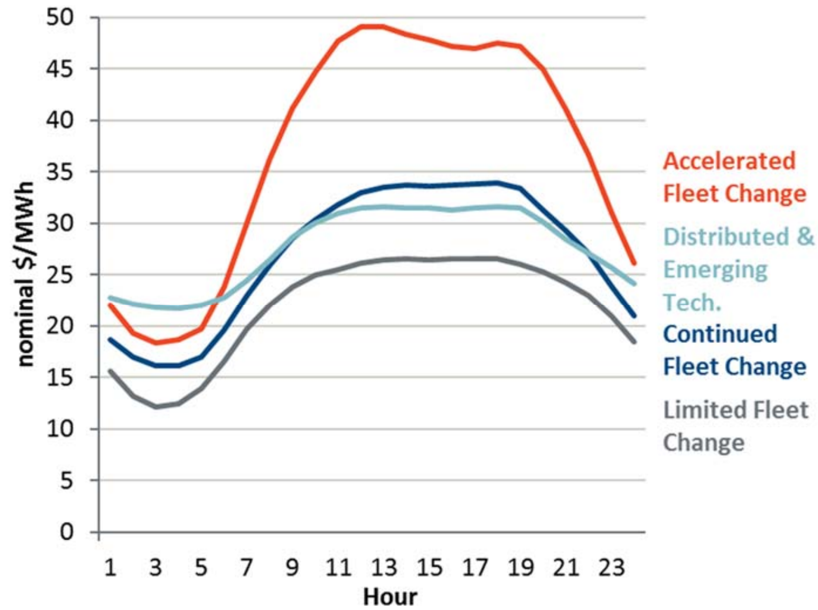
32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, with no net change in costs across the system as a whole.

33 See MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results." for additional details on MTEP18 scenarios.

CFC future lie somewhere in the middle of the four MTEP scenarios (energy prices in other years follow the same relative pattern across scenarios).

Figure 19: Average Energy Price by Hour of Day in 2022 MTEP Scenarios for NSP Hub



For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher energy prices, particularly in daytime hours. For our analysis years (2023, 2025 and 2030), we relied on prices from the nearest MTEP modeling year (2022, 2027, and 2032, respectively) and adjusted them accordingly for inflation (assumed to be 2.2% per year).

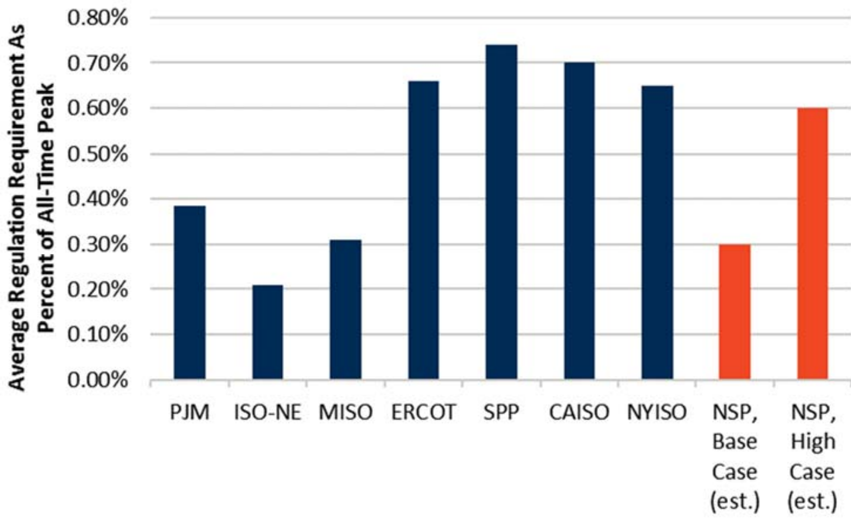
Ancillary services

The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

Frequency regulation is a high value resource with a very limited need. Across most markets, the need for frequency regulation capacity is less than 1% of the system peak. We assume that the frequency regulation needs in the NSP system across all analysis years are 25 MW (0.3% of annual peak) in the Base Case, and 50 MW in the High Sensitivity Case (0.6% of annual peak).[34] Figure 20 summarizes frequency regulation needs across various U.S. markets, demonstrating that the quantities of frequency regulation assumed in this study are consistent with experience elsewhere.

[34] Calculated assuming an annual peak of 8,335 MW after line losses.

Figure 20: Frequency Regulation Requirements Across Wholesale Markets



Sources and Notes: Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation values for all markets are average levels as of 2016.

Because regulation prices were not available from the 2018 MTEP, we utilized 2017 hourly generation regulation prices for the MISO system adjusted for inflation.

Table 10 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

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Table 10: Summary of Avoided Costs/Value Streams in 2023

Value Stream	Quantity of Need		Avoided Cost		Description
	Base Case	High Case	Base Case	High Case	
Avoided Generation Capacity	Unconstrained	Unconstrained	\$63.0/kW-year	\$81.5/kW-year	Base: Xcel's Brownfield CT costs minus estimated CT energy revenues from 2018 IRP, plus 2.4% reserve margin gross-up.
Avoided Transmission Capacity	Unconstrained	Unconstrained	\$3.1/kW-year	\$3.1/kW-year	72% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Avoided Distribution Capacity	Unconstrained	Unconstrained	\$8.0/kW-year	\$8.0/kW-year	28% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Geo-targeted Distribution Capacity	38 MW	38 MW	\$25.8/kW-year	\$25.8/kW-year	Total value of 14 projects identified as eligible for distribution capacity deferral by demand response.
Frequency Regulation	25 MW	50 MW	Avg: \$12.4/MWh	Avg: \$12.4/MWh	2017 MISO regulation prices. Assumes that NSP's share of regulation need is 25 MW in 2023 and 50 MW in 2030.
Avoided Energy	Unconstrained	Unconstrained	Avg: \$27.5/MWh	Avg: \$27.5/MWh	Hourly MISO MTEP18 modeled energy prices for NSP HUB. 2023 used prices from the CFC 2022 scenario, and 2030 used prices from the AFC 2032 scenario.
Top 10% Average			\$50.5/MWh	\$71.3/MWh	
Bottom 10% Average			\$8.1/MWh	\$8.6/MWh	

Notes: All values shown in nominal dollars. 2030 avoided costs are similar, rising at inflation.

Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

Capacity costs are allocated across the top 100 load hours of the year. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 100th load hour.

Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both generic distribution capacity deferral and geo-targeted distribution capacity deferral value

[35] Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

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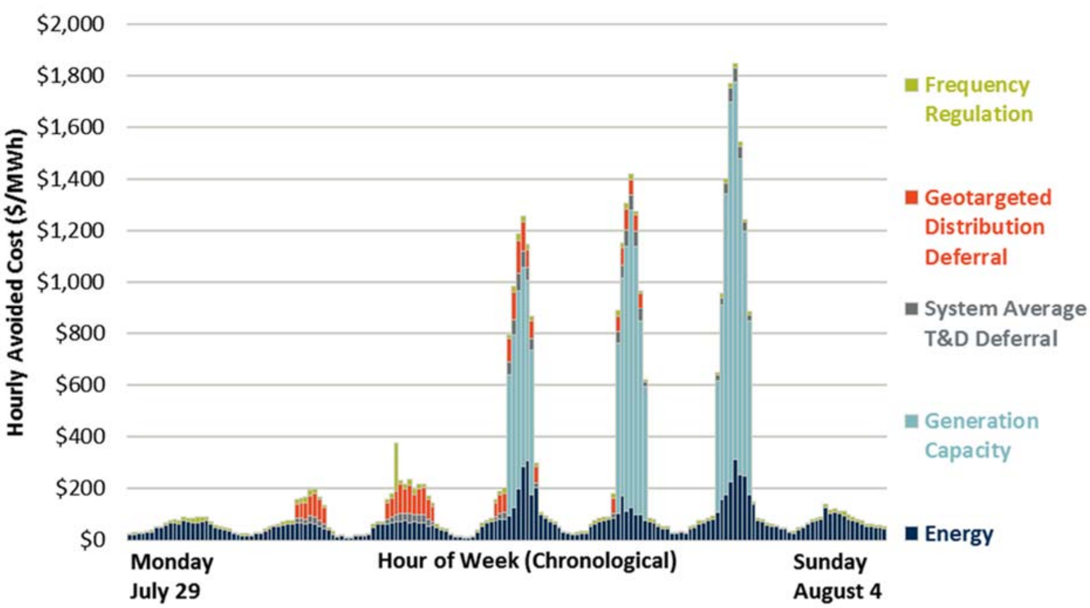
are allocated over a larger number of peak hours (roughly 330 hours, rather than 100 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

Figure 21: Chronological Allocation of Marginal Costs (Illustration for Week of July 29)



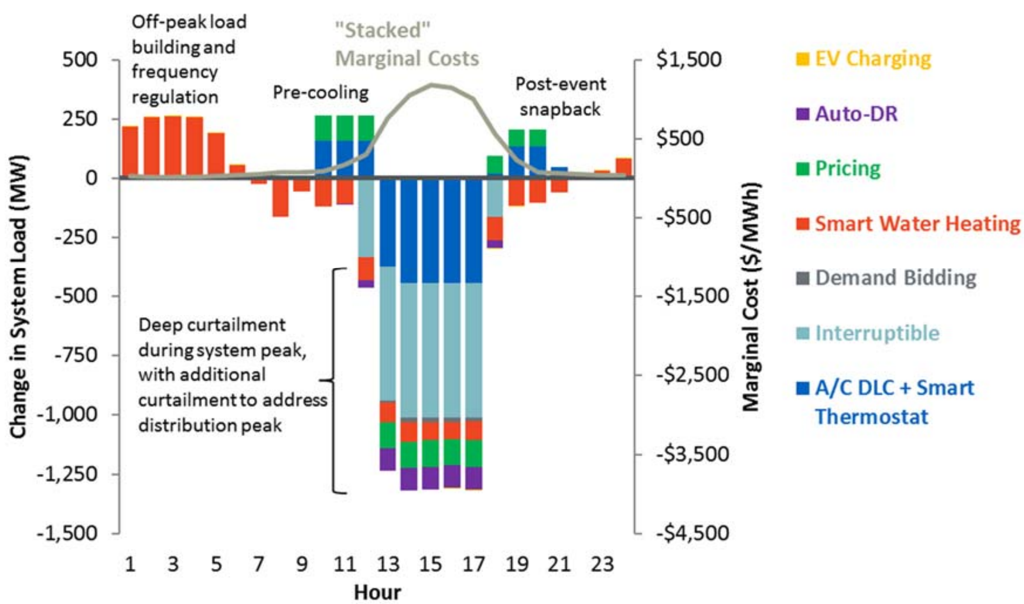
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for tradeoffs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use. Figure 22 illustrates how the dispatch of the High Sensitivity Case portfolio in this study compares to the hourly cost profile on those same days.

Figure 22: Illustrative Program Operations Relative to "Stacked" Marginal Costs



Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited for services that do not provide additional value to the system.

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Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in NSP's service territory at a "typical" incentive payment level. The estimates are tailored to NSP's customer base using data on current program enrollment, as well as survey-based market research conducted directly with NSP's customers.[36] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to NSP's customer base.

Table 11 summarizes these "base" participation rates for conventional DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning.

The 2017 values represent current participation levels. Values in future years reflect participation rates if the programs were offered as part of an expanded DR portfolio. This accounts for the fact that a single customer could not simultaneously participate in two different programs.

Residential air-conditioning load control participation assumptions reflect a transition from compressor switch-based direct load control program to a smart thermostat-based program. These programs are currently marketed by NSP as "Savers Switch" and "AC Rewards", respectively. Based on the aforementioned primary market research conducted in NSP's service territory, we estimate that a 66% participation rate among eligible customers is achievable at the medium incentive level for these programs collectively. In 2017, participation in air-conditioning load control programs reached 52% of eligible residential customers, mostly through the Savers Switch program. In the future, NSP will increase its marketing emphasis on the AC Rewards program as its primary air-conditioning load control program. Therefore, we assume that achievable incremental participation in residential air-conditioning load control transitions from an equal split between AC Rewards and Savers Switch in 2018 to a 75/25 split in favor of AC Rewards by

36 Ahmad Faruqui, Ryan Hledik, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," April 2014.

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2023. Additionally, NSP will focus on transitioning customers from Savers Switch to AC Rewards as compressor switches reach the end of their useful life. Based on information about the age of deployed switches and conversations with NSP, we assume that the number of switches replaced by smart thermostats grows from around 6,600/year in 2018 to 10,000/year in 2023 and onwards.

It is important to note that the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive levels.[37] Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

Table 11: Participation Assumptions for Conventional DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	A/C DLC - SFH	52%	50%	39%
Residential	Smart thermostat - SFH	0%	16%	24%
Residential	Smart thermostat - MDU	0%	35%	32%
Small C&I	A/C DLC	0%	30%	30%
Small C&I	Interruptible	0%	14%	12%
Small C&I	Demand Bidding	0%	2%	1%
Medium C&I	A/C DLC	73%	64%	64%
Medium C&I	Interruptible	3%	13%	11%
Medium C&I	Demand Bidding	0%	6%	5%
Large C&I	Interruptible	12%	44%	43%
Large C&I	Demand Bidding	0%	5%	4%

Notes:
Participation rates shown for programs at the portfolio level (i.e. accounts for program overlap). Lower participation rates for some programs in 2030 relative to 2023 result from customers switching to an opt-in CPP rate (for which participation estimates are shown separately). High Medium C&I participation in A/C DLC is relative to a small portion of the customer segment that is eligible for enrollment.

Table 12 illustrates the potential participation rates for each new DR program analyzed in the study. As noted above, these enrollment rates are consistent with "base" incentive payment levels and do not reflect enrollment associated with cost-effective payment levels. **Here, participation in each program is shown as if the program were offered in isolation.** In other words, it is the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

[37] This is the basis for our estimate of "technical potential".

Table 12: Participation Assumptions for New DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	Behavioral DR (Opt-out)	0%	80%	80%
Residential	CPP (Opt-in)	0%	0%	20%
Residential	CPP (Opt-out)	0%	0%	80%
Residential	EV Managed Charging - Home	0%	20%	20%
Residential	EV Managed Charging - Work	0%	20%	20%
Residential	Smart water heating	0%	15%	50%
Residential	Timed water heating	0%	50%	50%
Residential	TOU - EV Charging (Opt-in)	0%	0%	20%
Residential	TOU (Opt-in)	1%	0%	16%
Residential	TOU (Opt-out)	0%	0%	80%
Small C&I	Auto-DR (A/C)	0%	5%	5%
Small C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Small C&I	Auto-DR (Light Zonal)	0%	5%	5%
Small C&I	CPP (Opt-in)	0%	0%	20%
Small C&I	CPP (Opt-out)	0%	0%	80%
Small C&I	TOU (Opt-in)	3%	0%	10%
Small C&I	TOU (Opt-out)	0%	0%	80%
Medium C&I	Auto-DR (HVAC)	0%	5%	5%
Medium C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Medium C&I	Auto-DR (Light Zonal)	0%	5%	5%
Medium C&I	CPP (Opt-in)	0%	14%	14%
Medium C&I	CPP (Opt-out)	0%	79%	79%
Medium C&I	Thermal Storage	0%	3%	3%
Medium C&I	TOU (Opt-in)	21%	19%	19%
Medium C&I	TOU (Opt-out)	0%	0%	80%
Large C&I	Auto-DR (HVAC)	0%	5%	5%
Large C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Large C&I	Auto-DR (Light Zonal)	0%	5%	5%
Large C&I	CPP (Opt-in)	0%	22%	22%
Large C&I	CPP (Opt-out)	0%	81%	81%
Large C&I	TOU (Opt-in)	100%	100%	100%

Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In Load*Flex* model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum

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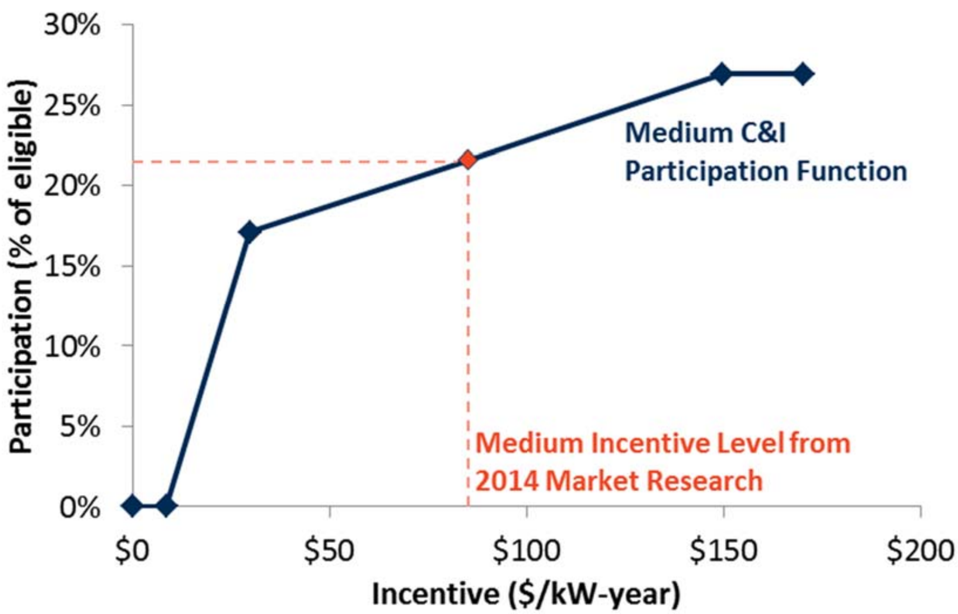
potential cost-effective participation for the program.[38] The DR adoption function for each program is derived from the results of the aforementioned 2014 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

An illustration of the participation function for the Medium C&I Interruptible program is provided in Figure 23. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $85/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $25/kW-yr, customer willingness to enroll in the program quickly drops off.

Figure 23: Medium C&I Interruptible Tariff Adoption Function



Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use (e.g., timed water heating and smart water heating), so their impacts are not additive.

38 In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

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In instances where two cost-effective programs target the exact same end-use, we have assumed that the portfolio would only include the program that produces the larger impact by the end of the study horizon. In the water heating example, this means that the smart water heating program was included and the timed water heating program was not.

In other cases, two "competing" programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

Appendix B: NSP's Proposed Portfolio

At a stakeholder meeting on August 8, 2018, NSP presented a draft portfolio of proposed DR programs. The DR portfolio that NSP is considering consists of the programs and deployment years summarized in Table 13.

Table 13: NSP's Draft Portfolio of DR Programs

Program	First Year of Rollout
Saver's Switch	Existing
A/C Rewards	Existing
EV home charging control	2020
Med/large C&I Auto-DR	2021
Med/large C&I interruptible tariff (program expansion)	2021
Med/large C&I Opt-in CPP	2022
Residential smart water heating	2023
Residential behavioral DR	2023
Residential opt-out TOU	2024

The potential for this portfolio was quantified under the Base and High Sensitivity cases for years 2023 and 2030. Results are summarized in Table 14. In the table, the values in the row labeled "All Proposed Programs" indicate the incremental technical potential in each of the programs that have been proposed by NSP. The values in the row "Cost-Effective Proposed programs" indicate the amount of incremental DR in the proposed programs that can be achieved at cost-effective incentive payment levels. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

Table 14: Incremental Potential in NSP's Draft Portfolio of DR Programs (MW)

	Base Case		High Sensitivity Case	
	2023	**2030**	**2023**	**2030**
All Proposed Programs	642	907	658	927
Cost-Effective Proposed Programs	262	461	411	677

Note: Values shown are incremental to the existing 850 MW portfolio.

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Appendix C: Base Case with Alternative Capacity Costs

For its 2019 IRP, NSP has developed cost assumptions for new CT capacity at brownfield and greenfield sites. Our Base Case assumptions rely on brownfield CT costs as the avoided generation cost estimate, as this is the lowest cost option available to NSP for future peaking generation development. To test the sensitivity of our findings to that assumption, we modeled an alternative case in which the avoided capacity cost in the Base Case is based on a greenfield CT rather than a brownfield CT.[39] Other Base Case assumptions remained unchanged.

The greenfield CT capacity cost is higher than the brownfield CT cost, which increases the benefits of DR programs due to higher avoided generation costs. Relative to the Base Case, the cost-effective incremental potential in the DR portfolio increases by 73 MW in 2023 and by 119 MW in 2030. Nearly all of this increase in potential is attributable to a further expansion of participation in programs that were already cost-effective in the Base Case. The additional potential is mostly in the smart thermostat program, increases from 112 MW to 148 MW in 2023 and from 169 MW to 220 MW in 2030. Other programs that were economic in the Base Case (residential smart water heating, additional C&I interruptible, and demand bidding) also have small increases in cost-effective potential.

The only program that was initially uneconomic under Base assumptions but becomes economic under the greenfield CT capacity cost assumption is HVAC-based Auto-DR: 3 MW of Large C&I Auto-DR becomes cost-effective in 2023, growing to 6 MW in 2030 (in addition to 32 MW of Medium C&I Auto-DR). Together, these programs account for 4% of additional potential in 2023, but over 30% of additional potential in 2030.

Table 15 compares the portfolio-level incremental DR potential for the Base Case with brownfield CT costs to the alternative case with greenfield CT costs. Annual program-level potential estimates are provided in Appendix D.

[39] Table 9 of this report summarizes the greenfield, brownfield and AEO 2018 CT costs used in this analysis.

Table 15: Incremental Cost-Effective Potential in Portfolio of DR Programs with Alternative CT Costs (MW)

	2023	2030
Base Case (Brownfield CT Cost)	306	468
Alternative Case (Greenfield CT Cost)	378	587
Difference (Alternative - Base)	73	119

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	6	11	17	23	29	30	34	40	49	60
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	20	20	20	20	20	20	20
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	1	1	4	6	6	6	6	7	7
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	4	9	13	17	22	23	25	29	35	42
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	19	19	19	21	22	22	22	22	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	32	32	32	31	30	30	30	30	30	30
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	14	18	16	15	15	15	15	15	15
Medium C&I	Interruptible	45	45	45	31	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	1	6	7	6	5	5	5	5	5	5
Large C&I	Interruptible	58	58	58	55	51	51	50	49	48	47
Portfolio-Level Total		**276**	**296**	**306**	**338**	**393**	**405**	**418**	**433**	**450**	**468**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	180	180	180	204	227	245	262	280	298	315
Residential	Smart water heating	6	13	19	26	33	34	38	44	53	65
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	21	21	21	21	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	19
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	2	10	12	12	12	12	12	12	13	13
Residential	Smart thermostat - SFH	148	148	148	159	170	180	190	200	210	220
Residential	Smart water heating	5	10	15	21	26	27	30	35	42	51
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	31	31	31	31	32	32	32	32	32	32
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	9	18	20	23	26	29	32
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	19	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	21	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	1	2	3	4	5	5	5	5	6	6
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	6	5	5	5	5	5	5
Large C&I	Interruptible	61	61	61	58	54	53	52	51	50	49
Portfolio-Level Total		**335**	**365**	**378**	**418**	**480**	**498**	**517**	**538**	**562**	**587**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	17	17	17	17	17	17	17
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	11	45	57	66	76	76	75	75	75	74
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	17	21	21	21	22	22	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	3	12	15	15	15	15	15	15	15	15
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	32	32	32	32	32	32	32	33	33	33
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	20	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	7	5	5	5	5	5	5
Large C&I	Interruptible	62	62	62	58	55	54	53	52	51	50
Portfolio-Level Total		**380**	**454**	**484**	**524**	**586**	**603**	**623**	**647**	**674**	**705**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	0	0	8	15	22	23	26	31	39	48
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	0	0	8	13	18	19	21	25	30	36
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	21	21	21	22	23	23	23	23	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	14	14	14	14	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	13	13	13	15	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	52	52	52	52	51	51	50	49	48	47
Portfolio-Level Total		**213**	**223**	**262**	**384**	**400**	**410**	**420**	**433**	**446**	**461**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	36	36	36	34	33	33	34	34	34	34
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	15	15	15	15	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	14	14	14	15	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	56	56	56	55	55	54	53	52	51	50
Portfolio-Level Total		**309**	**359**	**411**	**543**	**570**	**585**	**603**	**624**	**649**	**677**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Docket No. E002/M-21-814

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Xcel Energy		Information Request No.	81
Docket No.:	E002/M-21-814		
Response To:	Minnesota Department of Commerce		
Requestor:	Matthew Landi and Ben Havumaki		
Date Received:	October 5, 2022		

Question:
Topic: Incremental DI benefits and costs
Reference(s): Xcel's 2021-2022 TCRR Petition – Supplement Filing

Request:
1. For the benefits and costs in Table 7
    a. Please provide these benefits and costs in the same breakout as shown in Figures 4 and 5.
    b. Please provide just the incremental costs and incremental benefits that are included in Table 7 but not in Table 6 (i.e., the costs associated with DI) by the same categories as those included in Figures 4 and 5.

Response:
a. Please see Figures 1 and 2 below. Regarding Figure 2, we note that the Load Flexibility benefit of AMI-FAN CBA is not identical to the Energy Savings benefit of DI. The Load Flexibility benefit includes customer bill savings and avoided carbon emissions from time of use rates, as well as avoided revenue requirements from Critical Peak Pricing. The Energy Savings benefit of DI reflects only customer bill savings. For purposes of this response, Load Flexibility and Energy Savings are shown together in Figure 2.

Figure 1: AMI-FAN-DI 2022 Capital and O&M – NPV

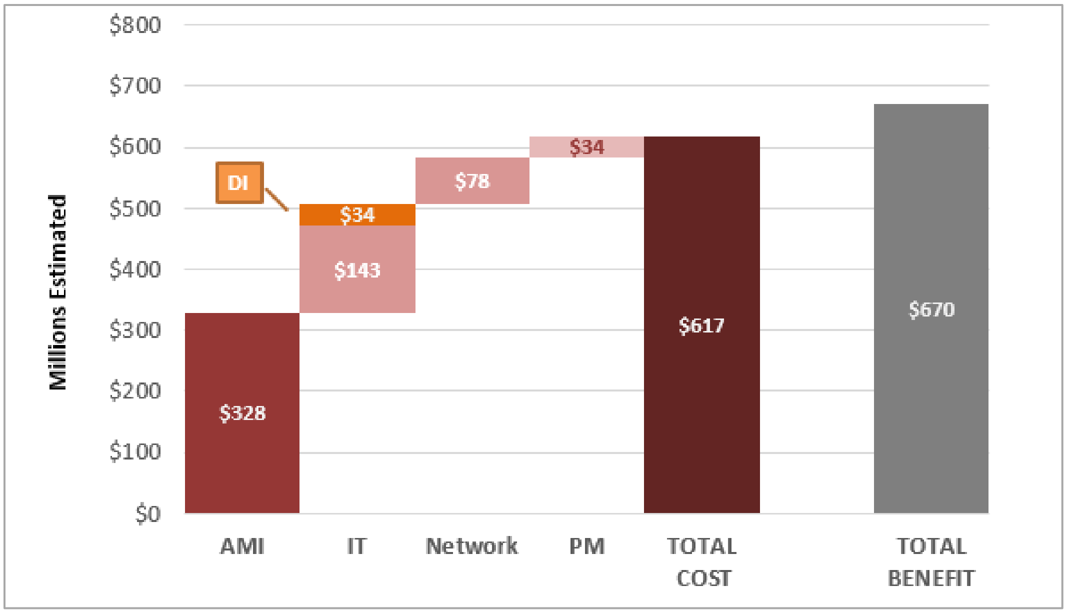
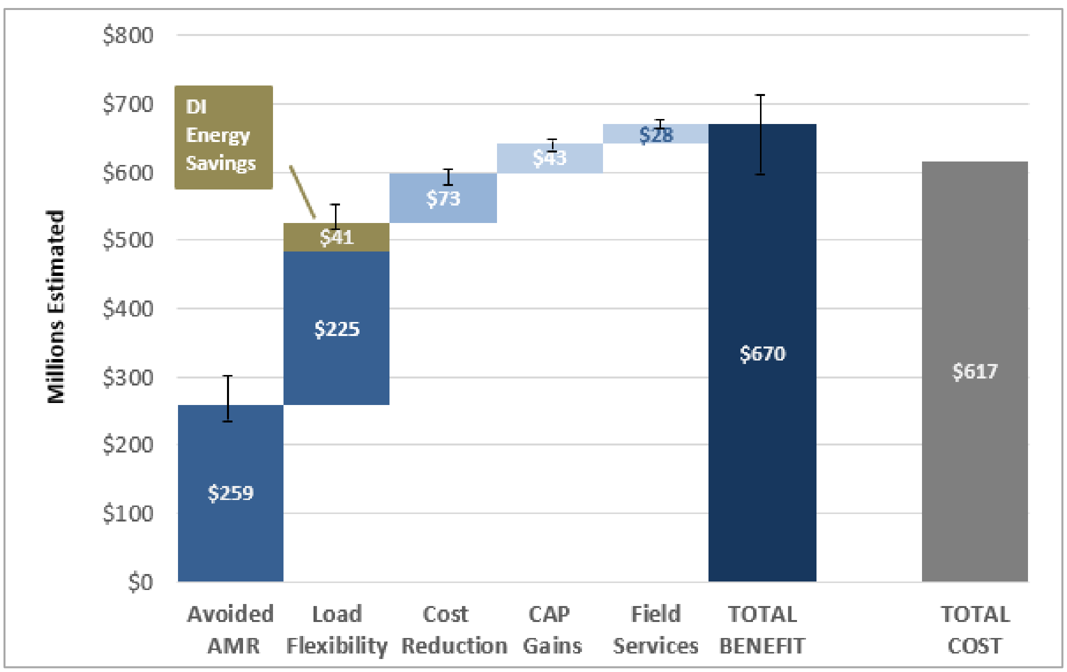


Figure 2: AMI-FAN-DI 2022 Benefit Base Scenario – NPV



b. Please see Figures 3 and 4 below.

Figure 3: DI 2022 Capital and O&M – NPV

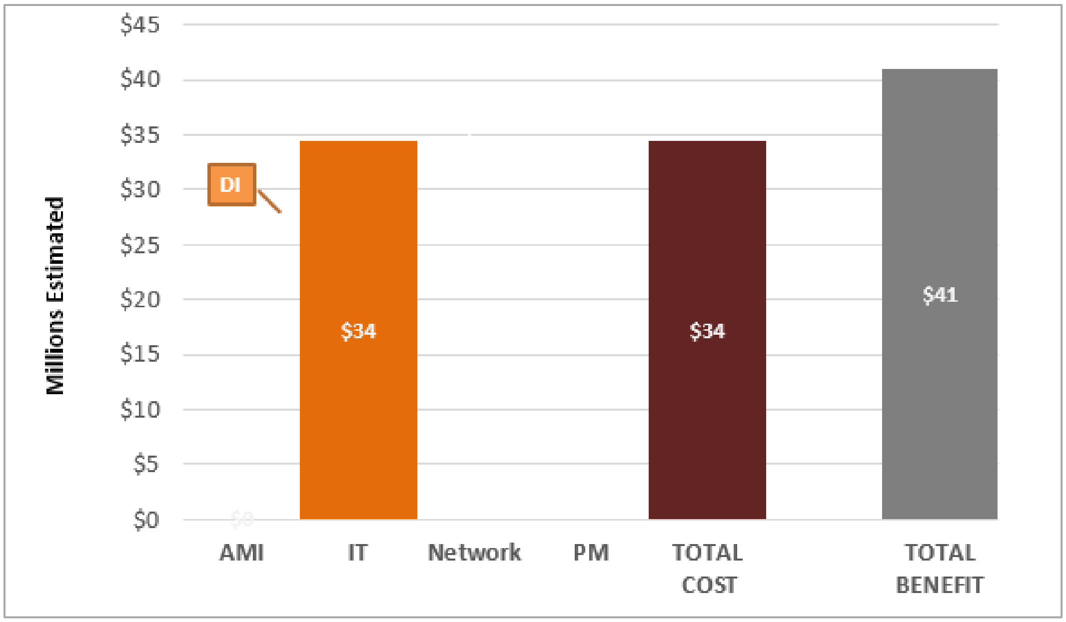
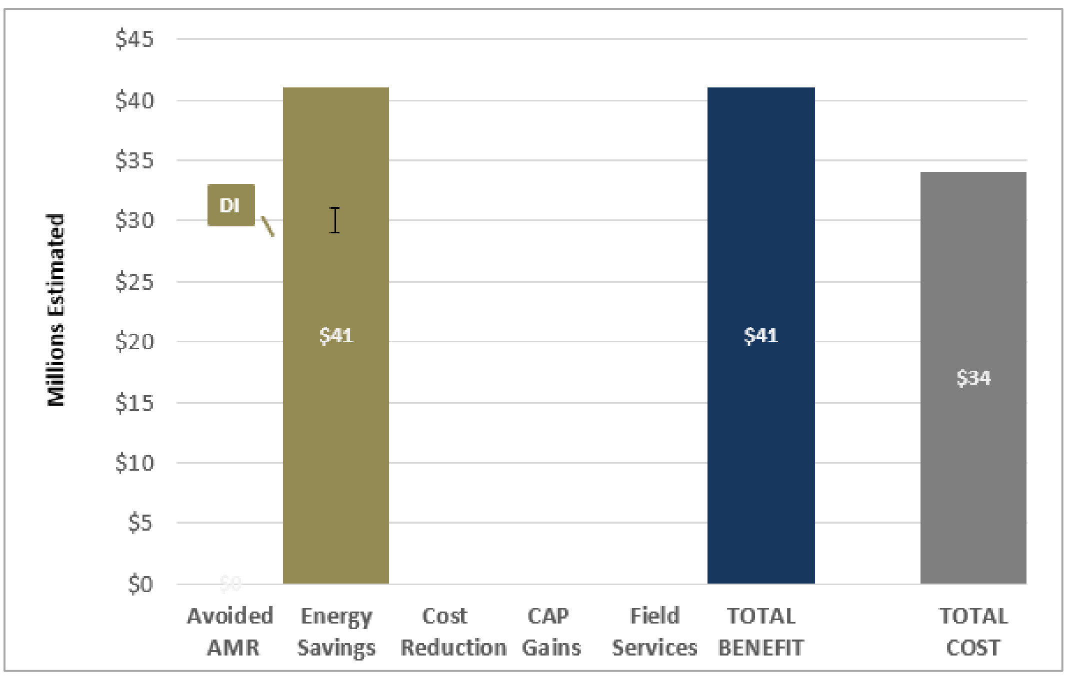


Figure 4: DI 2022 Benefit Base Scenario – NPV



Preparer:	Pablo Martinez
Title:	Senior Principal Risk
Department:	Risk Analytics
Telephone:	303-571-7639
Date:	October 12, 2022

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☒ **Public Document**

Xcel Energy		Information Request No. 88
Docket No.:	E002/M-21-814	
Response To:	Minnesota Department of Commerce	
Requestor:	Matthew Landi and Ben Havumaki	
Date Received:	October 5, 2022	

Question:
Topic: Qualitative benefits
Reference(s): Xcel's 2021-2022 TCRR Petition – Supplement Filing, Attachment D

Request:
1. For each of the qualitative benefits discussed, please indicate whether the Company ultimately anticipates that it will be able to quantify this impact, and if so, when the Company anticipates that it will be able to quantify this impact.

Response:
As discussed in Attachment D, we do have existing mechanisms to broadly measure these benefit areas:

- Improved customer choice and experience, leading to customer empowerment and satisfaction,
- Enhanced integration of distributed energy resources (DER),
- Environmental benefits of enhanced energy efficiency,
- Improved safety to both customers and Company employees, and,
- Improvements in power quality.

We do not anticipate being able to quantify these benefits in the context of AMI and FAN. As noted, the benefits cannot necessarily be directly attributed to AMI/FAN deployment; the direct contribution of AMI/FAN to these benefits cannot be parsed out; or many assumptions would need to be made in the absence of established methodologies for quantification. These limiting factors will remain.

That said, as we noted in Attachment D, we can report quantitative data that is *related* to customer satisfaction and AMI/FAN.

Preparer:	Karin Haas
Title:	Regulatory Policy Specialist
Department:	Regulatory Affairs
Telephone:	612-216-5690
Date:	October 12, 2022

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E002/M-20-680 and E002/M-21-814

Dated this **17th** day of **October 2022**

/s/Sharon Ferguson

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LORI	CLOBES	lclobes@mienergy.coop	MiEnergy Cooperative	31110 COOPERATIVE WAY PO BOX 626 RUSHFORD, MN 55971	Electronic Service	No	OFF_SL_21-814_M-21-814
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-814_M-21-814
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Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_21-814_M-21-814
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_21-814_M-21-814
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_21-814_M-21-814
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_21-814_M-21-814
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-814_M-21-814
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_21-814_M-21-814

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_21-814_M-21-814
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-814_M-21-814
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_21-814_M-21-814
Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate	75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul, MN 55155	Electronic Service	No	OFF_SL_21-814_M-21-814
Brian	Draxten	bhdraxten@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Electronic Service	No	OFF_SL_21-814_M-21-814
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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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Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_21-814_M-21-814
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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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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-814_M-21-814
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