414 Nicollet Mall
Minneapolis, MN 55401

November 15, 2019

**—Via Electronic Filing—**

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

RE: PETITION
TRANSMISSION COST RECOVERY RIDER
DOCKET NO. E002/M-19-____

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition for approval of 2019 and 2020 Transmission Cost Recovery Rider revenue requirements and the resulting adjustment factors by customer class.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service list.

If you have any questions regarding this filing please contact Rebecca Eilers at (612) 330-5570 or rebecca.d.eilers@xcelenergy.com or me at (612) 330-5941 or holly.r.hinman@xcelenergy.com.

Sincerely,

/s/

HOLLY HINMAN
REGULATORY MANAGER

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| Katie J. Sieben | Chair |
| Dan Lipschultz | Commissioner |
| Valerie Means | Commissioner |
| Matthew Schuerger | Commissioner |
| John A. Tuma | Commissioner |

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2019 AND 2020, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-19-___

**PETITION AND COMPLIANCE FILING**

## OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition requesting approval of proposed Transmission Cost Recovery (TCR) Rider revenue requirements for 2020 of approximately $81.9 million, which includes the 2019 carryover balance, and the corresponding TCR adjustment factors. This is a decrease from the $89.9 million revenue requirements approved in our 2017-2018 TCR.

At a high level, we propose to recovery three different categories of costs in the TCR:

- Costs related to one new transmission project—Huntley-Wilmarth 345 kV Transmission Line, which recently received a Certificate of Need and Route Permit from the Commission.
- Costs related to one distribution-grid modernization project previously certified by the Commission—Advanced Distribution Management System (ADMS). For the 2019-2020 recovery period, we are requesting approval of revenue requirements based on approximately $27.2 million in forecasted ADMS capital expenses, incremental above base rates.
- Costs for the transmission projects currently in the TCR Rider, but only until final rates are implemented at the conclusion of the Company's rate case filed on November 1, 2019.

Recovering costs for the projects currently in the TCR Rider is consistent with the Settlement in our most recently decided rate case and our proposal in the currently pending rate case. In accordance with the Settlement approved by the Commission in the Company's last concluded electric rate case, the three CapX2020 transmission projects currently included in the TCR Rider remain in the rider through the multi-year rate plan period (2016 through 2019) in lieu of rolling the projects into base rates.[1] In the Company's recently-filed electric multi-year rate plan (MYRP), however, we propose to roll into base rates the TCR Rider transmission projects that have been placed in-service as of December 31, 2019. In other words, all of the transmission projects currently being recovered through the rider are proposed to roll into base rates beginning with the 2020 test year. However, due to the anticipated length of time until final rates will be implemented at the conclusion of the rate case, we propose to continue recovery of these projects through the TCR Rider until final rates are implemented in the MYRP. These projects are not included in our interim rate request for the 2020 test year or the 2021 plan year, so there will be no double recovery between interim rates and the TCR Rider.

Revenue requirements have decreased slightly from 2018 revenue requirements in part because of a larger MISO RECB credit and a larger carryover from 2017 to 2018 than from 2018 to 2019. In addition, most of the transmission projects have been in service for at least a year, and so the revenue requirements decline for those projects as the newer projects ramp up and get closer to being placed in-service.

If our Petition is approved as proposed, the average residential customer using 675 kWh of electricity per month would be charged approximately $2.43 per month through the TCR Rider factor. This is a decrease of $0.23 per month compared to the current TCR adjustment factor.

Xcel Energy respectfully requests the Commission approve:

- TCR Rider eligibility of the Huntley-Wilmarth 345 kV Transmission Line project;
- 2019-2020 revenue requirements of $81,883,541;
- the resulting TCR adjustment factors by class to be included in the Resource Adjustment on bills for Minnesota electric customers for the 12 months beginning February 1, 2020;
- the ability to recalculate the adjustment factor for implementation in compliance based on the timing of the Commission's decision; and
- the proposed tariff revisions and customer notice.

[1] Docket No. E002/GR-15-826; FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 12, 2017).

Our Petition is structured as follows:

- Background;
- TCR Eligible Projects;
- 2019 and 2020 TCR Revenue Requirements and Adjustment Factors;
- TCR Variance Analysis Report;
- Removal of Internal Labor Costs;
- True-Up Report and Tracker Balance; and
- Proposed Tariff Sheet and Customer Notice.

## I. SUMMARY OF FILING

Pursuant to Minn. Rule 7829.1300, Subp. 1, a one paragraph summary of our filing accompanies this Petition.

## II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, copies of the summary of this filing have been served on the parties on Xcel Energy's miscellaneous electric service list.

## III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

### A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

### B. Name, Address, and Telephone Number of Utility Attorney

Mara K. Ascheman
Senior Attorney
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
(612) 215-4605

## C. Date of Filing and Proposed Effective Date of Rates

The date of this filing is November 15, 2019. The Company proposes the updated TCR adjustment factors be included in the Resource Adjustment line on the Company's retail electric billing rates effective the first day of the month following the Commission's Order approving this Petition. The proposed adjustment factor has assumed an implementation date of February 1, 2020 to allow for the required 60 day notice prior to a rate or tariff change. Should the Commission approve this Petition after February 1, 2020, we propose to recalculate the adjustment factor for implementation in compliance based on the timing of the Commission's decision.

## D. Statutes Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.16, Subd. 1 allows a utility to place a rate change in effect upon 60-days' notice to the Commission. Minn. Stat. § 216B.16, Subd. 7b (the Transmission Statute) allows for recovery, through an automatic adjustment mechanism of charges, the Minnesota jurisdictional costs of certain new transmission facilities, facilities and planning investments that support grid modernization efforts, and certain Midcontinent Independent Transmission System Operator (MISO) charges associated with regionally planned transmission projects. Minn. Stat. § 216B.1645 (the Renewable Energy Statute) allows for recovery, through an automatic adjustment mechanism, of all investments or expenditures entered into by a public utility in connection with satisfying renewable energy mandates of the Legislature.

Since no determination of Xcel Energy's general revenue requirement is necessary, Commission Rules define this filing as a "miscellaneous filing" under Minn. Rule 7829.0100, Subp. 11. The accounting process that we use to track revenues and costs and record the differences in the TCR Rider Tracker account comply with Accounting Standards prescribed under Minn. Stat. § 216B.10. Pursuant to Minn. Rule 7829.1400, initial comments on a miscellaneous filing are due within 30 days of filing, with replies due 10 days thereafter.

## E. Utility Employee Responsible for Filing

Holly Hinman
Regulatory Manager
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-5941

## IV. MISCELLANEOUS INFORMATION

The Company will serve a copy of the Petition summary on those persons on the electric utility general service list. Pursuant to Minn. Rule 7829.0700, we request that the following persons be placed on the Commission's official service list for this matter:


| | |
|---|---|
| Mara K. Ascheman | Lynnette Sweet |
| Senior Attorney | Regulatory Administrator |
| Xcel Energy | Xcel Energy |
| 414 Nicollet Mall, 401 - 8th Floor | 414 Nicollet Mall, 401 - 7th Floor |
| Minneapolis, MN 55401 | Minneapolis, MN 55401 |
| mara.k.ascheman@xcelenergy.com | regulatory.records@xcelenergy.com |


Any information requests in this proceeding should be submitted to Ms. Sweet at the Regulatory Records email address above.

## V. BACKGROUND

In 1997, the Renewable Energy Statute was enacted, authorizing the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for costs associated with utility investments or costs to comply with renewable energy mandates. In 2005, the Transmission Statute was enacted, authorizing the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for costs associated with eligible utility investments in transmission facilities, and in 2008 this statute was amended to allow inclusion of the costs of certain regional transmission facilities as determined by MISO.

The Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 approved the Company's TCR Rider tariff, which combined recovery of eligible projects under the Renewable Statute and the Transmission Statute in one annual automatic adjustment mechanism.

Since 2006, the Company's TCR Rider mechanism has been modified several times to allow recovery of additional costs subsequently authorized by the Minnesota Legislature. The Commission's March 20, 2008 Order in Docket No. E002/M-07-1156 approved recovery of greenhouse gas infrastructure costs incurred for the replacement of circuit breakers that contain sulfur hexafluoride (SF6). The Commission's June 25, 2009 Order in Docket No. E002/M-08-1284 approved recovery of Regional Expansion Criteria and Benefits (RECB) revenues and costs. In 2013, the Transmission Statute was modified to authorize TCR Rider eligibility of projects located in other states that have been approved by the regulatory commission of the state in which the new transmission facilities are to be constructed if those projects are determined by MISO to benefit the utility or integrated transmission system.

In 2015, the Transmission Statute was further modified to allow for the cost recovery of facilities and planning investments that support distribution-grid modernization efforts. Such projects must be certified by the Commission under Minn. Stat. § 216B.2425 in order to be eligible for rider recovery. The Commission's September 27, 2019 Order in Docket No. E002/M-17-797 approved rider recovery for the ADMS project, the first distribution-grid modernization project to be certified as part of the Company's first Biennial Grid Modernization Report originally filed in 2015 (Docket No. E002/M-15-962).[2]

We have categorized calculations associated with project costs and revenue requirements in four groups: (1) Transmission Statute projects; 2) Distribution-Grid Modernization projects authorized under the Transmission Statute; (3) Renewable Statute projects; and (4) Greenhouse Gas projects. It has been our past practice in TCR petitions to request approval for recovery of the total costs under a single recovery mechanism, the TCR Rider. This specific TCR Petition includes only Transmission Statute projects and Grid Modernization-Distribution projects.

We propose to implement new TCR adjustment factors beginning February 1, 2020, calculated to recover the revenue requirement over 12 months. The Company will true-up the difference between the revenues we will continue to collect under the current TCR Adjustment Factors with the revenue requirements the Commission approves in this TCR proceeding.

We also discuss in this filing how we propose to treat costs for projects currently being recovered through the TCR Rider in light of the recent MYRP filed by the Company in Docket No. E002/GR-19-564.

We provide the following Attachments in support of our Petition:

- Attachment 1. Project List and New Project Descriptions
- Attachment 1A. ADMS Business Case
- Attachment 2. Project Implementation Schedule
- Attachment 3A. Capital Expenditure Forecast, Excluding Internal Labor

[2] The Commission also certified the Company's Residential Time of Use Rate Pilot in its Order dated August 7, 2018 in Docket No. E002/M-17-775. Costs associated with the Residential TOU Rate Pilot are included in the Company's recently filed rate case in Docket No. E002/GR-19-564.

- Attachment 3B. Capital Expenditure Forecast, Including Internal Labor
- Attachment 4. Annual Tracker Summary
- Attachment 4A. ADMS Software Base Rate Removal
- Attachment 4B. ADMS-GIS Base Rate Removal
- Attachment 5. 2018 Tracker
- Attachment 6. 2019 Tracker
- Attachment 7. 2020 Tracker
- Attachment 8. 2021 Tracker
- Attachment 9. Revenues & TCR Rate Factor Determination
- Attachment 10. Universal Inputs
- Attachment 11. OATT Adjustment Factor Calculation
- Attachment 12. RECB
- Attachment 13. Annual Revenue Requirement by Project
- Attachment 14. Model Logic
- Attachment 15. ADIT Calculations
- Attachment 16. Proposed Tariff Sheet

## VI. ELIGIBLE PROJECTS

We provide the following required information to support designation of eligibility for TCR-eligible projects:

- Attachments 1 and 1A: Descriptions of Eligible Projects;
- Attachment 2: the Implementation Schedule for projects eligible under the Transmission Statute; and
- Attachment 3: Total TCR Project Capital Expenditures.

### A. Projects Previously Deemed Eligible for TCR Recovery[3]

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. § 216B.16, Subd. 7b:

- CapX2020 Fargo – Twin Cities
- CapX2020 La Crosse-Local
- CapX2020 La Crosse-MISO
- CapX2020 La Crosse-WI

[3] We note that while projects can be eligible for TCR cost recovery under Minn. Stat. § 216B.1645, none of the projects currently included under the rider are eligible under that statute.

In its Order dated February 7, 2014 in Docket No. E002/M-12-50, the Commission approved TCR Rider cost recovery for the following eligible project under Minn. Stat. § 216B.16, Subd. 7b:

- CapX2020 Brookings – Twin Cities

In its Order dated January 17, 2017 in Docket No. E002/M-15-891, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. § 216B.16, Subd. 7b:

- Badger – Coulee (also known as La Crosse – Madison)
- CapX2020 Big Stone – Brookings

In its Order dated September 27, 2019 in Docket No. E002/M-17-797, the Commission approved TCR Rider cost recovery for the following eligible project under Minn. Stat. § 216B.16, Subd. 7b:

- ADMS grid modernization project

In its FINDINGS OF FACT, CONCLUSIONS, AND ORDER dated June 12, 2017 in Docket No. E002/GR-15-826, the Commission approved a Settlement in our electric rate case proceeding wherein parties agreed that the three CapX2020 transmission projects included in the TCR Rider at that time, Fargo – Twin Cities, the three La Crosse segments, and Brookings – Twin Cities, should remain in the rider through the multi-year rate plan period (2016 through 2019) in lieu of rolling the projects into base rates. No costs associated with the above-noted projects are currently recovered through base rates.[4]

## B. New Project Eligible for TCR Recovery

The Company requests Commission approval of the following transmission project as eligible for TCR Rider recovery:

- *Huntley-Wilmarth 345 kV Transmission Line*—this project involves the construction of an approximately 50 mile, 345 kV transmission line in southern Minnesota and associated substation modifications, in partnership with ITC Midwest, and is scheduled to go in-service in 2021.

We provide full project information in support of rider eligibility in Attachment 1.

[4] Final rates were implemented on October 1, 2017 as approved in the Commission's September 29, 2017 Order in Docket No. E002/GR-15-826.

### C. ADMS Project Compliance

In its Order dated September 27, 2019 in Docket No. E002/M-17-797, the Commission approved TCR Rider recovery of the ADMS distribution-grid modernization project, but required that any future cost recovery filing for ADMS investments include an ADMS business case and a comprehensive assessment of qualitative and quantitative benefits to customers.[5] This information is provided as Attachment 1A.

In this Petition, we are seeking approval of the revenue requirements based on approximately $27.2 million in forecasted ADMS capital expenses, incremental above base rates, through 2020. The table below shows the derivation of this amount, compared to the amount approved for recovery in Docket No. E002/M-17-797 for the period through 2018.

**Table 1: ADMS Capital Expenditures**

| | Through 2018 | Through 2020 |
|---|---|---|
| Total project expenditures | $18,778,023 | $38,760,870 |
| State of Minnesota Electric Intangible Allocator | 87.5582% | 87.0691% |
| State of Minnesota allocated expenditures | $16,441,699 | $33,748,741 |
| Capital spend - Base Rate Removal (MN Jurisdiction) | $(6,137,058) | $(6,571,608) |
| Net capital spend requested in MN TCR | $10,304,641 | $27,177,133 |

## VIII. REVENUE REQUIREMENTS AND TCR ADJUSTMENT FACTORS

In this section, we provide the 2019-2020 revenue requirements and the resulting TCR adjustment factors for the TCR Rider projects and charges identified in this Petition. For illustrative purposes, we have assumed an effective date of February 1, 2020 and have calculated the adjustment factors over a 12-month period. We propose to recalculate the final TCR adjustment factors to recover the 2019-2020 revenue requirements based on the timing of the Commission's decision if it occurs

[5] The Commission's September 29, 2019 Order approving the 2017-18 TCR also required two other ADMS-related compliance filings. One compliance filing is due 120 days after the Commission's Order (i.e., at the end of January 2020). *See* Order Point 5. The other compliance filing is an annual filing, but the timeline has not yet been set. *See* Order Points 7 and 8. In our Integrated Distribution Plan (IDP), filed on November 1, 2019, in Docket No. E002/M-19-666, we proposed to submit a single ADMS report on January 25, 2020 in the TCR docket and the IDP docket, and request that January 25 be the due date for the ongoing annual ADMS report, beginning January 25, 2021 – and that these annual ADMS reports be filed in the most recent docket of future IDPs.

after February 1, 2020. We will provide the updated adjustment factor calculations as part of a compliance filing after the Commission issues an Order.

The 2019-2020 revenue requirements we propose to recover from Minnesota electric customers are approximately $81.9 million, a decrease compared to the $89.9 million of 2017-2018 revenue requirements approved in setting the current TCR Adjustment Factors.[6] Attachments 6 and 7 provide the supporting revenue requirements based on actual information through June 2019 and projected July 2019 through December 2020 TCR Tracker activity.[7] Attachment 9 provides our projected 2019-2020 TCR Rider revenues, calculated by customer class based on forecasted February 2020-January 2021 State of Minnesota billing month sales and the proposed TCR Adjustment Factors.[8]

## A. Proposed TCR Adjustment Factors

The costs recovered through the TCR Rider are allocated to the NSP Companies (Northern States Power Company Minnesota and Northern States Power Company Wisconsin), to the Company's State Jurisdictions (Minnesota, North Dakota and South Dakota), and to the Minnesota Jurisdiction Classes (Residential, C&I Non Demand, and C&I Demand) based on the demand allocation factors approved in the Company's last electric rate case (Docket No. E002/GR-15-826). This approach is consistent with the Commission Orders in past TCR proceedings requiring that the adjustment factors be calculated using the state jurisdictional allocators approved in the Company's last electric rate case.[9]

Within each of the non-demand metered classes of service, these allocated costs are recovered through a per kWh charge. We determine the per kWh charge for each class by applying a class-specific allocation factor to the Minnesota jurisdiction average per kWh TCR cost. The demand allocator is based on the sales forecast as

---

[6] See the September 27, 2019 Order and October 16, 2019 Compliance Filing in Docket E002/M-17-797. The current TCR adjustment factors were calculated to collect the 2017-2018 revenue requirements, updated with actual revenues and expenses, over a 12-month period beginning November 1, 2019.
[7] We note that revenue collections are actual through September 2019.
[8] The rate design for these factors was approved in the Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 and the October 21, 2011 Order in Docket No. E002/M-10-1064. The rate design was amended in Docket No. E002/GR-12-961 where the Commission ordered that system coincident summer peak allocators should be used to allocate transmission costs, and again in Docket No. E002/GR-13-826 when the Streetlighting Class was removed.
[9] See the Department's September 7, 2016 Response Comments in Docket No. E002/M-15-891 and the Commission's January 17, 2017 Order approving this approach. See also Ordering Point No. 1 of the Commission's August 14, 2014 Order in Docket No. E002/M-13-1179.

approved in our last electric rate case (Docket No. E002/GR-15-826). The resulting TCR Adjustment Factors recover the current costs.

For the demand metered class, the TCR adjustment factors are determined similarly; however, the factor to be billed is instead determined by using forecast year demands instead of sales to yield a per kW factor.

Table 2 below shows our proposed TCR adjustment factors and overall revenue requirements compared to the TCR adjustment factors which were implemented on November 1, 2019.

**Table 2: Adjustment Factor Comparison**

| | **2017-2018 Approved** | **2019-2020 Proposed** |
|---|---|---|
| Total Revenue Requirements | $89,917,029 | $81,883,541 |
| Residential Rate/kWh | $0.003948 | $0.003607 |
| Commercial Non-Demand/kWh | $0.003486 | $0.003185 |
| Demand/kW | $1.074 | $0.982 |

An average residential customer using 675 kWh of electricity per month would see a decrease on their bill of approximately $0.23 per month compared to the current TCR residential adjustment factor.

The proposed TCR Adjustment Factors are calculated assuming they are effective February 1, 2020. If the timing of a decision in this proceeding does not allow for a February implementation date, the Company requests that Adjustment Factors be recalculated to recover the 2019-2020 revenue requirements over the 12 months subsequent to the Commission Order to more closely match cost recovery with the eligible 2019-2020 costs, similar to the treatment authorized in past TCR Rider orders.

## B. TCR State of Minnesota Revenue Requirements

The detailed 2019-2020 Minnesota jurisdictional revenue requirements by project in support of the proposed TCR Adjustment Factors are included in Attachment 13. Transmission Statute project revenue requirements, including Distribution-Grid Modernization projects, are calculated using the guidance provided in Minn. Stat. § 216B.16, subd. 7b(b)(2) and the Commission's prior related orders.

### *1. Transmission Statute Revenue Requirements*

The Transmission Statute requires certain information be provided in support of our request. For ease, Table 3 below lists where the statutory filing requirements are located throughout this filing:

**Table 3: Filing Requirements**

| Requirement | Authority | Location in Filing |
|---|---|---|
| a description of and context for the facilities included for recovery | Minn. Stat. § 216B.16, Subdivision 7b[c] 1 | Attachments 1 and 1A contain the project descriptions for projects the Company believes are eligible for recovery through the TCR Rider. |
| a schedule for implementation of applicable projects | Minn. Stat. § 216B.16, Subdivision 7b[c] 2 | Attachment 2 contains an implementation schedule for each of the projects identified in Attachments 1 and 1A. |
| the utility's costs for these projects | Minn. Stat. § 216B.16, Subdivision 7b[c] 3 | Attachments 3A and 3B show the capital expenditure forecast for each identified project. Capital expenditures are accumulated from project inception through December 31, 2024. |
| a description of the utility's efforts to ensure the lowest costs to ratepayers for the project | Minn. Stat. § 216B.16, Subdivision 7b[c] 4 | The Company has made extensive efforts to ensure the lowest cost to ratepayers for the proposed TCR-eligible projects. These efforts are discussed in the Project Descriptions in Attachments 1 and 1A. |
| calculation to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph [b] | Minn. Stat. § 216B.16, Subdivision 7b[c] 5 | Attachment 9 contains the calculation of the proposed TCR adjustment factors by customer class. We provide the details of these calculations under the Cost Recovery section of this Petition. |

### *2. MISO Revenue Requirements*

In addition to allowing the Company to recover the costs of transmission projects being constructed by the NSP System, the Transmission Statute allows TCR Rider recovery of charges billed under a federal tariff (such as the MISO Tariff) associated with other transmission expansions being constructed in the MISO region by other utilities. The actual charges through September 2019 and projected charges from October 2019 through December 2021 from the regional transmission projects included in the 2018 through 2021 MTEP cost allocations are presented in Attachment 12.

Expenses based on Schedule 26 and 26A of the MISO Tariff for 2019 are forecast to be $134.0 million and forecast to be $131.3 million for 2020.[10] The Company expects these charges to be offset by 2019 and 2020 Schedule 26 and 26A revenues from MISO tariffs associated with regional rate recovery of NSP System project investments of $145.5 million and $135.7 million in 2019 and 2020, respectively.

The September 27, 2019 Order in Docket No. E002/M-17-797 required the Company to include the interest component of MISO ROE refunds in the TCR Rider revenue requirements. In compliance with that Order, our October 16, 2019 compliance filing in that docket manually adjusted the actual RECB amounts for 2018 to include interest related to the federally mandated ROE reduction from 12.38 percent to 10.82 percent for MISO transmission owners. The interest amount was subsequently recorded in FERC Account 421 and 431 and is thus included within the 2019 RECB revenues and expenses that appear in Attachment 12. To prevent double-counting of this interest payment which was manually added to the 2018 tracker, we have manually removed that amount from the 2019 tracker.

The forecast results in net estimated Schedule 26 and 26A revenues to NSP that are more than expenses (negative revenue requirements) of $15,794,622 (total NSP System) for 2019 and 2020 combined. The net revenues were further adjusted by an allocation to NSPW and other Company jurisdictions to arrive at the Minnesota jurisdiction of net RECB revenue of $11,574,780. This is shown in Attachments 4 and 12 as a negative revenue requirement. The Company believes the Schedule 26 and Schedule 26A cost recovery through the TCR Rider has been calculated consistent with the Transmission Statute, and it includes the MVP Auction Revenue Rights (MVP ARR) as we indicated in our June 19, 2015 Reply Comments in Docket No. E999/AA-14-579.

#### 3. *Impact on TCR Rider of Pending FERC Complaint*

Multiple actions are pending at FERC related to the return on equity (ROE) that MISO transmission owners use to determine their transmission formula rates for regionally shared facilities. We provide a description of those proceedings below. For the purposes of calculating TCR revenue requirements, we apply the ROE currently ordered; however, future true-ups may be necessary depending on the outcome of the pending proceedings.

---

[10] Pending complaints filed with FERC described further in Section VII. B. 3.

In November 2013, a group of industrial customers in the MISO region filed a complaint asking FERC to reduce the 12.38 percent return on equity (ROE) used in the transmission formula rates of jurisdictional MISO transmission owners, including NSPM. On September 28, 2016, the FERC issued an Order based on the methodology originally adopted in FERC Opinion 531, a case involving the base ROE for transmission owners in the New England ISO, approving a 10.32 percent ROE in September 2016, applicable for a refund period from November 12, 2013 to February 10, 2015 and prospectively from the date of the order. The total prospective ROE is 10.82 percent, which includes a 50 basis point adder for RTO membership.

In February 2015, an intervenor in the original ROE complaint filed a second complaint proposing to reduce the MISO region ROE, resulting in a second period of potential refund from February 12, 2015 to May 11, 2016. In June 2016, based on the Opinion 531 methodology, the administrative law judge recommended an ROE of 9.70 percent, the midpoint of the upper half of the discounted cash flow (DCF) range.

On April 14, 2017 the D.C. Circuit Court of Appeals vacated and remanded Opinion 531. The court decision found that the FERC had not established that the prior ROE was unjust and unreasonable, and that the FERC also failed to adequately support the newly approved ROE. Since Opinion 531 was also cited as the basis for the MISO decision, the impact of this court decision on both pending MISO complaint cases is uncertain.

In October 2018, the FERC issued an ROE order that addressed the D.C. Circuit's actions. Under a new proposed two-step ROE approach, the FERC indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the Discounted Cash Flow model, Capital Asset Pricing Model, and Expected Earnings model. The FERC proposed that, if necessary, it would then set a new ROE by averaging the results of these models plus a Risk Premium model.

The FERC subsequently made preliminary determinations in a November 2018 order that the MISO Transmission Owners' base ROE in effect for the first complaint period (12.38 percent) should be reduced. The FERC's preliminary analysis using the proposed ROE approach indicated a base ROE of 10.28 percent for the first complaint period, compared to the previously ordered base ROE of 10.32 percent. The FERC ordered additional briefings on the new methodology, which were filed in February and April 2019. The FERC may take action before the end of 2019.

On March 21, 2019, the FERC announced a Notice of Inquiry (NOI) seeking public comments on whether, and if so how, to revise ROE policies in light of the D.C. Circuit Court decision. The FERC also initiated an NOI on whether to revise its policies on incentives for electric transmission investments, including the RTO membership incentive. Initial comments on both NOIs were due in June 2019, with reply comments due in July and August of 2019. The FERC may take action before the end of 2019.

Refunds for the first complaint period, based on the September 2016 FERC order, were settled with MISO during the first half of 2017, and the impact of those refund settlements were included in the 2017 carry-over balance and the resulting calculation of the 2018 revenue requirements in our October 16, 2019 compliance filing in Docket No. E002/M-17-797.

In calculating the 2019 and 2020 TCR revenue requirements, we apply the currently-authorized 10.82 percent MISO ROE for 2020 activity. However, future adjustments to the TCR Tracker may be necessary pending the outcome of the various FERC actions and inquiries and the second complaint period.[11] We will keep the Commission informed of any additional outcomes in these MISO ROE proceedings at the FERC.

### 4. *Other Costs Included in Revenue Requirement Calculations*

In addition to inclusion of statutory requirements in our project revenue requirements models, the Company also includes costs approved by the Commission in previous TCR Rider Orders. For example, we use a projection of construction expenditures and costs for the 2019-2021 forecast period. Allowable costs other than those previously mentioned include property taxes, current and deferred taxes and book depreciation. Attachment 6 summarizes the 2019 projected revenue requirements for these projects, and Attachment 7 summarizes the projected revenue requirements for 2020. Attachment 13 shows the revenue requirement calculations by project. As shown on line 16 of Attachment 13, and consistent with our recovery request in Docket No. E002/M-17-797, we have included operating and maintenance (O&M) costs for the ADMS project in the TCR Rider. O&M and capital expenses for the ADMS project are combined in the ADMS project revenue requirements total on line 1 of Attachment 4 and line 1 of Attachments 5 through 8. We have not included O&M costs for any of the transmission projects recovered through the TCR Rider. Base assumptions are included in Attachment 10.

---

[11] This issue is also discussed in our recently filed rate case in Docket No. E002/GR-19-564. See the Direct Testimony of Mr. Ian R. Benson.

a. Interchange Agreement Allocator

For the purpose of determining the State of Minnesota jurisdictional revenue requirements for production and transmission plant investment, the Company uses a demand allocator, which reflects the sharing of costs between the Company and NSPW pursuant to the Interchange Agreement. Consistent with the allocation method approved by the Commission in our 2013 TCR Rider proceeding, we have used budget Interchange Agreement allocators for 2019 and 2020.[12] Any resulting over- or under-recovery from customers as a result of the use of the budget demand factors will be reflected in our next TCR Rider Petition that will use actual allocators as they are available.

b. Open Access Transmission Tariff (OATT) Calculation

We established the TCR transmission revenue requirement by also reflecting the revenue offset provided by wholesale transmission services under the MISO Tariff. The OATT revenue credit captures a portion of the revenue the Company receives from third party transmission customers who are charged the FERC-jurisdictional MISO tariff rate for use of the Company's transmission system. Our approach to this issue is consistent with the approach approved in the 2008 TCR petition, Docket No. E002/M-07-1156. This is separate from the revenue credit for MISO Schedule 26 and 26A RECB revenues.

The forecast period used to calculate the transmission formula rate under the MISO Transmission and Energy Market Tariff (TEMT) is consistent with the forecast period used to develop costs recovered under our TCR Adjustment Factors. In addition, the basis for both the MISO revenues and Transmission revenue requirements is a 13-month average plant balance.

Additionally, pursuant to Commission Order, we include CWIP in the OATT revenue credit calculation only for those projects that have not been designated by FERC as regionally shared projects or are not included in the MISO tariff (transmission serving generation or distribution). The CapX2020 La Crosse-Local project is included in the MISO tariff but has not been designated by FERC as a regionally shared project. Therefore, an OATT revenue credit has been applied to this project. Further, we

[12] Docket No. E002/M-13-1179, ORDER APPROVING 2014 TCR RATES AS MODIFIED, APPROVING 2013 TRACKER ACCOUNT, AND REQUIRING COMPLIANCE FILING, August 14, 2014. The 2019 Interchange Agreement allocators were approved by the FERC on May 1, 2019 in Docket No. ER19-1340. The final 2020 allocators will be filed with the FERC in early 2020, but the budgeted 2020 allocators are included in our recently-filed Minnesota electric rate case.

exclude any projects designated as RECB projects, since all RECB costs and Company revenues are included in the TCR Rider. To apply the OATT revenue credit to RECB projects would be reducing project revenue requirements for revenue received from others twice, once through RECB revenues and once through the OATT revenue credit. The OATT revenue credit is shown in Attachment 11.

### *5. Accumulated Deferred Income Taxes (ADIT)*

The Company has assumed no proration of ADIT for 2019 in this filing because we propose to implement the new rate after the 2019 test year has concluded. The Company calculated the 2020 revenue requirements using the alternative 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 15 to show how ADIT proration impacts the total revenue requirement for 2020 and 2021.

As can be seen from Attachment 15, 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 $429 of total revenue requirements for the 2020 calendar year.

The Company continues to work with the Department and other stakeholders towards agreement on an appropriate ADIT proration methodology and will update these calculations as needed.

### *6. Rate of Return*

With the exception of the return on equity (ROE), all other components of the rate of return approved in our last completed Minnesota electric rate case are shown on Attachment 10 and have been used to determine the return on CWIP and rate base. Allowable costs include the overall rate of return on investments, property taxes, current and deferred taxes, and book depreciation.

In compliance with Order Point 3 of the Commission's September 27, 2019 Order in Docket No. E002/M-17-797 and Order Point No. 4 of the Commission's September 30, 2019 Order in Docket No. E002/M-17-818, we have calculated the TCR Rider revenue requirements using an ROE of 9.06 percent.

### *7. ADMS Costs in Base Rates*

The ADMS costs included in base rates as a result of the 2016-2019 MYRP approved in Docket No. E002/GR-15-826 have been removed from our TCR Rider revenue requirements as shown on Attachments 4, 4A, and 4B. We note that this Petition reflects the updates made to the rate case removal as discussed in Information Request No. DOC-13 in Docket No. E002/M-17-797 and attached to the Department's April 2, 2018 Comments.

## IX. TCR VARIANCE ANALYSIS REPORT

Order Point 4 of the Commission's Order dated April 27, 2010 in Docket No. E002/M-09-1048 states:

> *In setting guidelines for evaluating project costs going forward, the TCR project costs 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.*

Below we provide a brief discussion of factors contributing to cost changes of several of the projects since our last TCR filing. All transmission projects currently being recovered through the TCR Rider are now in-service.

## A. Big Stone – Brookings Costs

At the time we initially requested recovery of the Big Stone – Brookings project in the 2015 TCR proceeding in Docket No. E002/M-15-891, the total project expenditure was estimated to be less than the estimated total project costs as submitted to the South Dakota Public Utilities Commission in the initial siting permit filings.[13] We showed a further reduction in this project's estimated expenditures in our 2017-2018 TCR proceeding in Docket No. E002/M-17-797. The project was placed in-service in September 2017, and the cost expenditures to-date presented in this 2019-2020 TCR proceeding are further reduced from the 2017-2018 forecast. Attachment 3B shows a reduction of 16 percent (or 18 percent with internal labor removed, as shown on Attachment 3A) compared to the 2017-2018 TCR filing.

Several factors contributed to the reductions, and these factors remain largely the same as discussed in our June 3, 2016 Reply Comments in Docket No. E002/M-15-891. Specifically, the lower cost is reflective of 1) value engineering, whereby we were able to substitute materials and methods with less expensive alternatives without sacrificing quality or functionality; 2) estimate refinement where our actual appropriation cost was less than originally scoped for the cost estimates; and 3) lower material prices. For example, steel commodity prices were at a 5-year historic low when the structures for this project were purchased, which helped reduce the total project cost. In addition to the factors discussed in previous filings, pipeline induction mitigation requirements were not as extensive as originally anticipated, resulting in savings to the project budget. Also, construction was completed ahead of schedule, which allowed for vegetation restoration to commence under fall planting conditions. With favorable spring rainfall, there was no need for restoration in Spring 2018, which contributed to cost savings. Because there is a true-up mechanism in the TCR Rider, customers are experiencing these project cost reductions through the TCR rate.

## B. CapX2020-Brookings

The CapX2020 – Brookings project went into service in 2015 and final costs have been recorded so we are closing the accounting records for the project. During the project closing process, we identified some Right of Way costs that had been inadvertently and inaccurately classified as Removal Work in Progress (RWIP) expenses that were actually Construction Work in Progress (CWIP) expenses. We made an accounting adjustment to reclassify those costs in 2019. Because RWIP

[13] SDPUC Docket Nos. EL06-002 and EL12-063, as discussed in the Company's June 3, 2016 Reply Comments in MPUC Docket No. E002/M-15-891.

costs are excluded from our rider revenue requirements, this adjustment appears as a new $8.6 million capital expense on Attachment 3. These expenditures are not new expenditures, but are only now showing as expenses to be recovered through the rider because of the reclassification.

## C. ADMS

In our 2017-2018 TCR Petition, we estimated total Minnesota jurisdictional capital costs for the ADMS project would be $69.1 million. This remains our capital forecast for the project. See Attachment 1A for a detailed breakdown of ADMS project costs.

We note that Attachments 3A and 3B show a capital cost variance for this project. This is due to the fact that our 2017-2018 petition only showed project costs through 2022 and the instant docket shows project costs through 2024 and the acceleration of the project spend in 2019 and 2020.

# X. REMOVAL OF INTERNAL LABOR COSTS

We have excluded internal labor costs from the Transmission Statute and Distribution-Grid Modernization projects included in this filing. Table 4 below shows the cumulative amount of internal labor costs that have been removed through 2020.

**Table 4: Internal Labor Expenditures Removed**

| Project | 2020 |
|---|---|
| CapX2020 Brookings – Twin Cities | $21,175,382 |
| CapX2020 Fargo – Twin Cities | $17,047,608 |
| CapX2020 La Crosse (WI, MISO, and Local) | $21,143,110 |
| CapX2020 Big Stone – Brookings | $9,397,441 |
| La Crosse – Madison | $2,808,140 |
| Huntley-Wilmarth | $1,549,406 |
| ADMS | $4,291,615 |

## XI. 2019 TCR COMPLIANCE FILING, TRUE-UP REPORT AND TRACKER BALANCE

As a required by the Commission's Order in our last TCR Rider proceeding, the Company updated the TCR Rider tracker with actuals through the end of 2018 before implementing new rates. The 2017-2018 true-up reports were submitted as part of our October 16, 2019 compliance filing in that docket. Since there have been no changes to the 2017-2018 TCR Rider tracker since that time, we have not included all 2017-2018 revenue requirement detailed support with this filing. However, the 2018 actual revenue requirements and revenues are also shown in this Petition on the Annual Tracker Summary provided as Attachment 4 and the detailed tracker as Attachment 5.

## XII. RATE CASE TREATMENT

In the Company's recently-filed MYRP, we propose to roll into base rates the projects that will be placed in service as of December 31, 2019. Specifically, the Company proposes to roll into base rates Big Stone-Brookings, CapX2020-Brookings, CapX2020-La Crosse Local, CapX2020-La Crosse MISO, CapX2020-La Crosse-WI, CapX2020-Fargo, and La Crosse-Madison, coincident with the implementation of final rates in the MYRP filed on November 1, 2019. However, due to the anticipated length of time until final rates will be implemented at the conclusion of the rate case, we propose to continue recovery of these projects through the TCR Rider where they have been recovered since construction of these projects began.

We believe this a reasonable approach since (1) we employed a similar approach when we transferred significant capital investments from the Metro Emissions Reduction Project (MERP) Rider, the RES Rider, and State Energy Policy (SEP) Rider to base rates; (2) continued rider recovery will result in a better matching of costs to recovery while ensuring against overlapping recovery of project costs; and (3) our interim rate request will be lower. Our MYRP also assumes certain other capital investments either eligible for rider recovery or already in a rider will continue to be recovered through the rider. In addition, this approach is consistent with our proposed treatment of TCR Rider projects in our 2015 rate case, where projects remained in the TCR Rider until the implementation of final rates, though ultimately the projects remained in the rider as a result of a Settlement.

We have structured our rate request in this way to reduce the interim rate increase and mitigate any potential for overlapping recovery. The interim rate revenue requirement was adjusted to remove these rate base and cost components associated with the roll in of TCR Rider projects to eliminate any potential double recovery.

## XIII. PROPOSED TARIFF SHEET AND CUSTOMER NOTICE

### A. Proposed Revised Tariff Sheet

Attachment 16 includes both redline and clean versions of our TCR Rider tariff sheet updated to show the proposed TCR Adjustment Factors by customer class. The tariff provides that the TCR adjustment factors are included in the Resource Adjustment and that factors will be applied to customer bills upon Commission approval. We propose an effective date of February 1, 2020; however, the tariff sheet and revised TCR factors will not be made effective until after the Commission acts on this Petition.

### B. Proposed Customer Notice

The Company plans to provide notice to customers regarding the change in the TCR Adjustment Factors reflected in their monthly electric bill. The following is our proposed language to be included as a notice on the customers' bill the month the TCR Adjustment Factors are implemented:

> *This month's Resource Adjustment includes a decrease in the Transmission Cost Recovery Adjustment (TCR), which recovers the costs of transmission and distribution investments, including delivery of renewable energy sources to customers. The TCR portion of the Resource Adjustment is $0.003607 per kWh for Residential Customers; $0.003185 per kWh for Commercial (Non-Demand) customers; and $0.982 per kW for Demand billed customers.*

We will work with the Department of Commerce and the Commission Staff if there are any suggestions to modify this proposed customer notice.

## CONCLUSION

The Company respectfully requests the Commission approve this Petition. Specifically, we request the Commission approve:

- revenue requirements based on approximately $27.2 million in forecasted ADMS capital expenses, incremental above base rates, in 2019 and 2020;
- TCR Rider eligibility of the Huntley-Wilmarth 345 kV Transmission Line project;
- 2019-2020 TCR Rider revenue requirements of $81,883,541;
- the resulting TCR adjustment factors by class to be included in the Resource Adjustment on bills for Minnesota electric customers for the 12 months beginning February 1, 2020;
- the ability to recalculate the adjustment factor for implementation in compliance based the timing of the Commission's decision; and
- the proposed tariff revisions and customer notice.

Dated: November 15, 2019

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| Katie Sieben | Chair |
| Dan Lipschultz | Commissioner |
| Valerie Means | Commissioner |
| Matthew Schuerger | Commissioner |
| John Tuma | Commissioner |

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2019 AND 2020, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-19-____

**PETITION AND COMPLIANCE FILING**

## SUMMARY OF FILING

Please take notice that on November 15, 2019 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of the 2019-2020 Transmission Cost Recovery (TCR) Rider revenue requirements of approximately $81.9 million and revised TCR adjustment factors to be included in the Resource Adjustment on customer bills for electric customers in Minnesota. We propose to recover costs related to one new transmission project in addition to projects that have been previously recovered through the rider.

**TCR Rate Rider Petition Attachments**
**Table of Contents**


| | |
|---|---|
| Attachment 1. | Project List and New Project Descriptions |
| Attachment 1A. | ADMS Business Case |
| Attachment 2. | Project Implementation Schedule |
| Attachment 3A. | Capital Expenditure Forecast, Excluding Internal Labor |
| Attachment 3B. | Capital Expenditure Forecast, Including Internal Labor |
| Attachment 4. | Annual Tracker Summary |
| Attachment 4A. | ADMS Software Base Rate Removal |
| Attachment 4B. | ADMS-GIS Base Rate Removal |
| Attachment 5. | 2018 Tracker |
| Attachment 6. | 2019 Tracker |
| Attachment 7. | 2020 Tracker |
| Attachment 8. | 2021 Tracker |
| Attachment 9. | Revenues & TCR Rate Factor Determination |
| Attachment 10. | Universal Inputs |
| Attachment 11. | OATT Adjustment Factor Calculation |
| Attachment 12. | RECB |
| Attachment 13. | Annual Revenue Requirement by Project |
| Attachment 14. | Model Logic |
| Attachment 15. | ADIT Calculations |
| Attachment 16. | Proposed Tariff Sheet |

**Transmission Cost Recovery Rider**
**Eligible Projects**

Attachment 1 lists the projects previously approved for recovery in the TCR Rider and describes new projects proposed to be included in the 2019-2020 TCR Rider.

# I. Transmission Projects

## A. Transmission and Renewable Projects Previously Approved as Eligible for TCR Cost Recovery Under Minn. Stat. 216B.16, Subd. 7B

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR Rider cost recovery for the following eligible projects:

- CapX2020 Fargo – Twin Cities
- CapX2020 La Crosse

In its Order dated February 7, 2014 in Docket No. E002/M-12-50, the Commission approved TCR Rider cost recovery for the following eligible project:

- CapX2020 Brookings – Twins Cities

In its Order dated January 17, 2017 in Docket No. E002/M-15-891, the Commission approved TCR Rider cost recovery for the following eligible projects:

- La Crosse – Madison (also referred to as Badger – Coulee)
- Big Stone – Brookings 345 kV Line

## B. Eligibility of New Transmission Projects:

The Company seeks eligibility determination for the following project:

### 1. Huntley-Wilmarth 345 kV Transmission Line

***Project Description and Context***
The Huntley-Wilmarth project is an approximately 50-mile 345 kV transmission line between Xcel Energy's existing Wilmarth Substation north of Mankato, Minnesota, and ITC Midwest's Huntley Substation south of Winnebago, Minnesota. The project

includes necessary modifications to the existing Wilmarth and Huntley substations to accommodate this new 345 kV transmission line. Xcel Energy and ITC Midwest will own the transmission line jointly as tenants in common. The Company will own 50 percent of the Huntley-Wilmarth line, while ITC Midwest will own the other 50 percent. The equipment and improvements inside the Wilmarth Substation will be owned solely by Xcel Energy. The equipment and improvements inside the Huntley Substation will be owned solely by ITC Midwest. Xcel Energy will be responsible for the construction and maintenance of the proposed 345 kV transmission line. Each party will be responsible for the construction and maintenance of its substation.

The Commission issued its Order approving the Huntley-Wilmarth 345 kV Transmission Line project and the final route on August 5, 2019 in Docket Nos. E002, ET6675/CN-17-184 and E002, ET6675/TL-18-185. The Commission approved the route recommended by the Administrative Law Judge that required 23 miles of new line to be co-located with an existing 345 kV line, and specified the use of monopole structures rather than H-frames, greatly reducing the farming impacts to landowners and to the environment.
At the November 7, 2019 agenda meeting, the Commission also approved orally a slight modification to the project route to further minimize both human and environmental impacts, and giving the companies additional routing flexibility in a small area should we reach agreement with all applicable land owners. The Order is pending.

The Huntley-Wilmarth project was studied, reviewed, and approved by the MISO Board of Directors as a Market Efficiency Project (MEP) in December 2016 in its annual Transmission Expansion Plan (MTEP16) report. As an MEP, the primary need for this project is to reduce transmission system congestion which will improve the efficiency of MISO's energy market resulting in lower wholesale energy costs. The project is needed to relieve the transmission congestion on the Iowa/Minnesota border and increase market access to lower cost generation, thereby providing economic benefits through reduced wholesale energy costs. The project will also strengthen the resiliency of the regional grid and improve the deliverability of energy by reducing curtailments of wind generators. In addition, the regional transmission system will become more robust because, under a variety of future scenarios, it will increase deliverability of energy, improve the ability of the transmission system to respond to different contingencies, and provide economic benefits.

***Efforts to Ensure Lowest Cost to Ratepayers***

All major materials (steel structures, switches, transformers, breakers and conductors) and construction labor for this project will take advantage of contracts that have been negotiated by the Company's sourcing group. These contracts were negotiated based on Xcel Energy system-wide use of materials and components resulting in lowest cost.

## C. Efforts to Ensure Lowest Cost to Ratepayers

The transmission projects currently included in the TCR rider are joint projects between utilities and, with the exception of the La Crosse – Madison project, are part of the CapX2020 Initiative. Many of the CapX2020 planning benefits described below are benefits also experienced by coordinating with another utility for projects such as the La Crosse – Madison project. Working with other utilities helps to ensure cost-effective construction and a less piecemeal approach to transmission project planning.

In particular, the CapX2020 group of utilities established a coordinated regional approach to addressing both regional and community reliability needs, and longer-term growth. To ensure cost-effective implementation of the CapX2020 projects, the Company, through its participation in the CapX2020 Initiative, provided for a prudent means of developing the projects. The CapX2020 Initiative was formed to meet the growing transmission needs of all utilities in the region. By coordinating regional planning, the region's utilities are able to develop complete solutions to regional transmission needs instead of disjointed solutions that could lead to duplicative transmission facilities being built. Further, by acting as a group, the CapX2020 Utilities obtain improved efficiency in permitting, routing, scheduling, material purchasing and overall project development. Overall, the Company's participation in the initiative allows us to lessen our costs and achieve greater benefits from the projects due to the strength and size of the organization. For example, by working together, the CapX2020 Utilities have been able to develop a comprehensive set of alternatives for improvement of the transmission system, as opposed to crafting disjointed solutions that would result from individual utility solutions.

In addition, working together within the regulatory environment to jointly file applications for permits in all of the affected jurisdictions allows regulators to more fully understand the scope, benefits and impacts of the projects and not be subjected to numerous separate filings by individual utilities on separate projects that may, at times, work at cross purposes. The joint approach taken by the Company and the other participating CapX2020 utilities is a prudent way to proceed with developing the projects in order to spread the costs among a broad array of utilities. An investment of approximately $1.8 billion for all of the projects would be difficult for any single utility to undertake. By collaborating with a number of other regional utilities, the Company is able to successfully spread its risks and balance its costs.

Finally, the Company and the participating utilities recognize that there are benefits arising from a coordinated effort in securing materials and services required to build the CapX2020 projects. As such, a joint sourcing approach has been utilized to pursue benefits in order to minimize or eliminate inter-project competition for labor and material resources, maximize leverage on vendors and specification standardization, establish a common request for proposal (RFP) process to present one "CapX2020 face" to the market and eliminate inefficiencies, maximize inter-project flexibility where possible for services. For example, utilizing a joint sourcing process across the projects creates a spend volume asset. This volume consolidation and early RFP activity allows manufacturers and suppliers the ability to plan fabrication in advance of the delivery needs. This approach works to avoid the premium costs associated with orders outside of the lead time and typically garners more attractive pricing when the suppliers, manufactures and contractors are able to advance plan their production schedules or field resources.

## II. Distribution-Grid Modernization Projects

### A. Distribution-Grid Modernization Project Previously Approved as Eligible for TCR Cost Recovery Under Minn. Stat. 216B.16, Subd. 7B (5)

In its Order dated September 27, 2019 in Docket No. E002/M-17-797, the Commission approved TCR Rider cost recovery for the following eligible project:

- Advanced Distribution Maintenance System (ADMS)

The September 27 Order requires the Company to include in any future cost recovery filing for ADMS investments and ADMS business case and a comprehensive assessment of qualitative and quantitative benefits to customers. We provide this information in Attachment 1A.

### B. Eligibility of New Distribution-Grid Modernization Projects

We are not seeking the determination of eligibility of any new Distribution-Grid Modernization projects at this time.

## III. Renewable Statute Projects

### A. Eligibility of New Renewable Statute Projects

We are not seeking the determination of eligibility of any new renewable projects at this time.

## IV. Greenhouse Gas Projects

### A. Eligibility of New Renewable Statute Projects

We are not seeking the determination of eligibility of any new greenhouse gas projects at this time.

# ADMS PROJECT COMPLIANCE

In the most recent Order on the Company's Transmission Cost Recovery Rider (TCR),[1] Order Point 6 requires the Company to:

> *include in any future cost recovery filing for [Advanced Distribution Management System] (ADMS) investments an ADMS business case and a comprehensive assessment of the qualitative and quantitative benefits to customers.*

The Company provides the following support for our ADMS cost recovery request, including a business case for ADMS investments which focuses primarily on the qualitative benefits to customers, and describes the function of ADMS as laying the groundwork for future benefits. The Company also discusses the current and near term ADMS investments, the Company's experience with ADMS in the Colorado jurisdiction, and a discussion of the project budget.

## I. INTRODUCTION AND OVERVIEW OF ADMS AND PRIOR COMMISSION PRECEDENT

By way of background, ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the

[1] *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 (Sept. 27, 2019).

monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid. Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, IVVO and FLISR in the near-term, while preparing the Company to implement advanced applications like Distributed Energy Resource Management System (DERMS) in the future.

The GIS data improvement needed to enable ADMS also furthers grid modernization efforts related to DER. Specifically, this effort will help DER adoption by improving the GIS model which is used for system planning and for hosting capacity analysis. The data collection and improvements will reduce the amount of time that planning engineers spend preparing each model for analysis. The verification and population of additional data attributes will also help our designers validate capacity necessary for EVs.

In our first Grid Modernization Biennial Report initially filed with the Commission on November 1, 2015 (Docket No. E002/M-15-962), we sought project certification of an Advanced Distribution Management System (ADMS). The Commission certified the project in its June 28, 2016 Order in that docket.

In the 2017 and 2018 TCR (Docket No. E002/M-17-797), the Company requested recovery of certain ADMS project costs. In its petition, the Company addressed the need for ADMS, customer benefits, the process for selecting the vendor, and budget information. Commission approved recovery of revenue requirements based upon approximately $10.2 million in actual expenditures, incremental above base rates, for ADMS through 2018 in the TCR rider. In so approving, the Commission noted that the Company's "acquisition process [for selecting a vendor with experience in developing, implementing, and supporting electric distribution real-time supervisory control and data acquisition (SCADA) and ADMS control systems] was thorough and targeted to avoid unreasonable expenditures."

Because the vendor for development and implementation has not changed and because the above referenced order point does not require information about the process for selecting a vendor, the Company is not repeating that information here in this docket. To the extent it is necessary or helpful, information about the vendor selection process can be found in Attachment 1A to the Company's initial filing in Docket No. E002/M-17-797.

## II. Need for ADMS and Customer Benefit

ADMS is a key foundational element for Grid Modernization. Once it is implemented, new grid capabilities and functionalities will be enabled that will help the Company fulfill the vision of a fully integrated advanced electric distribution grid.

### A. Qualitative Benefits

The key objectives of ADMS are to provide integrated grid preparedness, improve reliability, and to increase efficiency on the grid. Examples of how ADMS meets these objectives and a description of the qualitative customer benefits are below.

- *Integrated Grid Preparedness:* With an increasing penetration of Distributed Energy Resources (DER) forecasted, along with existing electric distribution grid impacts, it is essential to have a system that enables integration of grid technologies and functionalities. The existing electric distribution model and analysis tools available to the operators were not built to accommodate the increasing penetration of DER. ADMS allows the system to adapt by managing the complex interaction of DER, outage events, feeder switching operations and smart grid technologies in one system. This proactive approach to DER management will provide our customers with safe, reliable, and economic power.

  ADMS enables the Company to transition from a passive to an active DER management approach because of the DER Management capabilities within ADMS. DER Management runs in real-time and allows operators to monitor DER with an awareness of its effect on the entire electric distribution grid. For example, operational risks associated with DER are reduced because the DER Management capabilities can display reverse power flow and the hidden load[2] at every protective device along the feeder. By knowing what DER is active in the grid and its impact, the Company can continue to incorporate customer-requested DER on the grid and still ensure safe operations.

  ADMS applications are needed to provide operational assistance in the study and management of DER on the electric distribution grid. ADMS provides visibility and situational awareness of DER on the distribution grid through utilization of the real-time network model and load flow calculations. Along with this network model, several advanced analysis tools are available that will aid in increasing efficiency and accuracy of DER management and interconnection processes. This

[2] Load that is masked by DER and can cause trouble when performing switching operations.

increased efficiency and accuracy will also benefit customers.

- *Reliability:* ADMS supports operators in determining optimal solutions faster during outage restoration through utilization of the network model, load flow calculations, and advanced analysis tools. ADMS, in conjunction with automated grid components, can improve reliability and quality of service in terms of reducing outages, minimizing outage time, and enabling advanced energy efficiency. For example, operators can perform a restoration analysis that quickly provides them with options for outage restoration. Another example is a fault location tool, FLISR, which calculates the possible locations of the outage cause. Being able to determine optimal solutions faster during outage benefits customers by being able to restore service in a faster and more efficient manner.

  As discussed in our November 1, 2017 Grid Modernization Report filed in Docket No. E002/M-17-776, FLISR is an advanced application of ADMS that, in concert with field devices and proper communication, improves grid reliability and operational performance during outages.[3] FLISR provides remote monitoring control of the field devices and involves deploying automated switching devices with the objective of decreasing the duration and number of customers affected by an individual outage. ADMS-based FLISR is beneficial because it acts as the common distribution integrated control platform for multiple corporate objectives operating in the same area. This optimizes and ensures safety during FLISR operations because there is an awareness of the impact FLISR device operations have on the grid as a whole that a standalone FLISR system would not have.

  Additionally, ADMS provides a central management scheme with the agility for dynamic reaction to distribution grid changes so FLISR devices can automatically restore customers outside the fault zone. Automatic restoration in certain circumstances is also a customer benefit.

- *Operational Efficiency:* ADMS acts as an integrated distribution control platform that provides improved grid efficiency by enabling efficient execution of technologies on the same area of the grid through central control of automated devices. By having a system with central control, Xcel Energy can combine grid topology awareness with field automation to optimize outage response effectiveness and power quality performance on the grid. For example, distribution operators will

[3] *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration.* US DOE. December 2014. https://www.smartgrid.gov/files/B5_draft_report-12-18-2014.pdf

manage multiple technologies in one ADMS system which reduces the amount of time operators spend switching between different programs, gives the ability to optimize workspaces, and increases overall efficiency in operations.[4] Another example is the improvement in operational training that ADMS provides. These training tools are necessary to efficiently transfer knowledge about operations of the electric distribution grid to new employees.

ADMS' integration capabilities enable ADMS to extend the value of the smart grid technology to new and emerging grid performance objectives. For instance, ADMS uses Advanced Metering Infrastructure (AMI) meters as sensors, in near real-time, to improve power flow accuracy and advanced application performance within ADMS. Full realization of smart grid technology benefits is only leveraged in an integrated system. Currently, technologies implemented at Xcel Energy are stand-alone, so full realization of smart grid technology benefits cannot be leveraged.

ADMS enables the optimization of each smart grid technology by using a single as-operated network model with accurate load flow calculations. By acting as an integrated distribution control platform, multiple corporate objectives can be achieved in a safe and efficient manner.

- *Customer Satisfaction and Engagement:* A recent E Source survey found that, for business customers, reliability and information about their outage was a major factor in defining their relationship and satisfaction with their utility. The ADMS platform – especially when coupled with AMI - will provide the Company with more information about the nature of faults, helping us identify the cause, status, and predict the restoration time for outages. Today, the Company is typically unaware of an outage that occurs below the feeder level prior to customers contacting the Company to inform us that they are without power. This places the burden of reporting and engagement on the customer. With these technologies, the Company will provide customers with more information about service outages including more accurate estimates of restoration times.

  The ADMS system, coupled with other systems such as AMI and DERMS, will also help integrate DERs more efficiently. Today, the Company takes a conservative approach to the forecasted impact of resources because we do not

[4] Taylor, Tim and Kazemzadeh, Hormoz *Integrated SCADA/DMS/OMS: Increasing Distribution Operations Efficiency* http://assets.fiercemarkets.net/public/smartgridnews/dms_abb_02.pdf

have the granularity necessary to dynamically forecast the impact of resources such as batteries and solar. With more granular data we can better refine our estimations of the impact of new resources and better integrate more resources on the grid.

- *Safety:* By using an integrated ADMS platform, the Company can ensure safe operations between different technologies operating in the same area. In addition, ADMS provides a single network model which can reduce the workforce miscommunication safety risks associated with having multiple models of the distribution system. Other safety benefits are enabled by ADMS analysis tools. For example, load flow analysis calculates and displays bidirectional load flow which gives distribution operators both visibility and situational awareness for safe operations of the distribution grid with DER present.

- *Cybersecurity*: As Xcel Energy moves forward into the next generation of intelligent electric distribution, each facet of the electric network must be evaluated for cybersecurity risk. ADMS has incorporated zone methodologies to layer cybersecurity controls. This includes segmentation of control system communications by function and implementing advanced grid specific security processes and standards to protect, detect, respond and recover from cybersecurity risks of this foundational system. Reliable delivery of electricity is of paramount importance, protecting the integrity and security of this system is included with that responsibility.

- *Asset Optimization:* ADMS utilizes an enhanced network model with real-time load flow calculations. This provides accurate information and representation of the distribution grid, which is necessary for strategic operational planning of existing and future assets. Optimizing the use of assets is a key strategy to keeping infrastructure costs lower, thereby helping to keep overall rates lower.

## B. Quantitative Benefits

In the section immediately above we speak to the many qualitative benefits, and note that ADMS is a foundational platform upon which process improvements and advanced applications will be layered. At this time, the Company cannot forecast the quantitative benefits of the foundational ADMS platform with precision. For example, the Company cannot accurately forecast the time customers applying to interconnect will save due to the increased accuracy and efficiency of ADMS. Similarly, the Company cannot accurately forecast at this time the impact to reliability metrics the core ADMS program will produce. We do note, however, in the

Company's 2020 Rate Case Filing (Docket No. E002/GR-19-564, Direct Testimony of Company witness Ms. Kelly A. Bloch, Exhibit___(KAB-1), filed November 1, 2019, Sections E & G) and in the Company's Integrated Distribution Plan filing (Docket No. E002/M-19-666, Section F, page 156, filed November 1, 2019), that we quantify the benefits our IVVO and FLISR proposals will produce. Similarly, while we will see improvements in DER hosting capacity through ADMS and IVVO, we are unable to quantify them at this time. We are encouraged by the early progress in PSCo that our investments in these technologies is meeting - or exceeding - our expectations and that we will quickly gain experience to better quantify the future benefits of ADMS.

## III. ALTERNATIVES TO ADMS

The industry is moving to ADMS to provide the capabilities necessary for a more integrated grid and Xcel Energy needs to stay at the forefront of what is expected to become the industry standard in the near future. Prior to embarking on the ADMS initiative, the Company explored alternatives - but determined there are no comparable alternatives. There exist alternative means to obtain partial benefits, but none that comprehensively work to secure the broad range of benefits which ADMS is able to provide. Three approaches are described below.

*Targeted improvements*: Increasing the size of cables, for example, would increase capacity on the electric distribution grid. Although this improvement could allow for an increased amount of DER, it would only serve that one objective. In contrast, an ADMS allows for an increased amount of DER in addition to enabling DER Management. Increasing capacity on the grid, in comparison to ADMS, does not best support effective grid modernization because it fails to provide a real-time awareness of load flow which assists the Company in the management of DER.

*Autonomous systems:* Another way for the Company to achieve some of the benefits facilitated by ADMS is to install separate, autonomous systems that would integrate with existing SCADA and OMS systems instead of installing a fully integrated ADMS. This alternative does not provide the platform for smart grid technologies that is necessary to enable a fully integrated grid. Devices would operate on their own at individual sites in the field without awareness of each other. The Company has pursued implementing some autonomous systems (i.e. SmartVAR pilot,); however, these systems are isolated and are not able work together. If the Company wants multiple corporate objectives on the same distribution grid, ADMS is the necessary integrated distribution control platform that enables safe and efficient operation of multiple corporate objectives in the same area.

Status Quo: A final alternative would be for Xcel Energy to do nothing in way of grid enhancement, maintaining the status quo of current grid capabilities. This option limits the ability to integrate higher levels of DER and other advanced technologies and limits the ability to improve grid efficiency and reliability.

ADMS is currently the only comprehensive platform that can accomplish what is necessary to implement the Company's overall Grid Modernization initiative. It provides both situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. ADMS enables integration of DER and other technologies in addition to improving grid efficiency and reliability. ADMS, acting as the comprehensive integrated platform for grid technologies, provides the integrated system that is imperative for a modernized grid to operate efficiently and safely.

## IV. CURRENT AND NEAR TERM ADMS INVESTMENTS

### A. Initial ADMS System Roll-out

The Company began detailed design for implementation of ADMS in 2016. We first examined our service territories across all of the Xcel Energy jurisdictions to assess how to best roll out ADMS. We determined that the Public Service Company of Colorado (PSCo) would be ideal for the initial ADMS roll-out, owing to its varied nature, increasing penetration of DER, and Commission implementation requirements.

Implementation of the ADMS platform began with detailed design and the installation of hardware and software. Testing and verification of the network impedance model and of the functionality of the core applications of ADMS followed (and continues). As part of this process we also verify connectivity to the SCADA field devices which must interact with ADMS.

ADMS software development, configuration and integration building began in 2017 across all operating companies. Testing and deployment of the ADMS software began in 2018. The software was placed into service in the PSCo jurisdiction in April, 2019 and will be followed by implementation in NSP (currently planned for April, 2020)[5].

### *1. Work Completed in 2019*

The Company has made significant progress on ADMS in 2019. Hardware installations in data centers have been completed and software installed. Preparations for control center enablement are underway. The operator training environment was established and training has begun. Integrations of ADMS with other systems were completed. A comprehensive Site Acceptance Test of the ADMS system system began and is 50% complete as of early November 2019.

The expected in-service date of the NSPM ADMS software is the second quarter of 2020. The software in-service requires the network impedance model for a subset of the NSPM system, which consists of 80 feeders, making up 7 percent of all NSPM feeders. This network model includes a representative sample of feeders and substations that enable us to test the software and its capabilities against a minimal set of feeders by providing a diverse set of operating and grid conditions. The partial network impedance model consists of a select set of substations and feeders that were chosen based on the following set of criteria:

1. The selected substations and feeders were a good representative sample of the distribution grid of NSP.
2. The selected feeders were identified as having field devices which must connect to ADMS via SCADA.
3. Feeders which are clearly good choices to benefit from advanced applications and will serve as good feeders to prove IVVO and FLISR.

When the Company has determined that ADMS is properly functioning on the partial network impedance model, the software will be placed in-service. We will then be positioned to deploy core and advanced functionality to additional feeders. Key to that deployment rate will be the determinations as to the applicability and timing for FLISR and IVVO deployments in Minnesota. In addition to the full network impedance model, intelligent devices must be installed and operational to realize the full benefits of ADMS advanced applications.

---

[5] The NSP Companies include Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW).

### 2. *Work Expected to be Completed in 2020*

We plan to complete training, finalize the equipping of our Minneapolis control center, and go-live in the second quarter of 2020. To reach that goal we will complete final test phases of software and advanced applications. Our Grid Management group will validate that ADMS calculations are accurate for the initial set of feeders in preparation for testing the IVVO and FLISR applications. They will further test the IVVO and FLISR applications by running them in two separate test modes. The first, Open-Loop testing, has operators executing the suggested actions. The second, Test Mode, allows engineers to review suggested switch plans for accuracy over an extended peiod of time to ensure the validity of suggested operations. The two test modes allow the grid engineers and operators to review suggested actions while their confidence in the model and the algorithm grow. After several weeks of running in test mode, the IVVO application is placed in Closed-Loop mode, which allows ADMS to make decisions and execute them autonomously. FLISR testing will run in Open-Loop mode initially, with operators validating the location prediction and suggested switching sequences. Once we are comfortable with the accuracy of the FLISR solutions, we will enable Closed Loop mode.

We will equip the two additional NSPM control centers in a timeframe following the enablement of the Minneapolis control center. As those control centers come online, additional areas around Minnesota will support IVVO and FLISR applications. As the ADMS core software and servers are already built to accommodate all expected NSPM demand, work to enable additional control centers will consist of deployment of workstations and building relevant substation and feeder models for each given area.

## B. Geospatial Information System (GIS) Data Collection Effort

As discussed in our 2015 certification request, the Geospatial Information System (GIS) is a critical system that will be integrated with ADMS. Accordingly, concurrent to the roll-out of the hardware and software components of the ADMS system, we will carry out a critical GIS data collection effort. As mentioned above, GIS data is critical to the ADMS to provide location and specification information for all of the physical assets that make up the distribution system. ADMS will use that information to maintain the as-operated electrical model and advanced applications. While the Company maintains records of all its assets, the ADMS will require granular asset information in order to operate effectively. Therefore, the Company needs to review all of its physical asset records to ensure that the information available complies with the necessary level of detail needed for ADMS.

The GIS data collection effort is comprised of three components. The first is collecting data that will validate the physical characteristics of the current system. Since the ADMS is dependent on a robust dataset, we will leverage system and data knowledge and confirm the accuracy and completeness of the electric distribution grid model. This is accomplished by verifying the information contained in the corporate GIS via the performance of a physical data verification and capture effort with the goal of determining the level of readiness to support the ADMS application. We will also ensure the representations of customer load profiles and distributed generation are accurate to meet the needs of advanced applications.

The second is collecting the additional data that defines the electrical characteristics necessary to enable the ADMS model. We will collect data such as the size of wiring, the size and location of equipment such as transformers, switches, poles, phasing and connectivity, and device control settings. This process validates the various data attributes contained in the corporate GIS system.

The third is implementation of select intelligent field devices in order to test ADMS and ensure it has the necessary operating information. In order to ensure that ADMS is operating efficiently and effectively the Company must complete end-to-end testing of the system and that cannot be done without field devices to gather the information that is needed for ADMS to operate and demonstrate it functions appropriately. As a result, some intelligent field devices will be implemented early for purposes of this testing. These devices are permanent and will be used as part of the intelligent field device deployment. ADMS processes the information provided by these devices in near real-time and then uses the information in its application algorithms. ADMS then sends control commands from the advanced applications to the intelligent field devices to effect the necessary change in power flow on the grid.

The Company entered in to a Technology Partnering Agreement with the National Renewable Energy Laboratory (NREL) and our ADMS vendor, Schneider Electric, to perform a study to assist in determining the optimal mix of field device sensor data and asset data quality necessary to cost-effectively realize desired ADMS benefits. This study used four substations and six feeders with real data from Xcel Energy. A member of the Department of Energy sponsored ADMS "Testbed," a consortium of national laboratories; NREL was equipped to assist the Company in this effort by leveraging its demonstration laboratory to analyze how the Company model performed in ADMS with various levels of data. This effort has concluded and results are being analyzed. Initial indications are encouraging, showing that we can expect adequate performance with lower data collection if coupled with additional sensors. Now that we do have our ADMS functional, we are poised to validate the recommended scenarios, confirm findings and modify accordingly.

### *1. Work Completed in 2019*

To support our plan to test IVVO and FLISR functionality in Minnesota, we completed GIS data collection for 14 feeders at the Hiawatha West and Midtown substations in 2018. During 2019, we expanded upon that completed collection for an additional 11 substations and 80 feeders.

### *2. Work Expected to be Completed in 2020*

Data improvement efforts will continue with the addition of 50 feeders and 9 substations in Minnesota. Should the Commission approve the request for IVVO and/or FLISR, steps will be initiated for the collection of additional data to support those efforts.

## C. Training

The Company has partnered with Mosaic, a vendor specializing in ADMS training, to develop comprehensive training materials and provide the classroom instruction. This training uses electrical systems familiar to the operators, includes scenario-based examples, and incorporates business processes to ensure employee preparedness.

The Operator Training Simulator is an advanced application of ADMS that will be used regularly for operators and operating engineers. The operator training simulator has the following capabilities:

- Mimic the real-time distribution grid
- Training scenarios that operators can interact with
- Replay of past events
- Restoration drill scenarios support
- Regional drill support

We believe this initial training lays the right groundwork for the launch of the ADMS platform on our system, and the ongoing training ensures sustainable and long-lasting usability at Xcel Energy.

*1. Work done in 2019*

Core training materials have been developed and are now being used to train employees on the fundamentals of ADMS. Modifications to the scenario-based tranining materials (scenarios are are most effective when using electrical systems the operators are familiar with) will continue into early 2020, in time for the delivery of those modules. Training delivery is approximately 15% completed and will continue through Q2 2020.

*2. Work to be done in 2020*

Training will be completed in 2020 with approximately 58 system operators and 23 supporting employees receiving training.

## V. EXPERIENCE GAINED FROM PSCO DEPLOYMENT

Our PSCo roll-out provided valuable learnings in all areas. Because this is where our system integrations were first enacted, we have worked out complexities, finalized code, and validated performance. Through end-to-end device testing, we worked out interface issues and validated that the ADMS' SCADA will correctly interface with and operate substation and distribution line equipment. The Colorado deployment helped us modify our processes for testing to achieve greater efficiencies. Additionally we have learned how to better estimate the timeframes for, and synchronize the schedules of the workstreams (substation, distribution line work, and model preparation) for the required efforts. In general, the efforts in PSCo to date have indicated a longer timeline is required before benefits can be realized, and the NSPM schedule has been developed with that in mind.

## VI. PROJECT BUDGET

To ensure success and prudent spend related to the AGIS initiative, the Company has taken and will continue to take the following steps: engage in benchmarking with peer utilities in the industry; leverage industry leading technology experts; utilize key business partners in robust sourcing processes; establish formal internal governance structure that includes senior business leadership executives; establish rigid decision processes and financial governance including rigorous project change request and approval processes; and select an initiative level business management consultant to further support the overall governance and management of the projects.

Xcel Energy employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These processes are designed to ensure that the Company is both containing costs appropriately and spending money on the items necessary to achieve the desired outcomes and overall reasonable costs. These standard processes have been, and will continue to be, utilized within the ADMS project and the wider AGIS initiative we are pursuing. These standard processes include:

- **Product Selection** through an RFP process, as described in detail in Attachment 1A to our Petition in Docket No. E002/M-17-797, which is intended to ensure the most optimal solution for the Company's needs was selected and the price was negotiated to optimal costs to the Company.
- **Project and Initiative Governance Processes** which follow the Company's ULC (Universal Life Cycle) processes for all aspects of the project. This includes managing scope, risks, issues, milestones and financials. All changes to scope that have an impact on project costs, schedules, risk and benefits are reviewed through clearly defined levels of governance including project steering committees, AGIS Leadership, Integration Council (Cross-function Senior Leaders) and executive sponsors. This process, called PCR (Project Change Request), follows formal documentation and approval processes and limits at each level and are reviewed and documented in bi-weekly Change Board meetings with AGIS Leadership.
- **Contingency** that will be refined as the project progresses. The use of the contingency is closely managed and subject to internal approvals.

## A. Budget Development

Our preliminary ADMS project cost estimate, as previewed in our 2015 Grid Modernization Biennial Report, was $9 million per year for three years (2016, 2017 and 2018), for a total of $27 million. As noted at that time, this was a high level estimate based on preliminary vendor cost estimates and industry partner experience due to the timing of the grid modernization amendment being passed in June and the submission of our certification request in November.

After the conclusion of the RFP and vendor selection processes, a more detailed project estimate was created from the pricing and contract verbiage as well as internal labor and hardware to support the overall ADMS project.

Upon completion of detail design work, a detailed implementation plan was developed and the project estimates were updated. The ADMS project budget for

Minnesota was $69.1 million.[6] The cost estimate includes five key components: Labor, Software, Hardware, GIS Data Collection Efforts, and contingency. Because the ADMS is being developed as one software system across the Xcel Energy enterprise system and will be implemented in each specific operating company on a different timeline, the ADMS costs will be allocated to specific utilities and jurisdictions. The allocation process is discussed further below.

**Table 1: Project Capital Expenditures Budget Summary (Dollars in Millions, on a MN basis)[7]**

| | Pre-2018 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Labor** | 11.3 | 6.9 | 12.3 | 3.9 | 0.0 | 0.0 | 0.0 | 0.0 | 34.4 |
| **Software** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **GIS** | 0.0 | 0.4 | 0.7 | 1.7 | 0.9 | 2.6 | 3.9 | 2.6 | 12.8 |
| **Sub-total** | 11.3 | 7.3 | 13.0 | 5.6 | 0.9 | 2.6 | 3.9 | 2.6 | 47.2 |
| **Hardware** | 5.4 | 0.9 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.9 |
| **TOTAL** | 16.7 | 8.2 | 13.6 | 5.6 | 0.9 | 2.6 | 3.9 | 2.6 | 54.1 |

*1. Labor*

The ADMS labor estimate was developed from a bottoms-up forecast of all resources required to complete the Implementation phase. The bottoms-up labor estimate includes labor costs already incurred through the detail design phase along with estimates to complete the work for the build, test and implementation phases. Labor components for the implementation phase include external vendors (Schneider, General Electric and Oracle), Xcel Energy employees, and contractors. Vendor cost estimates are based on contractual agreements with each vendor. Employee and contractors include resources from Distribution, IT and program management. The employee and contractor labor forecast was based on a roll-up of all resources required to perform the project work and the estimate durations for each.

We have excluded internal labor costs from the ADMS project costs requested in the TCR.

[6] The total budget for Xcel Energy is $208.9 million.
[7] Please see Attachment 3B for the NSPM Total Company CWIP Expenditures for the ADMS project costs being requested in this TCR Petition.

*2. Software*

The software portion of the ADMS budget consists of license agreement and various third-party infrastructure. The Schneider license agreement is a fixed cost and has been fully executed. The third-party software consists of licenses for the operating systems, databases and security products to operate and secure the ADMS system. The cost estimates were based on the number of hardware environments, servers, and processors based on existing license agreement costs with the third-party companies.

*3. Hardware*

Detailed system processing requirements were gathered through the RFP process as well as the contract process with the selected vendor for the ADMS system. These detailed requirements were used by the project team and the Company's infrastructure team, in conjunction with the ADMS vendor's technical experts, to determine size, scale and costs for all aspects of the infrastructure needed to adequately, securely and reliably operate the ADMS system for the Company. The types of hardware required include processors, data storage, security hardware/software, network devices such as firewalls and core switches, as well as critical data center infrastructure including power, cooling and cabling.

Hardware costs have been excluded from the project revenue requirements requested in the TCR as discussed further below in the Cost Allocations section.

*4. GIS*

In order to create a GIS project budget the Company engaged in the following scoping activities:

- A gap analysis was conducted to determine the information currently available in the Company's GIS data model and what additional information is needed for ADMS to run successfully.
- Identification of changes required to the GIS data model to support ADMS.
- Identification of data that is to be captured from other sources (such as substation equipment databases) and how this will be provided to ADMS.
- Assessment of the quality of data currently held in the GIS and external sources and determine if additional data cleanup activities are required.
- Identification of data attributes that are to be field verified and updated in the GIS.

Two vendors participated in a Colorado data collection pilot effort in 2017. Their RFP responses provided expected costs for data collection by pole and substation. We used those per unit costs and extrapolated them using greater Public Service system information.

## B. Allocation

As described in the Company's most recent electric rate case, O&M costs for preliminary planning related to capital software projects that benefit more than one operating company are allocated consistent with the Cost Assignment and Allocation Manual (CAAM) and the Service Agreement between Xcel Energy Services Inc. (XES) and NSPM.[8] As described above, the ADMS project will be implemented across all operating companies of Xcel Energy.

When a new shared asset software system is in construction work in progress (CWIP), the accumulating charges will be collected under one work order for Xcel Energy Services. Since the Service Company will not own software, the appropriate percentage of ownership for each participating legal company would be identified at the time of the initial development of the project. Each company's share of the cost would be charged to that company's CWIP monthly while under development and ultimately classified to their own books. Each owner will depreciate their respective share of the asset and as such no allocation is usually necessary. Care is taken to identify all beneficiaries at the beginning of the project so as not to allow later users a free service. In the case of ADMS, all operating companies and jurisdictions will benefit.

Investment in hardware for ADMS is being made in both PSCo and NSPM to support the system in all operating companies. There are primary and back-up servers located in data centers in both Minnesota and Colorado that will serve the NSP, PSCo, and SPS systems. Due to the flexible use of the various hardware components to support all the instances of ADMS, the Company determined that these investments would be purchased as network equipment and therefore charged out to all operating companies through our standard shared asset allocation process, similar to other data center network equipment. A carrying cost on this hardware investment is further allocated to the various operating companies. As a result of this allocation process, we do not believe it is practicable to recover the hardware costs of the ADMS through a rate rider. Therefore, we have shown the detailed hardware costs

---

[8] *See* the Direct Testimony of Company Witness Ms. Melissa L. Schmidt in Docket No. E002/GR-19-564.

above for completeness in describing the project, but do not include these costs in the TCR revenue requirement. ADMS hardware costs will be included in a future rate case.

## C. O&M and Service Life

The Company's approved depreciation in Minnesota for communication equipment software and hardware is 10 years, and thus the ADMS project components have a 10-year life.[9] Each Xcel Energy operating company will in-service the ADMS components separately as they are completed. As noted above, we anticipate in-servicing the NSPM ADMS software components in 2020.

At this time, we estimate that once placed in-service, the Minnesota ADMS system should cost about $1.9 million per year in O&M costs to pay for external software support and maintenance, hardware support, wide-area network costs and internal labor supporting the application and technical infrastructure. As discussed above, our contract with Schneider includes an ongoing agreement to provide support. We have also budgeted for both capital & O&M labor for the engineering and support expenses anticipated to maintain and operate the system.

**Table 2:**
**Minnesota Project O&M Summary**
**(Dollars in Millions, MN Basis)**

| | Pre-2018 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|
| **Labor – Distribution and Internal Support** | 0.0 | 0.0 | 0.0 | 0.1 | 0.2 | 0.2 | 0.6 | 0.7 | 1.9 |
| **Training & Communications** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **I/T Hardware Support and Network** | 0.0 | 0.0 | 0.6 | 1.3 | 1.5 | 1.5 | 1.8 | 1.8 | 8.3 |
| **Software Maintenance Agreements** | 0.0 | 0.0 | 0.1 | 0.3 | 0.5 | 0.5 | 0.6 | 0.6 | 2.7 |
| **TOTAL** | 0.0 | 0.0 | 0.8 | 1.7 | 2.2 | 2.2 | 3.0 | 3.1 | 12.9 |

[9] The Commission approved a 10-year depreciation life for communication equipment software and hardware in its May 4, 2018 Order in Docket No. E002/D-17-581.

## CONCLUSION

ADMS is not only a foundation tool; it is a critical part—the "engine"—of the overall package of tools necessary to deliver reliability energy efficiency measures and to enable the integration of increasing quantities of distributed energy resources without compromising reliability and power quality. The Company has made significant progress in 2019 and plans are on track for achieving key milestones in 2020.

## Project Implementation Schedule

| Project Name | Regulatory Approval Docket No. | Regulatory Approval Filing Date | Regulatory Approval Order Dates | Design/Engineering/ Procurement | ROW Acquisition | Construction Start | Projected In-Service | Current Status | MISO Approval |
|---|---|---|---|---|---|---|---|---|---|
| CAPX2020 Brookings | ET-2/TL-08-1474<br><br>EL10-016 | 12/29/2008<br><br>11/23/2010 | Certificate of Need 5/22/2009<br><br>Route Permit MN 9/14/2010<br><br>Route Permit SD 6/14/2011 | November 2011 | November 2011 | October 2011 | March 2015 | Project is in-service. | |
| CAPX2020 – Fargo | E002, ET2/TL-09-246<br><br>E002, ET2/TL-09-1056 | 4/8/2009<br><br>10/1/2009 | Certificate of Need 5/22/2009<br><br>Monticello – St. Cloud Route Permit 7/12/2010<br><br>St. Cloud – Fargo Route Permit 5/1/2011 | Monticello – St. Cloud Engineering Start 1/2/2010 Procurement Start 7/1/2010<br><br>St. Cloud – Fargo Engineering Start 10/1/2010 Procurement Start 7/1/2011 | Monticello – St. Cloud 7/15/2010<br><br>St. Cloud – Fargo 5/15/2011 | Monticello – St. Cloud 11/1/2010<br><br>St. Cloud – Fargo 12/26/2011 | Monticello – St. Cloud 12/21/2011<br><br>St. Cloud – Fargo 10/15/2015 | Monticello – St. Cloud segment is in-service.<br><br>St. Cloud – Fargo segment is in-service. | |
| CapX2020 – La Crosse (Local, MISO, and WI) | E002/CN-06-1115<br><br>Local & MISO: ET-2/TL-09-1448 (MN)<br><br>WI: 5-CE-136 (WI) | 8/4/2006<br><br>1/19/2010<br><br>1/3/2011 | MN Certificate of Need 5/22/2009<br><br>MN Route Permit 5/30/2012<br><br>WI Certificate of Public Convenience and Necessity 5/30/2012 | October 2011 | January 2012 | January 2013 | September 2016 | Project is in-service. | N/A |

| **Project Name** | **Regulatory Approval Docket No.** | **Regulatory Approval Filing Date** | **Regulatory Approval Order Dates** | **Design/ Engineering/ Procurement** | **ROW Acquisition** | **Construction Start** | **Projected In-Service** | **Current Status** | **MISO Approval** |
|---|---|---|---|---|---|---|---|---|---|
| Big Stone – Brookings | EL12-063 (SD)<br><br>EL13-020 (SD) | 12/19/2012<br><br>6/3/2013 | Facility Permit for 35 miles of planned line issued January 2007 (recertified May 10, 2013)<br><br>Facility Permit for 40 miles of planned line issued February 20, 2014 | June 2014 | December 2016 | August 2015 | September 2017 | Project is in-service. | December 2011 (MTEP11) |
| La Crosse – Madison | 5-CE-142 (WI)<br><br>137-CE-160 (WI) | 08/19/2013 | WI Certificate of Public Convenience and Necessity 4/23/2015 | May 2014 | Start-June 2015<br>End-May 2018 | August 2016 | December 2018 | Project is in-service | December 2011 (MTEP11) |
| Huntley-Wilmarth | E002,ET6675/CN-17-184<br><br>E002,ET6675/TL-17-185 | 6/30/2017<br><br>1/22/2018 | 8/21/2019<br><br>8/21/2019 | July 2019 | Start–September 2019<br><br>End –September 2020 (estimated) | Estimated:<br>Start – June 2020<br><br>End – December 2021 | Estimated: December 2021 | Final Engineering/ Design<br>ROW Acquisition | |
| | | | | | | | | | |
| ADMS | E002/M-15-962 | 11/1/2015 | 6/28/2016<br>Certified through Biennial Grid Modification Report process | 2016 | N/A | 2017 | Second quarter 2020 | Software has been installed, and testing is in process. Field hardware for select feeders is being installed. | N/A |

**CWIP Expenditures With Internal Labor Removed**



| NSPM Rider Project | NSPM Rider Sub Project | Eligibility Date | Pre Eligible AFUDC | Pre-2018 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total | Internal Labor Removed: Previous Filing Expenditures | Internal Labor Removed: Dollar Variance | Internal Labor Removed: % Variance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ADMS | Capital | 1/1/2017 | 370,966 | 11,410,290 | 6,996,767 | 13,781,047 | 6,201,800 | 960,000 | 2,880,000 | 4,298,449 | 2,879,792 | 49,779,110 | | | |
| ADMS | Sub-Total ADMS | | 370,966 | 11,410,290 | 6,996,767 | 13,781,047 | 6,201,800 | 960,000 | 2,880,000 | 4,298,449 | 2,879,792 | 49,779,110 | 35,355,665 | 14,423,445 | 29% |
| Big Stone-Brookings | Land | 1/1/2016 | | 3,519,600 | | | | | | | | 3,519,600 | | | |
| Big Stone-Brookings | Line | 1/1/2016 | 421,972 | 47,835,513 | (1,793,684) | 96,009 | | | | | | 46,559,810 | | | |
| Big Stone-Brookings | Sub | 1/1/2016 | 4,225 | 4,405,400 | 31,789 | (14,142) | | | | | | 4,427,272 | | | |
| Big Stone-Brookings | Sub-Total Big Stone-Brookings | | 426,197 | 55,760,513 | (1,761,895) | 81,867 | | | | | | 54,506,682 | 64,501,736 | (9,995,054) | -18% |
| CAPX2020 Brookings | Land | 1/1/2012 | | 38,242,915 | 387,653 | 8,584,701 | | | | | | 47,215,269 | | | |
| CAPX2020 Brookings | Line | 1/1/2012 | 4,092,148 | 357,857,937 | 66,163 | | | | | | | 362,016,248 | | | |
| CAPX2020 Brookings | Sub | 1/1/2012 | 38,858 | 53,624,739 | | | | | | | | 53,663,597 | | | |
| CAPX2020 Brookings | Sub-Total CAPX2020 Brookings | | 4,131,006 | 449,725,591 | 453,816 | 8,584,701 | | | | | | 462,895,114 | 455,305,122 | 7,589,992 | 2% |
| CAPX2020 - La Crosse Local | Land | 5/1/2009 | | 9,403,280 | 1,293,565 | (217,124) | | | | | | 10,479,721 | | | |
| CAPX2020 - La Crosse Local | Line | 5/1/2009 | | 62,397,417 | (184,437) | (2,118) | | | | | | 62,210,862 | | | |
| CAPX2020 - La Crosse Local | Sub | 5/1/2009 | | 2,930,368 | | | | | | | | 2,930,368 | | | |
| CAPX2020 - La Crosse Local | Sub-Total CAPX2020 - La Crosse Local | | | 74,731,065 | 1,109,128 | (219,242) | | | | | | 75,620,951 | 76,260,285 | (639,334) | -1% |
| CAPX2020 - La Crosse MISO | Land | 5/1/2009 | | 6,936,748 | (35,587) | (34,023) | | | | | | 6,867,138 | | | |
| CAPX2020 - La Crosse MISO | Line | 5/1/2009 | | 53,771,562 | 310,612 | (913) | | | | | | 54,081,261 | | | |
| CAPX2020 - La Crosse MISO | Sub | 5/1/2009 | | 14,098,404 | | | | | | | | 14,098,404 | | | |
| CAPX2020 - La Crosse MISO | Sub-Total CAPX2020 - La Crosse MISO | | | 74,806,714 | 275,025 | (34,936) | | | | | | 75,046,803 | 75,154,213 | (107,410) | 0% |
| CAPX2020 - La Crosse MISO - WI | Land | 5/1/2009 | | 9,399,875 | 22,713 | 88,772 | | | | | | 9,511,360 | | | |
| CAPX2020 - La Crosse MISO - WI | Line | 5/1/2009 | | 108,633,125 | (725,053) | 550,893 | | | | | | 108,458,965 | | | |
| CAPX2020 - La Crosse MISO - WI | Sub | 5/1/2009 | | 18,406,328 | (10) | | | | | | | 18,406,318 | | | |
| CAPX2020 - La Crosse MISO - WI | Sub-Total CAPX2020 - La Crosse MISO - WI | | | 136,439,328 | (702,350) | 639,665 | | | | | | 136,376,643 | 137,649,210 | (1,272,567) | -1% |
| CAPX2020 Fargo | Land | 5/1/2009 | | 19,707,347 | 562,525 | 116,082 | | | | | | 20,385,954 | | | |
| CAPX2020 Fargo | Line | 5/1/2009 | 239,382 | 156,202,393 | 34,101 | 3,183 | | | | | | 156,479,059 | | | |
| CAPX2020 Fargo | Sub | 5/1/2009 | | 31,312,982 | | | | | | | | 31,312,982 | | | |
| CAPX2020 Fargo | Sub-Total CAPX2020 Fargo | | 239,382 | 207,222,722 | 596,626 | 119,265 | | | | | | 208,177,995 | 207,422,176 | 755,819 | 0% |
| Huntley - Wilmarth | Land | 1/1/2019 | | | | 887,993 | 3,299,540 | 956,716 | | | | 5,144,249 | | | |
| Huntley - Wilmarth | Line | 1/1/2019 | 148,058 | | 1,648,866 | 1,441,944 | 28,908,681 | 32,222,379 | 1,177,062 | | | 65,546,990 | | | |
| Huntley - Wilmarth | Sub-Total Huntley - Wilmarth | | 148,058 | | 1,648,866 | 2,329,937 | 32,208,221 | 33,179,095 | 1,177,062 | | | 70,691,239 | | 70,691,239 | 100% |
| LaCrosse - Madison | Land | 1/1/2016 | | 8,181,773 | 1,960,564 | 2,272,391 | 460,467 | | | | | 12,875,195 | | | |
| LaCrosse - Madison | Line | 1/1/2016 | 1,190,165 | 93,548,178 | 52,542,115 | 6,627,585 | 80,912 | | | | | 153,988,955 | | | |
| LaCrosse - Madison | Sub | 1/1/2016 | 2 | 945,143 | 3,785,041 | 11,746 | | | | | | 4,741,932 | | | |
| LaCrosse - Madison | Sub-Total LaCrosse - Madison | | 1,190,168 | 102,675,094 | 58,287,720 | 8,911,722 | 541,379 | | | | | 171,606,083 | 163,944,401 | 7,661,682 | 4% |
| | Total | | 6,505,777 | 1,112,771,317 | 66,903,703 | 34,194,026 | 38,951,400 | 34,139,095 | 4,057,062 | 4,298,449 | 2,879,792 | 1,304,700,620 | 1,215,592,807 | 89,107,813 | 7% |

**Northern States Power Company**
**State of Minnesota**
**Transmission Cost Recovery Rider**

## CWIP Expenditures Including Internal Labor



| NSPM Rider Project | NSPM Rider Sub Project | Eligibility Date | Pre Eligible AFUDC | Pre-2018 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total | Previous Filing Expenditures | Dollar Variance | % Variance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ADMS | Capital | 1/1/2017 | 370,966 | 12,915,377 | 8,341,877 | 14,964,057 | 6,460,208 | 1,000,000 | 3,000,000 | 4,477,551 | 3,000,000 | 54,530,036 | | | |
| ADMS | Sub-Total ADMS | | 370,966 | 12,915,377 | 8,341,877 | 14,964,057 | 6,460,208 | 1,000,000 | 3,000,000 | 4,477,551 | 3,000,000 | 54,530,036 | 36,922,526 | 17,607,510 | 32% |
| | | | | | | | | | | | | | | | |
| Big Stone-Brookings | Land | 1/1/2016 | | 3,550,920 | | | | | | | | 3,550,920 | | | |
| Big Stone-Brookings | Line | 1/1/2016 | 421,972 | 54,663,429 | (1,770,654) | 8,396 | | | | | | 53,323,143 | | | |
| Big Stone-Brookings | Sub | 1/1/2016 | 4,225 | 6,998,316 | 19,202 | 8,319 | | | | | | 7,030,062 | | | |
| Big Stone-Brookings | Sub-Total Big Stone-Brookings | | 426,197 | 65,212,665 | (1,751,452) | 16,716 | | | | | | 63,904,125 | 74,407,751 | (10,503,626) | -16% |
| | | | | | | | | | | | | | | | |
| CAPX2020 Brookings | Land | 1/1/2012 | | 38,248,348 | 387,653 | 8,584,701 | | | | | | 47,220,702 | | | |
| CAPX2020 Brookings | Line | 1/1/2012 | 4,092,148 | 360,133,499 | 67,613 | | | | | | | 364,293,260 | | | |
| CAPX2020 Brookings | Sub | 1/1/2012 | 38,858 | 72,517,676 | | | | | | | | 72,556,534 | | | |
| CAPX2020 Brookings | Sub-Total CAPX2020 Brookings | | 4,131,006 | 470,899,523 | 455,266 | 8,584,701 | | | | | | 484,070,495 | 476,508,075 | 7,562,420 | 2% |
| | | | | | | | | | | | | | | | |
| CAPX2020 - La Crosse Local | Land | 5/1/2009 | | 9,634,853 | 1,310,846 | (213,893) | | | | | | 10,731,807 | | | |
| CAPX2020 - La Crosse Local | Line | 5/1/2009 | | 64,715,535 | (173,729) | 796 | | | | | | 64,542,602 | | | |
| CAPX2020 - La Crosse Local | Sub | 5/1/2009 | | 4,169,261 | | | | | | | | 4,169,261 | | | |
| CAPX2020 - La Crosse Local | Sub-Total CAPX2020 - La Crosse Local | | | 78,519,649 | 1,137,117 | (213,097) | | | | | | 79,443,669 | 79,991,431 | (547,762) | -1% |
| | | | | | | | | | | | | | | | |
| CAPX2020 - La Crosse MISO | Land | 5/1/2009 | | 7,000,768 | (28,793) | (34,023) | | | | | | 6,937,953 | | | |
| CAPX2020 - La Crosse MISO | Line | 5/1/2009 | | 57,029,467 | 310,612 | (913) | | | | | | 57,339,166 | | | |
| CAPX2020 - La Crosse MISO | Sub | 5/1/2009 | | 16,942,687 | | | | | | | | 16,942,687 | | | |
| CAPX2020 - La Crosse MISO | Sub-Total CAPX2020 - La Crosse MISO | | | 80,972,922 | 281,820 | (34,936) | | | | | | 81,219,805 | 81,230,437 | (10,632) | 0% |
| | | | | | | | | | | | | | | | |
| CAPX2020 - La Crosse MISO - WI | Land | 5/1/2009 | | 9,579,374 | 25,736 | 97,358 | | | | | | 9,702,467 | | | |
| CAPX2020 - La Crosse MISO - WI | Line | 5/1/2009 | | 114,907,178 | (709,110) | 576,103 | | | | | | 114,774,171 | | | |
| CAPX2020 - La Crosse MISO - WI | Sub | 5/1/2009 | | 23,047,377 | 19 | | | | | | | 23,047,396 | | | |
| CAPX2020 - La Crosse MISO - WI | Sub-Total CAPX2020 - La Crosse MISO - WI | | | 147,533,928 | (683,355) | 673,461 | | | | | | 147,524,034 | 148,739,916 | (1,215,883) | -1% |
| | | | | | | | | | | | | | | | |
| CAPX2020 Fargo | Land | 5/1/2009 | | 19,822,234 | 563,393 | 116,082 | | | | | | 20,501,709 | | | |
| CAPX2020 Fargo | Line | 5/1/2009 | 239,382 | 168,336,971 | 36,467 | 3,183 | | | | | | 168,616,002 | | | |
| CAPX2020 Fargo | Sub | 5/1/2009 | | 36,107,892 | | | | | | | | 36,107,892 | | | |
| CAPX2020 Fargo | Sub-Total CAPX2020 Fargo | | 239,382 | 224,267,097 | 599,859 | 119,265 | | | | | | 225,225,603 | 224,467,401 | 758,202 | 0% |
| | | | | | | | | | | | | | | | |
| Huntley - Wilmarth | Land | 1/1/2019 | | | | 940,508 | 3,504,000 | 1,016,000 | | | | 5,460,508 | | | |
| Huntley - Wilmarth | Line | 1/1/2019 | 148,058 | | 1,648,866 | 943,016 | 30,700,040 | 34,219,075 | 1,250,000 | | | 68,909,056 | | | |
| Huntley - Wilmarth | Sub-Total Huntley - Wilmarth | | 148,058 | | 1,648,866 | 1,883,525 | 34,204,040 | 35,235,075 | 1,250,000 | | | 74,369,564 | | 74,369,564 | 100% |
| | | | | | | | | | | | | | | | |
| LaCrosse - Madison | Land | 1/1/2016 | | 8,192,342 | 1,971,962 | 2,326,657 | 489,000 | | | | | 12,979,961 | | | |
| LaCrosse - Madison | Line | 1/1/2016 | 1,190,165 | 94,386,546 | 52,584,279 | 6,711,587 | 89,000 | | | | | 154,961,578 | | | |
| LaCrosse - Madison | Sub | 1/1/2016 | 2 | 1,094,503 | 5,347,237 | 30,940 | | | | | | 6,472,683 | | | |
| LaCrosse - Madison | Sub-Total LaCrosse - Madison | | 1,190,168 | 103,673,392 | 59,903,478 | 9,069,184 | 578,000 | | | | | 174,414,222 | 172,607,418 | 1,806,804 | 1% |
| | | | | | | | | | | | | | | | |
| | Total | | 6,505,777 | 1,183,994,552 | 69,933,476 | 35,062,874 | 41,242,248 | 36,235,075 | 4,250,000 | 4,477,551 | 3,000,000 | 1,384,701,553 | 1,294,874,955 | 89,826,598 | 6% |

## Annual Tracker Summary

| Line No: | Amounts in dollars | 2018 Actual | 2019 Mixed | 2020 Forecast | 2021 Forecast |
|---|---|---|---|---|---|
| 1 | ADMS | 1,171,589 | 1,998,824 | 5,154,785 | 6,460,723 |
| 2 | Big Stone-Brookings | 4,302,758 | 4,104,418 | 4,005,316 | 3,889,018 |
| 3 | CAPX2020 Brookings | 33,786,412 | 32,899,527 | 32,294,421 | 31,531,051 |
| 4 | CAPX2020 - La Crosse Local | 4,385,486 | 4,037,035 | 4,190,729 | 4,066,245 |
| 5 | CAPX2020 - La Crosse MISO | 5,609,997 | 5,398,997 | 5,270,019 | 5,144,564 |
| 6 | CAPX2020 - La Crosse MISO - WI | 10,930,203 | 10,370,757 | 10,093,278 | 9,750,252 |
| 7 | CAPX2020 Fargo | 15,497,657 | 14,825,199 | 14,433,305 | 14,034,998 |
| 8 | Huntley - Wilmarth | - | 205,462 | 1,160,070 | 3,668,064 |
| 9 | LaCrosse - Madison | 9,547,041 | 16,179,062 | 16,009,721 | 15,478,096 |
| 10 | MISO RECB Sch.26/26a | (174,749) | (8,372,475) | (3,202,305) | (6,779,681) |
| 11 | Transmission Projects | 85,056,394 | 81,646,805 | 89,409,339 | 87,243,331 |
| 12 | Revenue Requirement in Base Rates (ADMS)* | (701,000) | (1,937,000) | (1,937,000) | (1,937,000) |
| 13 | TCR True-up Carryover | 5,561,635 | 1,036,546 | (5,588,798) | (1,101,880) |
| 14 | **Revenue Requirement (RR)** | **89,917,029** | **80,746,350** | **81,883,541** | **84,204,451** |
| 15 | Revenue Collections (RC) | 88,880,483 | 86,335,148 | 82,985,421 | 85,728,191 |
| 16 | **Carry Over Balance** | 1,036,546 | (5,588,798) | (1,101,880) | (1,523,740) |

**ADMS Software In Base Rates**
**Annual Revenue Requirement**
**2017-2019 Test Years**
**(000's)**

| | | Total Company | | | MN Jurisdiction | | | |
|---|---|---|---|---|---|---|---|---|
| | Rate Analysis | 2017 | 2018 | 2019 | 2017 | 2018 | 2019 | |
| 1 | Average Balances: | | | | | | | |
| 2 | Plant Investment | - | 2,217 | 4,434 | - | 1,936 | 3,873 | |
| 3 | Depreciation Reserve | - | 18 | 480 | - | 16 | 420 | |
| 4 | CWIP | 3,967 | 2,060 | - | 3,465 | 1,799 | - | |
| 5 | Accumulated Deferred Taxes | 68 | 434 | 772 | 59 | 379 | 674 | |
| 6 | Average Rate Base = line 2 - line 3 + line 4 - line 5 | 3,899 | 3,825 | 3,181 | 3,405 | 3,341 | 2,779 | |
| 7 | | | | | | | | |
| 8 | Revenues: | | | | | | | |
| 9 | Interchange Agreement offset = -line 40 x line 52 x line 53 | | | | - | - | - | |
| 10 | | | | | | | | |
| 11 | Expenses: | | | | | | | |
| 12 | Book Depreciation | - | 37 | 887 | - | 32 | 775 | |
| 13 | Annual Deferred Tax | 40 | 691 | (14) | 35 | 604 | (12) | |
| 14 | ITC Flow Thru | - | - | - | - | - | - | |
| 15 | Property Taxes | - | - | - | - | - | - | |
| 16 | subtotal expense = lines 12 thru 15 | 40 | 728 | 873 | 35 | 636 | 762 | |
| 17 | | | | | | | | |
| 18 | Tax Preference Items: | | | | | | | |
| 19 | Tax Depreciation & Removal Expense | - | 1,613 | 740 | - | 1,409 | 647 | |
| 20 | Tax Credits ( enter as negative) | - | - | - | - | - | - | |
| 21 | Avoided Tax Interest | - | - | - | - | - | - | |
| 22 | | | | | - | - | - | |
| 23 | AFUDC | 263 | 269 | - | 230 | 235 | - | |
| 24 | | | | | | | | |
| 25 | Returns: | | | | | | | |
| 26 | Debt Return = line 6 x (line 44 + line 45) | 88 | 86 | 72 | 77 | 76 | 63 | |
| 27 | Equity Return = line 6 x (line 46 + line 47) | 188 | 185 | 154 | 164 | 161 | 134 | |
| 28 | | | | | | | | |
| 29 | Tax Calculations: | | | | | | | |
| 30 | Equity Return = line 27 | 188 | 185 | 154 | 164 | 161 | 134 | |
| 31 | Taxable Expenses = lines 12 thru 14 | 40 | 728 | 873 | 35 | 636 | 762 | |
| 32 | plus Tax Additions = line 21 | - | - | - | - | - | - | |
| 33 | less Tax Deductions = (line 19 + line 23) | (263) | (1,882) | (740) | (230) | (1,644) | (647) | |
| 34 | subtotal | (35) | (969) | 286 | (30) | (847) | 250 | |
| 35 | Tax gross-up factor = t / (1-t) from line 50 | 0.705611 | 0.705611 | 0.705611 | 0.705611 | 0.705611 | 0.705611 | |
| 36 | Current Income Tax Requirement = line 34 x line 35 | (24) | (684) | 202 | (21) | (597) | 176 | |
| 37 | Tax Credit Revenue Requirement = line 20 x line 35 + line 20 | - | - | - | - | - | - | |
| 38 | Total Current Tax Revenue Requirement = line 36+ line 37 | (24) | (684) | 202 | (21) | (597) | 176 | |
| 39 | | | | | | | | |
| 40 | Total Capital Revenue Requirements | 29 | 46 | 1,300 | 25 | 40 | 1,136 | |
| 41 | = line 16 + line 26 + line 27 + line 38 - line 23 + line 9 | | | | | | | |
| 42 | O&M Expense | - | - | - | - | - | - | |
| 43 | Total Revenue Requirements | 29 | 46 | 1,300 | 25 | 40 | 1,136 | (1) |

| | **Capital Structure** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** |
|---|---|---|---|---|---|---|---|
| 44 | **Long Term Debt** | **2.2100%** | **2.2100%** | **2.1800%** | **2.2100%** | **2.2100%** | **2.1800%** |
| 45 | **Short Term Debt** | **0.0500%** | **0.0500%** | **0.0700%** | **0.0500%** | **0.0500%** | **0.0700%** |
| 46 | **Preferred Stock** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** |
| 47 | **Common Equity** | **4.8300%** | **4.8300%** | **4.8300%** | **4.8300%** | **4.8300%** | **4.8300%** |
| 48 | **Required Rate of Return** | **7.0900%** | **7.0900%** | **7.0800%** | **7.0900%** | **7.0900%** | **7.0800%** |
| 49 | **PT Rate** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** |
| 50 | **Tax Rate (MN)** | **41.3700%** | **41.3700%** | **41.3700%** | **41.3700%** | **41.3700%** | **41.3700%** |
| 51 | **MN JUR Electric Intangible Composite** | **87.3467%** | **87.3467%** | **87.3467%** | **87.3467%** | **87.3467%** | **87.3467%** |
| 52 | **IA Demand** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** |

(1) Revenue Requirements are spread evenly across 12 months in Attachments 5-8

**ADMS - GIS Model Improvements In Base Rates**
**Annual Revenue Requirement**
**2017-2019 Test Years**
**(000's)**

| | | **Total Company** | | | **MN Jurisdiction** | | |
|---|---|---|---|---|---|---|---|
| | **Rate Analysis** | 2017 | 2018 | 2019 | 2017 | 2018 | 2019 |
| 1 | Average Balances: | | | | | | |
| 2 | Plant Investment | 1,993 | 2,989 | 3,736 | 1,741 | 2,611 | 3,264 |
| 3 | Depreciation Reserve | 401 | 888 | 1,553 | 350 | 776 | 1,356 |
| 4 | CWIP | - | - | - | - | - | - |
| 5 | Accumulated Deferred Taxes | 356 | 493 | 534 | 311 | 430 | 466 |
| 6 | Average Rate Base = line 2 - line 3 + line 4 - line 5 | 1,236 | 1,608 | 1,649 | 1,080 | 1,405 | 1,441 |
| 7 | | | | | | | |
| 8 | Revenues: | | | | | | |
| 9 | Interchange Agreement offset = -line 40 x line 52 x line 53 | | | | - | - | - |
| 10 | | | | | | | |
| 11 | Expenses: | | | | | | |
| 12 | Book Depreciation | 393 | 592 | 744 | 343 | 517 | 650 |
| 13 | Annual Deferred Tax | 165 | 109 | (27) | 144 | 96 | (24) |
| 14 | ITC Flow Thru | - | - | - | - | - | - |
| 15 | Property Taxes | - | - | - | - | - | - |
| 16 | subtotal expense = lines 12 thru 15 | 558 | 702 | 718 | 487 | 613 | 627 |
| 17 | | | | | | | |
| 18 | Tax Preference Items: | | | | | | |
| 19 | Tax Depreciation & Removal Expense | 795 | 859 | 678 | 694 | 750 | 592 |
| 20 | Tax Credits ( enter as negative) | - | - | - | - | - | - |
| 21 | Avoided Tax Interest | - | - | - | - | - | - |
| 22 | | | | | - | - | - |
| 23 | AFUDC | 1 | 1 | 1 | 1 | 1 | 1 |
| 24 | | | | | | | |
| 25 | Returns: | | | | | | |
| 26 | Debt Return = line 6 x (line 44 + line 45) | 28 | 36 | 37 | 24 | 32 | 32 |
| 27 | Equity Return = line 6 x (line 46 + line 47) | 60 | 78 | 80 | 52 | 68 | 70 |
| 28 | | | | | | | |
| 29 | Tax Calculations: | | | | | | |
| 30 | Equity Return = line 27 | 60 | 78 | 80 | 52 | 68 | 70 |
| 31 | Taxable Expenses = lines 12 thru 14 | 558 | 702 | 718 | 487 | 613 | 627 |
| 32 | plus Tax Additions = line 21 | - | - | - | - | - | - |
| 33 | less Tax Deductions = (line 19 + line 23) | (796) | (860) | (678) | (696) | (751) | (592) |
| 34 | subtotal | (179) | (81) | 119 | (157) | (71) | 104 |
| 35 | Tax gross-up factor = t / (1-t) from line 50 | 0.705611 | 0.705611 | 0.705611 | 0.705611 | 0.705611 | 0.705611 |
| 36 | Current Income Tax Requirement = line 34 x line 35 | (126) | (57) | 84 | (110) | (50) | 73 |
| 37 | Tax Credit Revenue Requirement = line 20 x line 35 + line 20 | - | - | - | - | - | - |
| 38 | Total Current Tax Revenue Requirement = line 36+ line 37 | (126) | (57) | 84 | (110) | (50) | 73 |
| 39 | | | | | | | |
| 40 | Total Capital Revenue Requirements | 517 | 757 | 918 | 452 | 661 | 801 |
| 41 | = line 16 + line 26 + line 27 + line 38 - line 23 + line 9 | | | | | | |
| 42 | O&M Expense | - | - | - | - | - | - |
| 43 | Total Revenue Requirements | 517 | 757 | 918 | 452 | 661 | 801 (1) |

| | **Capital Structure** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** | **Weighted Cost** |
|---|---|---|---|---|---|---|---|
| 44 | **Long Term Debt** | **2.2100%** | **2.2100%** | **2.1800%** | **2.2100%** | **2.2100%** | **2.1800%** |
| 45 | **Short Term Debt** | **0.0500%** | **0.0500%** | **0.0700%** | **0.0500%** | **0.0500%** | **0.0700%** |
| 46 | **Preferred Stock** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** |
| 47 | **Common Equity** | **4.8300%** | **4.8300%** | **4.8300%** | **4.8300%** | **4.8300%** | **4.8300%** |
| 48 | **Required Rate of Return** | **7.0900%** | **7.0900%** | **7.0800%** | **7.0900%** | **7.0900%** | **7.0800%** |
| 49 | **PT Rate** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** | **0.0000%** |
| 50 | **Tax Rate (MN)** | **41.3700%** | **41.3700%** | **41.3700%** | **41.3700%** | **41.3700%** | **41.3700%** |
| 51 | **MN JUR Energy** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** |
| 52 | **MN JUR Electric Intangible Composite** | **87.3467%** | **87.3467%** | **87.3467%** | **87.3467%** | **87.3467%** | **87.3467%** |
| 53 | **IA Demand** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** | **100.0000%** |

(1) Revenue Requirements are spread evenly across 12 months in Attachments 6-7

| | | | 2018 Tracker | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Carryover** | **Jan-18** | **Feb-18** | **Mar-18** | **Apr-18** | **May-18** | **Jun-18** | **Jul-18** | **Aug-18** | **Sep-18** | **Oct-18** | **Nov-18** | **Dec-18** | **Annual Total** |
| | **Amounts in dollars** | | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** |
| Line No | | | | | | | | | | | | | | | |
| 1 | ADMS | | 77,731 | 80,744 | 84,357 | 87,612 | 91,492 | 95,273 | 98,396 | 102,237 | 106,302 | 110,898 | 116,107 | 120,440 | 1,171,589 |
| 2 | Big Stone-Brookings | | 369,415 | 362,708 | 361,189 | 359,474 | 358,728 | 357,984 | 357,197 | 356,456 | 355,738 | 355,264 | 354,815 | 353,791 | 4,302,758 |
| 3 | CAPX2020 Brookings | | 2,847,277 | 2,841,388 | 2,836,425 | 2,831,370 | 2,825,237 | 2,819,103 | 2,812,952 | 2,806,801 | 2,800,667 | 2,794,532 | 2,788,398 | 2,782,263 | 33,786,412 |
| 4 | CAPX2020 - La Crosse Local | | 368,603 | 367,869 | 368,428 | 368,694 | 367,040 | 365,635 | 366,018 | 367,588 | 360,029 | 357,864 | 363,660 | 364,057 | 4,385,486 |
| 5 | CAPX2020 - La Crosse MISO | | 473,095.32 | 471,602.89 | 470,935.24 | 469,968.98 | 468,731.02 | 467,797.47 | 466,826.36 | 465,796.11 | 464,892.79 | 464,039.02 | 463,073.16 | 463,238.29 | 5,609,996.65 |
| 6 | CAPX2020 - La Crosse MISO - WI | | 924,037 | 922,138 | 919,862 | 917,480 | 915,121 | 912,862 | 910,618 | 908,354 | 906,126 | 903,885 | 897,850 | 891,870 | 10,930,203 |
| 7 | CAPX2020 Fargo | | 1,305,134 | 1,302,054 | 1,301,089 | 1,300,087 | 1,296,954 | 1,293,850 | 1,290,746 | 1,287,649 | 1,284,558 | 1,281,542 | 1,278,535 | 1,275,460 | 15,497,657 |
| 8 | LaCrosse - Madison | | 548,045 | 626,749 | 680,341 | 724,262 | 763,471 | 802,464 | 819,958 | 853,899 | 880,644 | 902,125 | 941,831 | 1,003,251 | 9,547,041 |
| 9 | MISO RECB Sch.26/26a | | 544 | (379,513) | (290,613) | (121,748) | 498,942 | 335,696 | 491,058 | 299,480 | (453,755) | (513,540) | (297,561) | 256,260 | (174,749) |
| 10 | Transmission Projects | | 6,913,882 | 6,595,740 | 6,732,013 | 6,937,200 | 7,585,716 | 7,450,663 | 7,613,769 | 7,448,261 | 6,705,202 | 6,656,609 | 6,906,707 | 7,510,631 | 85,056,394 |
| 11 | Revenue Requirement in Base Rates (ADMS) | | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (58,417) | (701,000) |
| 12 | TCR True-up Carryover | 5,561,635 | 5,561,635 | | | | | | | | | | | | 5,561,635 |
| 13 | **Revenue Requirement (RR)** | | **12,417,100** | **6,537,324** | **6,673,596** | **6,878,784** | **7,527,299** | **7,392,247** | **7,555,352** | **7,389,844** | **6,646,785** | **6,598,192** | **6,848,291** | **7,452,214** | **89,917,029** |
| 14 | Revenue Collections (RC) | | 7,817,055 | 6,628,056 | 7,089,818 | 6,483,855 | 6,943,872 | 7,861,295 | 8,749,552 | 8,868,327 | 7,459,262 | 7,732,744 | 6,400,144 | 6,846,503 | 88,880,483 |
| 15 | Monthly RR - RC | | 4,600,045 | (90,732) | (416,222) | 394,929 | 583,427 | (469,048) | (1,194,200) | (1,478,483) | (812,477) | (1,134,552) | 448,147 | 605,711 | |
| 16 | Balance (RR - RC + Cumulative CC) | | 4,600,045 | 4,509,313 | 4,093,091 | 4,488,020 | 5,071,447 | 4,602,399 | 3,408,199 | 1,929,716 | 1,117,240 | (17,312) | 430,834 | 1,036,546 | |

| | | | 2019 Tracker | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Carryover** | **Jan-19** | **Feb-19** | **Mar-19** | **Apr-19** | **May-19** | **Jun-19** | **Jul-19** | **Aug-19** | **Sep-19** | **Oct-19** | **Nov-19** | **Dec-19** | **Annual Total** |
| | **Amounts in dollars** | | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Actual** | **Mixed** | **Mixed** | **Mixed** | **Forecast** | **Forecast** | **Forecast** | **Mixed** |
| Line No | | | | | | | | | | | | | | | |
| 1 | ADMS | | 135,277 | 140,146 | 144,859 | 149,980 | 154,019 | 157,598 | 162,351 | 168,559 | 174,891 | 188,151 | 201,037 | 221,956 | 1,998,824 |
| 2 | Big Stone-Brookings | | 345,671 | 345,339 | 344,575 | 343,809 | 343,011 | 342,452 | 341,886 | 341,082 | 340,308 | 339,535 | 338,761 | 337,988 | 4,104,418 |
| 3 | CAPX2020 Brookings | | 2,752,637 | 2,770,138 | 2,764,235 | 2,758,333 | 2,752,430 | 2,746,527 | 2,740,626 | 2,734,726 | 2,728,823 | 2,722,920 | 2,717,017 | 2,711,114 | 32,899,527 |
| 4 | CAPX2020 - La Crosse Local | | 341,401 | 340,015 | 339,203 | 338,393 | 337,582 | 336,772 | 335,964 | 335,156 | 334,349 | 333,541 | 332,733 | 331,925 | 4,037,035 |
| 5 | CAPX2020 - La Crosse MISO | | 455,482 | 454,390 | 453,394 | 452,398 | 451,402 | 450,406 | 449,410 | 448,415 | 447,419 | 446,423 | 445,427 | 444,431 | 5,398,997 |
| 6 | CAPX2020 - La Crosse MISO - WI | | 874,118 | 871,951 | 869,829 | 867,651 | 865,441 | 863,728 | 863,802 | 863,366 | 861,108 | 858,848 | 856,588 | 854,329 | 10,370,757 |
| 7 | CAPX2020 Fargo | | 1,251,230 | 1,248,655 | 1,246,080 | 1,243,074 | 1,240,062 | 1,237,050 | 1,234,038 | 1,231,026 | 1,228,014 | 1,225,002 | 1,221,990 | 1,218,978 | 14,825,199 |
| 8 | Huntley - Wilmarth | | 13,731 | 16,919 | (8,630) | 17,216 | 17,953 | 18,345 | 18,875 | 19,987 | 21,099 | 22,210 | 23,322 | 24,435 | 205,462 |
| 9 | LaCrosse - Madison | | 1,333,070 | 1,349,117 | 1,349,482 | 1,349,390 | 1,349,988 | 1,350,347 | 1,351,048 | 1,351,471 | 1,351,487 | 1,350,369 | 1,348,081 | 1,345,211 | 16,179,062 |
| 10 | MISO RECB Sch.26/26a | | (1,418,048) | (609,927) | (865,791) | (612,104) | (546,251) | (609,730) | (580,000) | (431,486) | (371,812) | (927,562) | (772,623) | (627,142) | (8,372,475) |
| 11 | Transmission Projects | | 6,084,569 | 6,926,742 | 6,637,236 | 6,908,140 | 6,965,638 | 6,893,495 | 6,918,001 | 7,062,302 | 7,115,685 | 6,559,437 | 6,712,335 | 6,863,226 | 81,646,805 |
| 12 | Revenue Requirement in Base Rates (ADMS) | | (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) |
| 13 | TCR True-up Carryover | 1,036,546 | 1,036,546 | - | - | - | - | - | - | - | - | - | - | - | 1,036,546 |
| 14 | **Revenue Requirement (RR)** | | **6,959,698** | **6,765,325** | **6,475,819** | **6,746,724** | **6,804,221** | **6,732,078** | **6,756,584** | **6,900,885** | **6,954,269** | **6,398,020** | **6,550,919** | **6,701,809** | **80,746,350** |
| 15 | 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 | 6,521,736 | 6,889,004 | 7,819,859 | 86,335,148 |
| 16 | Monthly RR - RC | | (335,290) | 281,283 | (839,407) | 136,496 | 243,608 | (91,551) | (1,682,337) | (1,580,528) | (141,220) | (123,716) | (338,085) | (1,118,050) | |
| 17 | Balance (RR - RC + Cumulative CC) | | (335,290) | (54,008) | (893,415) | (756,919) | (513,311) | (604,862) | (2,287,198) | (3,867,726) | (4,008,947) | (4,132,663) | (4,470,748) | (5,588,798) | |

**Northern States Power Company**
**State of Minnesota**
**Transmission Cost Recovery Rider**



| | | | 2020 Tracker | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Carryover** | **Jan-20** | **Feb-20** | **Mar-20** | **Apr-20** | **May-20** | **Jun-20** | **Jul-20** | **Aug-20** | **Sep-20** | **Oct-20** | **Nov-20** | **Dec-20** | **Annual Total** |
| | **Amounts in dollars** | | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** | **Forecast** |
| Line No | | | | | | | | | | | | | | | |
| 1 | ADMS | | 187,986 | 198,826 | 209,548 | 369,555 | 524,222 | 524,050 | 523,897 | 523,723 | 523,529 | 523,354 | 523,144 | 522,953 | 5,154,785 |
| 2 | Big Stone-Brookings | | 337,905 | 337,154 | 336,407 | 335,652 | 334,905 | 334,150 | 333,403 | 332,652 | 331,897 | 331,150 | 330,395 | 329,648 | 4,005,316 |
| 3 | CAPX2020 Brookings | | 2,718,504 | 2,713,539 | 2,708,585 | 2,703,609 | 2,698,655 | 2,693,679 | 2,688,725 | 2,683,760 | 2,678,784 | 2,673,830 | 2,668,853 | 2,663,899 | 32,294,421 |
| 4 | CAPX2020 - La Crosse Local | | 353,687 | 352,876 | 352,068 | 351,254 | 350,446 | 349,631 | 348,824 | 348,012 | 347,198 | 346,390 | 345,575 | 344,768 | 4,190,729 |
| 5 | CAPX2020 - La Crosse MISO | | 444,115 | 443,215 | 442,319 | 441,416 | 440,519 | 439,616 | 438,720 | 437,820 | 436,918 | 436,021 | 435,118 | 434,222 | 5,270,019 |
| 6 | CAPX2020 - La Crosse MISO - WI | | 853,203 | 851,003 | 848,809 | 846,603 | 844,409 | 842,203 | 840,010 | 837,810 | 835,604 | 833,410 | 831,204 | 829,010 | 10,093,278 |
| 7 | CAPX2020 Fargo | | 1,217,866 | 1,215,122 | 1,212,387 | 1,209,632 | 1,206,897 | 1,204,143 | 1,201,408 | 1,198,663 | 1,195,909 | 1,193,174 | 1,190,419 | 1,187,684 | 14,433,305 |
| 8 | Huntley - Wilmarth | | 16,232 | 23,999 | 31,767 | 44,180 | 61,234 | 78,299 | 96,915 | 117,086 | 137,269 | 160,550 | 185,391 | 207,149 | 1,160,070 |
| 9 | LaCrosse - Madison | | 1,351,924 | 1,349,294 | 1,346,611 | 1,343,459 | 1,339,915 | 1,336,353 | 1,332,796 | 1,329,153 | 1,325,497 | 1,321,882 | 1,318,226 | 1,314,611 | 16,009,721 |
| 10 | MISO RECB Sch.26/26a | | (666,239) | (535,932) | (469,850) | (582,261) | (440,585) | (142,372) | 567,495 | 29,521 | 256,014 | (560,435) | (417,802) | (239,859) | (3,202,305) |
| 11 | Transmission Projects | | 6,815,182 | 6,949,095 | 7,018,650 | 7,063,098 | 7,360,618 | 7,659,751 | 8,372,192 | 7,838,201 | 8,068,616 | 7,259,325 | 7,410,524 | 7,594,086 | 89,409,339 |
| 12 | Revenue Requirement in Base Rates (ADMS) | | (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) |
| 13 | TCR True-up Carryover | (5,588,798) | (5,588,798) | - | - | - | - | - | - | - | - | - | - | - | (5,588,798) |
| 14 | **Revenue Requirement (RR)** | | **1,064,968** | **6,787,678** | **6,857,233** | **6,901,682** | **7,199,201** | **7,498,335** | **8,210,775** | **7,676,785** | **7,907,199** | **7,097,909** | **7,249,108** | **7,432,669** | **81,883,541** |
| 15 | Revenue Collections (RC) | | 7,845,690 | 6,373,456 | 6,745,084 | 5,903,383 | 6,315,609 | 7,245,792 | 8,372,067 | 7,999,625 | 6,635,121 | 6,308,015 | 6,190,492 | 7,051,087 | 82,985,421 |
| 16 | Monthly RR - RC | | (6,780,722) | 414,222 | 112,149 | 998,299 | 883,592 | 252,543 | (161,292) | (322,840) | 1,272,078 | 789,894 | 1,058,616 | 381,582 | |
| 17 | Balance (RR - RC + Cumulative CC) | | (6,780,722) | (6,366,500) | (6,254,351) | (5,256,052) | (4,372,460) | (4,119,917) | (4,281,209) | (4,604,050) | (3,331,971) | (2,542,078) | (1,483,462) | (1,101,880) | |

| | | | 2021 Tracker | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Carryover | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Annual Total |
| | **Amounts in dollars** | | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast | Forecast |
| Line No | | | | | | | | | | | | | | | |
| 1 | ADMS | | 549,147 | 547,184 | 545,261 | 543,291 | 541,361 | 539,383 | 537,445 | 535,481 | 533,492 | 531,543 | 529,546 | 527,589 | 6,460,723 |
| 2 | Big Stone-Brookings | | 328,092 | 327,361 | 326,636 | 325,904 | 325,179 | 324,447 | 323,722 | 322,994 | 322,262 | 321,537 | 320,805 | 320,080 | 3,889,018 |
| 3 | CAPX2020 Brookings | | 2,652,989 | 2,648,365 | 2,643,753 | 2,639,129 | 2,634,517 | 2,629,893 | 2,625,281 | 2,620,663 | 2,616,040 | 2,611,427 | 2,606,804 | 2,602,192 | 31,531,051 |
| 4 | CAPX2020 - La Crosse Local | | 343,162 | 342,376 | 341,596 | 340,809 | 340,030 | 339,243 | 338,464 | 337,681 | 336,894 | 336,115 | 335,328 | 334,549 | 4,066,245 |
| 5 | CAPX2020 - La Crosse MISO | | 432,834 | 432,084 | 431,336 | 430,586 | 429,838 | 429,088 | 428,339 | 427,590 | 426,840 | 426,092 | 425,342 | 424,594 | 5,144,564 |
| 6 | CAPX2020 - La Crosse MISO - WI | | 822,285 | 820,510 | 818,734 | 816,960 | 815,184 | 813,409 | 811,633 | 809,858 | 808,083 | 806,307 | 804,532 | 802,757 | 9,750,252 |
| 7 | CAPX2020 Fargo | | 1,183,052 | 1,180,598 | 1,178,155 | 1,175,701 | 1,173,258 | 1,170,804 | 1,168,361 | 1,165,913 | 1,163,459 | 1,161,016 | 1,158,562 | 1,156,119 | 14,034,998 |
| 8 | Huntley - Wilmarth | | 194,258 | 212,622 | 230,999 | 250,881 | 272,280 | 295,184 | 319,606 | 342,535 | 362,470 | 376,416 | 385,859 | 424,953 | 3,668,064 |
| 9 | LaCrosse - Madison | | 1,308,762 | 1,305,305 | 1,301,884 | 1,298,428 | 1,295,007 | 1,291,550 | 1,288,129 | 1,284,691 | 1,281,234 | 1,277,813 | 1,274,357 | 1,270,936 | 15,478,096 |
| 10 | MISO RECB Sch.26/26a | | (989,349) | (928,703) | (740,713) | (835,977) | (756,442) | (478,983) | 268,130 | (314,833) | (1,813) | (835,628) | (664,226) | (501,143) | (6,779,681) |
| 11 | Transmission Projects | | 6,825,232 | 6,887,702 | 7,077,641 | 6,985,712 | 7,070,210 | 7,354,019 | 8,109,110 | 7,532,572 | 7,848,962 | 7,012,638 | 7,176,910 | 7,362,624 | 87,243,331 |
| 12 | Revenue Requirement in Base Rates (ADMS) | | (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) |
| 13 | TCR True-up Carryover | (1,101,880) | (1,101,880) | - | - | - | - | - | - | - | - | - | - | - | (1,101,880) |
| 14 | **Revenue Requirement (RR)** | | **5,561,935** | **6,726,285** | **6,916,225** | **6,824,296** | **6,908,793** | **7,192,602** | **7,947,693** | **7,371,155** | **7,687,545** | **6,851,221** | **7,015,494** | **7,201,207** | **84,204,451** |
| 15 | Revenue Collections (RC) | | 7,085,675 | 6,726,285 | 6,916,225 | 6,824,296 | 6,908,793 | 7,192,602 | 7,947,693 | 7,371,155 | 7,687,545 | 6,851,221 | 7,015,494 | 7,201,207 | 85,728,191 |
| 16 | Monthly RR - RC | | (1,523,740) | - | - | - | - | - | - | - | - | - | - | - | |
| 17 | Balance (RR - RC + Cumulative CC) | | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | (1,523,740) | |

**Northern States Power Company**
**State of Minnesota**
**Transmission Cost Recovery Rider**
**2019 Revenue Calculation**



| | Actual/Forecast Revenue (2) | | | | | kWh 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 (1)** | | | | | | | | | | | |
| **2017 TCR Rates** | | **$0.003503** | **$0.003384** | **$1.017** | **$0.000000** | | | | | | |
| **2019 TCR Rates** | | **$0.003948** | **$0.003486** | **$1.074** | **$0.000000** | | | | | | |
| Jan 2019 **Actual** | 7,294,988 | | | | | | | | | | |
| Feb 2019 **Actual** | 6,484,043 | | | | | | | | | | |
| March 2019 **Actual** | 7,315,226 | | | | | | | | | | |
| April 2019 **Actual** | 6,610,227 | | | | | | | | | | |
| May 2019 **Actual** | 6,560,614 | | | | | | | | | | |
| June 2019 **Actual** | 6,823,629 | | | | | | | | | | |
| July 2019 **Actual** | 8,438,921 | | | | | | | | | | |
| Aug 2019 **Actual** | 8,481,413 | | | | | | | | | | |
| Sept 2019 **Actual** | 7,095,489 | | | | | | | | | | |
| Oct 2019 **Fcst** | 6,521,736 | 2,123,963 | 209,209 | 4,188,564 | - | 2,277,617,568 | 606,326,938 | 61,822,879 | 1,598,726,170 | 10,741,581 | 4,118,549 |
| Nov 2019 **Fcst** | 6,889,004 | 2,504,852 | 226,538 | 4,157,614 | - | 2,214,532,255 | 634,461,021 | 64,985,176 | 1,502,691,279 | 12,394,779 | 3,871,149 |
| Dec 2019 **Fcst** | 7,819,859 | 3,030,337 | 267,777 | 4,521,745 | - | 2,493,025,717 | 767,562,568 | 76,814,912 | 1,634,299,649 | 14,348,588 | 4,210,191 |
| **Total Jan-Dec** | **$ 86,335,149** | **$ 7,659,152** | **$ 703,524** | **$ 12,867,923** | **$ -** | **6,985,175,540** | **2,008,350,527** | **203,622,967** | **4,735,717,098** | **37,484,948** | **12,199,889** |

**Notes:**

(1) 2017 TCR Adjustment Factors by customer group are those approved in Docket E002/M-15-891 and implemented on February 1, 2017. 2019 TCR Adjustment Factors by customer group reflect rates as filed in the compliance filing in Docket E002/M-17-797 on October 16, 2019, and became effective November 1, 2019.

(2) 2019 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.

(3) Sales by customer group are based on the 2019 State of Minnesota budget sales for 2019 by billing month including Interdepartmental in the Demand Group.

| | 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 (1)** | | | | | | | | | | | |
| **2019 TCR Rates** | | **$0.003948** | **$0.003486** | **$1.074** | **$0.000000** | | | | | | |
| **2020 TCR Rates** | | **$0.003607** | **$0.003185** | **$0.982** | **$0.000000** | | | | | | |
| Jan 2020 **Fcst** | 7,845,690 | 3,149,279 | 295,595 | 4,400,816 | - | 2,488,099,650 | 797,689,619 | 84,794,804 | 1,590,592,134 | 15,023,093 | 4,097,594 |
| Feb 2020 **Fcst** | 6,373,456 | 2,412,506 | 234,405 | 3,726,545 | - | 2,228,330,755 | 668,839,953 | 73,596,688 | 1,473,524,877 | 12,369,237 | 3,796,012 |
| March 2020 **Fcst** | 6,745,084 | 2,386,158 | 247,011 | 4,111,915 | - | 2,376,963,296 | 661,535,292 | 77,554,400 | 1,625,905,191 | 11,968,413 | 4,188,566 |
| April 2020 **Fcst** | 5,903,383 | 1,976,902 | 213,625 | 3,712,856 | - | 2,092,983,299 | 548,073,651 | 67,072,245 | 1,468,111,885 | 9,725,518 | 3,782,068 |
| May 2020 **Fcst** | 6,315,609 | 2,134,626 | 214,103 | 3,966,880 | - | 2,235,733,087 | 591,801,072 | 67,222,285 | 1,568,556,517 | 8,153,213 | 4,040,827 |
| June 2020 **Fcst** | 7,245,792 | 2,739,287 | 220,175 | 4,286,330 | - | 2,530,300,592 | 759,436,326 | 69,128,577 | 1,694,871,100 | 6,864,589 | 4,366,232 |
| July 2020 **Fcst** | 8,372,067 | 3,369,143 | 245,414 | 4,757,510 | - | 2,898,654,658 | 934,056,826 | 77,053,119 | 1,881,181,860 | 6,362,853 | 4,846,195 |
| Aug 2020 **Fcst** | 7,999,625 | 3,149,246 | 234,940 | 4,615,439 | - | 2,779,060,381 | 873,092,849 | 73,764,560 | 1,825,005,177 | 7,197,795 | 4,701,476 |
| Sept 2020 **Fcst** | 6,635,121 | 2,327,884 | 197,779 | 4,109,458 | - | 2,340,779,920 | 645,379,574 | 62,097,142 | 1,624,933,767 | 8,369,437 | 4,186,063 |
| Oct 2020 **Fcst** | 6,308,015 | 2,139,448 | 193,753 | 3,974,814 | - | 2,236,098,769 | 593,137,803 | 60,832,951 | 1,571,693,597 | 10,434,418 | 4,048,909 |
| Nov 2020 **Fcst** | 6,190,492 | 2,242,596 | 204,381 | 3,743,515 | - | 2,178,252,198 | 621,734,522 | 64,169,860 | 1,480,234,807 | 12,113,009 | 3,813,298 |
| Dec 2020 **Fcst** | 7,051,087 | 2,727,175 | 241,950 | 4,081,962 | - | 2,460,198,598 | 756,078,354 | 75,965,609 | 1,614,061,293 | 14,093,342 | 4,158,054 |
| **Total Jan-Dec** | **$ 82,985,421** | **$ 30,754,250** | **$ 2,743,131** | **$ 49,488,040** | **$ -** | **28,845,455,203** | **8,450,855,841** | **853,252,240** | **19,418,672,205** | **122,674,917** | **50,025,296** |

**Notes:**

(1) 2019 TCR Adjustment Factors by customer group reflect rates filed in Docket E002/M-17-0797 filed with the Commission on October 16, 2019, and implemented November 1, 2019.
2020 TCR Adjustment Factors by customer group are calculated on Attachment 9, page 4, and requested to be made effective February 1, 2020.

(2) 2020 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.

(3) Sales by customer group are based on the 2019 State of Minnesota budget sales for 2020 by billing month including Interdepartmental in the Demand Group.

**Northern States Power Company**
**State of Minnesota**
**Transmission Cost Recovery Rider**
**2021 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** | | | | | | | | | | | |
| **2020 TCR Rates (1)** | | **$0.003607** | **$0.003185** | **$0.982** | **$0.000000** | | | | | | |
| Jan 2021 **Fcst** | 7,085,675 | 2,828,507 | 268,536 | 3,988,632 | - | 2,460,446,266 | 784,171,563 | 84,312,712 | 1,577,157,424 | 14,804,567 | 4,062,985 |
| **Total Feb 2020 - Jan 2021** | | | | | | **28,817,801,819** | **8,437,337,785** | **852,770,148** | **19,405,237,495** | **122,456,391** | **49,990,686** |

**Notes:**

(1) 2020 TCR Adjustment Factors by customer group are calculated on Attachment 9, page 4.
(2) 2021 estimated revenues to be recovered under the TCR Rate Rider are calculated by multiplying the TCR Adjustment Factor, listed above, by the forecast sales for the month by customer group.
(3) Sales by customer group are based on the 2019 State of Minnesota budget sales for 2021 by billing month including Interdepartmental in the Demand Group.

**Northern States Power Company**
**State of Minnesota**
**Transmission Cost Recovery Rider**
**2020 TCR Adjustment Factor Calculation**

| | | | Customer Groups | | | | |
|---|---|---|---|---|---|---|---|
| | | **Retail** | **Residential** | **Commercial Non-Demand** | **Demand** | **Street Lighting** | **Total** |
| Transmission Demand Allocator | D10S | 100.00% | 36.14% | 3.28% | 60.59% | 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** | **1.2694** | **1.1210** | **0.8902** | **0.0000** | **1.0000** |
| | **MN kWh retail Sales** | **28,817,801,819** | 8,437,337,785 | 852,770,148 | 19,405,237,495 | 122,456,391 | 28,817,801,819 |
| | **MN kW Demand** | | | | 49,990,686 | | |
| **State of Mn Cost per kWh** | **Total Sales/Costs** | **$0.002841** | | | | | |
| | **MN retail Cost** | **81,883,541** | 30,433,477 | 2,716,073 | 49,075,846 | - | |
| | | **Basis** | | | | | |
| **TCR Adjustment Factor (2)** | | **per kWh** | **$0.003607** | **$0.003185** | | **$0.000000** | |
| | | **per kW** | | | **$0.982** | | |

**Notes:**

1) The Group Weighting Factors are calculated by dividing the transmission demand allocation percentage for each customer group, by the corresponding sales allocation percentage for the same customer group. The transmission demand 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.

**Key Inputs**

| Line No | **Capital Structure** | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | **2018 Compliance** | | | **2019** | | | **2020** | | | **2021** | | |
| 2 | Capital Structure | Cost | Ratio | WACC | Cost | Ratio | WACC | Cost | Ratio | WACC | Cost | Ratio | WACC |
| 3 | Long Term Debt | 4.77% | 46.41% | 2.21% | 4.75% | 45.81% | 2.18% | 4.75% | 45.81% | 2.18% | 4.75% | 45.81% | 2.18% |
| 4 | Short Term Debt | 4.45% | 1.09% | 0.05% | 4.31% | 1.69% | 0.07% | 4.31% | 1.69% | 0.07% | 4.31% | 1.69% | 0.07% |
| 5 | Preferred Stock | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 6 | Common Equity | 9.06% | 52.50% | 4.76% | 9.06% | 52.50% | 4.76% | 9.06% | 52.50% | 4.76% | 9.06% | 52.50% | 4.76% |
| 7 | **Required Rate of Return** | | | 7.02% | | | 7.01% | | | 7.01% | | | 7.01% |
| 8 | **(Rates and Ratios from Settlement in Docket E002/GR-15-826, ROE as discussed in TCR petition)** | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | |
| 10 | **Property Tax Rates** | | | | | | | | | | | | |
| 11 | Property Tax Rate | | | 1.675% | | | 1.541% | | | 1.541% | | | 1.541% |
| 12 | | | | | | | | | | | | | |
| 13 | **Income Tax Rates** | | | | | | | | | | | | |
| 14 | Federal Tax Rate | | | 21.00% | | | 21.00% | | | 21.00% | | | 21.00% |
| 15 | StateTax Rate | | | 9.80% | | | 9.80% | | | 9.80% | | | 9.80% |
| 16 | State Composite Income Tax Rate | | | 28.7420% | | | 28.7420% | | | 28.7420% | | | 28.7420% |
| 17 | Company Composite Income Tax Rate | | | 28.1092% | | | 28.1092% | | | 28.1092% | | | 28.1092% |
| 18 | | | | | | | | | | | | | |
| 19 | **OATT** | | | | | | | | | | | | |
| 20 | Annual OATT Credit Factor | | | 24.56% | | | 28.13% | | | 23.29% | | | 23.29% |
| 21 | | | | | | | | | | | | | |
| 22 | **Allocators (As Approved in Docket E002/GR-15-826)** | | | | | | | | | | | | |
| 23 | MN 12-month CP demand (Electric Demand) | | | 87.3461% * | | | 87.3461% * | | | 87.3461% * | | | 87.3461% * |
| 24 | NSPM 36-month CP demand (Interchange Electric) | | | 84.2615% | | | 83.8864% | | | 83.9342% | | | 83.7041% |
| 25 | Jurisdictional Allocator | | | 73.5991% | | | 73.2715% | | | 73.3133% | | | 73.1123% |
| 26 | * As Approved in Docket E002/GR-15-826 | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | | |
| 28 | **Book Depreciation Lives** | | | | | | | | | | | | |
| 29 | Land | | | 0 | | | 0 | | | 0 | | | 0 |
| 30 | Line | | | 63.33 | | | 62.94 | | | 62.94 | | | 62.94 |
| 31 | Sub | | | 56.41 | | | 56.34 | | | 56.34 | | | 56.34 |
| 32 | ADMS | | | 11.52 | | | 11.44 | | | 11.44 | | | 11.44 |
| 33 | | | | | | | | | | | | | |
| 34 | **Net Salvage %** | | | | | | | | | | | | |
| 35 | Land | | | 0.00% | | | 0.00% | | | 0.00% | | | 0.00% |
| 36 | Line | | | -43.84% | | | -43.88% | | | -43.88% | | | -43.88% |
| 37 | Sub | | | -14.39% | | | -14.35% | | | -14.35% | | | -14.35% |
| 38 | ADMS | | | 0.00% | | | 0.00% | | | 0.00% | | | 0.00% |
| 39 | | | | | | | | | | | | | |
| 40 | **Book Depreciation Rates** | | | | | | | | | | | | |
| 41 | Land | | | 0 | | | 0 | | | 0 | | | 0 |
| 42 | Line | | | 2.2713% | | | 2.2858% | | | 2.2858% | | | 2.2858% |
| 43 | Sub | | | 2.0276% | | | 2.0296% | | | 2.0296% | | | 2.0296% |
| 44 | ADMS | | | 8.6800% | | | 8.7382% | | | 8.7382% | | | 8.7382% |

**Northern States Power Company**
**Transmission Revenue From Others**
**NSP Revenue Credits for FERC Account 456**

**2018 Actual**
**Amounts in dollars**

| Line No. | SAP Account | Description | | Total 2018 | Revenue included in OATT Credit | Revenue Excluded in OATT Credit |
|---|---|---|---|---|---|---|
| 1 | 4140001 | PTP - Firm | MISO | 7,583,904 | | 7,583,904 |
| 2 | 4140001 | PTP - Non Firm | MISO | 469,923 | | 469,923 |
| 3 | 4140051 | Network | MISO | 26,017,290 | 26,017,290 | |
| 4 | 4140201 | Sch 1 - Sch, Sys Ctrl & D | MISO | 920,093 | 920,093 | |
| 5 | 4140211 | Sch 2 - Reactive Supply | MISO | 9,126,319 | 9,126,319 | |
| 6 | 4140211 | Sch 24 - Bal Auth | MISO | 1,118,076 | 1,118,076 | |
| 7 | 4140301 | Other RTO GFA Revenue | MISO | - | - | |
| 8 | 4140351 | Trans Expansion Plan Att GG | MISO | 69,099,374 | | 69,099,374 |
| 9 | 4140351 | Trans Expansion Plan Att GG - True Up | MISO | (277,396) | (277,396) | |
| 10 | 4140351 | Trans Expansion Plan Att MM | MISO | 59,152,524 | | 59,152,524 |
| 11 | 4140351 | Trans Expansion Plan Att MM - True Up | MISO | (732,167) | (732,167) | |
| 12 | 4140051 | Joint Pricing Zone - Network | JPZ | 49,926,491 | 49,926,491 | |
| 13 | 4140211 | Sch 2 - Reactive Supply | JPZ | 126,983 | 126,983 | |
| 14 | 4140101 | Contracts - Sioux Falls | | 173,653 | | 173,653 |
| 15 | 4140101 | Contracts - WPPI | | 40,320 | | 40,320 |
| 16 | 4140101 | Contracts - UND | | 63,879 | | 63,879 |
| 17 | 4140101 | Contracts - Granite Falls | | 16,477 | | 16,477 |
| 18 | 4140101 | Contracts - EGF | | 51,717 | | 51,717 |
| 19 | 4140101 | Contracts - Facilities SD State Pen | | 13,812 | | 13,812 |
| 20 | | Total NSP Revenue | | 222,891,272 | 86,225,689 | 136,665,583 |

| | |
|---|---|
| Line 36 Attachment O - 2018 Actual | 86,225,689 |
| Line 1 Attachment O - 2018 Actual | 351,138,418 |
| 2018 OATT Credit Factor = Line 36 / Line 1 | 24.56% |

**Northern States Power Company**
**Transmission Revenue From Others**
**NSP Revenue Credits for FERC Account 456**

**2019 Forecast**
**Amounts in dollars**

| Line No. | SAP Account | Description | | Total 2019 | Revenue included in OATT Credit | Revenue Excluded in OATT Credit |
|---|---|---|---|---|---|---|
| 1 | 4140001 | PTP - Firm | MISO | 7,637,508 | | 7,637,508 |
| 2 | 4140001 | PTP - Non Firm | MISO | 405,139 | | 405,139 |
| 3 | 4140051 | Network | MISO | 29,921,219 | 29,921,219 | |
| 4 | 4140201 | Sch 1 - Sch, Sys Ctrl & D | MISO | 919,774 | 919,774 | |
| 5 | 4140211 | Sch 2 - Reactive Supply | MISO | 9,549,758 | 9,549,758 | |
| 6 | 4140211 | Sch 24 - Bal Auth | MISO | 1,126,005 | 1,126,005 | |
| 7 | 4140301 | Other RTO GFA Revenue | MISO | - | - | |
| 8 | 4140351 | Trans Expansion Plan Att GG | MISO | 69,059,196 | | 69,059,196 |
| 9 | 4140351 | Trans Expansion Plan Att GG - True Up | MISO | (430,971) | (430,971) | |
| 10 | 4140351 | Trans Expansion Plan Att MM | MISO | 75,725,059 | | 75,725,059 |
| 11 | 4140351 | Trans Expansion Plan Att MM - True Up | MISO | 6,947,651 | 6,947,651 | |
| 12 | 4140051 | Joint Pricing Zone - Network | JPZ | 55,928,355 | 55,928,355 | |
| 13 | 4140211 | Sch 2 - Reactive Supply | JPZ | 126,983 | 126,983 | |
| 14 | 4140101 | Contracts - Sioux Falls | | 157,703 | | 157,703 |
| 15 | 4140101 | Contracts - WPPI | | 40,320 | | 40,320 |
| 16 | 4140101 | Contracts - UND | | 65,157 | | 65,157 |
| 17 | 4140101 | Contracts - Granite Falls | | 16,807 | | 16,807 |
| 18 | 4140101 | Contracts - EGF | | 52,752 | | 52,752 |
| 19 | 4140101 | Contracts - SD State Pen | | 14,088 | | 14,088 |
| 20 | | Total NSP Revenue | | 257,262,503 | 104,088,774 | 153,173,729 |

| | |
|---|---|
| Line 36 Attachment O - 2019 Forecast | 104,088,774 |
| Line 1 Attachment O - 2019 Forecast | 369,993,223 |
| 2019 OATT Credit Factor = Line 36 / Line 1 | 28.13% |

**Northern States Power Company**
**Transmission Revenue From Others**
**NSP Revenue Credits for FERC Account 456**

**2020 Forecast**
**Amounts in dollars**

| Line No. | SAP Account | Description | | Total 2020 | Revenue included in OATT Credit | Revenue Excluded in OATT Credit |
|---|---|---|---|---|---|---|
| 1 | 4140001 | PTP - Firm | MISO | 7,423,362 | | 7,423,362 |
| 2 | 4140001 | PTP - Non Firm | MISO | 476,645 | | 476,645 |
| 3 | 4140051 | Network | MISO | 32,947,448 | 32,947,448 | |
| 4 | 4140201 | Sch 1 - Sch, Sys Ctrl & D | MISO | 727,020 | 727,020 | |
| 5 | 4140211 | Sch 2 - Reactive Supply | MISO | 10,217,657 | 10,217,657 | |
| 6 | 4140211 | Sch 24 - Bal Auth | MISO | 1,151,346 | 1,151,346 | |
| 7 | 4140301 | Other RTO GFA Revenue | MISO | | - | |
| 8 | 4140351 | Trans Expansion Plan Att GG | MISO | 68,646,034 | | 68,646,034 |
| 9 | 4140351 | Trans Expansion Plan Att GG - True Up | MISO | (8,268,063) | (8,268,063) | |
| 10 | 4140351 | Trans Expansion Plan Att MM | MISO | 76,287,774 | | 76,287,774 |
| 11 | 4140351 | Trans Expansion Plan Att MM - True Up | MISO | (998,957) | (998,957) | |
| 12 | 4140051 | Joint Pricing Zone - Network | JPZ | 53,623,315 | 53,623,315 | |
| 13 | 4140211 | Sch 2 - Reactive Supply | JPZ | 126,983 | 126,983 | |
| 14 | 4140101 | Contracts - Sioux Falls | | 174,696 | | 174,696 |
| 15 | 4140101 | Contracts - WPPI | | 40,320 | | 40,320 |
| 16 | 4140101 | Contracts - UND | | 66,569 | | 66,569 |
| 17 | 4140101 | Contracts - Granite Falls | | 17,143 | | 17,143 |
| 18 | 4140101 | Contracts - EGF | | 53,807 | | 53,807 |
| 19 | 4140101 | Contracts - Facilities SD State Pen | | 14,364 | | 14,364 |
| 20 | | Other (Kasota,Shakopee,St James) | | 46,887 | 46,887 | |
| 21 | | Total NSP Revenue | | 242,774,350 | 89,573,636 | 153,200,714 |

| | |
|---|---|
| Line 36 Attachment O - 2020 Forecast | 89,573,636 |
| Line 1 Attachment O - 2020 Forecast | 384,539,045 |
| 2020 OATT Credit Factor = Line 36 / Line 1 | 23.29% |

## Regional Expansion Criteria and Benefits

**Amounts in dollars**

| Line No. | | 2018 Actual | MISO Refund Adjustment* | Jan-19 Actual | Feb-19 Actual | Mar-19 Actual | Apr-19 Actual | May-19 Actual | Jun-19 Actual | Jul-19 Actual | Aug-19 Actual | Sep-19 Actual | Oct-19 Forecast | Nov-19 Forecast | Dec-19 Forecast | 2019 Mixed | 2020 Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Revenue** | | | | | | | | | | | | | | | | |
| 1 | Schedule 26 | 68,485,202 | 613,538 | 5,832,159 | 5,039,671 | 5,554,888 | 4,725,315 | 5,142,084 | 6,043,049 | 7,121,525 | 6,691,381 | 5,961,414 | 5,249,416 | 4,937,461 | 5,308,516 | 68,220,417 | 60,377,970 |
| 2 | Schedule 26(a) | 58,585,541 | 566,983 | 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 | 5,880,862 | 5,913,805 | 6,638,292 | 77,249,142 | 75,288,814 |
| 3 | Total Revenue | 127,070,743 | 1,180,521 | 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 | 11,130,278 | 10,851,266 | 11,946,808 | 145,469,559 | 135,666,784 |
| 4 | | | | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | | | | |
| 6 | **Expense** | | | | | | | | | | | | | | | | |
| 7 | Schedule 26 | 73,526,334 | 482,182 | 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 | 5,132,467 | 5,038,407 | 5,749,559 | 71,551,569 | 66,141,510 |
| 8 | Schedule 26(a) | 53,306,975 | 194,619 | 5,557,665 | 4,927,677 | 4,970,388 | 4,754,204 | 4,995,894 | 5,541,198 | 5,869,255 | 5,844,907 | 5,003,924 | 4,731,886 | 4,758,393 | 5,341,334 | 62,491,344 | 65,157,298 |
| 9 | Total Expense | 126,833,309 | 676,801 | 11,461,226 | 10,184,060 | 10,574,107 | 9,576,323 | 10,660,343 | 11,874,507 | 13,468,705 | 13,203,119 | 11,611,676 | 9,864,353 | 9,796,800 | 11,090,893 | 134,042,913 | 131,298,808 |
| 10 | | | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | | | |
| 12 | Total | (237,434) | (503,720) | (1,431,614) | (832,420) | (1,181,620) | (835,391) | (745,517) | (832,152) | (791,576) | (588,886) | (507,444) | (1,265,925) | (1,054,466) | (855,915) | (11,426,646) | (4,367,976) |
| 13 | Demand Allocator - State of MN Jur. | 73.5991% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.2715% | 73.3133% |
| 14 | RECB Revenue Requirement | (174,749) | (369,083) | (1,048,965) | (609,927) | (865,791) | (612,104) | (546,251) | (609,730) | (580,000) | (431,486) | (371,812) | (927,562) | (772,623) | (627,142) | (8,372,475) | (3,202,305) |
| 15 | RECB in Base Rates | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | **Net RECB Revenue Requirements** | **(174,749)** | **(369,083)** | **(1,048,965)** | **(609,927)** | **(865,791)** | **(612,104)** | **(546,251)** | **(609,730)** | **(580,000)** | **(431,486)** | **(371,812)** | **(927,562)** | **(772,623)** | **(627,142)** | **(8,372,475)** | **(3,202,305)** |

* As ordered in Docket No. E-002/M-17-797, Xcel was required to include the net amount of interest payments paid and received related to the federally mandated ROE reduction from 12.38% to 10.82% for MISO transmission owners in our 2018 Compliance filing. We had been excluding that activity from RECB revenue & expenses until 2019 following the May 2019 Hearing for that docket. Thus, that prior period activity is incorporated in the 2019 revenues and expenses, but was already recognized in the 2018 Compliance filing, as ordered. Therefore, it was recognized in 2018, and then is backed out in 2019 to avoid double counting the impact.

**Northern States Power Company**
**State of Minnesota**
**Transmission Cost Recovery Rider**



Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-19 | Feb-19 | Mar-19 | Apr-19 | May-19 | Jun-19 | Jul-19 | Aug-19 | Sep-19 | Oct-19 | Nov-19 | Dec-19 | Annual 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **ADMS** | | | | | | | | | | | | | |
| 2 | CWIP Balance | 19,708,445 | 20,299,866 | 21,182,527 | 21,899,736 | 22,448,648 | 23,023,454 | 23,935,048 | 24,958,909 | 25,908,916 | 25,571,851 | 26,417,420 | 30,361,441 | 30,361,441 |
| 3 | Plant In-Service | - | - | - | - | - | - | - | - | - | 1,476,694 | 1,476,694 | 2,197,629 | 2,197,629 |
| 4 | Depreciation Reserve | - | - | - | - | - | - | - | - | - | 5,377 | 16,130 | 29,507 | 29,507 |
| 5 | Accumulated Deferred Taxes | 56,815 | 66,419 | 76,024 | 85,628 | 95,233 | 104,837 | 114,441 | 124,046 | 133,650 | 143,255 | 152,859 | 162,464 | 162,464 |
| 6 | Average Rate Base | 19,191,221 | 19,942,538 | 20,669,975 | 21,460,305 | 22,083,762 | 22,636,016 | 23,369,612 | 24,327,735 | 25,305,064 | 26,337,590 | 27,312,520 | 30,046,112 | 30,046,112 |
| 7 | Tax Depreciation Expense | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 36,627 | 439,526 |
| 8 | CPI-TAX INTEREST | - | - | - | - | - | - | - | - | - | - | - | - | |
| 9 | Debt Return | 35,984 | 37,392 | 38,756 | 40,238 | 41,407 | 42,443 | 43,818 | 45,615 | 47,447 | 49,383 | 51,211 | 56,336 | 530,030 |
| 10 | Equity Return | 76,125 | 79,105 | 81,991 | 85,126 | 87,599 | 89,790 | 92,699 | 96,500 | 100,377 | 104,472 | 108,340 | 119,183 | 1,121,307 |
| 11 | Current Income Tax Requirement | 19,806 | 21,008 | 22,171 | 23,436 | 24,433 | 25,317 | 26,491 | 28,024 | 29,587 | 33,408 | 37,137 | 42,569 | 333,387 |
| 12 | Book Depreciation | - | - | - | - | - | - | - | - | - | 5,377 | 10,753 | 13,378 | 29,507 |
| 13 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 14 | Deferred Taxes | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 9,604 | 115,253 |
| 15 | Property Tax Expense | - | - | - | - | - | - | - | - | - | - | - | - | |
| 16 | Operating Expenses | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 13,849 | 166,192 |
| 17 | Total Revenue Requirement | 155,368 | 160,959 | 166,372 | 172,254 | 176,893 | 181,003 | 186,462 | 193,592 | 200,865 | 216,094 | 230,894 | 254,920 | 2,295,675 |
| 18 | Rider Revenue Requirement | 135,277 | 140,146 | 144,859 | 149,980 | 154,019 | 157,598 | 162,351 | 168,559 | 174,891 | 188,151 | 201,037 | 221,956 | 1,998,824 |
| 19 | **Big Stone-Brookings** | | | | | | | | | | | | | |
| 20 | CWIP Balance | (86,776) | (84,948) | (82,187) | (80,274) | (79,826) | 11,230 | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 21 | Plant In-Service | 54,519,215 | 54,517,773 | 54,518,409 | 54,516,393 | 54,509,697 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 |
| 22 | Depreciation Reserve | 1,541,033 | 1,637,229 | 1,733,425 | 1,829,620 | 1,925,807 | 2,021,987 | 2,118,163 | 2,214,340 | 2,310,517 | 2,406,693 | 2,502,870 | 2,599,047 | 2,599,047 |
| 23 | Accumulated Deferred Taxes | 11,583,725 | 11,629,383 | 11,675,040 | 11,720,698 | 11,766,355 | 11,812,013 | 11,857,670 | 11,903,328 | 11,948,985 | 11,994,643 | 12,040,301 | 12,085,958 | 12,085,958 |
| 24 | Average Rate Base | 41,374,592 | 41,236,947 | 41,096,985 | 40,956,779 | 40,811,755 | 40,710,810 | 40,607,379 | 40,459,930 | 40,318,096 | 40,176,261 | 40,034,427 | 39,892,593 | 39,892,593 |
| 25 | Tax Depreciation Expense | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 258,054 | 3,096,653 |
| 26 | Debt Return | 77,577 | 77,319 | 77,057 | 76,794 | 76,522 | 76,333 | 76,139 | 75,862 | 75,596 | 75,330 | 75,065 | 74,799 | 914,394 |
| 27 | Equity Return | 164,119 | 163,573 | 163,018 | 162,462 | 161,887 | 161,486 | 161,076 | 160,491 | 159,928 | 159,366 | 158,803 | 158,241 | 1,934,450 |
| 28 | Current Income Tax Requirement | 19,164 | 19,108 | 18,884 | 18,659 | 18,424 | 18,259 | 18,093 | 17,857 | 17,630 | 17,403 | 17,176 | 16,949 | 217,605 |
| 29 | Book Depreciation | 95,790 | 96,197 | 96,196 | 96,195 | 96,187 | 96,179 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 1,153,804 |
| 30 | Deferred Taxes | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 45,658 | 547,890 |
| 31 | Property Tax Expense | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 69,459 | 833,514 |
| 32 | Total Revenue Requirement | 471,768 | 471,314 | 470,272 | 469,227 | 468,137 | 467,374 | 466,601 | 465,504 | 464,448 | 463,393 | 462,337 | 461,282 | 5,601,656 |
| 33 | Rider Revenue Requirement | 345,671 | 345,339 | 344,575 | 343,809 | 343,011 | 342,452 | 341,886 | 341,082 | 340,308 | 339,535 | 338,761 | 337,988 | 4,104,418 |
| 34 | **CAPX2020 Brookings** | | | | | | | | | | | | | |
| 35 | CWIP Balance | 2,582 | 2,582 | 2,582 | 2,582 | 2,582 | 2,582 | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 36 | Plant In-Service | 462,892,932 | 462,892,932 | 462,892,932 | 462,892,932 | 462,892,932 | 462,892,932 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 |
| 37 | Depreciation Reserve | 39,879,243 | 40,662,778 | 41,446,312 | 42,229,846 | 43,013,380 | 43,796,914 | 44,580,451 | 45,363,990 | 46,147,529 | 46,931,068 | 47,714,607 | 48,498,147 | 48,498,147 |
| 38 | Accumulated Deferred Taxes | 97,079,101 | 97,378,149 | 97,677,197 | 97,976,244 | 98,275,292 | 98,574,340 | 98,873,388 | 99,172,436 | 99,471,484 | 99,770,532 | 100,069,580 | 100,368,628 | 100,368,628 |
| 39 | Average Rate Base | 322,186,110 | 325,395,879 | 324,313,297 | 323,230,714 | 322,148,132 | 321,065,550 | 319,982,967 | 318,900,381 | 317,817,794 | 316,735,207 | 315,652,620 | 314,570,033 | 314,570,033 |
| 40 | Tax Depreciation Expense | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 1,843,190 | 22,118,275 |
| 41 | Debt Return | 604,099 | 610,117 | 608,087 | 606,058 | 604,028 | 601,998 | 599,968 | 597,938 | 595,908 | 593,879 | 591,849 | 589,819 | 7,203,748 |
| 42 | Equity Return | 1,278,005 | 1,290,737 | 1,286,443 | 1,282,149 | 1,277,854 | 1,273,560 | 1,269,266 | 1,264,972 | 1,260,677 | 1,256,383 | 1,252,089 | 1,247,794 | 15,239,928 |
| 43 | Current Income Tax Requirement | 208,693 | 213,828 | 212,096 | 210,364 | 208,632 | 206,900 | 205,169 | 203,438 | 201,706 | 199,974 | 198,242 | 196,509 | 2,465,551 |
| 44 | Book Depreciation | 783,534 | 783,534 | 783,534 | 783,534 | 783,534 | 783,534 | 783,537 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 9,402,437 |
| 45 | Deferred Taxes | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 299,048 | 3,588,575 |
| 46 | Property Tax Expense | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 583,384 | 7,000,614 |
| 47 | Total Revenue Requirement | 3,756,763 | 3,780,649 | 3,772,593 | 3,764,537 | 3,756,481 | 3,748,424 | 3,740,372 | 3,732,319 | 3,724,263 | 3,716,207 | 3,708,150 | 3,700,094 | 44,900,852 |
| 48 | Rider Revenue Requirement | 2,752,637 | 2,770,138 | 2,764,235 | 2,758,333 | 2,752,430 | 2,746,527 | 2,740,626 | 2,734,726 | 2,728,823 | 2,722,920 | 2,717,017 | 2,711,114 | 32,899,527 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-19 | Feb-19 | Mar-19 | Apr-19 | May-19 | Jun-19 | Jul-19 | Aug-19 | Sep-19 | Oct-19 | Nov-19 | Dec-19 | Annual 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 49 | **CAPX2020 - La Crosse Local** | | | | | | | | | | | | | |
| 50 | CWIP Balance | 4,760 | 5,875 | 5,997 | 6,085 | 6,236 | 6,267 | - | - | - | - | - | - | - |
| 51 | Plant In-Service | 75,620,026 | 75,618,296 | 75,617,685 | 75,617,172 | 75,616,594 | 75,616,141 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 |
| 52 | Depreciation Reserve | 4,437,232 | 4,578,485 | 4,719,735 | 4,860,985 | 5,002,234 | 5,143,481 | 5,284,733 | 5,425,989 | 5,567,245 | 5,708,501 | 5,849,757 | 5,991,013 | 5,991,013 |
| 53 | Accumulated Deferred Taxes | 16,091,393 | 16,156,268 | 16,221,143 | 16,286,019 | 16,350,894 | 16,415,769 | 16,480,644 | 16,545,520 | 16,610,395 | 16,675,270 | 16,740,145 | 16,805,020 | 16,805,020 |
| 54 | Average Rate Base | 55,307,034 | 54,992,790 | 54,786,111 | 54,579,528 | 54,372,978 | 54,166,430 | 53,959,366 | 53,752,508 | 53,546,377 | 53,340,245 | 53,134,114 | 52,927,983 | 52,927,983 |
| 55 | Tax Depreciation Expense | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 | 372,419 |
| 56 | Debt Return | 103,701 | 103,111 | 102,724 | 102,337 | 101,949 | 101,562 | 101,174 | 100,786 | 100,399 | 100,013 | 99,626 | 99,240 | 1,216,623 |
| 57 | Equity Return | 219,385 | 218,138 | 217,318 | 216,499 | 215,679 | 214,860 | 214,039 | 213,218 | 212,401 | 211,583 | 210,765 | 209,948 | 2,573,833 |
| 58 | Current Income Tax Requirement | 21,500 | 20,913 | 20,581 | 20,250 | 19,919 | 19,589 | 19,259 | 18,930 | 18,600 | 18,270 | 17,940 | 17,610 | 233,362 |
| 59 | Book Depreciation | 141,463 | 141,253 | 141,251 | 141,250 | 141,249 | 141,248 | 141,252 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 1,695,245 |
| 60 | Deferred Taxes | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 64,875 | 778,503 |
| 61 | Property Tax Expense | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 97,386 | 1,168,628 |
| 62 | OATT Credit | 182,369 | 181,629 | 181,195 | 180,762 | 180,330 | 179,897 | 179,465 | 179,034 | 178,602 | 178,171 | 177,739 | 177,308 | 2,156,500 |
| 63 | Total Revenue Requirement | 465,940 | 464,048 | 462,940 | 461,834 | 460,728 | 459,623 | 458,519 | 457,417 | 456,315 | 455,212 | 454,110 | 453,007 | 5,509,693 |
| 64 | Rider Revenue Requirement | 341,401 | 340,015 | 339,203 | 338,393 | 337,582 | 336,772 | 335,964 | 335,156 | 334,349 | 333,541 | 332,733 | 331,925 | 4,037,035 |
| 65 | **CAPX2020 - La Crosse MISO** | | | | | | | | | | | | | |
| 66 | CWIP Balance | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 67 | Plant In-Service | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 |
| 68 | Depreciation Reserve | 5,569,928 | 5,697,633 | 5,825,339 | 5,953,044 | 6,080,750 | 6,208,455 | 6,336,161 | 6,463,866 | 6,591,571 | 6,719,277 | 6,846,982 | 6,974,688 | 6,974,688 |
| 69 | Accumulated Deferred Taxes | 15,934,718 | 15,989,644 | 16,044,571 | 16,099,497 | 16,154,423 | 16,209,349 | 16,264,275 | 16,319,202 | 16,374,128 | 16,429,054 | 16,483,980 | 16,538,906 | 16,538,906 |
| 70 | Average Rate Base | 53,650,941 | 53,450,841 | 53,268,209 | 53,085,578 | 52,902,946 | 52,720,315 | 52,537,683 | 52,355,051 | 52,172,420 | 51,989,788 | 51,807,156 | 51,624,525 | 51,624,525 |
| 71 | Tax Depreciation Expense | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 323,108 | 3,877,300 |
| 72 | Debt Return | 100,596 | 100,220 | 99,878 | 99,535 | 99,193 | 98,851 | 98,508 | 98,166 | 97,823 | 97,481 | 97,138 | 96,796 | 1,184,185 |
| 73 | Equity Return | 212,815 | 212,022 | 211,297 | 210,573 | 209,848 | 209,124 | 208,399 | 207,675 | 206,951 | 206,226 | 205,502 | 204,777 | 2,505,210 |
| 74 | Current Income Tax Requirement | 29,178 | 28,858 | 28,566 | 28,273 | 27,981 | 27,689 | 27,397 | 27,105 | 26,812 | 26,520 | 26,228 | 25,936 | 330,542 |
| 75 | Book Depreciation | 127,706 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 1,532,466 |
| 76 | Deferred Taxes | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 54,926 | 659,114 |
| 77 | Property Tax Expense | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 96,414 | 1,156,964 |
| 78 | Total Revenue Requirement | 621,635 | 620,145 | 618,786 | 617,427 | 616,068 | 614,709 | 613,350 | 611,991 | 610,631 | 609,272 | 607,913 | 606,554 | 7,368,481 |
| 79 | Rider Revenue Requirement | 455,482 | 454,390 | 453,394 | 452,398 | 451,402 | 450,406 | 449,410 | 448,415 | 447,419 | 446,423 | 445,427 | 444,431 | 5,398,997 |
| 80 | **CAPX2020 - La Crosse MISO - WI** | | | | | | | | | | | | | |
| 81 | CWIP Balance | 190 | 24,334 | 44,862 | 48,011 | 830 | 648 | (874) | 0 | 0 | 0 | 0 | 0 | 0 |
| 82 | Plant In-Service | 135,741,091 | 135,741,423 | 135,742,259 | 135,742,493 | 135,800,676 | 135,935,601 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 |
| 83 | Depreciation Reserve | 11,761,910 | 12,093,390 | 12,424,873 | 12,756,362 | 13,087,854 | 13,419,484 | 13,751,856 | 14,084,832 | 14,417,808 | 14,750,784 | 15,083,760 | 15,416,736 | 15,416,736 |
| 84 | Accumulated Deferred Taxes | 31,452,183 | 31,533,653 | 31,615,122 | 31,696,591 | 31,778,060 | 31,859,530 | 31,940,999 | 32,022,468 | 32,103,937 | 32,185,406 | 32,266,876 | 32,348,345 | 32,348,345 |
| 85 | Average Rate Base | 92,731,507 | 92,332,951 | 91,942,921 | 91,542,339 | 91,136,571 | 90,796,413 | 90,670,075 | 90,476,130 | 90,062,121 | 89,647,676 | 89,233,231 | 88,818,786 | 88,818,786 |
| 86 | Tax Depreciation Expense | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 622,023 | 7,464,273 |
| 87 | Debt Return | 173,872 | 173,124 | 172,393 | 171,642 | 170,881 | 170,243 | 170,006 | 169,643 | 168,866 | 168,089 | 167,312 | 166,535 | 2,042,608 |
| 88 | Equity Return | 367,835 | 366,254 | 364,707 | 363,118 | 361,508 | 360,159 | 359,658 | 358,889 | 357,246 | 355,602 | 353,958 | 352,315 | 4,321,250 |
| 89 | Current Income Tax Requirement | 64,034 | 63,399 | 62,776 | 62,138 | 61,490 | 61,001 | 61,098 | 61,032 | 60,369 | 59,706 | 59,043 | 58,380 | 734,465 |
| 90 | Book Depreciation | 331,473 | 331,479 | 331,483 | 331,490 | 331,492 | 331,630 | 332,372 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 3,986,299 |
| 91 | Deferred Taxes | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 81,469 | 977,631 |
| 92 | Property Tax Expense | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 174,302 | 2,091,624 |
| 93 | Total Revenue Requirement | 1,192,984 | 1,190,027 | 1,187,131 | 1,184,158 | 1,181,142 | 1,178,804 | 1,178,906 | 1,178,310 | 1,175,229 | 1,172,145 | 1,169,061 | 1,165,977 | 14,153,876 |
| 94 | Rider Revenue Requirement | 874,118 | 871,951 | 869,829 | 867,651 | 865,441 | 863,728 | 863,802 | 863,366 | 861,108 | 858,848 | 856,588 | 854,329 | 10,370,757 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-19 | Feb-19 | Mar-19 | Apr-19 | May-19 | Jun-19 | Jul-19 | Aug-19 | Sep-19 | Oct-19 | Nov-19 | Dec-19 | Annual 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 95 | **CAPX2020 Fargo** | | | | | | | | | | | | | |
| 96 | CWIP Balance | (313) | (313) | (313) | (313) | (313) | (313) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 97 | Plant In-Service | 208,060,400 | 208,176,482 | 208,178,308 | 208,178,308 | 208,178,308 | 208,178,308 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 |
| 98 | Depreciation Reserve | 20,891,459 | 21,281,140 | 21,670,933 | 22,060,729 | 22,450,524 | 22,840,319 | 23,230,114 | 23,619,908 | 24,009,703 | 24,399,498 | 24,789,292 | 25,179,087 | 25,179,087 |
| 99 | Accumulated Deferred Taxes | 45,530,852 | 45,693,459 | 45,856,066 | 46,018,673 | 46,181,280 | 46,343,887 | 46,506,494 | 46,669,101 | 46,831,708 | 46,994,315 | 47,156,922 | 47,319,529 | 47,319,529 |
| 100 | Average Rate Base | 141,913,186 | 141,419,673 | 140,926,283 | 140,374,795 | 139,822,393 | 139,269,991 | 138,717,589 | 138,165,187 | 137,612,785 | 137,060,384 | 136,507,982 | 135,955,581 | 135,955,581 |
| 101 | Tax Depreciation Expense | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 968,067 | 11,616,801 |
| 102 | Debt Return | 266,087 | 265,162 | 264,237 | 263,203 | 262,167 | 261,131 | 260,095 | 259,060 | 258,024 | 256,988 | 255,952 | 254,917 | 3,127,023 |
| 103 | Equity Return | 562,922 | 560,965 | 559,008 | 556,820 | 554,629 | 552,438 | 550,246 | 548,055 | 545,864 | 543,673 | 541,482 | 539,290 | 6,615,392 |
| 104 | Current Income Tax Requirement | 59,305 | 58,561 | 57,817 | 56,935 | 56,051 | 55,168 | 54,284 | 53,400 | 52,516 | 51,632 | 50,748 | 49,864 | 656,281 |
| 105 | Book Depreciation | 389,569 | 389,681 | 389,793 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 4,677,197 |
| 106 | Deferred Taxes | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 162,607 | 1,951,284 |
| 107 | Property Tax Expense | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 267,172 | 3,206,063 |
| 108 | Total Revenue Requirement | 1,707,663 | 1,704,148 | 1,700,634 | 1,696,532 | 1,692,421 | 1,688,311 | 1,684,199 | 1,680,088 | 1,675,977 | 1,671,867 | 1,667,756 | 1,663,645 | 20,233,241 |
| 109 | Rider Revenue Requirement | 1,251,230 | 1,248,655 | 1,246,080 | 1,243,074 | 1,240,062 | 1,237,050 | 1,234,038 | 1,231,026 | 1,228,014 | 1,225,002 | 1,221,990 | 1,218,978 | 14,825,199 |
| 110 | **Huntley - Wilmarth** | | | | | | | | | | | | | |
| 111 | CWIP Balance | 2,576,287 | 2,877,512 | 2,680,557 | 2,844,982 | 2,902,143 | 2,968,614 | 2,979,906 | 3,031,697 | 3,083,487 | 3,135,288 | 3,187,078 | 3,238,869 | 3,238,869 |
| 112 | Plant In-Service | - | - | - | - | - | - | 181,756 | 323,003 | 464,251 | 605,498 | 746,746 | 887,993 | 887,993 |
| 113 | Depreciation Reserve | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 114 | Accumulated Deferred Taxes | (9,902) | (10,010) | (10,117) | (10,225) | (10,332) | (10,440) | (10,547) | (10,654) | (10,762) | (10,869) | (10,977) | (11,084) | (11,084) |
| 115 | Average Rate Base | 2,196,454 | 2,736,855 | 2,789,098 | 2,772,940 | 2,883,841 | 2,945,765 | 3,075,631 | 3,268,781 | 3,461,927 | 3,655,077 | 3,848,228 | 4,041,373 | 4,041,373 |
| 116 | Tax Depreciation Expense | - | - | - | - | - | - | - | - | - | - | - | - | |
| 117 | CPI-TAX INTEREST | 6,310 | 7,127 | (80,286) | 7,468 | 7,915 | 8,098 | 7,497 | 7,694 | 7,892 | 8,091 | 8,290 | 8,490 | 4,586 |
| 118 | Debt Return | 4,118 | 5,132 | 5,230 | 5,199 | 5,407 | 5,523 | 5,767 | 6,129 | 6,491 | 6,853 | 7,215 | 7,578 | 70,642 |
| 119 | Equity Return | 8,713 | 10,856 | 11,063 | 10,999 | 11,439 | 11,685 | 12,200 | 12,966 | 13,732 | 14,498 | 15,265 | 16,031 | 149,448 |
| 120 | Current Income Tax Requirement | 6,016 | 7,210 | (27,964) | 7,405 | 7,763 | 7,936 | 7,902 | 8,290 | 8,679 | 9,068 | 9,457 | 9,847 | 61,610 |
| 121 | Book Depreciation | - | - | - | - | - | - | - | - | - | - | - | - | |
| 122 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 123 | Deferred Taxes | (107) | (107) | (107) | (107) | (107) | (107) | (107) | (107) | (107) | (107) | (107) | (107) | (1,289) |
| 124 | Property Tax Expense | - | - | - | - | - | - | - | - | - | - | - | - | |
| 125 | Total Revenue Requirement | 18,739 | 23,091 | (11,779) | 23,497 | 24,502 | 25,037 | 25,761 | 27,278 | 28,795 | 30,312 | 31,830 | 33,348 | 280,411 |
| 126 | Rider Revenue Requirement | 13,731 | 16,919 | (8,630) | 17,216 | 17,953 | 18,345 | 18,875 | 19,987 | 21,099 | 22,210 | 23,322 | 24,435 | 205,462 |
| 127 | **LaCrosse - Madison** | | | | | | | | | | | | | |
| 128 | CWIP Balance | 447,746 | 340,917 | 434,914 | 819,241 | 12,049 | 12,364 | 2,895 | 2,895 | 2,895 | 2,895 | 2,895 | 2,895 | 2,895 |
| 129 | Plant In-Service | 165,520,076 | 166,324,578 | 166,695,498 | 167,063,584 | 168,298,788 | 168,877,179 | 169,451,585 | 170,007,159 | 170,477,983 | 170,760,478 | 170,939,392 | 171,061,806 | 171,061,806 |
| 130 | Depreciation Reserve | 621,389 | 1,045,033 | 1,469,591 | 1,894,476 | 2,320,462 | 2,747,781 | 3,176,413 | 3,606,153 | 4,036,860 | 4,468,160 | 4,899,693 | 5,331,316 | 5,331,316 |
| 131 | Accumulated Deferred Taxes | 1,442,624 | 1,705,190 | 1,967,756 | 2,230,321 | 2,492,887 | 2,755,453 | 3,018,018 | 3,280,584 | 3,543,150 | 3,805,715 | 4,068,281 | 4,330,847 | 4,330,847 |
| 132 | Average Rate Base | 162,335,861 | 163,909,540 | 163,804,168 | 163,725,546 | 163,627,758 | 163,441,899 | 163,323,179 | 163,191,683 | 163,012,093 | 162,695,183 | 162,231,905 | 161,688,426 | 161,688,426 |
| 133 | Tax Depreciation Expense | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 1,359,248 | 16,310,972 |
| 134 | CPI-TAX INTEREST | - | - | - | - | - | - | - | - | - | - | - | - | |
| 135 | Debt Return | 304,380 | 307,330 | 307,133 | 306,985 | 306,802 | 306,454 | 306,231 | 305,984 | 305,648 | 305,053 | 304,185 | 303,166 | 3,669,351 |
| 136 | Equity Return | 643,932 | 650,175 | 649,757 | 649,445 | 649,057 | 648,320 | 647,849 | 647,327 | 646,615 | 645,358 | 643,520 | 641,364 | 7,762,716 |
| 137 | Current Income Tax Requirement | (14,669) | (9,222) | (9,022) | (9,016) | (8,728) | (8,488) | (8,149) | (7,912) | (7,809) | (8,077) | (8,724) | (9,557) | (109,372) |
| 138 | Book Depreciation | 416,383 | 423,644 | 424,558 | 424,885 | 425,986 | 427,320 | 428,631 | 429,740 | 430,707 | 431,300 | 431,533 | 431,623 | 5,126,309 |
| 139 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 140 | Deferred Taxes | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 262,566 | 3,150,788 |
| 141 | Property Tax Expense | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 206,765 | 2,481,184 |
| 142 | Total Revenue Requirement | 1,819,357 | 1,841,258 | 1,841,756 | 1,841,630 | 1,842,447 | 1,842,936 | 1,843,893 | 1,844,471 | 1,844,492 | 1,842,966 | 1,839,844 | 1,835,926 | 22,080,975 |
| 143 | Rider Revenue Requirement | 1,333,070 | 1,349,117 | 1,349,482 | 1,349,390 | 1,349,988 | 1,350,347 | 1,351,048 | 1,351,471 | 1,351,487 | 1,350,369 | 1,348,081 | 1,345,211 | 16,179,062 |
| 144 | **MISO RECB Sch.26/26a** | | | | | | | | | | | | | |
| 145 | Total Revenue Requirement | (1,431,614) | (832,420) | (1,181,620) | (835,391) | (745,517) | (832,152) | (791,576) | (588,886) | (507,444) | (1,265,925) | (1,054,466) | (855,915) | -11,426,646 |
| 146 | Rider Revenue Requirement | (1,048,965) | (609,927) | (865,791) | (612,104) | (546,251) | (609,730) | (580,000) | (431,486) | (371,812) | (927,562) | (772,623) | (627,142) | -8,372,475 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Annual 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **ADMS** | | | | | | | | | | | | | |
| 2 | CWIP Balance | 31,801,219 | 33,240,998 | 34,642,575 | (62,593) | (62,815) | (63,037) | (63,258) | (63,480) | (63,701) | (63,923) | (64,145) | (64,366) | (64,366) |
| 3 | Plant In-Service | 2,357,851 | 2,518,072 | 2,678,294 | 37,543,463 | 37,703,685 | 37,863,906 | 38,024,128 | 38,184,350 | 38,344,571 | 38,504,793 | 38,665,014 | 38,825,236 | 38,825,236 |
| 4 | Depreciation Reserve | 46,094 | 63,846 | 82,766 | 229,210 | 503,179 | 778,314 | 1,054,616 | 1,332,085 | 1,610,720 | 1,890,522 | 2,171,491 | 2,453,627 | 2,453,627 |
| 5 | Accumulated Deferred Taxes | 292,391 | 357,355 | 485,187 | 617,210 | 745,042 | 877,065 | 1,004,897 | 1,134,825 | 1,266,848 | 1,394,680 | 1,526,703 | 1,654,535 | 1,654,535 |
| 6 | Average Rate Base | 33,093,842 | 34,546,745 | 35,981,476 | 36,627,671 | 36,449,633 | 36,203,058 | 35,959,508 | 35,712,695 | 35,462,620 | 35,215,569 | 34,963,160 | 34,713,776 | 34,713,776 |
| 7 | Tax Depreciation Expense | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 662,881 | 7,954,569 |
| 8 | CPI-TAX INTEREST | - | - | - | - | - | - | - | - | - | - | - | - | |
| 9 | Debt Return | 62,051 | 64,775 | 67,465 | 68,677 | 68,343 | 67,881 | 67,424 | 66,961 | 66,492 | 66,029 | 65,556 | 65,088 | 796,743 |
| 10 | Equity Return | 131,272 | 137,035 | 142,727 | 145,290 | 144,584 | 143,605 | 142,639 | 141,660 | 140,668 | 139,688 | 138,687 | 137,698 | 1,685,555 |
| 11 | Current Income Tax Requirement | (155,328) | (152,533) | (149,767) | (97,296) | (46,144) | (46,068) | (45,987) | (45,911) | (45,841) | (45,765) | (45,699) | (45,627) | (921,966) |
| 12 | Book Depreciation | 16,586 | 17,753 | 18,920 | 146,444 | 273,969 | 275,135 | 276,302 | 277,469 | 278,635 | 279,802 | 280,969 | 282,136 | 2,424,119 |
| 13 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 14 | Deferred Taxes | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 129,928 | 1,559,131 |
| 15 | Property Tax Expense | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 2,822 | 33,864 |
| 16 | Operating Expenses | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 28,574 | 342,892 |
| 17 | Total Revenue Requirement | 215,905 | 228,354 | 240,668 | 424,439 | 602,075 | 601,878 | 601,703 | 601,503 | 601,280 | 601,078 | 600,837 | 600,619 | 5,920,339 |
| 18 | Rider Revenue Requirement | 187,986 | 198,826 | 209,548 | 369,555 | 524,222 | 524,050 | 523,897 | 523,723 | 523,529 | 523,354 | 523,144 | 522,953 | 5,154,785 |
| 19 | **Big Stone-Brookings** | | | | | | | | | | | | | |
| 20 | CWIP Balance | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 21 | Plant In-Service | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 |
| 22 | Depreciation Reserve | 2,695,223 | 2,791,400 | 2,887,577 | 2,983,753 | 3,079,930 | 3,176,107 | 3,272,283 | 3,368,460 | 3,464,637 | 3,560,813 | 3,656,990 | 3,753,167 | 3,753,167 |
| 23 | Accumulated Deferred Taxes | 12,127,437 | 12,148,176 | 12,188,986 | 12,231,134 | 12,271,943 | 12,314,091 | 12,354,901 | 12,396,379 | 12,438,527 | 12,479,337 | 12,521,484 | 12,562,294 | 12,562,294 |
| 24 | Average Rate Base | 39,752,848 | 39,615,193 | 39,478,206 | 39,339,882 | 39,202,896 | 39,064,571 | 38,927,585 | 38,789,930 | 38,651,605 | 38,514,619 | 38,376,294 | 38,239,308 | 38,239,308 |
| 25 | Tax Depreciation Expense | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 243,192 | 2,918,301 |
| 26 | Debt Return | 74,537 | 74,278 | 74,022 | 73,762 | 73,505 | 73,246 | 72,989 | 72,731 | 72,472 | 72,215 | 71,956 | 71,699 | 877,412 |
| 27 | Equity Return | 157,686 | 157,140 | 156,597 | 156,048 | 155,505 | 154,956 | 154,413 | 153,867 | 153,318 | 152,775 | 152,226 | 151,683 | 1,856,213 |
| 28 | Current Income Tax Requirement | 21,035 | 20,814 | 20,595 | 20,374 | 20,155 | 19,934 | 19,714 | 19,494 | 19,273 | 19,054 | 18,832 | 18,613 | 237,887 |
| 29 | Book Depreciation | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 1,154,120 |
| 30 | Deferred Taxes | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 41,479 | 497,745 |
| 31 | Property Tax Expense | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 839,915 |
| 32 | Total Revenue Requirement | 460,906 | 459,882 | 458,862 | 457,833 | 456,813 | 455,784 | 454,765 | 453,740 | 452,711 | 451,691 | 450,662 | 449,643 | 5,463,291 |
| 33 | Rider Revenue Requirement | 337,905 | 337,154 | 336,407 | 335,652 | 334,905 | 334,150 | 333,403 | 332,652 | 331,897 | 331,150 | 330,395 | 329,648 | 4,005,316 |
| 34 | **CAPX2020 Brookings** | | | | | | | | | | | | | |
| 35 | CWIP Balance | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 36 | Plant In-Service | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 |
| 37 | Depreciation Reserve | 49,281,686 | 50,065,225 | 50,848,764 | 51,632,303 | 52,415,842 | 53,199,381 | 53,982,920 | 54,766,459 | 55,549,999 | 56,333,538 | 57,117,077 | 57,900,616 | 57,900,616 |
| 38 | Accumulated Deferred Taxes | 100,495,158 | 100,558,423 | 100,682,913 | 100,811,484 | 100,935,974 | 101,064,545 | 101,189,035 | 101,315,566 | 101,444,137 | 101,568,627 | 101,697,198 | 101,821,688 | 101,821,688 |
| 39 | Average Rate Base | 313,573,705 | 312,663,635 | 311,755,606 | 310,843,496 | 309,935,467 | 309,023,357 | 308,115,328 | 307,205,258 | 306,293,148 | 305,385,119 | 304,473,009 | 303,564,980 | 303,564,980 |
| 40 | Tax Depreciation Expense | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 14,785,847 |
| 41 | Debt Return | 587,951 | 586,244 | 584,542 | 582,832 | 581,129 | 579,419 | 577,716 | 576,010 | 574,300 | 572,597 | 570,887 | 569,184 | 6,942,810 |
| 42 | Equity Return | 1,243,842 | 1,240,232 | 1,236,631 | 1,233,013 | 1,229,411 | 1,225,793 | 1,222,191 | 1,218,581 | 1,214,963 | 1,211,361 | 1,207,743 | 1,204,141 | 14,687,901 |
| 43 | Current Income Tax Requirement | 371,792 | 370,336 | 368,883 | 367,424 | 365,971 | 364,512 | 363,059 | 361,603 | 360,144 | 358,691 | 357,231 | 355,779 | 4,365,425 |
| 44 | Book Depreciation | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 9,402,469 |
| 45 | Deferred Taxes | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 1,518,366 |
| 46 | Property Tax Expense | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 7,132,938 |
| 47 | Total Revenue Requirement | 3,708,066 | 3,701,294 | 3,694,537 | 3,687,749 | 3,680,992 | 3,674,204 | 3,667,447 | 3,660,675 | 3,653,887 | 3,647,130 | 3,640,342 | 3,633,585 | 44,049,910 |
| 48 | Rider Revenue Requirement | 2,718,504 | 2,713,539 | 2,708,585 | 2,703,609 | 2,698,655 | 2,693,679 | 2,688,725 | 2,683,760 | 2,678,784 | 2,673,830 | 2,668,853 | 2,663,899 | 32,294,421 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Annual 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 49 | **CAPX2020 - La Crosse Local** | | | | | | | | | | | | | |
| 50 | CWIP Balance | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 51 | Plant In-Service | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 |
| 52 | Depreciation Reserve | 6,132,269 | 6,273,526 | 6,414,782 | 6,556,038 | 6,697,294 | 6,838,550 | 6,979,806 | 7,121,062 | 7,262,318 | 7,403,574 | 7,544,830 | 7,686,086 | 7,686,086 |
| 53 | Accumulated Deferred Taxes | 16,857,593 | 16,883,880 | 16,935,605 | 16,989,026 | 17,040,751 | 17,094,172 | 17,145,897 | 17,198,471 | 17,251,892 | 17,303,617 | 17,357,038 | 17,408,763 | 17,408,763 |
| 54 | Average Rate Base | 52,728,003 | 52,534,173 | 52,341,192 | 52,146,515 | 51,953,534 | 51,758,857 | 51,565,876 | 51,372,046 | 51,177,369 | 50,984,388 | 50,789,711 | 50,596,730 | 50,596,730 |
| 55 | Tax Depreciation Expense | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 | 328,731 |
| 56 | Debt Return | 98,865 | 98,502 | 98,140 | 97,775 | 97,413 | 97,048 | 96,686 | 96,323 | 95,958 | 95,596 | 95,231 | 94,869 | 1,162,403 |
| 57 | Equity Return | 209,154 | 208,386 | 207,620 | 206,848 | 206,082 | 205,310 | 204,545 | 203,776 | 203,004 | 202,238 | 201,466 | 200,700 | 2,459,129 |
| 58 | Current Income Tax Requirement | 29,950 | 29,640 | 29,331 | 29,020 | 28,711 | 28,399 | 28,091 | 27,781 | 27,469 | 27,160 | 26,849 | 26,540 | 338,941 |
| 59 | Book Depreciation | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 1,695,073 |
| 60 | Deferred Taxes | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 52,573 | 630,877 |
| 61 | Property Tax Expense | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 1,165,273 |
| 62 | OATT Credit | 146,472 | 146,136 | 145,802 | 145,464 | 145,130 | 144,792 | 144,458 | 144,122 | 143,784 | 143,450 | 143,113 | 142,778 | 1,735,500 |
| 63 | Total Revenue Requirement | 482,433 | 481,326 | 480,225 | 479,113 | 478,012 | 476,900 | 475,799 | 474,692 | 473,581 | 472,479 | 471,368 | 470,266 | 5,716,196 |
| 64 | Rider Revenue Requirement | 353,687 | 352,876 | 352,068 | 351,254 | 350,446 | 349,631 | 348,824 | 348,012 | 347,198 | 346,390 | 345,575 | 344,768 | 4,190,729 |
| 65 | **CAPX2020 - La Crosse MISO** | | | | | | | | | | | | | |
| 66 | CWIP Balance | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 67 | Plant In-Service | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 |
| 68 | Depreciation Reserve | 7,102,393 | 7,230,099 | 7,357,804 | 7,485,510 | 7,613,215 | 7,740,921 | 7,868,626 | 7,996,332 | 8,124,037 | 8,251,742 | 8,379,448 | 8,507,153 | 8,507,153 |
| 69 | Accumulated Deferred Taxes | 16,576,097 | 16,594,692 | 16,631,283 | 16,669,074 | 16,705,664 | 16,743,455 | 16,780,046 | 16,817,237 | 16,855,027 | 16,891,618 | 16,929,409 | 16,965,999 | 16,965,999 |
| 70 | Average Rate Base | 51,450,761 | 51,285,865 | 51,121,568 | 50,956,072 | 50,791,776 | 50,626,280 | 50,461,984 | 50,297,088 | 50,131,592 | 49,967,295 | 49,801,799 | 49,637,503 | 49,637,503 |
| 71 | Tax Depreciation Expense | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 260,013 | 3,120,161 |
| 72 | Debt Return | 96,470 | 96,161 | 95,853 | 95,543 | 95,235 | 94,924 | 94,616 | 94,307 | 93,997 | 93,689 | 93,378 | 93,070 | 1,137,243 |
| 73 | Equity Return | 204,088 | 203,434 | 202,782 | 202,126 | 201,474 | 200,818 | 200,166 | 199,512 | 198,855 | 198,204 | 197,547 | 196,895 | 2,405,901 |
| 74 | Current Income Tax Requirement | 43,954 | 43,690 | 43,427 | 43,162 | 42,899 | 42,634 | 42,371 | 42,108 | 41,843 | 41,580 | 41,315 | 41,052 | 510,035 |
| 75 | Book Depreciation | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 1,532,466 |
| 76 | Deferred Taxes | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 37,191 | 446,288 |
| 77 | Property Tax Expense | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 1,156,426 |
| 78 | Total Revenue Requirement | 605,777 | 604,550 | 603,327 | 602,095 | 600,873 | 599,641 | 598,419 | 597,191 | 595,960 | 594,737 | 593,506 | 592,283 | 7,188,358 |
| 79 | Rider Revenue Requirement | 444,115 | 443,215 | 442,319 | 441,416 | 440,519 | 439,616 | 438,720 | 437,820 | 436,918 | 436,021 | 435,118 | 434,222 | 5,270,019 |
| 80 | **CAPX2020 - La Crosse MISO - WI** | | | | | | | | | | | | | |
| 81 | CWIP Balance | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 82 | Plant In-Service | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 |
| 83 | Depreciation Reserve | 15,749,712 | 16,082,688 | 16,415,664 | 16,748,640 | 17,081,616 | 17,414,592 | 17,747,568 | 18,080,544 | 18,413,520 | 18,746,496 | 19,079,472 | 19,412,448 | 19,412,448 |
| 84 | Accumulated Deferred Taxes | 32,418,589 | 32,453,712 | 32,522,823 | 32,594,201 | 32,663,312 | 32,734,690 | 32,803,801 | 32,874,046 | 32,945,423 | 33,014,535 | 33,085,912 | 33,155,024 | 33,155,024 |
| 85 | Average Rate Base | 88,409,953 | 88,006,732 | 87,604,645 | 87,200,291 | 86,798,204 | 86,393,850 | 85,991,763 | 85,588,542 | 85,184,189 | 84,782,101 | 84,377,748 | 83,975,660 | 83,975,660 |
| 86 | Tax Depreciation Expense | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 582,917 | 6,995,008 |
| 87 | Debt Return | 165,769 | 165,013 | 164,259 | 163,501 | 162,747 | 161,988 | 161,235 | 160,479 | 159,720 | 158,966 | 158,208 | 157,454 | 1,939,338 |
| 88 | Equity Return | 350,693 | 349,093 | 347,498 | 345,894 | 344,300 | 342,696 | 341,101 | 339,501 | 337,897 | 336,302 | 334,698 | 333,103 | 4,102,778 |
| 89 | Current Income Tax Requirement | 68,971 | 68,326 | 67,683 | 67,036 | 66,393 | 65,746 | 65,102 | 64,457 | 63,810 | 63,167 | 62,520 | 61,877 | 785,089 |
| 90 | Book Depreciation | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 3,995,712 |
| 91 | Deferred Taxes | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 70,245 | 842,934 |
| 92 | Property Tax Expense | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 2,101,481 |
| 93 | Total Revenue Requirement | 1,163,777 | 1,160,776 | 1,157,784 | 1,154,775 | 1,151,783 | 1,148,774 | 1,145,782 | 1,142,781 | 1,139,772 | 1,136,780 | 1,133,771 | 1,130,778 | 13,767,332 |
| 94 | Rider Revenue Requirement | 853,203 | 851,003 | 848,809 | 846,603 | 844,409 | 842,203 | 840,010 | 837,810 | 835,604 | 833,410 | 831,204 | 829,010 | 10,093,278 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Annual 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 95 | **CAPX2020 Fargo** | | | | | | | | | | | | | |
| 96 | CWIP Balance | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 97 | Plant In-Service | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 |
| 98 | Depreciation Reserve | 25,568,881 | 25,958,676 | 26,348,470 | 26,738,265 | 27,128,060 | 27,517,854 | 27,907,649 | 28,297,443 | 28,687,238 | 29,077,032 | 29,466,827 | 29,856,621 | 29,856,621 |
| 99 | Accumulated Deferred Taxes | 47,432,826 | 47,489,475 | 47,600,945 | 47,716,070 | 47,827,540 | 47,942,665 | 48,054,135 | 48,167,432 | 48,282,557 | 48,394,027 | 48,509,152 | 48,620,622 | 48,620,622 |
| 100 | Average Rate Base | 135,427,834 | 134,924,742 | 134,423,477 | 133,918,558 | 133,417,293 | 132,912,374 | 132,411,109 | 131,908,017 | 131,403,098 | 130,901,833 | 130,396,913 | 129,895,649 | 129,895,649 |
| 101 | Tax Depreciation Expense | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 793,257 | 9,519,081 |
| 102 | Debt Return | 253,927 | 252,984 | 252,044 | 251,097 | 250,157 | 249,211 | 248,271 | 247,328 | 246,381 | 245,441 | 244,494 | 243,554 | 2,984,889 |
| 103 | Equity Return | 537,197 | 535,201 | 533,213 | 531,210 | 529,222 | 527,219 | 525,231 | 523,235 | 521,232 | 519,244 | 517,241 | 515,253 | 6,314,699 |
| 104 | Current Income Tax Requirement | 99,641 | 98,836 | 98,034 | 97,226 | 96,424 | 95,616 | 94,814 | 94,009 | 93,201 | 92,399 | 91,592 | 90,790 | 1,142,582 |
| 105 | Book Depreciation | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 4,677,535 |
| 106 | Deferred Taxes | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 113,297 | 1,359,570 |
| 107 | Property Tax Expense | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 3,207,896 |
| 108 | Total Revenue Requirement | 1,661,182 | 1,657,438 | 1,653,708 | 1,649,950 | 1,646,220 | 1,642,463 | 1,638,732 | 1,634,989 | 1,631,231 | 1,627,501 | 1,623,744 | 1,620,013 | 19,687,171 |
| 109 | Rider Revenue Requirement | 1,217,866 | 1,215,122 | 1,212,387 | 1,209,632 | 1,206,897 | 1,204,143 | 1,201,408 | 1,198,663 | 1,195,909 | 1,193,174 | 1,190,419 | 1,187,684 | 14,433,305 |
| 110 | **Huntley - Wilmarth** | | | | | | | | | | | | | |
| 111 | CWIP Balance | 4,202,499 | 5,166,121 | 6,129,742 | 8,538,804 | 10,947,858 | 13,356,911 | 16,247,785 | 19,138,649 | 22,029,513 | 25,884,008 | 29,256,683 | 32,147,550 | 32,147,550 |
| 112 | Plant In-Service | 1,162,955 | 1,437,916 | 1,712,878 | 1,987,840 | 2,262,801 | 2,537,763 | 2,812,725 | 3,087,686 | 3,362,648 | 3,637,610 | 3,912,572 | 4,187,533 | 4,187,533 |
| 113 | Depreciation Reserve | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 114 | Accumulated Deferred Taxes | (24,253) | (30,838) | (43,795) | (57,176) | (70,133) | (83,515) | (96,471) | (109,640) | (123,022) | (135,979) | (149,360) | (162,317) | (162,317) |
| 115 | Average Rate Base | 4,763,827 | 6,015,583 | 7,267,123 | 9,241,808 | 11,938,785 | 14,636,181 | 17,574,063 | 20,753,063 | 23,932,270 | 27,592,869 | 31,494,797 | 34,914,486 | 34,914,486 |
| 116 | Tax Depreciation Expense | - | - | - | - | - | - | - | - | - | - | - | - | |
| 117 | CPI-TAX INTEREST | 9,993 | 13,163 | 16,343 | 21,887 | 29,802 | 37,743 | 46,494 | 56,058 | 65,653 | 76,849 | 88,865 | 99,351 | 562,201 |
| 118 | Debt Return | 8,932 | 11,279 | 13,626 | 17,328 | 22,385 | 27,443 | 32,951 | 38,912 | 44,873 | 51,737 | 59,053 | 65,465 | 393,984 |
| 119 | Equity Return | 18,897 | 23,862 | 28,826 | 36,659 | 47,357 | 58,057 | 69,710 | 82,320 | 94,931 | 109,452 | 124,929 | 138,494 | 833,495 |
| 120 | Current Income Tax Requirement | 6,341 | 9,622 | 12,907 | 18,303 | 25,811 | 33,329 | 41,559 | 50,503 | 59,460 | 69,833 | 80,922 | 90,623 | 499,214 |
| 121 | Book Depreciation | - | - | - | - | - | - | - | - | - | - | - | - | |
| 122 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 123 | Deferred Taxes | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (13,169) | (158,030) |
| 124 | Property Tax Expense | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 1,140 | 13,683 |
| 125 | Total Revenue Requirement | 22,140 | 32,734 | 43,331 | 60,262 | 83,524 | 106,800 | 132,192 | 159,707 | 187,236 | 218,992 | 252,875 | 282,553 | 1,582,347 |
| 126 | Rider Revenue Requirement | 16,232 | 23,999 | 31,767 | 44,180 | 61,234 | 78,299 | 96,915 | 117,086 | 137,269 | 160,550 | 185,391 | 207,149 | 1,160,070 |
| 127 | **LaCrosse - Madison** | | | | | | | | | | | | | |
| 128 | CWIP Balance | 2,895 | 2,895 | 2,895 | 2,895 | 2,895 | 2,895 | - | - | - | - | - | - | - |
| 129 | Plant In-Service | 171,243,545 | 171,409,275 | 171,573,122 | 171,583,480 | 171,590,072 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 |
| 130 | Depreciation Reserve | 5,763,003 | 6,194,746 | 6,626,519 | 7,058,321 | 7,490,147 | 7,922,003 | 8,353,881 | 8,785,759 | 9,217,637 | 9,649,515 | 10,081,393 | 10,513,271 | 10,513,271 |
| 131 | Accumulated Deferred Taxes | 4,565,327 | 4,682,567 | 4,913,265 | 5,151,527 | 5,382,225 | 5,620,488 | 5,851,186 | 6,085,666 | 6,323,928 | 6,554,626 | 6,792,888 | 7,023,587 | 7,023,587 |
| 132 | Average Rate Base | 161,160,324 | 160,667,864 | 160,170,196 | 159,587,248 | 158,933,211 | 158,274,408 | 157,618,400 | 156,950,594 | 156,280,454 | 155,617,877 | 154,947,737 | 154,285,161 | 154,285,161 |
| 133 | Tax Depreciation Expense | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 1,263,881 | 15,166,569 |
| 134 | CPI-TAX INTEREST | - | - | - | - | - | - | - | - | - | - | - | - | |
| 135 | Debt Return | 302,176 | 301,252 | 300,319 | 299,226 | 298,000 | 296,765 | 295,535 | 294,282 | 293,026 | 291,784 | 290,527 | 289,285 | 3,552,175 |
| 136 | Equity Return | 639,269 | 637,316 | 635,342 | 633,029 | 630,435 | 627,822 | 625,220 | 622,571 | 619,912 | 617,284 | 614,626 | 611,998 | 7,514,824 |
| 137 | Current Income Tax Requirement | 16,762 | 15,996 | 15,212 | 14,291 | 13,254 | 12,212 | 11,172 | 10,103 | 9,031 | 7,971 | 6,899 | 5,839 | 138,742 |
| 138 | Book Depreciation | 431,687 | 431,743 | 431,774 | 431,802 | 431,825 | 431,856 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 5,181,956 |
| 139 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 140 | Deferred Taxes | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 234,480 | 2,813,762 |
| 141 | Property Tax Expense | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 219,663 | 2,635,958 |
| 142 | Total Revenue Requirement | 1,844,037 | 1,840,450 | 1,836,790 | 1,832,492 | 1,827,657 | 1,822,798 | 1,817,947 | 1,812,978 | 1,807,991 | 1,803,060 | 1,798,073 | 1,793,143 | 21,837,418 |
| 143 | Rider Revenue Requirement | 1,351,924 | 1,349,294 | 1,346,611 | 1,343,459 | 1,339,915 | 1,336,353 | 1,332,796 | 1,329,153 | 1,325,497 | 1,321,882 | 1,318,226 | 1,314,611 | 16,009,721 |
| 144 | **MISO RECB Sch.26/26a** | | | | | | | | | | | | | |
| 145 | Total Revenue Requirement | (908,757) | (731,016) | (640,880) | (794,210) | (600,962) | (194,197) | 774,069 | 40,267 | 349,205 | (764,439) | (569,886) | (327,170) | -4,367,976 |
| 146 | Rider Revenue Requirement | (666,239) | (535,932) | (469,850) | (582,261) | (440,585) | (142,372) | 567,495 | 29,521 | 256,014 | (560,435) | (417,802) | (239,859) | -3,202,305 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Annual 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **ADMS** | | | | | | | | | | | | | |
| 2 | CWIP Balance | (64,467) | (64,568) | (64,669) | (64,770) | (64,870) | (64,971) | (65,072) | (65,173) | (65,274) | (65,375) | (65,475) | (65,576) | (65,576) |
| 3 | Plant In-Service | 38,905,337 | 38,985,438 | 39,065,539 | 39,145,639 | 39,225,740 | 39,305,841 | 39,385,942 | 39,466,043 | 39,546,144 | 39,626,244 | 39,706,345 | 39,786,446 | 39,786,446 |
| 4 | Depreciation Reserve | 2,736,637 | 3,020,231 | 3,304,408 | 3,589,168 | 3,874,512 | 4,160,439 | 4,446,949 | 4,734,043 | 5,021,720 | 5,309,980 | 5,598,823 | 5,888,250 | 5,888,250 |
| 5 | Accumulated Deferred Taxes | 1,821,389 | 2,030,958 | 2,233,874 | 2,443,443 | 2,646,359 | 2,855,927 | 3,058,843 | 3,265,086 | 3,474,654 | 3,677,570 | 3,887,139 | 4,090,055 | 4,090,055 |
| 6 | Average Rate Base | 34,384,349 | 33,971,478 | 33,564,676 | 33,150,639 | 32,742,671 | 32,327,467 | 31,918,332 | 31,505,288 | 31,088,334 | 30,677,450 | 30,259,329 | 29,847,279 | 29,847,279 |
| 7 | Tax Depreciation Expense | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 1,018,026 | 12,216,312 |
| 8 | CPI-TAX INTEREST | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Debt Return | 64,471 | 63,697 | 62,934 | 62,157 | 61,393 | 60,614 | 59,847 | 59,072 | 58,291 | 57,520 | 56,736 | 55,964 | 722,695 |
| 10 | Equity Return | 136,391 | 134,754 | 133,140 | 131,498 | 129,879 | 128,232 | 126,609 | 124,971 | 123,317 | 121,687 | 120,029 | 118,394 | 1,528,901 |
| 11 | Current Income Tax Requirement | (158,268) | (158,693) | (159,109) | (159,536) | (159,953) | (160,382) | (160,802) | (161,227) | (161,659) | (162,081) | (162,515) | (162,939) | (1,927,163) |
| 12 | Book Depreciation | 283,011 | 283,594 | 284,177 | 284,760 | 285,344 | 285,927 | 286,510 | 287,094 | 287,677 | 288,260 | 288,843 | 289,427 | 3,434,623 |
| 13 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | Deferred Taxes | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 206,242 | 2,474,908 |
| 15 | Property Tax Expense | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 49,856 | 598,273 |
| 16 | Operating Expenses | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 48,999 | 587,988 |
| 17 | Total Revenue Requirement | 630,702 | 628,448 | 626,240 | 623,977 | 621,760 | 619,488 | 617,262 | 615,007 | 612,723 | 610,484 | 608,191 | 605,943 | 7,420,225 |
| 18 | Rider Revenue Requirement | 549,147 | 547,184 | 545,261 | 543,291 | 541,361 | 539,383 | 537,445 | 535,481 | 533,492 | 531,543 | 529,546 | 527,589 | 6,460,723 |
| 19 | **Big Stone-Brookings** | | | | | | | | | | | | | |
| 20 | CWIP Balance | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 21 | Plant In-Service | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 | 54,506,681 |
| 22 | Depreciation Reserve | 3,849,343 | 3,945,520 | 4,041,697 | 4,137,873 | 4,234,050 | 4,330,227 | 4,426,403 | 4,522,580 | 4,618,757 | 4,714,933 | 4,811,110 | 4,907,287 | 4,907,287 |
| 23 | Accumulated Deferred Taxes | 12,601,943 | 12,640,249 | 12,677,338 | 12,715,644 | 12,752,733 | 12,791,039 | 12,828,128 | 12,865,826 | 12,904,131 | 12,941,221 | 12,979,526 | 13,016,616 | 13,016,616 |
| 24 | Average Rate Base | 38,103,482 | 37,969,000 | 37,835,734 | 37,701,252 | 37,567,986 | 37,433,503 | 37,300,237 | 37,166,363 | 37,031,881 | 36,898,615 | 36,764,132 | 36,630,866 | 36,630,866 |
| 25 | Tax Depreciation Expense | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 229,740 | 2,756,880 |
| 26 | Debt Return | 71,444 | 71,192 | 70,942 | 70,690 | 70,440 | 70,188 | 69,938 | 69,687 | 69,435 | 69,185 | 68,933 | 68,683 | 840,756 |
| 27 | Equity Return | 151,144 | 150,610 | 150,082 | 149,548 | 149,020 | 148,486 | 147,958 | 147,427 | 146,893 | 146,365 | 145,831 | 145,302 | 1,778,665 |
| 28 | Current Income Tax Requirement | 22,296 | 22,081 | 21,868 | 21,653 | 21,440 | 21,225 | 21,011 | 20,797 | 20,582 | 20,369 | 20,154 | 19,940 | 253,416 |
| 29 | Book Depreciation | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 96,177 | 1,154,120 |
| 30 | Deferred Taxes | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 37,698 | 452,370 |
| 31 | Property Tax Expense | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 69,993 | 839,915 |
| 32 | Total Revenue Requirement | 448,751 | 447,751 | 446,759 | 445,758 | 444,766 | 443,766 | 442,774 | 441,778 | 440,777 | 439,785 | 438,784 | 437,793 | 5,319,242 |
| 33 | Rider Revenue Requirement | 328,092 | 327,361 | 326,636 | 325,904 | 325,179 | 324,447 | 323,722 | 322,994 | 322,262 | 321,537 | 320,805 | 320,080 | 3,889,018 |
| 34 | **CAPX2020 Brookings** | | | | | | | | | | | | | |
| 35 | CWIP Balance | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 36 | Plant In-Service | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 |
| 37 | Depreciation Reserve | 58,684,155 | 59,467,694 | 60,251,233 | 61,034,772 | 61,818,311 | 62,601,851 | 63,385,390 | 64,168,929 | 64,952,468 | 65,736,007 | 66,519,546 | 67,303,085 | 67,303,085 |
| 38 | Accumulated Deferred Taxes | 101,918,555 | 101,984,832 | 102,049,006 | 102,115,284 | 102,179,458 | 102,245,735 | 102,309,909 | 102,375,135 | 102,441,413 | 102,505,586 | 102,571,864 | 102,636,038 | 102,636,038 |
| 39 | Average Rate Base | 302,684,574 | 301,834,757 | 300,987,044 | 300,137,227 | 299,289,514 | 298,439,697 | 297,591,984 | 296,743,220 | 295,893,403 | 295,045,690 | 294,195,873 | 293,348,160 | 293,348,160 |
| 40 | Tax Depreciation Expense | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 1,014,852 | 12,178,229 |
| 41 | Debt Return | 567,534 | 565,940 | 564,351 | 562,757 | 561,168 | 559,574 | 557,985 | 556,394 | 554,800 | 553,211 | 551,617 | 550,028 | 6,705,358 |
| 42 | Equity Return | 1,200,649 | 1,197,278 | 1,193,915 | 1,190,544 | 1,187,182 | 1,183,811 | 1,180,448 | 1,177,081 | 1,173,711 | 1,170,348 | 1,166,977 | 1,163,614 | 14,185,558 |
| 43 | Current Income Tax Requirement | 417,292 | 415,932 | 414,576 | 413,216 | 411,860 | 410,500 | 409,144 | 407,786 | 406,426 | 405,070 | 403,710 | 402,354 | 4,917,863 |
| 44 | Book Depreciation | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 9,402,469 |
| 45 | Deferred Taxes | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 65,226 | 782,709 |
| 46 | Property Tax Expense | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 7,132,938 |
| 47 | Total Revenue Requirement | 3,628,650 | 3,622,326 | 3,616,018 | 3,609,694 | 3,603,386 | 3,597,062 | 3,590,753 | 3,584,437 | 3,578,113 | 3,571,805 | 3,565,481 | 3,559,172 | 43,126,896 |
| 48 | Rider Revenue Requirement | 2,652,989 | 2,648,365 | 2,643,753 | 2,639,129 | 2,634,517 | 2,629,893 | 2,625,281 | 2,620,663 | 2,616,040 | 2,611,427 | 2,606,804 | 2,602,192 | 31,531,051 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Annual 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 49 | **CAPX2020 - La Crosse Local** | | | | | | | | | | | | | |
| 50 | CWIP Balance | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 51 | Plant In-Service | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 | 75,620,951 |
| 52 | Depreciation Reserve | 7,827,342 | 7,968,598 | 8,109,855 | 8,251,111 | 8,392,367 | 8,533,623 | 8,674,879 | 8,816,135 | 8,957,391 | 9,098,647 | 9,239,903 | 9,381,159 | 9,381,159 |
| 53 | Accumulated Deferred Taxes | 17,458,327 | 17,505,429 | 17,551,036 | 17,598,138 | 17,643,745 | 17,690,847 | 17,736,454 | 17,782,808 | 17,829,910 | 17,875,517 | 17,922,619 | 17,968,226 | 17,968,226 |
| 54 | Average Rate Base | 50,405,910 | 50,217,551 | 50,030,688 | 49,842,330 | 49,655,467 | 49,467,109 | 49,280,246 | 49,092,636 | 48,904,278 | 48,717,415 | 48,529,056 | 48,342,194 | 48,342,194 |
| 55 | Tax Depreciation Expense | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 | 306,495 |
| 56 | Debt Return | 94,511 | 94,158 | 93,808 | 93,454 | 93,104 | 92,751 | 92,400 | 92,049 | 91,696 | 91,345 | 90,992 | 90,642 | 1,110,909 |
| 57 | Equity Return | 199,943 | 199,196 | 198,455 | 197,708 | 196,967 | 196,220 | 195,478 | 194,734 | 193,987 | 193,246 | 192,499 | 191,757 | 2,350,190 |
| 58 | Current Income Tax Requirement | 32,695 | 32,394 | 32,095 | 31,793 | 31,494 | 31,193 | 30,894 | 30,594 | 30,293 | 29,994 | 29,692 | 29,393 | 372,524 |
| 59 | Book Depreciation | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 141,256 | 1,695,073 |
| 60 | Deferred Taxes | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 46,354 | 556,254 |
| 61 | Property Tax Expense | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 97,106 | 1,165,273 |
| 62 | OATT Credit | 142,504 | 142,177 | 141,853 | 141,527 | 141,203 | 140,877 | 140,553 | 140,228 | 139,901 | 139,577 | 139,251 | 138,927 | 1,688,577 |
| 63 | Total Revenue Requirement | 469,363 | 468,287 | 467,221 | 466,145 | 465,079 | 464,003 | 462,937 | 461,866 | 460,791 | 459,724 | 458,649 | 457,582 | 5,561,646 |
| 64 | Rider Revenue Requirement | 343,162 | 342,376 | 341,596 | 340,809 | 340,030 | 339,243 | 338,464 | 337,681 | 336,894 | 336,115 | 335,328 | 334,549 | 4,066,245 |
| 65 | **CAPX2020 - La Crosse MISO** | | | | | | | | | | | | | |
| 66 | CWIP Balance | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 67 | Plant In-Service | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 | 75,046,803 |
| 68 | Depreciation Reserve | 8,634,859 | 8,762,564 | 8,890,270 | 9,017,975 | 9,145,681 | 9,273,386 | 9,401,092 | 9,528,797 | 9,656,503 | 9,784,208 | 9,911,913 | 10,039,619 | 10,039,619 |
| 69 | Accumulated Deferred Taxes | 16,990,027 | 17,000,176 | 17,010,002 | 17,020,150 | 17,029,977 | 17,040,125 | 17,049,951 | 17,059,939 | 17,070,087 | 17,079,913 | 17,090,062 | 17,099,888 | 17,099,888 |
| 70 | Average Rate Base | 49,485,770 | 49,347,916 | 49,210,384 | 49,072,530 | 48,934,999 | 48,797,145 | 48,659,613 | 48,521,920 | 48,384,066 | 48,246,535 | 48,108,681 | 47,971,149 | 47,971,149 |
| 71 | Tax Depreciation Expense | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 163,236 | 1,958,832 |
| 72 | Debt Return | 92,786 | 92,527 | 92,269 | 92,011 | 91,753 | 91,495 | 91,237 | 90,979 | 90,720 | 90,462 | 90,204 | 89,946 | 1,096,389 |
| 73 | Equity Return | 196,294 | 195,747 | 195,201 | 194,654 | 194,109 | 193,562 | 193,016 | 192,470 | 191,923 | 191,378 | 190,831 | 190,286 | 2,319,471 |
| 74 | Current Income Tax Requirement | 68,872 | 68,652 | 68,432 | 68,211 | 67,991 | 67,771 | 67,551 | 67,330 | 67,110 | 66,890 | 66,669 | 66,449 | 811,927 |
| 75 | Book Depreciation | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 127,705 | 1,532,466 |
| 76 | Deferred Taxes | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 9,987 | 119,848 |
| 77 | Property Tax Expense | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 96,369 | 1,156,426 |
| 78 | Total Revenue Requirement | 592,013 | 590,987 | 589,964 | 588,938 | 587,915 | 586,889 | 585,865 | 584,841 | 583,815 | 582,791 | 581,766 | 580,742 | 7,036,527 |
| 79 | Rider Revenue Requirement | 432,834 | 432,084 | 431,336 | 430,586 | 429,838 | 429,088 | 428,339 | 427,590 | 426,840 | 426,092 | 425,342 | 424,594 | 5,144,564 |
| 80 | **CAPX2020 - La Crosse MISO - WI** | | | | | | | | | | | | | |
| 81 | CWIP Balance | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 82 | Plant In-Service | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 | 136,376,644 |
| 83 | Depreciation Reserve | 19,745,424 | 20,078,400 | 20,411,376 | 20,744,352 | 21,077,328 | 21,410,304 | 21,743,280 | 22,076,256 | 22,409,232 | 22,742,208 | 23,075,184 | 23,408,160 | 23,408,160 |
| 84 | Accumulated Deferred Taxes | 33,188,048 | 33,181,263 | 33,174,693 | 33,167,908 | 33,161,338 | 33,154,553 | 33,147,984 | 33,141,306 | 33,134,521 | 33,127,951 | 33,121,166 | 33,114,597 | 33,114,597 |
| 85 | Average Rate Base | 83,609,660 | 83,283,469 | 82,957,063 | 82,630,872 | 82,304,466 | 81,978,275 | 81,651,869 | 81,325,570 | 80,999,379 | 80,672,973 | 80,346,782 | 80,020,376 | 80,020,376 |
| 86 | Tax Depreciation Expense | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 323,635 | 3,883,625 |
| 87 | Debt Return | 156,768 | 156,157 | 155,544 | 154,933 | 154,321 | 153,709 | 153,097 | 152,485 | 151,874 | 151,262 | 150,650 | 150,038 | 1,840,839 |
| 88 | Equity Return | 331,652 | 330,358 | 329,063 | 327,769 | 326,474 | 325,180 | 323,886 | 322,591 | 321,298 | 320,003 | 318,709 | 317,414 | 3,894,397 |
| 89 | Current Income Tax Requirement | 134,846 | 134,324 | 133,802 | 133,280 | 132,758 | 132,236 | 131,714 | 131,192 | 130,670 | 130,148 | 129,626 | 129,104 | 1,583,700 |
| 90 | Book Depreciation | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 332,976 | 3,995,712 |
| 91 | Deferred Taxes | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (6,677) | (80,129) |
| 92 | Property Tax Expense | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 175,123 | 2,101,481 |
| 93 | Total Revenue Requirement | 1,124,688 | 1,122,261 | 1,119,832 | 1,117,404 | 1,114,975 | 1,112,548 | 1,110,119 | 1,107,691 | 1,105,263 | 1,102,834 | 1,100,407 | 1,097,978 | 13,336,000 |
| 94 | Rider Revenue Requirement | 822,285 | 820,510 | 818,734 | 816,960 | 815,184 | 813,409 | 811,633 | 809,858 | 808,083 | 806,307 | 804,532 | 802,757 | 9,750,252 |

Amounts in dollars

| Line No: | NSPM Rider Rev Req by Rider Project | Jan-21 | Feb-21 | Mar-21 | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Annual 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 95 | **CAPX2020 Fargo** | | | | | | | | | | | | | |
| 96 | CWIP Balance | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 97 | Plant In-Service | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 | 208,177,995 |
| 98 | Depreciation Reserve | 30,246,416 | 30,636,211 | 31,026,005 | 31,415,800 | 31,805,594 | 32,195,389 | 32,585,183 | 32,974,978 | 33,364,773 | 33,754,567 | 34,144,362 | 34,534,156 | 34,534,156 |
| 99 | Accumulated Deferred Taxes | 48,708,245 | 48,769,454 | 48,828,719 | 48,889,928 | 48,949,193 | 49,010,401 | 49,069,667 | 49,129,904 | 49,191,112 | 49,250,377 | 49,311,586 | 49,370,851 | 49,370,851 |
| 100 | Average Rate Base | 129,418,231 | 128,967,228 | 128,518,168 | 128,067,165 | 127,618,105 | 127,167,102 | 126,718,042 | 126,268,011 | 125,817,008 | 125,367,948 | 124,916,945 | 124,467,885 | 124,467,885 |
| 101 | Tax Depreciation Expense | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 604,506 | 7,254,072 |
| 102 | Debt Return | 242,659 | 241,814 | 240,972 | 240,126 | 239,284 | 238,438 | 237,596 | 236,753 | 235,907 | 235,065 | 234,219 | 233,377 | 2,856,210 |
| 103 | Equity Return | 513,359 | 511,570 | 509,789 | 508,000 | 506,218 | 504,430 | 502,648 | 500,863 | 499,074 | 497,293 | 495,504 | 493,723 | 6,042,470 |
| 104 | Current Income Tax Requirement | 144,756 | 144,035 | 143,316 | 142,595 | 141,876 | 141,155 | 140,436 | 139,716 | 138,995 | 138,276 | 137,555 | 136,836 | 1,689,548 |
| 105 | Book Depreciation | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 389,795 | 4,677,535 |
| 106 | Deferred Taxes | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 60,237 | 722,843 |
| 107 | Property Tax Expense | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 267,325 | 3,207,896 |
| 108 | Total Revenue Requirement | 1,618,131 | 1,614,775 | 1,611,433 | 1,608,077 | 1,604,735 | 1,601,379 | 1,598,037 | 1,594,688 | 1,591,332 | 1,587,990 | 1,584,634 | 1,581,292 | 19,196,502 |
| 109 | Rider Revenue Requirement | 1,183,052 | 1,180,598 | 1,178,155 | 1,175,701 | 1,173,258 | 1,170,804 | 1,168,361 | 1,165,913 | 1,163,459 | 1,161,016 | 1,158,562 | 1,156,119 | 14,034,998 |
| 110 | **Huntley - Wilmarth** | | | | | | | | | | | | | |
| 111 | CWIP Balance | 34,972,508 | 37,797,457 | 40,622,406 | 43,918,189 | 47,213,962 | 50,980,561 | 54,747,169 | 58,042,942 | 60,867,891 | 62,280,375 | 63,692,849 | - | - |
| 112 | Plant In-Service | 4,267,573 | 4,347,614 | 4,427,654 | 4,507,694 | 4,587,734 | 4,667,775 | 4,747,815 | 4,827,855 | 4,907,895 | 4,987,935 | 5,067,976 | 69,514,178 | 69,514,178 |
| 113 | Depreciation Reserve | - | - | - | - | - | - | - | - | - | - | - | 61,307 | 61,307 |
| 114 | Accumulated Deferred Taxes | (152,825) | (118,617) | (85,496) | (51,288) | (18,167) | 16,041 | 49,162 | 82,827 | 117,034 | 150,156 | 184,363 | 217,485 | 217,485 |
| 115 | Average Rate Base | 37,940,407 | 40,811,193 | 43,683,061 | 46,789,259 | 50,131,956 | 53,708,975 | 57,522,497 | 61,100,063 | 64,206,257 | 66,371,892 | 67,830,204 | 68,889,363 | 68,889,363 |
| 116 | Tax Depreciation Expense | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 277,963 | 3,335,554 |
| 117 | CPI-TAX INTEREST | 106,251 | 115,556 | 124,891 | 135,002 | 145,893 | 157,566 | 170,023 | 181,773 | 192,065 | 199,400 | 204,517 | 104,241 | 1,837,179 |
| 118 | Debt Return | 71,138 | 76,521 | 81,906 | 87,730 | 93,997 | 100,704 | 107,855 | 114,563 | 120,387 | 124,447 | 127,182 | 129,168 | 1,235,597 |
| 119 | Equity Return | 150,497 | 161,884 | 173,276 | 185,597 | 198,857 | 213,046 | 228,173 | 242,364 | 254,685 | 263,275 | 269,060 | 273,261 | 2,613,974 |
| 120 | Current Income Tax Requirement | 5,022 | 13,368 | 21,728 | 30,776 | 40,517 | 50,949 | 62,075 | 72,538 | 81,659 | 88,083 | 92,480 | 78,456 | 637,650 |
| 121 | Book Depreciation | - | - | - | - | - | - | - | - | - | - | - | 61,307 | 61,307 |
| 122 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 123 | Deferred Taxes | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 33,665 | 403,974 |
| 124 | Property Tax Expense | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 5,377 | 64,527 |
| 125 | Total Revenue Requirement | 265,699 | 290,815 | 315,952 | 343,145 | 372,413 | 403,740 | 437,144 | 468,506 | 495,772 | 514,847 | 527,763 | 581,234 | 5,017,030 |
| 126 | Rider Revenue Requirement | 194,258 | 212,622 | 230,999 | 250,881 | 272,280 | 295,184 | 319,606 | 342,535 | 362,470 | 376,416 | 385,859 | 424,953 | 3,668,064 |
| 127 | **LaCrosse - Madison** | | | | | | | | | | | | | |
| 128 | CWIP Balance | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 129 | Plant In-Service | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 | 171,606,080 |
| 130 | Depreciation Reserve | 10,945,150 | 11,377,028 | 11,808,906 | 12,240,784 | 12,672,662 | 13,104,540 | 13,536,418 | 13,968,296 | 14,400,175 | 14,832,053 | 15,263,931 | 15,695,809 | 15,695,809 |
| 131 | Accumulated Deferred Taxes | 7,241,458 | 7,444,841 | 7,641,767 | 7,845,151 | 8,042,077 | 8,245,460 | 8,442,387 | 8,642,542 | 8,845,925 | 9,042,852 | 9,246,235 | 9,443,161 | 9,443,161 |
| 132 | Average Rate Base | 153,635,412 | 153,000,150 | 152,371,346 | 151,736,084 | 151,107,280 | 150,472,018 | 149,843,214 | 149,211,181 | 148,575,919 | 147,947,115 | 147,311,853 | 146,683,049 | 146,683,049 |
| 133 | Tax Depreciation Expense | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 1,141,815 | 13,701,782 |
| 134 | CPI-TAX INTEREST | - | - | - | - | - | - | - | - | - | - | - | - | |
| 135 | Debt Return | 288,066 | 286,875 | 285,696 | 284,505 | 283,326 | 282,135 | 280,956 | 279,771 | 278,580 | 277,401 | 276,210 | 275,031 | 3,378,552 |
| 136 | Equity Return | 609,420 | 606,901 | 604,406 | 601,886 | 599,392 | 596,872 | 594,378 | 591,871 | 589,351 | 586,857 | 584,337 | 581,843 | 7,147,515 |
| 137 | Current Income Tax Requirement | 40,189 | 39,173 | 38,167 | 37,150 | 36,144 | 35,128 | 34,122 | 33,111 | 32,094 | 31,088 | 30,072 | 29,066 | 415,504 |
| 138 | Book Depreciation | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 431,878 | 5,182,537 |
| 139 | AFUDC | - | - | - | - | - | - | - | - | - | - | - | - | |
| 140 | Deferred Taxes | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 200,155 | 2,401,859 |
| 141 | Property Tax Expense | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 220,362 | 2,644,345 |
| 142 | Total Revenue Requirement | 1,790,071 | 1,785,344 | 1,780,665 | 1,775,937 | 1,771,258 | 1,766,530 | 1,761,851 | 1,757,148 | 1,752,420 | 1,747,741 | 1,743,014 | 1,738,334 | 21,170,313 |
| 143 | Rider Revenue Requirement | 1,308,762 | 1,305,305 | 1,301,884 | 1,298,428 | 1,295,007 | 1,291,550 | 1,288,129 | 1,284,691 | 1,281,234 | 1,277,813 | 1,274,357 | 1,270,936 | 15,478,096 |
| 144 | **MISO RECB Sch.26/26a** | | | | | | | | | | | | | |
| 145 | Total Revenue Requirement | (1,353,191) | (1,270,243) | (1,013,117) | (1,143,416) | (1,034,631) | (655,134) | 366,737 | (430,616) | (2,480) | (1,142,938) | (908,501) | (685,443) | -9,272,973 |
| 146 | Rider Revenue Requirement | (989,349) | (928,703) | (740,713) | (835,977) | (756,442) | (478,983) | 268,130 | (314,833) | (1,813) | (835,628) | (664,226) | (501,143) | -6,779,681 |

# Revenue Requirement Model Logic

Revenue Requirement Calculation
Amounts in dollars

| | CAPX2020 Brookings | Dec 2019 | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total 2020 Sum of Jan through Dec 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Plant In-Service (CAA Input) | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | 462,895,514 | |
| B | Depreciation Reserve (CAA Input) | 48,498,147 | 49,281,686 | 50,065,225 | 50,848,764 | 51,632,303 | 52,415,842 | 53,199,381 | 53,982,920 | 54,766,459 | 55,549,999 | 56,333,538 | 57,117,077 | 57,900,616 | |
| C | Accumulated Deferred Taxes (CAA Input) | 100,368,628 | 100,495,158 | 100,558,423 | 100,682,913 | 100,811,484 | 100,935,974 | 101,064,545 | 101,189,035 | 101,315,566 | 101,444,137 | 101,568,627 | 101,697,198 | 101,821,688 | |
| D | (PIS - Reserve - ADIT) | 314,028,740 | 313,118,670 | 312,271,866 | 311,363,837 | 310,451,726 | 309,543,698 | 308,631,587 | 307,723,558 | 306,813,489 | 305,901,378 | 304,993,349 | 304,081,239 | 303,173,210 | |
| E | **Average Rate Base (Prior Net Plant + Cur Net Plant)/2-ADT** | | **313,510,440** | **312,663,635** | **311,755,606** | **310,843,496** | **309,935,467** | **309,023,357** | **308,115,328** | **307,205,258** | **306,293,148** | **305,385,119** | **304,473,009** | **303,564,980** | |
| | | | | | | | | | | | | | | | |
| F | Tax Depreciation Expense (CAA Input) | | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | 1,232,154 | |
| G | Debt Return (Ave RB * Wtd Cost of Debt) | | 587,832 | 586,244 | 584,542 | 582,832 | 581,129 | 579,419 | 577,716 | 576,010 | 574,300 | 572,597 | 570,887 | 569,184 | |
| H | Equity Return (Ave RB * Wtd Cost of Equity) | | 1,243,591 | 1,240,232 | 1,236,631 | 1,233,013 | 1,229,411 | 1,225,793 | 1,222,191 | 1,218,581 | 1,214,963 | 1,211,361 | 1,207,743 | 1,204,141 | |
| I | Current Income Tax Requirement (See Below) | | 371,691 | 370,336 | 368,883 | 367,424 | 365,971 | 364,512 | 363,059 | 361,603 | 360,144 | 358,691 | 357,231 | 355,779 | |
| J | Book Depreciation (CAA Input) | | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | |
| K | Deferred Taxes (CAA Input) | | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | |
| L | Property Taxes ( A * Prop Tax Factor) | | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | 594,412 | |
| M | Total Revenue Requirement (G+H+I+J+K+L) | | 3,707,596 | 3,701,294 | 3,694,537 | 3,687,749 | 3,680,992 | 3,674,204 | 3,667,447 | 3,660,675 | 3,653,887 | 3,647,130 | 3,640,342 | 3,633,585 | |
| N | Jurisdiction Revenue Requirement (M * MN Jur) | | 2,718,159 | 2,713,539 | 2,708,585 | 2,703,609 | 2,698,655 | 2,693,679 | 2,688,725 | 2,683,760 | 2,678,784 | 2,673,830 | 2,668,853 | 2,663,899 | |
| O | **Rider Revenue Requirement (N)** | | **2,718,159** | **2,713,539** | **2,708,585** | **2,703,609** | **2,698,655** | **2,693,679** | **2,688,725** | **2,683,760** | **2,678,784** | **2,673,830** | **2,668,853** | **2,663,899** | **32,294,076** |

| Capital Structure | 2020 Weighted Cost |
|---|---|
| Long Term Debt | 2.1800% |
| Short Term Debt | 0.0700% |
| Preferred Stock | 0.0000% |
| Common Equity | 4.7600% |
| Required Rate of Return | 7.0100% |
| | |
| Tax Rate (MN) | 28.7420% |
| MN Jurisdictional Factor | 73.31325% |

| | |
|---|---|
| Reconciliation to Attachment 4 | |
| Line 3 of Annual Tracker Summary | 32,294,421 |
| Difference | (345) |

| | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Equity Return (Item H) | 1,243,591 | 1,240,232 | 1,236,631 | 1,233,013 | 1,229,411 | 1,225,793 | 1,222,191 | 1,218,581 | 1,214,963 | 1,211,361 | 1,207,743 | 1,204,141 |
| Book Depreciation (Item J) | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 | 783,539 |
| Deferred Taxes (Item K) | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 | 126,531 |
| Less Tax Depreciation (Item F) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) | (1,232,154) |
| Plus CPI-Tax Interest (If Applicable) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sum | 921,507 | 918,148 | 914,546 | 910,928 | 907,326 | 903,708 | 900,106 | 896,497 | 892,878 | 889,277 | 885,659 | 882,057 |
| Tax Rate (T/(1-T) | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% | 40.34% |
| Tax Calc (Sum * Tax Rate) | 371,691 | 370,336 | 368,883 | 367,424 | 365,971 | 364,512 | 363,059 | 361,603 | 360,144 | 358,691 | 357,231 | 355,779 |

**ADIT Prorate Calculation**

| Line No. | | | Jan-20 | Feb-20 | Mar-20 | Apr-20 | May-20 | Jun-20 | Jul-20 | Aug-20 | Sep-20 | Oct-20 | Nov-20 | Dec-20 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Pro-Rate Days** | A | 15 | 14 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | |
| 2 | **Pro-Rate Factor** | B = A/# days in month | 0.000000 | 0.500000 | 0.483871 | 0.500000 | 0.483871 | 0.500000 | 0.483871 | 0.483871 | 0.500000 | 0.483871 | 0.500000 | 0.483871 | |
| 3 | | | | | | | | | | | | | | | |
| 4 | **Deferred Beg Bal** | C | 228,440,012 | 229,251,944 | 230,063,876 | 230,875,807 | 231,687,739 | 232,499,671 | 233,311,602 | 234,123,534 | 234,935,465 | 235,747,397 | 236,559,329 | 237,371,260 | |
| 5 | **Deferred Tax Exp Activity** | D | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 811,932 | 9,743,179 |
| 6 | **Deferred Tax End Bal** | E=C+D | 229,251,944 | 230,063,876 | 230,875,807 | 231,687,739 | 232,499,671 | 233,311,602 | 234,123,534 | 234,935,465 | 235,747,397 | 236,559,329 | 237,371,260 | 238,183,192 | |
| 7 | **Average ADIT End Bal** | F=(C+E)/2 | 228,845,978 | 229,657,910 | 230,469,841 | 231,281,773 | 232,093,705 | 232,905,636 | 233,717,568 | 234,529,500 | 235,341,431 | 236,153,363 | 236,965,294 | 237,777,226 | |
| 8 | | | | | | | | | | | | | | | |
| 9 | **Deferred Tax Exp Prorated Activity** | G=B*D | - | 405,966 | 392,870 | 405,966 | 392,870 | 405,966 | 392,870 | 392,870 | 405,966 | 392,870 | 405,966 | 392,870 | |
| 10 | **Deferred Tax End Bal Prorated** | H = C+G | 228,440,012 | 229,657,910 | 230,456,746 | 231,281,773 | 232,080,609 | 232,905,636 | 233,704,472 | 234,516,404 | 235,341,431 | 236,140,267 | 236,965,294 | 237,764,130 | |
| 11 | | | | | | | | | | | | | | | |
| 12 | **Revenue Requirement Factor** | I= (WACC+(Equity Return*T/(1-T)))/12 | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | |
| 13 | | | | | | | | | | | | | | | |
| 14 | **RR of ADIT Pro-rate** | J = (F-H)*I | - | - | 97 | - | 97 | - | 97 | 97 | - | 97 | - | 97 | 585 |
| 15 | | | | | | | | | | | | | | | |
| 16 | **Jurisdictional Allocator** | K | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | 73.3133% | |
| 17 | | | | | | | | | | | | | | | |
| 18 | **MN Jur RR of ADIT Pro-rate** | L = J*K | **-** | **-** | **71** | **-** | **71** | **-** | **71** | **71** | **-** | **71** | **-** | **71** | **429** |
| 19 | | | | | | | | | | | | | | | |
| 20 | | | | | | | | | | | | | | | |
| 21 | | | **Jan-21** | **Feb-21** | **Mar-21** | **Apr-21** | **May-21** | **Jun-21** | **Jul-21** | **Aug-21** | **Sep-21** | **Oct-21** | **Nov-21** | **Dec-21** | **Total** |
| 22 | | | | | | | | | | | | | | | |
| 23 | **Pro-Rate Days** | A | 15 | 14 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | |
| 24 | **Pro-Rate Factor** | B = A/# days in month | 0.483871 | 0.500000 | 0.483871 | 0.500000 | 0.483871 | 0.500000 | 0.483871 | 0.483871 | 0.500000 | 0.483871 | 0.500000 | 0.483871 | |
| 25 | | | | | | | | | | | | | | | |
| 26 | **Deferred Beg Bal** | C | 238,183,192 | 238,856,784 | 239,530,376 | 240,203,968 | 240,877,560 | 241,551,152 | 242,224,744 | 242,898,336 | 243,571,928 | 244,245,520 | 244,919,113 | 245,592,705 | |
| 27 | **Deferred Tax Exp Activity** | D | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 673,592 | 8,083,105 |
| 28 | **Deferred Tax End Bal** | E=C+D | 238,856,784 | 239,530,376 | 240,203,968 | 240,877,560 | 241,551,152 | 242,224,744 | 242,898,336 | 243,571,928 | 244,245,520 | 244,919,113 | 245,592,705 | 246,266,297 | |
| 29 | **Average ADIT End Bal** | F=(C+E)/2 | 238,519,988 | 239,193,580 | 239,867,172 | 240,540,764 | 241,214,356 | 241,887,948 | 242,561,540 | 243,235,132 | 243,908,724 | 244,582,316 | 245,255,909 | 245,929,501 | |
| 30 | | | | | | | | | | | | | | | |
| 31 | **Deferred Tax Exp Prorated Activity** | G=B*D | 325,932 | 336,796 | 325,932 | 336,796 | 325,932 | 336,796 | 325,932 | 325,932 | 336,796 | 325,932 | 336,796 | 325,932 | |
| 32 | **Deferred Tax End Bal Prorated** | H = C+G | 238,509,123 | 239,193,580 | 239,856,308 | 240,540,764 | 241,203,492 | 241,887,948 | 242,550,676 | 243,224,268 | 243,908,724 | 244,571,452 | 245,255,909 | 245,918,636 | |
| 33 | | | | | | | | | | | | | | | |
| 34 | **Revenue Requirement Factor** | I= (WACC+(Equity Return*T/(1-T)))/12 | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | 0.744% | |
| 35 | | | | | | | | | | | | | | | |
| 36 | **RR of ADIT Pro-rate** | J = (F-H)*I | 81 | - | 81 | - | 81 | - | 81 | 81 | - | 81 | - | 81 | 566 |
| 37 | | | | | | | | | | | | | | | |
| 38 | **Jurisdictional Allocator** | K | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | 73.1123% | |
| 39 | | | | | | | | | | | | | | | |
| 40 | **MN Jur RR of ADIT Pro-rate** | L = J*K | **59** | **-** | **59** | **-** | **59** | **-** | **59** | **59** | **-** | **59** | **-** | **59** | **414** |

# Redline

**APPLICATION**
Applicable to bills for electric service provided under the Company's retail rate schedules.

**RIDER**
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

**DETERMINATION OF TCR ADJUSTMENT FACTORS**
A separate TCR Adjustment Factor shall be calculated for the following three customer groups: (1) Residential, ~~C~~
(2) Commercial Non-Demand, and (3) Demand Billed. The TCR Adjustment Factor for each group shall be the ~~C~~
value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Commission. The TCR factor for each rate schedule is: ~~T~~

| | | |
|---|---|---|
| Residential | ~~$0.003948~~$0.003607 per kWh | R |
| Commercial (Non-Demand) | ~~$0.003486~~$0.003185 per kWh | R |
| Demand Billed | ~~$1.074~~$0.982 per kW | R |

~~C~~
~~C~~

Recoverable Transmission and Distribution Costs shall be the annual revenue requirements for transmission and distribution costs associated with transmission projects and distribution planning and facilities eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

# Clean

**APPLICATION**
Applicable to bills for electric service provided under the Company's retail rate schedules.

**RIDER**
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

**DETERMINATION OF TCR ADJUSTMENT FACTORS**
A separate TCR Adjustment Factor shall be calculated for the following three customer groups: (1) Residential, (2) Commercial Non-Demand, and (3) Demand Billed. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Commission. The TCR factor for each rate schedule is:

| | | |
|---|---|---|
| Residential | $0.003607 per kWh | R |
| Commercial (Non-Demand) | $0.003185 per kWh | R |
| Demand Billed | $0.982 per kW | R |

Recoverable Transmission and Distribution Costs shall be the annual revenue requirements for transmission and distribution costs associated with transmission projects and distribution planning and facilities eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

## CERTIFICATE OF SERVICE

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

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

<u>xx</u> electronic filing

**XCEL ENERGY MISCELLANEOUS ELECTRIC SERVICE LIST**

Dated this 15th day of November 2019

/s/

______________________________

Lynnette Sweet

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| David | Aafedt | daafedt@winthrop.com | Winthrop & Weinstine, P.A. | Suite 3500, 225 South Sixth Street<br><br>Minneapolis,<br>MN<br>554024629 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Christopher | Anderson | canderson@allete.com | Minnesota Power | 30 W Superior St<br><br>Duluth,<br>MN<br>558022191 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Alison C | Archer | aarcher@misoenergy.org | MISO | 2985 Ames Crossing Rd<br><br>Eagan,<br>MN<br>55121 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| James J. | Bertrand | james.bertrand@stinson.com | STINSON LLP | 50 S 6th St Ste 2600<br><br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| James | Canaday | james.canaday@ag.state.mn.us | Office of the Attorney General-RUD | Suite 1400<br>445 Minnesota St.<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| John | Coffman | john@johncoffman.net | AARP | 871 Tuxedo Blvd.<br><br>St, Louis,<br>MO<br>63119-2044 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Generic Notice | Commerce Attorneys | commerce.attorneys@ag.state.mn.us | Office of the Attorney General-DOC | 445 Minnesota Street Suite 1800<br><br>St. Paul,<br>MN<br>55101 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Riley | Conlin | riley.conlin@stoel.com | Stoel Rives LLP | 33 S. 6th Street<br>Suite 4200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| George | Crocker | gwillc@nawo.org | North American Water Office | PO Box 174<br><br>Lake Elmo,<br>MN<br>55042 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| John | Farrell | jfarrell@ilsr.org | Institute for Local Self-Reliance | 1313 5th St SE #303<br><br>Minneapolis,<br>MN<br>55414 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Sharon | Ferguson | sharon.ferguson@state.mn.us | Department of Commerce | 85 7th Place E Ste 280<br><br>Saint Paul,<br>MN<br>551012198 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Edward | Garvey | edward.garvey@AESLconsulting.com | AESL Consulting | 32 Lawton St<br><br>Saint Paul,<br>MN<br>55102-2617 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Janet | Gonzalez | Janet.gonzalez@state.mn.us | Public Utilities Commission | Suite 350<br>121 7th Place East<br>St. Paul,<br>MN<br>55101 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Michael | Hoppe | il23@mtn.org | Local Union 23, I.B.E.W. | 932 Payne Avenue<br><br>St. Paul,<br>MN<br>55130 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Alan | Jenkins | aj@jenkinsatlaw.com | Jenkins at Law | 2265 Roswell Road<br>Suite 100<br>Marietta,<br>GA<br>30062 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Linda | Jensen | linda.s.jensen@ag.state.mn.us | Office of the Attorney General-DOC | 1800 BRM Tower 445 Minnesota Street<br><br>St. Paul,<br>MN<br>551012134 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Richard | Johnson | Rick.Johnson@lawmoss.com | Moss & Barnett | 150 S. 5th Street<br>Suite 1200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Sarah | Johnson Phillips | sarah.phillips@stoel.com | Stoel Rives LLP | 33 South Sixth Street<br>Suite 4200<br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Mark J. | Kaufman | mkaufman@ibewlocal949.org | IBEW Local Union 949 | 12908 Nicollet Avenue South<br><br>Burnsville,<br>MN<br>55337 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Thomas | Koehler | TGK@IBEW160.org | Local Union #160, IBEW | 2909 Anthony Ln<br><br>St Anthony Village, MN 55418-3238 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Michael | Krikava | mkrikava@briggs.com | Briggs And Morgan, P.A. | 2200 IDS Center<br>80 S 8th St<br>Minneapolis, MN 55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Peder | Larson | plarson@larkinhoffman.com | Larkin Hoffman Daly & Lindgren, Ltd. | 8300 Norman Center Drive<br>Suite 1000<br>Bloomington, MN 55437 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Douglas | Larson | dlarson@dakotaelectric.com | Dakota Electric Association | 4300 220th St W<br><br>Farmington, MN 55024 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Kavita | Maini | kmaini@wi.rr.com | KM Energy Consulting, LLC | 961 N Lost Woods Rd<br><br>Oconomowoc, WI 53066 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Pam | Marshall | pam@energycents.org | Energy CENTS Coalition | 823 7th St E<br><br>St. Paul, MN 55106 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Joseph | Meyer | joseph.meyer@ag.state.mn.us | Office of the Attorney General-RUD | Bremer Tower, Suite 1400<br>445 Minnesota Street<br>St Paul, MN 55101-2131 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Stacy | Miller | stacy.miller@minneapolismn.gov | City of Minneapolis | 350 S. 5th Street<br>Room M 301<br>Minneapolis, MN 55415 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| David | Moeller | dmoeller@allete.com | Minnesota Power | 30 W Superior St<br><br>Duluth, MN 558022093 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Andrew | Moratzka | andrew.moratzka@stoel.com | Stoel Rives LLP | 33 South Sixth St Ste 4200<br><br>Minneapolis, MN 55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| David | Niles | david.niles@avantenergy.com | Minnesota Municipal Power Agency | 220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Carol A. | Overland | overland@legalectric.org | Legalectric - Overland Law Office | 1110 West Avenue Red Wing, MN 55066 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Jeff | Oxley | jeff.oxley@state.mn.us | Office of Administrative Hearings | 600 North Robert Street St. Paul, MN 55101 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| 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 | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Kevin | Reuther | kreuther@mncenter.org | MN Center for Environmental Advocacy | 26 E Exchange St, Ste 206 St. Paul, MN 551011667 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Richard | Savelkoul | rsavelkoul@martinsquires.com | Martin & Squires, P.A. | 332 Minnesota Street Ste W2750 St. Paul, MN 55101 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Ken | Smith | ken.smith@districtenergy.com | District Energy St. Paul Inc. | 76 W Kellogg Blvd St. Paul, MN 55102 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Byron E. | Starns | byron.starns@stinson.com | STINSON LLP | 50 S 6th St Ste 2600 Minneapolis, MN 55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| James M | Strommen | jstrommen@kennedy-graven.com | Kennedy & Graven, Chartered | 200 S 6th St Ste 470 Minneapolis, MN 55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Eric | Swanson | eswanson@winthrop.com | Winthrop & Weinstine | 225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |

| First Name | Last Name | Email | Company Name | Address | Delivery Method | View Trade Secret | Service List Name |
|---|---|---|---|---|---|---|---|
| Lynnette | Sweet | Regulatory.records@xcelenergy.com | Xcel Energy | 414 Nicollet Mall FL 7<br><br>Minneapolis,<br>MN<br>554011993 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Thomas | Tynes | jjazynka@energyfreedomcoalition.com | Energy Freedom Coalition of America | 101 Constitution Ave NW Ste 525 East<br><br>Washington,<br>DC<br>20001 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Lisa | Veith | lisa.veith@ci.stpaul.mn.us | City of St. Paul | 400 City Hall and Courthouse<br>15 West Kellogg Blvd.<br>St. Paul,<br>MN<br>55102 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Joseph | Windler | jwindler@winthrop.com | Winthrop & Weinstine | 225 South Sixth Street, Suite 3500<br><br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Daniel P | Wolf | dan.wolf@state.mn.us | Public Utilities Commission | 121 7th Place East<br>Suite 350<br>St. Paul,<br>MN<br>551012147 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |
| Patrick | Zomer | Patrick.Zomer@lawmoss.com | Moss & Barnett a Professional Association | 150 S. 5th Street, #1200<br><br>Minneapolis,<br>MN<br>55402 | Electronic Service | No | GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric |