October 16, 2020

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

RE: **Comments of the Minnesota Commerce Department, Division of Energy Resources**
Docket No. E002/M-19-721

Dear Mr. Seuffert:

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

> Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2019 and 2020, and Revised Adjustment Factors.

The Petition was filed on November 15, 2019 by:

> Holly Hinman
> Regulatory Manager
> Xcel Energy
> 414 Nicollet Mall
> Minneapolis, MN 55401

The Department requests that Xcel Energy provide additional information in Reply Comments. The Department will provide a final set of recommendations to the Minnesota Public Utilities Commission after it has reviewed the information the Company provides.

Sincerely,

/s/ MARK JOHNSON
FINANCIAL ANALYST

/s/ TRICIA DEBLEECKERE
PLANNING DIRECTOR

MJ/TD/ar
Attachment

MN COMMERCE DEPARTMENT

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Commerce Department
Division of Energy Resources

Docket No. E002/M-19-721

I. BACKGROUND

On August 1, 2006, Northern States Power d/b/a Xcel Energy (Xcel or the Company) filed a petition in Docket No. E002/M-06-1103 requesting approval of a Transmission Cost Recovery (TCR) Rider. The TCR Rider was proposed to replace the existing Renewable Transmission Cost Recovery (RCR) Rider and reflect changes required by Minn. Stat. §216B.16, subd. 7(b), which was newly adopted during the 2005 legislative session.

On November 20, 2006, the Minnesota Public Utilities Commission (Commission) issued an *Order Approving Transmission Cost Recovery Rider* in Docket No. E002/M-06-1103. The Commission's Order approved Xcel's proposed tariff for the TCR Rider with the condition that Xcel must maintain separate tracker accounts for projects approved under the renewable cost recovery statute, and those approved under the transmission cost recovery statute.

The Commission has issued Orders regarding Xcel's TCR Rider in several dockets since its November 20, 2006 Order. Most recently, on September 27, 2019 the Commission issued its *Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements* in Docket No. E002/M-17-797 (2017-2018 TCR Rider).

On November 15, 2019, Xcel filed the instant petition requesting approval of its 2019-2020 revenue requirements, tracker balance, and updated TCR adjustment factors (2019-2020 TCR Rider or Petition).

On December 9, 2019, the Minnesota Department of Commerce, Division of Energy Resources (Department) sought a time extension request for comments and recommended provisional approval of Xcel's Petition since it resulted in a rate reduction for customers. In response, Xcel agreed with this approach and filed a letter indicating such.[1]

On February 21, 2020, the Commission issued an Order granting provisional approval of Xcel's 2019-2020 TCR Rider, with the understanding that a final decision on these matters would be made after receipt of interested parties' comments.

On February 26, 2020, Xcel filed its provisional tariff sheet in redline and final format for implementation on March 1, 2020.[2]

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[1] Xcel Energy Letter, December 20, 2019 in Docket No. E002/M-19-721.
[2] Xcel Provisional Tariff – Compliance Filing, February 26, 2020 in Docket No. E002/M-19-721.

II. SUMMARY OF FILING

Xcel requested approval of its 2019-2020 revenue requirements, tracker balance, and updated TCR adjustment factors for the Minnesota jurisdiction. A summary of Xcel's proposed projects and related revenue requirements for the period is included in Table 1 below:

Table 1. Proposed 2019-2020 MN Revenue Requirements ($)[3]

Project	2018 Actual	2019 Actual/ Forecasted	2020 Forecasted
ADMS	$1,171,589	$1,998,824	$5,154,785
Big Stone-Brookings	$4,302,758	$4,104,418	$4,005,316
CapX2020- Brookings	$33,786,412	$32,899,527	$32,294,421
CapX2020-LaCrosse Local	$4,385,486	$4,037,035	$4,190,729
CapX2020-LaCrosse MISO	$5,609,997	$5,398,997	$5,270,019
CapX2020-LaCrosse MISO-WI	$10,930,203	$10,370,757	$10,093,278
CapX2020-Fargo	$15,497,657	$14,825,199	$14,433,305
Huntley-Wilmarth HVTL		$205,462	$1,160,070
LaCrosse-Madison	$9,547,041	$16,179,062	$16,009,721
MISO RECB Sch. 26/26a	($174,749)	($8,372,475)	($3,202,305)
Transmission Projects	$85,056,394	$81,646,805	$89,409,339
Rev. Reqm't in Base Rates	$701,000	($1,937,000)	($1,937,000)
TCR True-Up Carryover	$5,561,635	$1,036,546	($5,588,798)
Revenue Requirements (RR)	$89,917,029	$80,746,350	$81,883,541
Revenue Collections (RC)	$88,880,483	$86,335,148	$82,985,421
Carry Over Balance	**$1,036,546**	**($5,588,798)**	**($1,101,880)**

As shown, Xcel has requested approval of 2019 and 2020 revenue requirements of $80.8 million and $81.9 million, respectively. Both totals represent a decrease relative to approved 2017 and 2018 annual revenue requirements which totaled $90.7 million and $89.9 million, respectively.[4] As stated above, the Commission approved this provisional decrease in rates until this matter could be evaluated and final rates would be set.

[3] See Petition, Attachment 4.
[4] Xcel's October 16, 2019 compliance filing in Docket No. E002/M-17-797, Attachment 4.

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

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

Table 2. Xcel's Prior and Provisionally Approved (Proposed) TCR Rate Adjustment Factors

	Prior 2017-2018		**Proposed 2019-2020**	
Customer Class	**Charge per kWh**	**Charge per kW**	**Charge per kWh**	**Charge per kW**
Residential	$0.003948	N/A	$0.003607	N/A
Commercial (Non-Demand)	$0.003486	N/A	$0.003185	N/A
Demand Billed	N/A	$1.074	N/A	$0.982
Total Revenue Requirements	$89,917,029		$81,883,541	

Xcel stated that the monthly bill of an average residential customer using 675 kWh of electricity per month would decrease by $0.23 per month under its proposed rates, from a bill impact of $2.67 (675 kWh*$0.003948) to $2.43 per month (675 kWh*$0.003607) for residential customers.

Xcel's proposed rate factors are calculated assuming an implementation date of February 1, 2020. Xcel proposed to recalculate its rates based on the authorized rates and actual implementation date to recover its full 2020 revenue requirement over the remaining months of 2020. The Commission authorized similar treatment in past TCR orders.

III. DEPARTMENT ANALYSIS

A. STATUTORY REQUIREMENTS

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

> Subd. 7b. Transmission cost adjustment. (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues of:

(1) **new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 [Certificate of Need Statute] or are certified as a priority project or deemed to be a priority transmission project under section 216B.2425 [State Transmission Plan Statute]**;

(2) new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator [MISO] to benefit the utility or integrated transmission system; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

> (1) a description of and context for the facilities included for recovery;
>
> (2) a schedule for implementation of applicable projects;
>
> (3) the utility's costs for these projects;
>
> (4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and
>
> (5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).
>
> (d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers. [emphasis added]

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

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

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

B. *PROJECT ELIGIBILITY*

The projects for which Xcel has requested cost recovery in its Petition were determined to be eligible by the Commission in prior TCR proceedings, except for the Huntley-Wilmarth Project. Moreover, as of the time of filing these comments, all projects included in the Petition are in-service with the exception of the Huntley-Wilmarth Project (which has an anticipated in-service date of 2021).[5] The Department notes that there has been no change in the eligibility status of any of the existing transmission projects and concludes that they remain eligible for cost recovery under the TCR Statute.

The Huntley-Wilmarth Project is a 50-mile 345-kilovolt (kV) transmission line that will run between Xcel Energy's Wilmarth Substation north of Mankato, Minnesota and ITCM's Huntley Substation south of Winnebago, Minnesota. Xcel and ITCM will own the transmission line as tenants in common, with a 50-50 ownership split. 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 MISO's annual Transmission Expansion Plan (MTEP16).

On August 5, 2019, the Commission issued an Order granting a Certificate of Need for the Huntley-Wilmarth 345-kV High Voltage Transmission Line Project at an expected cost of $140.1 million (in 2016 dollars) and escalated to $155.8 million for the years in which costs are expected to be incurred (mainly 2020 and 2021).[6] As a result, the Department concludes that the Huntley-Wilmarth Project is eligible for cost recovery under the TCR Statute.

C. *REASONABLENESS OF PROJECT REVENUE REQUIREMENTS AND COST RECOVERY CAPS*

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

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

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[5] See Petition, Attachment 2.

[6] See Commission's August 5, 2019 Order in Docket No. E002/CN-17-184; Ordering Point No. 2 adopted the Administrative Law Judge's (ALJ) Report, including finding no. 165 on page 36 of the ALJ Report, which shows estimated project costs of $140.1 million (in 2016 dollars) escalated to $155.8 million for the years in which costs are expected to be incurred (mostly 2020 and 2021).

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

> Accordingly, the Commission continues to believe that project costs included in the TCR rider should be capped at certificate of need levels, and concurs with the Department that the appropriate cap for the Bemidji project is $74 million. **The TCR rider mechanism gives Otter Tail the extraordinary ability to charge its ratepayers for facilities prior to the ordinary timing (the first rate case after the project goes into service) and without undergoing the full scrutiny of a rate case. Holding the Company to its initial estimate is an important tool to enforce fiscal discipline.**
>
> Further, imposition of a cap protects the integrity of the certificate of need process, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. And, capping costs at the certificate of need levels is consistent with the Commission's actions in similar cases involving other utilities' riders.
>
> The Company is recovering the cost of these transmission facilities through a rider, a unique regulatory tool essentially designed to enable utilities to begin recovering the prudent and reasonable costs of critically needed capital investments between rate cases. The rate case remains the primary vehicle for determining prudence and reasonableness.
>
> In the absence of a rate case, the best available proxy for determining prudence and reasonableness is the cost determination made on the record of a certificate of need or cost recovery eligibility proceeding. Here, the relevant proceeding is a certificate of need case. Otter Tail should continue recovering the costs it sponsored in its certificate of need case unless and until it demonstrates in a rate case that higher costs are prudent and reasonable. [emphasis added] [footnotes omitted]

1. Transmission Projects

Table 3 below summarizes the Company's initial transmission project cost estimates, escalated cost estimates, current investments, and estimated investments through 2022.

Table 3
Transmission Project Costs and Cost Caps (in millions)[7]

Project	Initial Cost Estimate		Initial Cost Estimate Escalated		Project Investment Through 2020		Estimated Project Investment Through 2022	
	(a)		(b)		(c)		(d)	
In-State Projects								
CAPX2020 Brookings	523.9	[1]	625.6	[2]	484.1	[3]	484.1	[4]
CAPX2020 La Crosse Local					79.4	[3]	79.4	[4]
CAPX2020 La Crosse MISO					81.2	[3]	81.2	[4]
CAPX2020 La Crosse MISO - WI					147.5	[3]	147.5	[4]
CAPX2020 La Crosse	276.5	[1]	330.3	[2]	308.1	[3]	308.1	[4]
CAPX2020 Fargo	231.0	[1]	275.9	[2]	224.5	[3]	224.5	[4]
Huntely Wilmarth HVTL	70.1	[5]	77.9	[6]	37.9	[3]	74.4	[4]
Out of State Projects								
Big Stone - Brookings	92.2	[1]			63.9	[3]	63.9	[4]
La Crosse - Madison	179.1	[1]			174.4	[3]	174.4	[4]

Sources:
[1] Department's April 2, 2018 Comments in the 2017-2018 TCR Rider
[2] Department's April 2, 2018 Comments in the 2017-2018 TCR Rider; escalateed through 2015
[3], Petition, Attachment 3B, sum of costs through 2020
[4]: Petition, Attachment 3B
[5]: $140.1/2 = $70.1 million.
[6]: $155.8 million/2 = $77.9 million.

The Department reviewed Xcel's actual and forecasted capital expenditures for each transmission project included in the 2019-2020 TCR Rider. As shown in the above table, all transmission projects are below their initial estimates or escalated initial estimates. As a result, the Department recommends that the Commission approve recovery of the proposed transmission capital costs in this proceeding.

[7] Includes internal labor. Actual costs included in TCR revenue requirement calculations exclude internal labor costs as shown in Attachment 3A and Attachment 13 of the Petition.

2. Advanced Distribution – Management System (ADMS)

On June 28, 2016, the Commission issued its Order certifying Xcel's Advanced Distribution–Management System (ADMS) under Minn. Stat. § 216B.2425 in Docket No. E002/M-15-962 (ADMS Order). Specifically, the Commission stated the following in Ordering Point No 1:[8]

> The Commission hereby certifies the ADMS project. Certification of this project does not imply any decision regarding recovery of the project's costs. Any rider recovery of costs associated with a certified project will be determined in response to a utility petition for rider recovery of those costs under Minn. Stat. § 216B.16, subd. 7b.

At that time, and as explained in the Commission's ADMS Order, Xcel estimated that total ADMS capital costs would be approximately $9 million per year for 2016, 2017, and 2018 ($27 million total) for the Minnesota jurisdiction, with an expected completion date of 2018.[9]

In Xcel's 2017-2018 TCR Rider, Docket No. E002/M-17-797, the Company significantly increased its total estimated capital costs for the ADMS Project, by over 155 percent, to $69.1 million for the Minnesota jurisdiction through 2025.[10] The $69.1 million figure consisted of $29.4 million in labor costs, $3.2 million in software licensing costs, $31.0 million for data collection on the Company's existing distribution system, and $5.6 million in hardware.[11] However, Xcel clarified in reply comments that it did not intend to request recovery of hardware costs and removed them from the amounts proposed to be recovered.[12] In its September 27, 2019 *Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements* in Docket No. E002/M-17-797 (2017-2018 TCR Rider Order), the Commission approved recovery of Xcel's ADMS revenue requirements based on approximately $10.2 million in actual capital costs incurred through 2018 for the Minnesota jurisdiction.[13] The Department notes that the $10.2 million in ADMS capital costs was in addition to the approximately $6.1 million in ADMS capital costs included in base rates through 2018.[14]

In the instant Petition, Xcel stated that its estimated total ADMS capital costs for the Minnesota jurisdiction remains at $69. 1 million.[15] In addition, Xcel stated that it is requesting approval of 2019-2020 revenue requirements based on approximately $27.2 million in total ADMS capital costs for the

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[8] Commission's June 28, 2016 *ORDER CERTIFYING ADVANCED DISTRIBUTION-MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. § 216B.2425 AND REQUIRING DISTRIBUTION STUDY* in Docket No. E002/M-15-962, Ordering Point No. 1.
[9] *Ibid.*, page 5.
[10] Xcel's November 8, 2017 initial filing in Docket No. E002/M-17-797, Attachment 1A, pages 1 and 19.
[11] *Ibid.*, page 19.
[12] Xcel's May 14, 2018 reply comments in Docket No. E002/M-17-797, page 2.
[13] Commission's September 27, 2019 *ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS* in Docket No. E002/M-17-797, Ordering Point No. 1.
[14] See Xcel's October 16, 2019 compliance filing in Docket No. E002/M-17-797, page 2.
[15] Petition at 20.

Minnesota jurisdiction through 2020. [16] The Department notes that the $27.2 million in ADMS capital costs is in addition to the approximately $6.6 million in ADMS capital costs included in base rates through 2020.[17] As result, the Department notes that Xcel is seeking to recover a combined total of $33.4 million ($27.2 + $6.6) in ADMS capital costs from Minnesota ratepayers.

The Department notes the importance of the principles that the Commission established in rider orders, that recovery is capped at the cost estimate used in the Certificate of Need or analogous proceeding. The Commission's regulatory tools to hold utilities financially accountable are focused largely in mechanisms to ensure that utilities have adequate incentives to minimize costs. For example, as noted by the National Regulatory Research Institute (NRRI), because utilities must pay for cost increases between rate cases, a rate case "provides strong motivation for the utility to control those costs between rate cases."[18]

Holding utilities accountable for minimizing costs is particularly important when there are new types of facilities being built and competitive bidding does not provide a check on the costs that a utility proposes to charge to ratepayers. Since regulators are responsible for protecting ratepayers from paying unreasonable costs, the Commission's approach of holding a utility accountable to the costs originally proposed and certified for a facility is critical to protect the public interest.

D. TCR RIDER COMPLIANCE REGARDING ADMS

The Commission's 17-797 Order was extensive and required significant additional information from the Company in future cost recovery filings. Specifically, Ordering Points 6 and 9 stated:

1. Xcel must include in any future cost recovery filing for ADMS investments an ADMS business case and a comprehensive assessment of qualitative and quantitative benefits to customers.
2. If and when Xcel requests cost recovery for Advanced Grid Intelligence and Security investments, the filing must include a business case and comprehensive assessment of qualitative and quantitate benefits to customers, considering, at a minimum, the following:

    A. Scope of Investment

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[16] Petition at 9.
[17] Id
[18] NRRI: "The Two Sides of Cost Trackers: Why Regulators Must Consider Both" (https://mn.gov/puc/assets/nrri_two_sides_cost_trackers_2007_tcm14-12043.pdf)

1. Investment Description
   a. Detailed description of proposed investment and project life; and
   b. If multiple components, overview of costs and descriptions of each:
      i. Include purpose and role;
      ii. Explain known and potential future use cases for each component;
      iii. Explain known and potential value streams and how each component fits with state policy, statues, rules and Commission orders; and
      iv. Describe beneficiaries of each investment (who, how many, over what time period).
   c. Articulation of principles, objectives, capability, functionalities, and technologies enabled by investment; and
   d. Interrelation and interdependencies with other existing or future investments, including overlapping costs: scope, amount, timing.
2. Alternatives considered:
   a. If a Request for Proposal was used provide:
      i. The RFP issued, including list of all services or assets scoped in the RFP;
      ii. Provide summary of responses;
      iii. Provide assessment of bids and factors used for selection; And
      iv. The scope of offerings or services included in the selected bid.
   b. If not, what was used.
3. Costs
   a. Provide sufficient information to determine what is included in the investment in each of the following categories:
      i. Direct Costs (product, service, customer, project, or activity);
      ii. Indirect Costs;
      iii. Tangible Costs;
      iv. Intangible Costs; and
      v. Real Costs.

b. If needed, provide the utility's definition of each category and whether internal or external labor costs are included in the category and the instant petition. If the costs are not included in the petition, include information on where and when those costs will be sought to be recovered.
c. If there is overlap or costs included in both categories, outline the overlapping costs and explain.
d. For each of the cost categories outline whether the investment has been partially approved or included in previous or on-going docket riders, rate cases, or other cost recovery mechanisms or note all costs are included in the instant petition.

4. Detailed Analysis of the type of proposed (or multiple) cost effectiveness analysis utilized:
   a. Least-cost, best-fit (Xcel proposes in IDP Reply comments);
   b. Utility Cost-test; and
   c. Integrated Power System and Societal Cost test.

B. Provide a cost benefit analysis for: 1) each investment component with overlapping costs or benefits in isolation and 2) each bundled components, as appropriate:
   1. Provide Discount Rate Used and Basis; and
   2. Identify cost categories and benefit categories used (explain metrics), including an explanation of how benefits can be monitored over time and proposal for reporting to Commission:
      a. Identify quantitative costs and qualitative costs:
         i. Use quantitative methods to address qualitative benefits to the extent possible;
         ii. Explain system used to assess value and priorities to qualitative benefits (points and/or weighting); and
         iii. Identify sensitivity ranges on estimates or value.
      b. Include a long-term bill impact analysis;
      c. Include a reference case/scenario without the project (or group of projects); and
      d. Apply the following principles to ensure the investment analysis has:
         i. compared with traditional resources or technologies;

ii. clearly accounted for state regulatory and policy goals;
iii. accounted for all relevant costs and benefits, including those difficult to quantify;
iv. provided symmetry across relevant costs and benefits;
v. applied a full life-cycle analysis;
vi. provided a sufficient incremental and forward-looking view;
vii. is transparent;
viii. avoided combining or conflating different costs and benefits;
ix. discuss customer equity issues, as needed;
x. assessed bundles and portfolio where reasonable; and
xi. addressed locational and temporal values.

Xcel addressed Ordering Point 6 on page 9 and Attachment 1A of its Petition. The Department reviewed the information contained therein and concludes that Xcel complied with Ordering Point 6 of the Commission's 17-797 Order.

The Department notes that Xcel did not appear to specifically address Ordering Point 9 in its Petition. Given the separate Ordering Points addressing ADMS and future AGIS investments, Xcel appears to have assumed that Ordering Point 9 was not applicable to its Petition. The Department notes that, while Xcel's assumption may be reasonable given the separate Ordering Points, and since ADMS costs are already included in the TCR Rider, it also appears that Ordering Point 9 sets forth the detailed information required to be included in Xcel's business case and comprehensive qualitative and quantitative assessment of benefits to customers required in Ordering Point 6. The Department flags this issue for potential clarification by the Commission to ensure that future TCR Rider petitions are complete and provide the information required by the Commission.

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

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

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

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

Similar to previous TCR filings, Xcel proposed to recover the net charges it pays other electric utilities through MISO Schedules 26/26A in its TCR Rider. Under Xcel's proposal, it would recover the estimated amount of payments it makes under MISO Schedules 26/26A net of the estimated amount of revenues it receives from other utilities under MISO Schedules 26/26A. Specifically, Xcel proposed to include its estimated 2019 and 2020 MISO Schedule 26/26A net revenues of $8,372,475 and $3,202,305, respectively, in its TCR Rider. According to Xcel, this also includes MVP Auction Revenue Rights (MVP ARR).[19] Xcel's MISO Schedule 26/26A calculations are provided in Attachment 12 of the Petition.

The Department notes that Xcel reports all of its MISO Schedule 26/26A revenues and expenses in its TCR Rider filings. Xcel does not include any of these revenues or expenses in base rates, regardless of whether a specific transmission project is included in the TCR Rider or base rates.

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[19] Petition at 13.

Regarding MVP ARRs, the Department recommends that Xcel provide in reply comments a break-out of the amount of MVP ARRs embedded in its estimated 2019 and 2020 MISO Schedule 26/26A net revenues of $8,372,475 and $3,202,305, respectively. In addition, the Department recommends that the Commission require Xcel to separately identify these amounts in future TCR Rider filings.

Unlike Minnesota Power's recent TCR Rider filing[20] and Otter Tail Power's recent TCR Rider filing,[21] the Department was unable to locate the revenues Xcel receives under MISO Schedules 37 and 38 in its Petition. The Department recommends that Xcel explain in reply comments if its MISO Schedule 37 and 38 revenues are included in its 2019-2020 annual revenue requirement calculations and, if so, to clearly identify the amounts. If MISO Schedule 37 and 38 revenues are not included in its 2019-2020 annual revenue requirement calculations, the Department recommends that the Commission require Xcel to identify and include its MISO Schedule 37 and 38 revenues in its 2019-2020 annual revenue requirement calculations.

The Department will provide its overall recommendation regarding Xcel's proposed net RECB charges included for recovery after it has reviewed the Company's reply comments.

F. OTHER WHOLESALE TRANSMISSION REVENUES (NON-RECB)

The Department notes that the bulk of Minnesota regulated electric utilities' transmission assets over 100 kilovolts are considered to be non-RECB projects for MISO purposes and are included in the utilities' base rates rather than a transmission rider. Similar to RECB charges that are reflected in MISO Schedules 26/26A, these non-RECB charges (wholesale transmission revenues and expenses) are reflected in MISO Schedule 9 revenues for the party that owns the transmission assets and in MISO Schedule 9 expenses for any party that uses the transmission assets (including the owner of the assets). As such, any wholesale transmission revenues and expenses (MISO Schedule 9 revenues and expenses) associated with these facilities are generally reflected in base rates. These MISO Schedule 9 charges are determined under each utility's open-access transmission tariff (OATT) approved by the Federal Energy Regulatory Commission (FERC).

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

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[20] Minnesota Power's July 9, 2019 initial filing in Docket No. E015/M-19-440, Attachment B-5.
[21] Otter Tail Power Company's November 30, 2018 initial filing in Docket No. E017/M-18-748, Attachment 9A.

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

As shown in Attachment 11 of the Petition, Xcel calculated its net OATT credits in percentage terms for years 2018, 2019, and 2020. Xcel used these net OATT credit percentages to determine the dollar amount of the OATT credit reflected in the annual revenue requirement calculations shown in Attachment 13 of the Petition. The Department agrees with this approach and concludes that Xcel's net OATT credit calculations appear reasonable and consistent with previous TCR filings.

G. FERC ISSUES

1. FERC Return on Equity Interest Adjustment

In the 2017-2018 TCR Rider Order, the Commission required Xcel to include the net amount of interest payments paid and received related to the federal mandated return on equity (ROE) reduction from 12.38% to 10.82% for MISO transmission owners in their 2018 compliance filing. Regarding this issue, Xcel stated the following in the instant Petition:[22]

> 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.

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

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[22] See Petition, Attachment 12.

2. FERC Transmission Audit Refund

Since the filing of the Petition, on March 27, 2020, Xcel filed a letter with FERC in response to an audit of Xcel-NSPM's FERC Form 1 and Transmission Formula Rate (FERC Transmission Audit). In the letter, Xcel included its Refund Report summarizing refunds being made to wholesale customers as a result of three of the six audit findings. The audit findings of FERC's audit were as follows:

> Audit staff found six areas of noncompliance:
>
> 1. *Income Tax Receivables* – NSPM incorrectly recorded an income tax receivable that represented a refund for a tax overpayment in Account 165, Prepayments, instead of in Account 143, Other Accounts Receivable. The incorrect accounting led to an overstatement of NSPM's rate base used in its wholesale transmission formula rate calculations and overbillings to wholesale transmission customers.
>
> 2. *Accounting for Prepayments* – NSPM misclassified certain costs in Account 165, Prepayments, resulting in an overstatement of the account. The misclassifications in Account 165 resulted in an overstatement of NSPM's rate base used in the wholesale transmission formula rate calculations and overbillings to wholesale transmission customers.
>
> 3. *Accounting for Miscellaneous Expenses* – NSPM's accounting classifications for some expenses were not consistent with the requirements of the Uniform System of Accounts. In addition, there were instances when the accounting misclassifications led to improper amounts being included in the wholesale transmission formula rate and NSPM overbilling its wholesale transmission customers.
>
> 4. *Accounting Classification for Contingent Liabilities* – NSPM did not use the proper accounts to classify certain contingent liabilities in accordance with the requirements of the Uniform System of Accounts.
>
> 5. *Depreciation Rates* – During the audit period, NSPM used depreciation rates that were not previously filed with the Commission in the development of its wholesale transmission formula rate.
>
> 6. *Accounting for Retirement Units* – NSPM inconsistently implemented a change to accounting for the retirement of transmission insulators to a retirement unit from a minor item of property, resulting in the gross balances of plant in service and the accumulated provision for depreciation

> being inappropriately stated in its financial reports, which adversely impacted the amounts used for billings to wholesale transmission customers.

Xcel noted it would refund $3.9 million (inclusive of $.82 million in interest) throughout the 2021 rate year. Xcel also noted that it would apply interest to the refund amount through 2020 pursuant to the procedures set forth in Attachment O-NSP of its OATT.[23]

The Department recommends that Xcel clearly identify the amount and location of the Transmission Audit Refund in its next TCR filing to ensure that it is being passed back to Minnesota ratepayers.

H. COMPLIANCE FILING, TRUE-UP REPORT, AND TRACKER BALANCES

Xcel discussed its TCR Compliance Filing, True-up Report, and Tracker Balances on page 21 of its Petition. Xcel's tracker balance calculations are shown in Attachments 4-8 of its Petition. As shown therein, Xcel proposed to increase its 2019 TCR revenue requirements by $1,036,546 for prior under-recoveries. In addition, Xcel proposed to decrease its 2020 TCR revenue requirements by $5,588,798 for estimated over-recoveries.

The Department reviewed Xcel's true-up and tracker balance calculations. The Department notes that Xcel's calculations appear reasonable and consistent with past TCR Rider filings.

I. RATE OF RETURN ON INVESTMENT

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

In its 2017-2018 TCR Rider Order, the Commission required Xcel to use a 9.06 return on equity (ROE) for all proceedings until a new ROE has been established in Xcel's next rate case.

In the instant Petition, Xcel used the 9.06 ROE to calculate its annual revenue requirements. The Department concludes that Xcel's ROE is consistent with the Commission's 2017-2018 TCR Rider Order.

[23] See FERC Docket FA17-5-000, Letter Dated March 24, 2020, based on FERC's Audit Report dated July 31, 2019. Further information about FERC Staff's audit are in Attachment A to these comments.

J. ADMS DEPRECIATION LIFE

In Attachment 1A, page 18 of 19 of its Petition, Xcel calculated its ADMS project depreciation expense based on a 10-year life, which was approved by the Commission in Xcel's depreciation filing in Docket No. E002/D-17-581.

The Department notes that Xcel proposed a number of changes to several components associated with its AGIS initiative in its current depreciation filing in Docket No. E002/D-20-635.[24] As a result, the Department recommends that Xcel explain in reply comments if the Company's proposed depreciation changes impact its initial 10-year depreciation life for the ADMS project in this proceeding. If so, the Department recommends that Xcel provide the depreciation changes and incorporate them in to its proposed 2019-2020 annual revenue requirement calculations in reply comments.

K. INTERNAL CAPITLIZED LABOR

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

L. PRORATED ACCUMULATED DEFERRED INCOME TAXES

Xcel stated the following on page 17 of its Petition regarding prorated 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.

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[24] See Xcel's July 31, 2020 initial filing in Docket No. E002/D-20-635, pages 8-11.

> 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.

Overall the Department agrees with Xcel's approach for calculating prorated accumulated deferred income taxes. However, the Department recommends that Xcel update its prorated accumulated deferred income taxes for 2020 in reply comments to reflect that 2020 is nearly complete.

M. ALLOCATION OF COSTS

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

To allocate total system costs between NSPM and NSPW, the Company uses a demand allocator which reflects the sharing of costs between NSPM and NSPW pursuant to its Interchange Agreement. Xcel stated that it used its budgeted Interchange Agreement allocators for 2019 and 2020. Xcel stated that that any future over- or under-recovery due to the use of its budgeted allocators will be reflected in their next TCR Rider filing that will use actual allocators as they are available.

The Interchange Agreement demand allocator, reported on Attachment 10, line 24 of the Petition, is based on 36-month coincident peak demand. NSPM proposed to use allocation factors of 83.8864 percent, and 83.9342 percent, in 2019 and 2020, respectively. The Company's proposed cost allocation between NSPM and NSPW is consistent with the methodology used in previous TCR filings, and the Department concludes that it is reasonable.

To allocate NSPM's share of total system costs between NSPM's three state jurisdictions, the Company proposed to use demand allocators based on 12-month coincident peak demand, as shown in the Petition, Attachment 10, line 23. The allocator proposed, 87.3461 percent, is consistent with the jurisdictional allocator the Company proposed in its most recent rate case, Docket No. E002/GR-15-826 (the 2016 Rate Case), and is consistent with the allocator the Department used in its Direct Testimony in the 2016 Rate Case, which served as the basis for the settlement of that case. The Department concludes that the Company's proposed jurisdictional allocator is reasonable.

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

1. Recovery from Minnesota Customer Classes and Applicable Recovery Rates

NSPM's Minnesota jurisdictional customer classes include Residential, Commercial Non-Demand, and Demand. The Company proposed to recover costs allocated to its Residential and Non-Demand customers on an energy-only basis (i.e. via a per kWh charge), and to recover costs allocated to its Demand customer class on a demand-only basis (i.e. via a per kW charge). This recovery method is consistent with the method used in prior TCR Rider filings; thus, the Department concludes that it is reasonable.

IV. SUMMARY OF RECOMMENDATIONS

In summary, the Department will make its overall final recommendations after reviewing the Company's reply comments but at this time:

- concludes that the Huntley-Wilmarth Project is eligible for cost recovery under the TCR Statute in this proceeding.
- recommends that the Commission approve recovery of the proposed transmission capital costs in this proceeding.
- requests that the Commission confirm the Department's understanding that Xcel's ADMS project costs that can be recovered through the TCR Rider are capped at $69.1 million.
- concludes that Xcel complied with Ordering Point 6 of the Commission's 17-797 Order.
- recommends that Xcel provide in reply comments a break-out of the amount of MVP ARRs embedded in its estimated 2019 and 2020 MISO Schedule 26/26A net revenues of $8,372,475 and $3,202,305, respectively. In addition, the Department recommends that the Commission require Xcel to separately identify these amounts in future TCR Rider filings.

- recommends that Xcel explain in reply comments if its MISO Schedule 37 and 38 revenues are included in its 2019-2020 annual revenue requirement calculations and, if so, to clearly identify the amounts. If MISO Schedule 37 and 38 revenues are not included in its 2019-2020 annual revenue requirement calculations, the Department recommends that the Commission require Xcel to identify and include MISO Schedule 37 and 38 revenues in its 2019-2020 annual revenue requirement calculations.

- recommends that Xcel clearly identify the FERC Transmission Audit refund amount and its location in in its next TCR Rider filing to ensure it is being passed back to Minnesota ratepayers.

- recommends that Xcel explain in reply comments if the Company's proposed depreciation changes in Docket No. E002/D-20-635 impact its initial 10-year depreciation life for the ADMS project in this proceeding. If so, the Department recommends Xcel provide the depreciation changes and incorporate them in to its proposed 2019-2020 annual revenue requirement calculations in reply comments.

- Recommends that Xcel update its prorated accumulated deferred income tax balances for 2020 to reflect that 2020 is nearly complete.

/ar

Attachment A: FERC Staff's Audit in FERC Docket FA17-5

D. Summary of Recommendations and Corrective Actions Taken

Audit staff's recommendations and corrective actions that NSPM needs to take to remedy this report's findings are summarized below. Section IV contains more detailed discussion of the recommendations and corrective actions.

Income Tax Receivables

1. Recalculate the annual transmission revenue requirement and billing to wholesale customers by eliminating the amount of income tax overpayments from rate base for year 2013.

2. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) the calculation of refunds that results from eliminating income tax overpayments from its 2013 transmission rate base, including interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) in which refunds will be made.

3. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

4. Refund the amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of the Commission's regulations.

Accounting for Prepayments

5. Revise procedures to ensure that NSPM records capital contributions and expenditures for joint venture projects in Account 134, Other Special Deposits.

6. Revise procedures to ensure that NSPM records receivables for refunds of insurance premiums in Account 143, Other Accounts Receivable.

7. Record correcting journal entries to reclassify capital contributions and expenditures for joint venture projects and insurance premium refund receivables to the proper accounts as of December 31 of years 2013, 2014, 2015, 2016 and 2017.

8. Record journal entries to properly correct the overstatement of prepayment balances as of December 31 of years 2013, 2014, 2015 and 2016, caused by the accounting error relating to a payment to an external vendor.

9. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) the calculation of refunds that resulted from correcting the overstatement of prepayment balances, including interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) in which refunds will be made.

10. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

11. Refund the amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of the Commission's regulations.

Accounting for Miscellaneous Expenses

12. Record necessary journal entries to reclassify compromise settlements and related expenditures to non-operating expense accounts for years 2013, 2014 and 2016.

13. With regard to compromise settlements, submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) the calculation of refunds that resulted from correcting its improper classification of compromise settlements, including interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) in which refunds will be made.

14. With regard to compromise settlements, file a refund report with the Commission after receiving DAA's assessment of the refund analysis.

15. With regard to compromise settlements, refund the amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of the Commission's regulations.

16. Update accounting policies and procedures to ensure that NSPM classifies the changes in the fair value of non-hedge derivative instruments consistent with the Commission's regulations.

17. Update accounting policies and procedures to ensure that NSPM classifies costs relating to the operation of the shared facilities consistent with the Commission's regulations.

Accounting Classification for Contingent Liabilities

18. Refrain from recording liabilities in Account 228.2 until NSPM receives approval from a regulatory authority or authorities.

19. Record correcting journal entries to reclassify balances in Account 228.2 to Account 242, Miscellaneous Current and Accrued Liabilities (if a current liability), or Account 253, Other Deferred Credits (if noncurrent liability).

Depreciation Rates

20. Implement processes and procedures to ensure that depreciation rates and related studies are filed in the dockets relating to NSPM's Transmission Formula Rate when depreciation rates are changed.
21. File current depreciation studies in dockets relating to NSPM's Transmission Formula Rates within 60 days.

Accounting for Retirement Units

22. Rewrite and implement a capitalization policy for transmission insulators that clearly and uniformly indicates processes and procedures that are consistent for either a minor item of property or a retirement unit, but not both, as per 18 C.F.R. Part 101, Electric Plant Instruction No. 10.

23. Train appropriate staff in the proper implementation of the new capitalization policy.

24. Disclose any material change in plant in service, depreciation reserve, and depreciation expense totals, as well as any other impacted accounts in the next FERC Form No. 1 filing.

E. Compliance and Implementation of Recommendations

Audit staff further recommends that NSPM submit for audit staff review:

• A plan for implementing audit staff's recommendations. NSPM should provide this plan to DAA within 30 days after the final audit report is issued.

• Quarterly reports to DAA describing NSPM's progress in completing each corrective action recommended in the final audit report. NSPM should make these nonpublic quarterly filings no later than 30 days after the end of each calendar quarter, beginning with the first quarter after submission of the implementation plan, and continuing until NSPM completes all recommended corrective actions.

• Copies of any written policies and procedures developed in response to the recommendations in the final audit report. These documents should be submitted for audit staff's review in the first quarterly filing made by or on behalf of NSPM after NSPM completes the written policy or procedure.

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Comments

Docket No. E002/M-19-721

Dated this **16th** day of **October 2020**

/s/Sharon Ferguson

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