MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	October 1, 2020	Agenda Item **2
Company	Minnesota Power	
Docket No.	**E-015/M-19-523**	
	In the Matter of Minnesota Power's Renewable Resources Rider and 2020 Renewable Factor	
Issues	Should the Commission approve Minnesota Power's 2020 Renewable Resources Rider factors with modifications?	

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✓ **Relevant Documents**	**Date**
Minnesota Power – Petition	August 15, 2019
Department of Commerce – Comments	December 23, 2019
Minnesota Power – Reply Comments (TS)	February 14, 2020
PUC – Notice of Supplementary Comment Period	June 12, 2020
Minnesota Power – Supplementary Comments	July 9, 2020
Department of Commerce – Supplementary Comments (TS)	July 9, 2020
Minnesota Power – Reply to Supplementary Comments	July 21, 2020

The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

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I. Statement of the Issues

Should the Commission approve Minnesota Power's 2020 Renewable Resources Rider factors with modifications?

II. Background

A. Minnesota Power's Renewable Resources Rider

On May 11, 2007, the Commission established Minnesota Power's (MP) Renewable Resources Rider (RRR) through an order to allow recovery of investments and expenditures related to transmission upgrades for the Oliver Wind II power purchase agreement with FPS Energy under Minn. Stat. § 216B.1645.

Beginning in 2010, MP also utilized its RRR to recover costs related to the Bison Wind Energy Center. MP started cost recovery for Bison 1 in 2010 and subsequently began recovering costs for the remaining Bison facilities in 2013 and 2015. Additionally, MP used the RRR to recover costs for Thomson Dam – Hydro restoration Projects beginning in 2016.

On November 2, 2016, concurrent with the filing of its 2016 general rate case (Docket No. E-015/GR-16-664), MP filed its 2017 RRR Factor Filing.[1] The Commission granted provisional approval of the 2017 renewable factor on December 21, 2016, with implementation effective January 1, 2017. On November 8, 2017, the Commission approved the 2017 Factor Filing.

In its November 8, 2017 Order in Docket No. E-015/M-16-776, the Commission "Required MP to make a compliance filing at the conclusion of its 2016 rate case describing the final resolution of the true-up for RRR projects moved into base rates and the cash collections thereon."

On June 5, 2018, MP filed its 2018 RRR Factor Petition in Docket No. E-015/M-18-375. MP requested Commission approval to recover updated tracker balance, updated investments and expenditures related to the two remaining projects associated with the Thomson Project that were not rolled into base rates in the 2016 rate case, and a true-up of actual production tax credits. MP also included reimbursements of sums related to the Bison 6 LGIA.

In an Order[2] dated July 30, 2018, the Commission "[g]ranted provisional approval of the Renewable Resource Rider billing factors as outlined in the Department's June 29, 2018 letter effective on the first day of the month following a Commission Order on this issue, or as soon as practical thereafter." In an Order dated November 19, 2018, docket 18-375, the Commission allowed Minnesota Power to implement its 2018 Renewable Resources Rider factors concurrent with the anticipated implementation date of final rates in docket 16-664, and required MP to file the updated rate factors in a compliance filing before implementation.

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[1] Docket No. E-015/M-16-776.

[2] Docket No. E-015/M-18-375.

B. MP's Petition in this Docket

On August 15, 2019, Minnesota Power filed the instant petition, seeking Commission approval[3] of its 2020 Renewable Resource factors.

On December 23, 2019, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed Comments requesting that MP provide additional information in reply comments.

On February 14, 2020, MP submitted Reply Comments responding to the Department's request for additional information, providing updated exhibits and calculations, and requesting approval of modified 2020 RRR factors.

On June 12, 2020, the Minnesota Public Utilities Commission (PUC) published a Notice of Supplemental Comment Period in response to Minnesota Power's resolution of its rate case (Docket Nos. E-015/GR-19-442 and E-015/M-20-429) seeking comments on the resolutions impact on the instant docket.

On July 9, 2020, Minnesota Power filed Reply Comments to the PUC's Notice of Supplementary Comments, proposing to modify the revenue requirements to include the two Thompson projects that were to be rolled into base rates in MP's resolved 2019 rate case; to continue customer credits for the Bison 6 LGIA transfer; and to revert to truing up PTCs to the 2017 test year (rather than the "resolved" 2020 test year).

On July 9, 2020, the Department submitted Response Comments stating that the Department recommends approval with modifications.

On July 21, 2020, Minnesota Power filed Supplemental Reply Comments, stating that the Company should be allowed to update the 2020 RRR revenue requirements to include costs that were to be rolled into base rates, to include a true-up of PTC amounts, and to continue to credit customers for the corrected Bison 6 LGIA.

III. Minn. Stat. §216B.1645. Power Purchase Contract or Investment

The Purchase Power Contract or Investment statute, Minn. Stat. §216B.1645, is the relevant statute for MP's renewable resource rider.

Subdivision 1 of Minn. Stat. §216B.1645 pertains to Commission authority. According to the statute, "upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in various other sections of Minn. Stat., Ch. 216B.

[3] Pursuant to Minn. Stat. §216B.1645, subd. 2a.

Subdivision 2a pertains to cost recovery. According to subd. 2a, "a utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy certain requirements of various sections of the statute."

A complete copy of Minn. Stat. §216B.1645 can be found in Attachment 2.

IV.Parties' Comments

A. Minnesota Power - Petition

1. Projects Included in Renewable Resources Rider

Minnesota Power is proposing to provide a credit to ratepayers due to the Company's sale of renewable energy credits to Oconto Electric Cooperative as a result of a power sales agreement, effective in January 2019.

In addition, MP proposes to recover (true-up) its updated 2018 and 2019 tracker balances reflecting investments and expenditures resulting from the two remaining projects associated with the Thomson Project.

The Bison Wind Project and most of the projects related to the Thompson Project were rolled into base rates in the 2016 rate case. In its 2019 rate case,[4] the Company requested approval to roll the last two Thompson projects into base rates and, therefore, there are no new costs for those two projects in the 2020 RRR calculations.

On April 19, 2017, MP filed an Affiliate Interest Agreement[5] seeking approval to transfer the Bison 6 LGIA to its affiliate, ALLETE Clean Energy (ACE). On March 16, 2018, the Commission approved the transfer and crediting customers through the renewable resources rider.[6] The 2018 RRR calculations included the detailed cost amounts provided in compliance filings.[7] In its 2020 rate case filing, MP was seeking approval to reimburse customers through base rates, therefore the 2020 RRR revenue requirements excluded reimbursement to customers effective January 1, 2020 (the starting date of the 2020 test year).

The Company said that it is committed to continued compliance reporting per the requirements in Order Points 2.A., 2.B., and 2.C. of the March 16, 2018 Order in Docket No. E015/AI-17-304 in the RRR. Also, MP stated that:

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[4] Docket Nos. E-015/GR-19-442 and E-015/M-20-429, both subsequently resolved.

[5] Docket No. E-015/AI-17-304.

[6] Ibid, Order.

[7] Ibid, April 17, 2018 and May 7, 2018.

In the event the Commission denies the request to reimburse customers through base rates, the credit would continue in the renewable resources rider retroactive to January 1, 2020.

Finally, pursuant to the Commission's March 12, 2018 Order in MP's 2016 Rate Case, the Company performed an annual true-up of actual production tax credits (PTC's) from the Bison Wind Energy Center for 2018 and 2019.[8] MP noted that a PTC true-up was not budgeted in 2020, since 2020 will be a rate case test year and a variance between the test year and 2020 budget will not exist.

2. Renewable Resources Factor

MP stated that its proposed factor will result in a rate increase for all customer classes, with the exception of the large power (LP) customer class. It will result in an increase of about 2.64 percent for the average residential customer; the rate for the LP class will remain about the same, decreasing by 0.09 percent compared to the 2018 RRR factor. The factor that will be placed on customer bills will consist mainly of the projected December 31, 2019 tracker balance based on updated 2018 & 2019 calculations, with a small 2020 amount resulting from credits related to the REC's sold to Oconto.

B. Department of Commerce - Comments

1. Department Summary of Filing

a. Revenue Requirement and Tracker Balance

The Department of Commerce, Division of Energy Resources summarized the RRR factors currently in effect, as approved in Docket No. E-015/M-18-375, as follows:

- projected 2018 revenue requirements associated with two small projects related to the Thomson Hydroelectric Restoration Project (Thomson Project);
- credits to ratepayers related to the transfer of a Large Generator Interconnection Agreement (LGIA) from the Company to its affiliate, ALLETE Clean Energy, Inc. (ACE);
- a true-up of actual production tax credits (PTCs) relative to the amount built into MP's base rates; and
- a tracker balance that trues-up actual costs and revenues to projected costs and revenues from prior periods.

Table 1, below, is a summary of the revenue requirements that Minnesota Power proposed to collect through its RRR in 2020.

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[8] In compliance with Order Point 37 of the March 12, 2018 Order in Docket No. E-015/GR-16-664: "Minnesota Power shall . . . perform an annual true-up of actual production tax credits through the Renewable Resources Rider".

Table 1: Summary of 2020 Revenue Requirement[9] ($ Millions)

	MN Jurisdiction Total	Large Power	All Other Retail Classes
2018 Year-End Tracker Balance	(7.8)	(10.1)	2.3
2019 Projected Net Revenue Requirements	1.3	0.8	0.5
2020 Projected Cash Collections	7.6	4.5	3.1
Projected 2019 Year-End Tracker Balance	1.1	(4.8)	5.9
2020 Net Revenue Requirements	(0.0)	(0.0)	(0.0)
Total 2020 RRR Factor Revenue Requirements	1.1	(4.8)	5.9

Petition, Exhibit B-1, pages 1-2.

The Department pointed out that the 2019 projected revenue requirements reflect actual cash collections through May 2019 and projected cash collections through the remainder of 2019. The Department further noted that the 2020 net revenue requirements consist of an overall tracker balance of $1.1 million and about $15,000 in revenue credits from the Oconto REC sales; all other projects were being rolled into base rates.

b. Rate Design

The Department stated that MP has proposed using the same rate design approved in its last RRR filing[10] as summarized below in Table 2.

Table 2: Summary of Current and Proposed RRR Factors[11]

	Current	Proposed	Increase
Large Power			
Demand (cents/kW – month)	-33.0	-35.0	-2.0
Energy (cents/kWh)	-0.037	-0.040	-0.003
All Other Retail Classes			
Energy (cents/kWh)	-0.096	0.019	0.115

Source: Petition, Exhibit A-1.

2. Department Analysis

a. Project Eligibility, Total Project Costs, and Cost Caps

The Department observed that, since the Company proposed to roll the last two projects remaining in the RRR into base rates, and MP is not adding any new projects to the RRR, then the 2020 revenue requirements consist of only the tracker balance of about $1.1 million plus about $15,000 in REC sales to Oconto. The Department concluded that there are no issues with respect to project eligibility.

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9 Department of Commerce Comments, December 23, 2019, page 2.

10 Docket No. E-015/M-18-375

11 DOC Comments, page 3.

Further, since MP's Thomson projects used the same capital cost totals as those approved in the Company's prior RRR docket, the Department concluded that these capital costs do not exceed cost caps previously established.

b. 2018-2020 Annual Revenue Requirements

i. Allowance for Funds Used During Construction (AFUDC), Construction Work in Process (CWIP), and Internal Capitalized Costs

The Department stated that, as shown in Petition Exhibit B-3, MP appropriately excluded internal capitalized costs and any related AFUDC from its rate base and revenue requirement calculations. The Department concluded that MP's treatment of AFUDC and return on CWIP are reasonable.

ii. Tax Depreciation, Deferred Income Taxes and Prorated Accumulated Deferred Income Tax Liabilities

The Department noted that since all projects were rolling into rate base effective January 1, 2020, there would be no deferred taxes associated with the revenue requirements, and therefore, no need to pro-rate any accumulated deferred income tax liability. However, during its review, the Department discovered that MP included no tax depreciation for one of its Thomson projects (THM Replace/Refurbish Dam 6). MP, in DOC IR No. 1, pointed out that the correction would be small. However, since the Department is recommending other modifications, the Department recommended that MP correct the small tax depreciation deficiency.

iii. Production Tax Credits (PTC)

The Department noted that MP did not include any expected 2020 PTC activity in revenue requirements because the Company's proposed rate case included a 2020 test year. MP had planned that the total amount of PTC's would be accounted for in that rate case, with a true-up between forecast PTCs and actuals in a future RRR filing.

The Department reviewed MP's PTC calculation and concluded that they were correct and reasonable.

iv. Rate of Return and Class Allocators

The Department found that, beginning April 1, 2018, MP applied the cost of capital approved in its 2016 rate case.[12] However, for the three months prior to that date, MP applied the rate from its 2009 rate case,[13] instead of the correct cost of capital from the 2016 rate case. In its

[12] Docket No. E-015/GR-16-664.

[13] Docket No. E-015/GR-09-1151.

response to DOC IR No. 8, MP agreed to update its 2018 revenue requirements in a compliance filing in this docket.

MP also used the Large Power Class Allocator from the 2009 rate case for the first three months of 2018 and the Department recommended that the Commission require MP to update its calculation to use the correct 2016 rate case allocator.

v. Sale of Renewable Energy Credits (RECs) to Oconto

In its petition, Minnesota Power said that it expected to sell approximately 6,500 RECs each year to Oconto. MP stated that it expects to comply with Minnesota's Renewable Energy Standard (RES) through 2053 with no concerns over the sale of RECs. The Company included revenue credits of $17,786 and $15,470 for 2019 and 2020 respectively.

The Department said that it agrees that it is reasonable to sell a small number of RECs to Oconto and credit customers for a share of the proceeds. However, the Department noted that MP had not provided any details in its petition and requested the Company include the following in reply comments:

- the price it will receive for the RECs its sells to Oconto, along with an explanation of how that price is determined;
- an explanation of how the number of RECs sold to Oconto each year will be determined;
- an explanation of whether and how the total amount of revenue received from Oconto for the sale of RECs will be allocated to MP's different jurisdictions; and
- supporting calculations showing how the proposed revenue credits for 2019 and 2020 in the RRR were estimated.

vi. Thomson Base Rate Revenue Credit

The Department noted that a portion of the capital costs for the two Thomson projects that effectively replace plant that was retired is currently in base rates and, therefore, MP is including a revenue requirement credit for that amount; as it has in prior RRR dockets. Except for using the incorrect rate of return for the first three months of 2018, the Department concluded that this was reasonable.

3. Department Conclusion

The Department requested that MP provide in reply comments additional information related to its proposed sales of RECs to Oconto, the decreased revenue credit from its affiliate for the Bison 6 LGIA, and additional information related to potential true-ups for 2017 and 2018 revenue requirements and cash collections for projects that were rolled into base rates in the 2016 Rate Case.

With respect to the REC sales to Oconto, the Department requested that MP provide:

- the price it will receive for the RECs its sells to Oconto, along with an explanation of how that price is determined;
- an explanation of how the number of RECs sold to Oconto each year will be determined;
- an explanation of whether and how the total amount of revenue received from Oconto for the sale of RECs will be allocated to MP's different jurisdictions; and
- supporting calculations showing how the proposed revenue credits for 2019 and 2020 in the RRR were estimated.

Regarding the proposed reduction of the credit from MP's affiliate, ALLETE Clean Energy, Inc. to MP's ratepayers for the Large Generator Interconnection Agreement (LGIA), the Department requests that MP discuss in reply comments why it is reasonable to decrease the credit for ratepayers that the Company represented in its petition for approval to sell this asset to its affiliate.

With respect to true-ups for projects rolled into base rates in the 2016 rate case, the Department requests that MP provide:

- a response to the Departments proposal for estimating a true-up amount to include in the 2020 factors; and
- actual 2017 and 2018 rate base and O&M costs associated with the Bison Projects and Thomson projects that were rolled into base rates in the 2016 Rate Case.

C. Minnesota Power – Reply Comments

Minnesota Power stated that, in addition to the data requested by the Department (immediately above), it is attaching revised exhibits A-1 and B-1 through B-5 which have been revised to reflect the Department's request for updated calculations. Also, a completely new exhibit, B-6, is attached showing the Department's recommended calculation method to true-up for the Bison and Thomson projects, plus an updated 2017 tracker.

Table 4, below, shows the revenue requirement impacts that are discussed and identified in exhibits:

Table 4: Revenue Requirement Impacts and Updated RRR Factor[14]

August 15, 2019 Petition Total RRR Factor (*Exhibit B-1, pg. 1*)	$1,123,181
Tax Depreciation Impact Thomson Project - Replace/Refurbish Dam 6	$(714)
ROE/Allocation Factor Adjustment to 1/1/17 Impact	$(67,897)
Interim Rate Period Under-collection Impact (*Exhibit B-6*)	$1,984,093
Update Total RRR Factor (*Exhibit B-1, pg. 1*)	$3,038,663

[14] Minnesota Power Reply Comments, February 14, 2020, p. 2.

1. Sale Agreement with Oconto for RECs

MP stated that it entered into an agreement with Oconto for the period from January 2019 through May 2026 that included selling excess Renewable Energy Credits (RECs). The Company said that these sales will have no impact on MP's Minnesota Renewable Energy Standards (RES).

MP provided the Department's requested pricing, quantities sold, jurisdictional revenue allocations, and supporting calculations showing how the proposed revenue credits were estimated. However, these details are not published here because the information has been designated as trade-secret.

Table 5, below, shows how the proposed revenue credits for 2019 and 2020 were estimated in the Petition.

Table 5: Oconto Revenue Credit Calculation

Description	2019	2020
Total Revenue Credit	$18,150	$18,350
Jurisdictional Split	0.84307	0.84307
Jurisdictional Revenue Credit	$15,302	$15,470

2. Updated Rate Impacts from Adjusted Factors

In Table 6, below, MP provided a summary of its updated, estimated rate impacts by customer class. The rate increase in cents per KWh reflect the incremental change from the current 2018 factors to the proposed factors in this docket.

Table 6: Estimated Customer Impact

Rate Class Impacts 1/	
Residential	
Average Current Rate (¢/kWh)	10.846
Increase (Decrease) (¢/kWh)	0.310
Increase (Decrease) (%)	2.86%
Average Impact ($/month)	$2.25
General Service	
Average Current Rate (¢/kWh)	10.805
Increase (Decrease) (¢/kWh)	0.310
Increase (Decrease) (%)	2.87%
Average Impact ($/month)	$8.52
Large Light & Power	
Average Current Rate (¢/kWh)	8.247
Increase (Decrease) (¢/kWh)	0.310
Increase (Decrease) (%)	3.76%
Average Impact ($/month)	$765
Large Power	
Average Current Rate (¢/kWh)	6.176
Increase (Decrease) (demand + energy combined) (¢/kWh)	0.016
Increase (Decrease) (%)	0.26%
Average Impact ($/month)	$8,932
Lighting	
Average Rate (¢/kWh)	16.171
Increase (Decrease) (¢/kWh)	0.310
Increase (Decrease) (%)	1.92%
Average Impact ($/month)	$1.05

Notes:
1/ Average current rates are 2019 estimated rates based on Final 2017 TY General Rates in 2016 Rate Case (E-015/GR-16-664) without riders adjusted to include current rider rates. Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Boswell 4 Emission Reduction rates, Conservation Program Adjustment rates, and estimated 2019 Fuel and Purchased Energy. Average $/month impact based on 2020 budgeted billing units. The increase/decrease in cents/kWh is the incremental increase/decrease due to the new factor being implemented.

3. Correction to Thomson Restoration Project Final Cost

In preparing its responses to Department information requests in MP's 2019 rate case, the Company discovered certain numerical errors in testimony regarding the Thomson Projects and reported corrections to those errors on page 11 of its reply comments.

4. Other Issues Raised by the Department

i. Tax Depreciation

The Department had recommended that the Commission require MP to update revenue requirement calculations for the THM Replacement/Refurbish Dam 6 project to include tax depreciation. This revision resulted in a revenue requirement reduction of $714 and the updated tracker reflects this amount.

ii. Rate of Return and Class Allocators

As requested by the Department, MP has revised its calculation to apply rate of return and class allocators from the 2016 rate case to the first three months of 2018, resulting in a reduction in revenue requirements of $67,897.

D. Minnesota Public Utilities Commission – Notice of Supplemental Comment Period

On April 23, 2020, Minnesota Power submitted a letter requesting approval to resolve its pending 2019 rate case.[15] As a result, the PUC issued a Notice of Supplemental Comment Period with these topics open for comment:

- Minnesota Power's proposed Renewable Resources Cost Recovery revenue requirement.
- Minnesota Power's proposed Renewable Resources Cost Recovery Rider rates.
- Does Minnesota Power's resolution of its rate case (Docket Nos. E-015/GR-19-442 and E-015/M-20-429) have any impact on parties' positions and, if so, what effect?
- Are there other issues or concerns related to this matter?

E. Department of Commerce – Supplemental Comments on MPUC Notice

In its comments, the Department recommended approval, with modifications.

1. Sale of RECs to Oconto

The Department stated that in its reply comments, MP explained the terms of its power sales agreement with Oconto. The Department said that while data on REC prices are somewhat scarce, the Oconto terms compare favorably to the REC prices reported by various Minnesota electric utilities in Docket No. E-999/PR-18-12. Therefore, the Department concluded that Minnesota Power's proposed treatment of revenues associated with REC sales to Oconto is reasonable.

2. Other Issues Addressed in Minnesota Power's Reply Comments

a. Tax Depreciation

The Company corrected its calculations for tax depreciation, which reduced its revenue requirements by $714.

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[15] *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates In Minnesota,* Docket No. E015/GR-19-442 and *In the Matter of the Emergency Petition of Minnesota Power for Approval to Move Asset-Based Wholesale Sales Credits to the Fuel Adjustment Clause and Resolve Rate Case,* Docket No. E015/M-20-429.

b. Rate of Return and Class Allocators

The Department had requested that Minnesota Power update its calculation to implement the 2016 Rate Case rate of return and class allocators effective January 1, 2017, the effective date determined in the 2016 Rate Case. MP updated its calculations resulting in a reduction of $67,897 in revenue requirements.

V. PUC Staff Summary of Resolved Issues

Issue	Department's Conclusion
Project eligibility	All of the projects in the petition are eligible for recovery under the RRR.
Total project cost caps	The 2018 and 2019 revenue requirements for the two Thompson projects use the same capital cost totals approved in the prior RRR and, therefore, do not exceed cost caps.
Revenue Requirements – CWIP, AFUDC, and Internal Capitalized Costs	MP appropriately excluded internal capitalized costs and its proposed treatment of AFUDC and return on CWIP is reasonable.
Tax Depreciation, Deferred Income Taxes and Prorated Accumulated Deferred Income Tax Liabilities	MP did not pro-rate its ADITL, which is reasonable. However, MP did not include tax depreciation for one of the Thomson projects, but updated the totals in reply comments, resulting in a $714 revenue requirement reduction.
Rate of Return	The cost of capital approved in MP's 2016 rate case should have been used for all of 2018 in MP's petition. The Company updated its 2018 revenue requirements to use the correct cost of capital in a compliance filing in this docket.
Class Allocators	The Department noted that MP used the Large Power Allocator from the 2009 rate case for the first 3 months of 2018 and recommended that MP be required to update the calculations using the class allocator approved in the 2016 rate case. MP updated its calculations in reply comments resulting in a reduction to overall revenue requirements of $67,897.
Sale of RECs to Oconto	The Oconto terms compare favorably to the REC prices reported by various Minnesota electric utilities in Docket No. E-999/PR-18-12. Therefore, the Department concluded that Minnesota Power's proposed treatment of revenues associated with REC sales to Oconto is reasonable.
Thomson Base Rate Revenue Credit	The Department reviewed MP's calculations and, aside from using the incorrect rate of return for the first three months of 2018 (noted above under "Rate of Return"), concluded they are reasonable.

VI. Disputed Issues

A. 2019 Rate Case Resolution

In its petition, Minnesota Power proposed to remove the costs of the two remaining Thomson projects and the LGIA credits from the 2020 RRR revenue requirements because they planned to roll both into base rates effective with the 2020 test-year in the 2019 general rate case (subsequently resolved), in docket # E-015/GR-19-442..

1. Minnesota Power – Supplemental Comments on MPUC Notice

Minnesota Power stated that when it submitted its Petition in the current docket, the Company had already publicly announced its intent to file its next general rate case in early November 2019. As a result, costs related to the two remaining Thomson project and credits related to the transfer of the Bison 6 LGIA were removed from its tracker effective January 1, 2020 as MP planned to roll these items into rate base in the 2019 rate case.

In addition, pursuant to Order Point No. 37 in MP's 2016 rate case, the Company implemented a true-up procedure to account for differences between the Production Tax Credits generated by the Bison Wind Energy Center and the amounts included in base rates during the 2017 test year, in the 2016 rate case. MP stated that since it anticipated that the new level of PTC's to be included in its 2020 test year for the 2019 rate case would be the new standard to measure against, the Company did not include an expected PTC true-up in the 2020 tracker balance.

As a result of MP's resolution of its 2019 rate case, the Company proposed the following treatment for the Thomson Project, Bison 6 LGIA, and PTCs:

a. Thomson Project

Reestablish cost recovery for the two remaining projects of the Thomson Project through this 2020 RRR effective January 1, 2020, with the adjustment to account for 2020 costs to be in a required compliance filing after issuance of the Commission's order.

b. Bison 6 LGIA

MP proposed to continue to credit customers for the Bison 6 LIGA through the RRR effective January 1, 2020, the start date used for the 2019 Rate Case test year. The amount of the credit is in dispute and is discussed in section B. Bison 6 LGIA Credit below.

c. Production Tax Credits

As stated above, the Company did not include an expected PTC true up amount in this rider. Since the resolution of the 2019 Rate Case, MP proposes to revert to the 2017 test year amounts to determine the expected PTC true-up amount for 2020. Again, with the adjustment to account for 2020 costs to be in a required compliance filing.

2. Department Supplemental Reply Comments

a. Topics Open for Comment from the Commission's Notice

With respect to open issues from MP's 2019 rate case resolution, the Department noted that resolution of the rate case does "have an impact on the projects and costs included in the rider, but the impact on the final rider rates is small enough that the Department concludes that it would be reasonable to move forward without making further changes in this Docket".

Further, the Department said that:

> Because the 2019 Rate Case is [resolved], and the rates from the Company's prior rate case will be maintained (with an adjustment related to energy and capacity asset-based wholesale margins),[16] none of those projects or credits will be rolled into base rates, and thus will remain in the rider. However, as shown in Table [8] below, the costs and credits initially proposed to be rolled into base rates largely offset each other.

Table 8: Components of RRR Initially Proposed to be Rolled into Base Rates in the 2019 Rate Case[17]

Component	2019 Revenue Requirement
Two remaining Thomson Projects	$730,963
Thomson Base Rate Revenue Credit	($2,389)
Bison 6 LGIA Credit	($920,501)
Total	($191,877)

To put this number into context, the Department pointed out that MP's 2018 PTC true-up amount was $6.1 million. Since the total in the above table is smaller, it can be reflected in a future true-up and the Department concluded that there is no need to update the analysis in the instant docket to reflect 2020 revenue requirements.

b. Department Conclusion

In its conclusion the Department said:

> [T]he Department concludes that the revenue requirements and updated RRR factors presented in Minnesota Power's Reply Comments are reasonable, with the exception of the Company's inclusion of its proposal to charge ratepayers for the Company's errors in 2018 and 2019 revenue requirements and its estimated true-up amount resulting from its under-collection of interim rates. The Department recommends that the Commission approve Minnesota Power's updated RRR factors, modified to exclude 1) the $0.5 million surcharge for 2018 and 2019 revenue requirements and 2) its estimated interim rate under-collection of $2.0

[16] See Docket No. E015/M-20-429.

[17] Department Comments, July 9, 2020, Table 2, p. 11.

million. The Department attempted to calculate updated factors, which are shown in Attachment 1[18] to these Comments.

3. MP Supplemental Reply Comments

a. 2019 Rate Case Resolution Impact

Minnesota Power disagrees with the Department's argument that the impact of the rate case is small enough that it would be reasonable to move forward without further adjustment to the 2020 RRR. Since the Company is authorized to include the costs for those projects, the Department's recommendation "would negate the purpose of the rider and postpone recovery of costs incurred as early as 2018 until at least 2022".

b. Topics Open for Comment from the Commission's Notice

With the 2019 rate case resolved, Minnesota Power proposed the following:

- Reestablish cost recovery for the two remaining projects of the Thomson Project through the 2020 RRR effective January 1, 2020, the start date used for the 2019 Rate Case test year;
- Continue to credit customers for the Bison 6 LIGA through the RRR effective January 1, 2020, the start date used for the 2019 Rate Case test year; and
- Revert to the 2017 test year amounts to determine the expected PTC true up amount for 2020.

MP said that it believes the Department's recommendations align with the first two proposals above, but that the Department did not specifically address how the Company should handle the third proposal: handling the PTC true-up for the 2020 RRR. MP stated that the Department "seems to wrap it into its stance that because of the relatively small size of the total costs and credits of the projects that the Company had planned to roll into base rate, 'these costs and credits for 2020 can be reflected in a future true-up' and sees no need to update the analysis in the 2020 RRR Docket to reflect 2020 revenue requirements".

Minnesota Power said it disagreed with the Department's stance on this issue and that the Company is authorized to include the true-up amount for PTCs. Further, adopting the Department's recommendation "would negate the purpose of the rider and postpone the true up until at least 2022 or later". The Company concluded:

> These are unprecedented times and no party could have anticipated the circumstances that would justify resolution and withdrawal of the 2019 Rate Case when the 2020 RRR Petition was filed on August 15, 2019. The Company should not be penalized by withholding recovery of authorized costs until the effective date of its 2021 Renewable Resource Factor sometime in 2021 or the effective date of its next general rate case, which under the resolution cannot be submitted until at least March 1, 2021.

[18] See Department's Attachment 1 included in these briefing papers.

4. PUC Staff Disputed Issue Discussion

a. Minnesota Power's Position

When MP submitted its 2020 Renewable Resources Rider, the Company had announced its intent to file the 2019 Rate Case. As a result, MP removed the 2020 revenue requirements for the two remaining Thomson Projects and the Bison 6 LGIA Credit from the tracker effective January 1, 2020 anticipating that these would be rolled into base rates. However, since the 2019 Rate Case resolved, MP now proposes to reestablish cost recovery for the Thompson Projects and Bison 6 LGIA Credit by adjusting the 2020 factor to include 2020 revenue requirements for these items.

In addition, pursuant to Order Point No. 37 in MP's 2016 retail rate case[19] the Company had been truing-up to account for differences in PTCs generated by the Bison Wind Energy Center compared to what was included in base rates in the 2016 rate case. Since the 2019 rate case resolution, MP is proposing to revert to the 2017 test year to determine the expected PTC true-up amount for 2020, to be reflected in a compliance filing following the Commission's order in this docket.

In its supplemental reply comments MP objected to the Department's position that the 2020 RRR proceed without allowing the Company to include revenue requirements for the items listed immediately above, stating that it would deprive MP of timely collection of costs that the rider statute was designed to promote.

b. Department Position

In an e-mail,[20] the Department stated that it does not have strong objections to updating the revenue requirements but does have some concerns regarding the volume and nature of the issues included in a compliance filing. The Department pointed out that, while the PTC true-up is not expected to be overly complicated, it is not just a simple true-up of an historical period and may require additional information requests.

c. PUC Staff Analysis

Since the Department has no strong objections, staff accepts MP's argument that it should be able to recover the costs from projects that would have been rolled into its resolved 2019 rate case.

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[19] Docket No. E-015/GR-16-664, Order, March 12, 2018.

[20] See Attachment 3.

B. Bison 6 LGIA Customer Credit

1. Department Comments - Bison 6 LGIA Credit

Minnesota Power received Commission approval to transfer a Large Generation Interconnection Agreement (Bison 6 LGIA) to its affiliate ALLETE Clean Energy, Inc. (ACE) in a March 16, 2018 Order.[21] In the order, the Commission required that, beginning February 4, 2018, the Company credit ratepayers with the following:

- a lump sum of $121,179 to reflect legal and regulatory costs as well as the costs of system impact and facility studies related to the LGIA;[22]
- Bison 6's share of the capital costs and revenue requirements (using the inputs, such as return on equity, established in the 2016 Rate Case) for a transmission line and other plant related to the Bison 6 LGIA; and
- ongoing operating and maintenance expenses, including taxes other than income taxes.

In its review, the Department noted that the allocated portion of Bison 6 LGIA's share of capital costs and revenue requirement fell from 28.504 percent to 18.241 percent, lowering the size of the ratepayer's credit. After further review, the Department concluded that MP had corrected an error in its original allocator and that 18.241 percent is the correct allocator to use to allocate the costs of the Bison 6 LGIA related property. However, the Department expressed concern that MP did not identify the error resulting in a 36 percent lower credit for ratepayers than the Company represented in Docket No. E-015/AI-17-304. The Department requested that MP explain why it is reasonable to decrease the credit for ratepayers below what was authorized in the approval to sell the asset to its affiliate.

2. MP Reply Comments - LGIA Bison 6 Customer Credit Adjustment

MP states that it had inadvertently used a 28.504 percent allocator when filing the initial petition in Docket No. E-015/AI-17-304. The use of the incorrect allocator was discovered in preparing the petition in this docket and was corrected. The correct allocator is 18.241 percent.

In response to the Department's concern about transparency, MP said:

> It is not routine for utilities to submit documents into the original dockets in which Commission approval was sought for adjustments that occur in the cost recovery dockets. For this reason, and the fact customers have been reimbursed since December 1, 2018, it wasn't intuitive to the Company that submitting notice of

[21] Docket No. E-015/AI-17-304.

[22] See Department Comments, December 23, 2019, footnote 8: "In its April 17, 2018 Compliance Filing in the LGIA Docket, MP reported that these costs have since risen to $122,601. The Commission's March 16, 2018 Order Approving Sale of Bison 6 Interconnection Agreement stated that MP's ratepayers should be credited with the lump sum of $121,179 "or more" indicating that ratepayers should be credited for the full amount of the legal and regulatory costs.

> the change in allocator and customer credit in Docket No. E015/AI-17-304 was necessary. In hindsight, Minnesota Power agrees with the Department that the Company should have more thoroughly considered all of the dockets affected by the corrected calculation, as well as communication within the Petition specific to the updated calculation. The Company will make a concerted effort to file information in all related dockets going forward.

Further, the Company identified two reasons why it was reasonable to correct the allocator:

1. The 18.242 allocation factor has been verified by the Department as being the correct allocator for Bison 6 LGIA related property, and
2. The lower allocator percentage does not change what ACE paid for the transfer, nor does it affect the contracts with ACE in any way.

Finally, MP pointed out that customers received a significant benefit when the Commission decided that customers would be credited starting February 4, 2018 rather than December 2019 when ACE began using the facility. Further, MP said:

> This decision is not consistent with effective dates determined for other agreements as the Company argued in Docket No. E015/AI-17-304. As a result, Minnesota Power began crediting customers for use of the facilities 22 months prior to when ACE became a joint user of the facilities. This equates to an approximately $1.67 million benefit to customers.

3. Department Supplemental Comments [on MPUC Notice] Bison 6 LGIA Credit

In its previous comments the Department noted that Bison 6 LGIA's share of capital costs and revenue requirements had fallen from 28.504 percent to 18.241 percent, lowering the size of the credit to ratepayers. The Department concluded that the change represented a correction to MP's prior RRR filing. The Department expressed concerns regarding MP's transparency and noted that MP did not provide any information about the correction in the original docket approving the transfer, nor did the Company note the change in the text of the petition, it simply decreased the credit without explanation.

The Department stated that MP said the decrease in the allocation was reasonable because:

- the updated allocation percentage is the correct percentage;
- the change does not change what ACE paid for the Bison 6 LGIA, and does not affect the contracts with ACE in any way;
- the change partially offsets the significant ($1.67 million) benefit to ratepayers resulting from the Commission's decision to make the Bison 6 LGIA credits begin as of February 4, 2018, rather than December 2019, when ACE began using the facilities, which the Company stated was inconsistent with the effective date of other, similar agreements.

The Department said that it was strongly troubled by MP's third statement in that the Department views this as "a de facto request for reconsideration of the Commission's Order in the LGIA Transfer Docket." In any case, the Department concluded that MP's update is reasonable, at least on a going forward basis. Additionally, the Department concluded that the Commission's decision in the LGIA Transfer Docket would not have been affected if the correct allocation percentage had been provided at that time.

In addition, the DOC noted the following: [I]n Minnesota Power's prior RRR filing, the Company included the larger, erroneous credit in its calculation of 2018 revenue requirements.[23] In its Petition in this Docket, Minnesota Power updated its 2018 Revenue Requirements to reflect the smaller credit, thus the revenue requirements calculated in this Petition are roughly $1.0 million higher than they otherwise would have been, as they reflect $0.5 million decreases in the LGIA Credit for both 2018 and 2019. The Department supports a reduction in the LGIA Credit on a going-forward basis but opposes charging ratepayers higher rates in 2020 for the Company's error in calculating the LGIA credits for 2018 and 2019. The Department estimated that adjusting the Bison 6 LGIA credit in this way decreases the total 2018 and 2019 revenue requirements by $0.8 million.[24]

4. MP Supplemental Reply Comments - Bison 6 LGIA Corrected Calculation

As the Department previously noted, the allocator used to calculate the Bison 6 LGIA's share of capital costs and revenue requirements for the transmission line and related plant (18.241 percent) was lower than that used in the original Bison 6 LGIA Docket[25] and in the 2018 RRR Petition[26] (28.504 percent in each of those filings). The lower allocator resulted in a reduction to the credit to MP customers.

MP explained that use of the original higher allocator was an inadvertent error; agreed with the Department that the corrected allocator should have been discussed within the text of its Petition in this docket; and committed to a greater focus on transparency in future filings.

However, the Company takes issue with the Department's assertion that:

> Minnesota Power customers received a significant benefit when the Commission determined customers would begin being credited effective February 4, 2018, instead of December 2019 when ACE began using the facilities as proposed by the Company. This decision is not consistent with effective dates determined for other agreements as the Company argued in Docket No. E015/AI-17-304. As a result, Minnesota Power began crediting customers for use of the facilities 22 months prior to when ACE became a joint user of the facilities. This equates to an approximately $1.67 million benefit to customers.

[23] See Docket No. E-015/M-18-375.

[24] See Department's Attachment 1 included in these briefing papers.

[25] Docket No. E-015/AIA-17-304, Petition, April 19, 2017.

[26] Docket No. E-015/M-18-375.

Minnesota Power asserted that it was merely pointing out details from the regulatory process and how the Bison 6 LGIA transfer was financially beneficial to customers (even though the credit has been lowered by using the corrected allocator). The Company further pointed out that:

> In addition to the fact that the Bison 6 LGIA was in suspension status, and would have been terminated by MISO (Midcontinent Independent System Operator) if unutilized on February 4, 2018, resulting in zero offsetting revenue credits to customers; the Commission's decision to begin crediting customers well before ACE became a joint user of the facilities also significantly benefited customers financially.

In summary, MP said that the allocator error was unintentional and apologized for the oversight. Further, MP stated that the Commission's decisions in its March 16, 2018 Order approving the sale of the Bison 6 LGIA and setting the effective date for the credit to begin on February 4, 2018 credits customers for the fair share of ACE's use of the facilities. Therefore, MP respectfully requested that the Commission affirm the lowering of the customer credit for this 2020 Renewable Factor as effective February 4, 2018. Minnesota Power disagreed with the Department's recommendation to implement the lower credit on a going-forward only basis (e.g. excluding impact on the revenue requirements for 2018 and 2019) as being "contrary to the determination by the Commission in the Bison 6 LGIA Docket".[27]

5. PUC Staff Disputed Issue Discussion

a. Minnesota Power Position

As previously stated, the Company had inadvertently used an incorrect allocator (28.504 percent) instead of the correct allocator of 18.241 percent in calculations in its initial petition requesting approval for the Bison 6 LGIA transfer to ALLETE Clean Energy. MP is proposing to update the 2020 RRR factor for 2018 and 2019 impacts of correcting the error for this credit.

b. Department Position

The Department stated the revenue requirements calculated in the Petition are approximately $1.0 million higher than they should have been due to the allocation factor error (about $0.5 million annually for 2018 and 2019). The Department said that, although it supports the reduction in the LGIA Credit on a going forward basis, it opposes "charging ratepayers higher rates in 2020 for the Company's error in calculating the LGIA credits for 2018 and 2019".

c. PUC Staff Analysis

Because MP stated that the erroneous allocation factor was an inadvertent calculation error, that the error did not result in additional benefits to its affiliate (ALLETE Clean Energy), and that the Department acknowledged that it believes the Commission's decision in the Bison 6 LGIA

[27] Minnesota Power Supplemental Reply Comments, July 21, 2020, p. 6.

transfer authorization docket[28] would not have been different if the correct allocation factor had been known; staff does not believe there would be a lot of merit in refusing MP's request to change the allocation factor for cost recovery purposes in the 2020 RRR.

C. True-ups and Trackers

1. Department Comments

The Department stated that MP's petition is the first RRR filing since its completion of the 2016 rate case, but MP is only proposing to true-up actual costs and revenues related to the two Thomson projects remaining in the RRR. The Department expected the petition to also include true-ups for actual costs and revenues for projects that were rolled into base rates while interim rates were in effect during the 2016 rate case.

<u>2016 Rate Case RRR True-up</u>
The Department pointed out that Ordering Point 6 of the Commission's November 8, 2017 Order in the 2016 RRR Docket[29] required "MP to make a compliance filing at the conclusion of its 2016 rate case describing the final resolution of the true-up for RRR projects moved into base rates and the cash collections thereon." The Company did file the required compliance filing on December 9, 2019, and stated that its actual RRR cash collections for projects that were rolled into base rates during the 23 month interim rate period, when annualized, resulted in actual collections of $62.2 million versus the $64.6 million projected.

The Department went on to point out its concerns regarding the method used to roll projects into base rates during the 2016 rate case. The Department explained that when utilities roll projects from rate riders into base rates there are generally two options:

1. Roll projects into rates at the beginning of the interim rate period so that the full costs of the projects are in the interim rate, or
2. Roll projects into rates at the end of the interim rate period so that the rider rate covers the costs through the interim rate period.

The Department noted that Minnesota Power chose a "hybrid method" where it continued to collect for the projects under rider rates during interim rates but did not remove those projects from the interim rate request. Instead, MP offset the project costs included in the interim rate request with a revenue credit reflecting expected cash collections for the projects via the rate rider.

The Department expressed a number of concerns regarding this complicated roll-in process during the 2016 rate case. The Department said that "it seems clear that MP intended to true-up the projected costs and revenues for project[s] included in the RRR with actual costs and revenues, and that this true-up was to apply to projects that were ultimately rolled into base rates as well as those that remained in the RRR."

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[28] Docket No. E-015/AI-17-304.

[29] Docket No. E-015/M-16-776.

The Department said that MP, in its response to DOC IR No. 4, "attempted to explain why a true-up of those costs and revenues is unnecessary, and why it used its hybrid method of rolling rider project costs into base rates."[30] The Department agreed that final base rates at the end of a rate case should be the same whether rolled in project costs are included at the beginning of interim rates or at the end. However, since interim revenue collections were less than the amount assumed in the revenue credit included in interim rates, the Department said that "the rider mechanism requires a true-up to actual revenues and actual costs, not between estimated and actual revenues."[31]

The Department went on to say:

> MP's unusual approach of also including costs and the associated revenue credit in MP's 2016 Rate Case greatly complicates the calculation of any true-up to actuals. In a normal rider true-up calculation, actual revenues from the prior period are compared to a calculation of revenue requirements for the same period that has been updated to reflect actual costs. In this case, because the rider rates in effect during the interim rate period were calculated using the cost of capital established in MP's 2009 rate case, and the cost of capital was lowered from 8.180 percent to 7.064 percent during the 2016 Rate Case, this normal true-up calculation would show a significant over-recovery for 2017 and the first 11 months of 2018. However, because MP included a credit for revenues collected via the RRR in its calculation of interim rates as well as the interim rate refund, the over-recovery associated with the lower cost of capital was effectively refunded to ratepayers via the interim rate refund, and to refund that amount via the RRR would be to double-count it. Thus, it does not seem possible to apply normal rider true-up procedure in a meaningful way.
>
> One possible alternative to the normal rider true-up procedure would be to develop separate revenue and cost true-up amounts for these periods. For example, in its response to DOC IR No. 6, MP reported that its actual base rate RRR cash collections during the 23-month interim rate period were $119,133,357. The Company also noted that at the conclusion of its 2016 Rate Case, its final estimate for the RRR base rate revenue credit reflected in its interim rate refund calculations was $64,583,859 for the 12-month test year (2017). When grossed up to reflect the 23-month interim rate period, this amount yields a 23-month estimate of $123,785,730. Thus, over the 23-month interim rate period, MP under-collected RRR base rate revenue by $4,652,373.
>
> With respect to costs, as described above, MP has already effectively refunded the over-collection attributable to the lower cost of capital established in the 2016 Rate Case, and MP has already reflected the difference between actual PTCs earned versus projected PTCs in its PTC true-up. Thus, an estimate of any refund

[30] Instant Docket, Department Comments, December 23, 2019, Attachment 4.

[31] Ibid, page 12.

> or surcharge amounts related to costs would have to isolate the impacts of differences in projected and actual rate base, as well as differences in projected and actual operating and maintenance (O&M) expenses. One way to achieve this would be for MP to use the projected rate base and O&M estimates for 2017 included in its petition in Docket No. E015/M-16-776 and calculate a simple estimate of revenue requirements using the cost of capital and tax rate approved in the 2016 Rate Case to develop an estimate of costs reflected in the rider that haven't already been trued-up in the interim rate refund calculation. MP could then update the actual rate base data, O&M expenses, and the allocators (to reflect those approved in the 2016 Rate Case) to develop an estimate of actual costs, and the difference between the projected level of costs use to set the RRR factors and the actual level of costs could be credited or charged to ratepayers.
>
> Because the RRR factors based on projected 2017 costs were in effect during the entire interim rate period, the projected revenue requirements for that period could be used for both 2017 and the first 11 months of 2018. However, MP would have to develop separate actual revenue requirements for 2017 and 2018 to reflect the additional depreciation in 2018, as well as year-to-year changes in O&M.
>
> The difference between projected costs and actual costs could then be netted against (or added to) the revenue shortfall to determine an approximate true-up amount that could be reflected in the 2020 RRR Factors.

The Department asked MP to respond and provide actual 2017 and 2018 rate base and O&M costs from the Bison Projects and Thomson projects that were rolled into base rates in the 2016 rate case.

Finally, the Department noted that in DOC IR No. 5 MP was asked to update actual revenue requirements for all projects rolled into base rates in the 2016 rate case. MP responded by requesting the withdrawal of IR No. 5 as being extremely labor and time intensive. The Department said that it is willing to wait until it reviews MP's response comments before it decides if the data requested in this IR is truly necessary.

2. MP Reply Comments - True-ups and Tracker Balances

Minnesota Power said that, as explained in the Department's Comments, a normal true-up cannot be used for the 23-month interim rate period because many components of the revenue requirements for projects rolled into base rate in the 2016 rate case were already included in the interim base rates.

The Company explained its modified true-up calculation as follows:

> To develop the true-up, Minnesota Power started with the rate base and O&M estimates from the most recent filings containing all of the projects. This information was modified to include previously removed internal costs and AFUDC on internal costs, as the amounts rolled into Minnesota Power's 2017 Test Year

included both of those, resulting in a larger rate base and larger credit to customers. The 2017 data was extended to each project on a monthly basis for all of 2018. Then the differences in tax and book basis were calculated (Jan 2018 minus Jan 2017 for example) to come up with a decrease in rate base that could be attributed to changes in tax and book basis in 2018 relative to 2017. This change was then multiplied by the rate of return established in the Company's 2016 rate case to develop a true-up amount associated with the additional depreciation in 2018. O&M for both 2017 and 2018 is compared against the 2017 estimate previously provided. This amount is also included in the true-up outlined in Exhibit B-6. The true-up is then netted against the $4.65 million cash collection shortfall as discussed in the second paragraph of page 14 of the Department's Initial Comments.

3. Department Supplemental Comments [on MPUC Notice] True-Ups and Tracker Balances

The Department stated that prior to filing its 2016 Rate Case, MP was recovering costs associated with a number of renewable projects via its RRR and that it planned to roll many of those projects into base rates in its 2016 Rate Case. As previously noted, rather than rolling the projects into base rates at the beginning of the 2016 Rate Case in interim rates, or at the end of the rate case when final rates were implemented, the Company adopted a hybrid approach in which it continued to recover the costs of those projects via the RRR while interim rates were in effect, but included both the costs of those projects and expected RRR revenues in its interim rate calculations.

The Department said that MP's "unusual hybrid approach of including costs and the associated revenue credit in MP's 2016 Rate Case greatly complicates the calculation of true-ups to actuals". Therefore, DOC proposed the following:

Table 7: Alternative Cost True-Up Methodology Suggested by the Department

		2017	**2018**
	Updated Project Costs:	2017 Projected Revenue Requirements from Docket E015/M-16-776, updated with cost of capital approved in 2016 Rate Case	2017 Projected Revenue Requirements from Docket E015/M-16-776, updated with cost of capital approved in 2016 Rate Case and new corporate tax rate effective Jan. 1. 2018
less:	Actual Costs	2017 Actual Revenue Requirements calculated with actual rate base data and cost of capital approved in 2016 Rate Case	2018 Actual Revenue Requirements calculated with actual 2018 rate base data and cost of capital approved in 2016 Rate Case and new corporate tax rate effective Jan. 1, 2018
equals:		2017 Cost True-Up	2018 Cost True-Up

The Department stated that MP, in its reply comments, "did not calculate a true-up for 2017 and did not calculate a true-up amount for 2018 that reasonably reflects the difference between the costs assumed in rates and actual costs". Further, the Company's rate base calculations do not include deferred tax assets (DTAs) related to net operating losses (DTA-NOLs) and production tax credits (DTA-PTCs). The Department went on to note that deferred tax assets were a significant portion of rate base.

Because of this, the Department recommended that:

> [T]he Commission move forward without requiring the Company to true-up its costs and revenues for projects rolled-in from the RRR into base rates in the 2016 Rate Case. Because of the uncertainty surrounding the impact a proper accounting of DTAs will have on the final true-up estimate, the benefits of pursuing this issue further are questionable at best. The Company's calculations, though not a full accounting of costs, indicate a net under-collection of $2.0 million dollars during 2017 and the first 11 months of 2018. While it is possible that Minnesota Power's $2.0 million under-collection estimate will revert to an overcollection if the Company were to update its cost true-ups to reflect its consumption of DTAs, it is also likely that not requiring a true-up will resolve this issue in favor of ratepayers by not increasing rates to address a net under-collection.

Lastly, the Department cited Order Point 47 of the Commission's March 12, 2018 Order in the 2016 Rate Case that says (in part):

> In future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate case at the end of the rate case if Minnesota Power wants to continue rider recovery.

4. MP Supplemental Reply Comments - True-ups and Tracker Balances

Minnesota Power said that its February 14 Reply Comments included its good faith attempt to estimate the interim rate true-up using the methodology recommended by the Department and was included as Exhibit B6. The Company estimated that both the 2017 Projected Base Rate and the 2017 Actual rate base would be the same and, therefore, there would be nothing to true-up for 2017. The only year that differed from the 2017 test year was 2018, which MP approximated by using changes in rate base caused by additional 2018 tax and book depreciation and then compared to 2017 (actuals or projected) to calculate the true-up.

Minnesota Power continued to contend that a true-up is not needed even though this type of true-up would likely favor MP "as a result of low actual billing units compared to the higher projected billing units included in the 2017 test year in Minnesota Power's last rate case."

5. PUC Staff Disputed Issue discussion

a. Minnesota Power's Position

In its Petition, MP did not propose to true-up either the revenues or costs related to projects rolled into base rates in its 2016 rate case.

In Reply Comments, MP said that, per the Department's initial comments, a normal true-up cannot be used for the 23 month interim rate period of the 2016 rate case because many of the revenue requirement components for the projects that were rolled into base rates were already included in the interim rate refund calculation when final rates were established. The Company stated that it estimated its true-up based on the Department's suggested alternative true-up procedure.[32]

In calculating the true-up, MP modified the rate base and O&M estimates from the most recent filings for all projects by adding back the previously removed internal costs and the AFUDC on internal costs. This adjusted 2017 test year data was then extended on a monthly basis throughout 2018 and the differences in tax basis were calculated to come up with a decrease in rate base that could be attributed to change in tax and book basis in 2018 relative to 2017. The change was then multiplied by the rate of return in the 2016 rate case to develop a true-up amount associated with the additional depreciation in 2018. A similar true-up was also calculated for O&M. These true-ups were then netted against the $4.65 million cash collection shortfall to approximate a true-up to be included in the 2020 RRR factors.

In its Supplemental Reply Comments, Minnesota Power stated that it has contended that this true-up is not needed even though this type of true-up would likely favor MP "as a result of low actual billing units compared to the higher projected billing units included in the 2017 test year in Minnesota Power's last rate case".[33]

b. Department Position

In its comments,[34] the Department suggested an alternative to the normal true-up procedure that, essentially, recommended estimating separate revenue and cost true-ups; proposing that the revenue true-up be calculated as the difference between (a) actual revenues during the 23 month interim rate period, and (b) the assumed amount of RRR revenue credited to ratepayers in MP's calculation in the 2016 rate case.

However, the Department reported that:

> [T]he Company's calculations with respect to rate base and return on rate base do not match the Department's suggested methodology. Rather than calculating separate true-up amounts for 2017 and 2018 in the manner shown in Table [7][35] above, Minnesota Power appears to have calculated its proposed true-up amount difference between 2018 actuals and 2017 actuals. Thus, the Company did not calculate a true-up amount for 2017, and did not calculate a true-up amount for

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[32] See Department Comments, December 23, 2020, p. 13, third paragraph.

[33] Minnesota Power Supplemental Reply Comments, p. 6 (July 21, 2020)

[34] Ibid

[35] Briefing Papers, p. 24, "Table 7: Alternative Cost True-Up Methodology Suggested by the Department".

2018 that reasonably reflects the difference between the costs assumed in rates and actual costs. Further, the Company's rate base calculations do not include deferred tax assets related to net operating losses (DTA-NOLs) and production tax credits (DTA-PTCs).

Finally, the Department recommended that the Commission not require MP to true-up its costs and revenues for projects rolled into 2016 rate case base rates, because of the uncertainty surrounding the impact that a proper accounting of Deferred Tax Assets (DTAs) would have on the final true-up estimate.

c. PUC Staff Analysis

Staff acknowledges the Department's argument that the current true-up provided by MP is not completely accurate due to the calculation methods used and the absence of the full impact of deferred tax assets. This issue may be resolved considering the Department now recommends that the Commission not require MP to true-up its costs and revenues for projects rolled into 2016 rate case base rates and MP contends that this true-up is not needed.

D. Bison Wind Production Reporting

1. MP Initial Petition - Bison Wind Production

In compliance with Order Point 4 of the November 19, 2018 Order in Docket No. E015/M-18-375, Minnesota Power provided "the actual production for the Bison projects over the prior year and explains the underperformance compared to the 1,888,000 megawatt-hours assumed in the eligibility filings." The data is for actual production at Bison Wind for the period beginning July 1, 2018 through June 30, 2019. The Company noted that Bison Wind generated 1,496,131 MWh (megawatt hours), which was lower than the total energy estimate assumed in eligibility filings, primarily due to below average wind speeds in 2018.

2. Department Comments - Energy Production at the Bison Wind Facilities

In past RRR reviews the Department has expressed concerns regarding low levels of energy production at Bison wind projects compared to the levels MP projected to justify cost effectiveness in respective eligibility filings.

As shown in Table 3, below, Bison wind production continued to lag behind initial estimates, particularly at Bison 1 through 3. The Company noted in its petition[36] that production at Bison 4 was lower due to a high number of inverter module failures which resulted in the manufacturer replacing them at no cost to the Company. MP explained that these module issues resulted in about a 4 percent reduction in wind production during 2018.

[36] Minnesota Power Petition, August 15, 2019, page 24.

Table 3: 2014-2018 Wind Production at the Bison Wind Projects

Project	Initial Production Estimate (MWh)	Actual Production 2014 (MWh)	2015 (MWh)	2016 (MWh)	2017 (MWh)	2018 (MWh)	2014-2018 Average (MWh)		2014-2018 Average (% of Est.)
Bison 1	300,000	266,640	239,519	263,376	271,815	228,732	254,016		84.7%
Bison 2	380,000	324,087	294,291	328,831	328,923	276,225	310,471		81.7%
Bison 3	365,000	326,727	293,757	326,999	333,816	278,525	311,965		85.5%
Bison 4	835,000	44,820	712,033	832,159	840,920	712,649	774,440	1/	92.7%
Total	1,880,000	962,274	1,539,600	1,751,365	1,775,474	1,496,131	1,650,893		87.8%

Source: MP Response to DOC IR 2. See Attachment 2.
1/ 2015-2018 average, as Bison 4 was placed into service in December 2014.

The Company requested that the Commission discontinue the requirement to report on Bison wind production in future RRR petitions, but the Department remains concerned and continues to recommend that the Commission require continued reporting

3. MP Reply Comments - Bison Wind Projects Wind Production Reporting

The Company acknowledged that production for Bison 1, 2, and 3 wind projects have underperformed compared to initial estimates and MP expects future performance for these units to be similar to past production levels. MP explained the complexity of developing estimated future production and cited the short timeframe between eligibility filings for the first three units as a contributing factor. Further, MP noted that by the time the Bison 4 eligibility filing was submitted, the Company had much more data on which to develop production projections.

The Department recommended that MP be required to continue to report production levels in future RRR filings so the situation can be monitored. MP stated that this is unnecessary since the Company has been and continues to report Bison wind generation in the Fuel Adjustment Clause Forecast True Up filings each year. MP asked that it be freed from this additional reporting. Alternatively, MP said that it is agreeable to setting a threshold for triggering reporting in RRR filings based on a more current realistic expectation of production level.

4. Department Supplemental Comments [on MPUC Notice] Bison Wind Production Reporting

In response to MP's request to discontinue reporting related to the Bison Wind production the Department said that, notwithstanding the Company's additional discussion, the Department recommended that MP be required to continue reporting on its Bison Wind production in future RRR Dockets.

5. MP Supplemental Reply Comments - Bison Wind Reporting

Regarding continued Bison Wind production reporting Minnesota Power said:

> The Company's response in its February 14 Reply Comments does not suggest that regulatory determinations caused the Company to underestimate wind production as asserted by the Department. Instead, it points out the value of learning through experience and the possibility that had Minnesota Power implemented its third phase of wind development in alignment with the timeline presented in the Company's 2010 IRP Short-term Plan, it may have gained knowledge from its experience with the Bison 2 wind facility that could have resulted in greater accuracy when estimating the generating production for the Bison 3 Wind Project.

Although the Department still recommended that MP continue to report production levels at the Bison Wind Energy Center, the Company believes it is unnecessary since MP continues to report Bison Wind generation in the Fuel Adjustment Clause Forecast True Up filings each year. Therefore, MP respectfully requested to cease this redundant reporting requirement. In the alternative, MP is open to setting a threshold for triggering reporting in future RRR filings based on "a more realistic expectation of production levels of these units."

6. PUC Staff Disputed Issue Discussion

a. Minnesota Power's Position

In its petition, MP requested that the Commission discontinue its requirement that the Company continue to discuss actual production at the Bison Wind Energy Center in comparison to original estimates of production. The Company acknowledged that, primarily, the Bison 1, 2, and 3 projects have underperformed. In its reply comments MP stated that it expects future performance for these units to be similar to past production levels.

In addition, MP said that it believes the continuing requirement to be unnecessary since the Company has been and will continue to report Bison generation figures in the annual Fuel Adjustment Clause Forecast True Up filings. MP said that removing this redundant reporting requirement would free up resources for other Commission initiatives and compliance activities. As an alternative to continued RRR production reporting, the Company offered to set up a threshold for "triggering reporting in future RRR filings based on a more realistic expectation of production levels of these [Bison] units".

b. Department Position

The Department said that it continued to be troubled by low levels of production at the Bison Wind Energy Center and pointed out that as recently as its last RRR filing[37] the Commission required this reporting in all future RRR submissions. The Department continued to maintain its recommendation that MP be required to submit this reporting in future RRR dockets.

c. Staff Analysis

Staff notes that the Bison generation data provided in MP's most recent 2020 AAA Report[38] is not as detailed and does not contain a comparison of Bison Wind production by individual facility nor a comparison to original production estimates.

[38] Docket No. 20-171, *Report--2018-2019 Annual Automatic Adjustment of Charges Report*, March 2, 2020

VII. Decision Alternatives

1. Approve Minnesota Power's 2020 Renewable Resources Rider (RRR) factor with modifications. (MP, DOC)

Thomson Projects

2. Authorize MP to update the RRR for the revenue requirements for the two remaining Thomson Projects that were previously planned to be rolled into base rates in MP's resolved 2019 rate case through a compliance filing in this docket. (MP)

or

3. Do not allow MP to update the RRR revenue requirements for the two remaining Thomson Projects currently but allow MP to include them in the RRR tracker balance for future RRR cost recovery. (DOC)

Bison 6 LGIA Customer Credit

4. Require Minnesota Power to lower the Bison 6 LGIA Customer Credit corrected for the Large Power Class Allocator (28.504 percent to 18.241 percent) for 2018 and 2019 and on a going forward basis. Allow MP to update the RRR factor for the revenue requirements that were previously planned to be rolled into base rates in MP's resolved 2019 rate case through a compliance filing in this docket. (MP)

or

5. Allow MP to lower the Bison 6 LGIA Customer Credit (by correcting the Large Power Class Allocator from 28.504 to 18.241 percent), but on a going forward basis only (i.e. 2020 forward). This would eliminate MP's approximately $1 million in cost recovery from the RRR 2020 factor for its error in 2018 and 2019. Additionally, allow this 2020 true-up in MP's next RRR filing for 2021. (DOC)

Production Tax Credits (PTC)

6. Authorize Minnesota Power to include a true-up to actual PTCs for the Bison Wind Energy Center based on the 2017 test year (from the 2016 rate case) in the 2020 rider factor through a compliance filing in this docket. (MP)

or

7. Do not allow MP to update the RRR revenue requirements for a PTC true-up currently but allow MP to include them in its RRR tracker balance for future RRR cost recovery. (DOC)

2016 Rate Case True-up

8. Do not require the Company to true-up its costs and revenues for projects rolled-in from the RRR into base rates in the 2016 rate case. (DOC, MP does not appear to object)

or

9. Require MP to re-calculate its 2016 rate case true-up using the Department's recommended methodology to include the full impact of deferred tax assets in 2016 final base rates.

or

10. Allow MP to include in its revenue requirements the true-up revenue under-collection of $1,984,093 it calculated in its February 14, 2020 Reply Comments.

Bison Wind Production

11. Authorize MP to report Bison Wind Production only in its annual Fuel Adjustment Clause Forecast True Up filings. (MP) [Staff note: Attachment 20 in MP's AAA filings include trade secret Curtailment Reporting by month but only at a total Bison level.]

and/or

12. In a compliance filing, allow MP to propose a threshold that, if met, would require a comparison report of actual wind production to original estimates by individual Bison Wind facility. (MP)

or

13 Require MP to continue detailed Bison Wind Production reporting in future RRR filings. (DOC)

Effective Date

14. Authorize MP to implement the 2020 RRR factor on or after January 1, 2021 to eliminate the inclusion of forecasted costs and resulting need for ADIT proration if the Commission authorizes MP to update its revenue requirements to include 2020 costs in this docket. (Staff)

or

15. Authorize MP to implement the 2020 RRR factor effective on the first day of the month following the issuance of the Commission's order in this docket. (Staff)

Compliance Filing

16. Require MP to submit a compliance filing within ten days of the date of this order showing the final revenue requirement calculations, rate adjustment factors, and all related tariff changes. (Staff)

Department Calculation of Updated RRR Factors

		Minnesota Power Petition	Minnesota Power Reply Comments	Department Response Comments 1/
2018 Year-End Tracker Balance (Over)/Under Collection				
MN Jurisdiction		$ (7,750,576)	$ (7,800,743)	$ (7,800,743)
Large Power		$ (10,050,083)	$ (10,084,535)	$ (10,084,535)
All Other Classes		$ 2,299,507	$ 2,283,792	$ 2,283,792
2019 Projected Net Revenue Requirements				
MN Jurisdictional & Class Revenue Requirements		$ 1,254,668	$ 1,236,225	$ 1,236,225
Large Power		$ 773,831	$ 762,456	$ 762,456
All Other Retail Classes		$ 480,837	$ 473,769	$ 473,769
2019 Projected Rider Cash Collections				
MN Jurisdiction		$ 7,634,559	$ 7,634,559	$ 7,634,559
Large Power		$ 4,525,087	$ 4,525,087	$ 4,525,087
All Other Classes		$ 3,109,472	$ 3,109,472	$ 3,109,472
Interim Rate Undercollection				
MN Jurisdiction		n/a	$ 1,984,093	n/a
Large Power		n/a	$ 1,223,712	n/a
All Other Classes		n/a	$ 760,381	n/a
2019 Projected Year-End Tracker Balance (Over)/Under Collection				
MN Jurisdiction		$ 1,138,651	$ 3,054,134	$ 1,070,041
Large Power		$ (4,751,165)	$ (3,573,280)	$ (4,796,992)
All Other Classes		$ 5,889,816	$ 6,627,414	$ 5,867,033
2020 Net Revenue Requirements				
MN Jurisdictional & Class Revenue Requirements		$ (15,470)	$ (15,470)	$ (15,470)
Large Power		$ (9,542)	$ (9,542)	$ (9,542)
All Other Retail Classes		$ (5,929)	$ (5,929)	$ (5,929)
Adjustment to Bison 6 LGIA Credit (See page 2)				
MN Jurisdictional & Class Revenue Requirements		n/a	n/a	$ (836,853)
Large Power		n/a	n/a	$ (516,138)
All Other Retail Classes		n/a	n/a	$ (320,716)
Total 2020 RRR Factor Revenue Requirements				
MN Jurisdictional & Class Revenue Requirements		$ 1,123,181	$ 3,038,664	$ 217,718
Large Power		$ (4,760,707)	$ (3,582,822)	$ (5,322,672)
All Other Retail Classes		$ 5,883,887	$ 6,621,485	$ 5,540,388
Billing Units				
Large Power	kW - month	630,521	630,521	630,521
	kWh	5,288,437,000	5,288,437,000	5,288,437,000
All Other Retail Classes	kWh	3,099,359,000	3,099,359,000	3,099,359,000
Proposed Factors				
Large Power	($/kW - month)	(0.35)	(0.27)	(0.39)
	(¢/kWh)	(0.040)	(0.030)	(0.044)
All Other Retail Classes	(¢/kWh)	0.190	0.214	0.179

1/ The Department's position reflects costs from Minnesota Power's Reply Comments, but omits the Interim Rate Undercollection.

Department Estimate of Bison 6 LGIA Credit Adjustment

	As Filed in Minnesota Power's Reply Comments 1/	Adjusted to Reflect Original, Erroneous Allocation of Minnesota Power's Share of Bison 6 Plant Costs 2/	Difference
Bison 6 Average Rate Base	36,681,510	36,681,510	
Return on Average Rate Base			
After Tax Return on Equity	1,825,815	1,825,815	
Income Tax Component	736,455	736,455	
Interest Expense Component	765,323	765,323	
Total Return on Average Rate Base	3,327,593	3,327,593	
Depreciation Expense	1,715,440	1,715,440	
Total Return on Average Rate Base and Depreciation Expense in Base Rates	5,043,033	5,043,033	
Bison 6 LGIA share of allocated plant costs	*18.241%*	*28.504%*	
Bison 6 LGIA allocated Return on Rate Base and Depreciation Expense	919,900	1,437,466	
Allocated Operation & Maintenance Expense associated with Bison 6 LGIA	159,148	159,148	
Annual Base Rate Revenue Credit	1,079,048	1,596,614	
MN Jurisdictional Allocator	0.84360	0.84360	
MN Jurisdictional Annual Base Rate Revenue Credit	910,285	1,346,904	436,619
Single Lump Sum Related to Transaction Costs	122,601	122,601	
Total Base Rate Revenue Credit for first 12 months	1,032,886	1,469,505	436,619
Monthly Credit Feb. 2018 - Jan. 2019	86,074	122,459	36,385
Monthly Credit Feb. 2019 - Dec. 2019	75,857	112,242	36,385
Impact on 2018 Rev. Req. (11 months of 1st monthly credit)	946,812	1,347,046	400,234
Impact on 2019 Rev. Req. (1 mos. of 1st monthly credit, 11 mos. of 2nd credit)	920,501	1,357,120	436,619
Total Adjustment			836,853
Large Power Class Allocation			0.61676
Large Power Class Adjustment			516,138
All Other Classes Adjustment			320,716

1/ Minnesota Power Reply Comments, Ex. B-2, pg. 6

Minn. Stat. §216B.1645. Power Purchase Contract or Investment.

Subdivision 1. Commission authority.

Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424, and to satisfy the renewable energy objectives and standards set forth in section 216B.1691, including reasonable investments and expenditures made to:

(1) transmit the electricity generated from sources developed under those sections that is ultimately used to provide service to the utility's retail customers, including studies necessary to identify new transmission facilities needed to transmit electricity to Minnesota retail customers from generating facilities constructed to satisfy the renewable energy objectives and standards, provided that the costs of the studies have not been recovered previously under existing tariffs and the utility has filed an application for a certificate of need or for certification as a priority project under section 216B.2425 for the new transmission facilities identified in the studies;

(2) provide storage facilities for renewable energy generation facilities that contribute to the reliability, efficiency, or cost-effectiveness of the renewable facilities; or

(3) develop renewable energy sources from the account required in section 116C.779.

Subd. 2. Cost recovery.

The expenses incurred by the utility over the duration of the approved contract or useful life of the investment and expenditures made pursuant to section 116C.779 shall be recoverable from the ratepayers of the utility, to the extent they are not offset by utility revenues attributable to the contracts, investments, or expenditures. Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission under subdivision 1, which, in the case of transmission expenditures, are limited to the portion of actual transmission costs that are directly allocable to the need to transmit power from the renewable sources of energy. The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market.

Subd. 2a. Cost recovery for utility's renewable facilities.

(a) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9. For facilities not subject to review by the commission under section 216B.2422 or 216B.243, a utility shall petition the commission for eligibility for cost recovery under this section prior to requesting cost recovery for the facility. The commission may approve, or approve as modified, a rate schedule that:

(1) allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:

(i) return on investment;

(ii) depreciation;

(iii) ongoing operation and maintenance costs;

(iv) taxes; and

(v) costs of transmission and other ancillary expenses directly allocable to transmitting electricity generated from a project meeting the specifications of this paragraph;

(2) provides a current return on construction work in progress, provided that recovery of these costs from Minnesota ratepayers is not sought through any other mechanism;

(3) allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;

(4) allocates recoverable costs appropriately between wholesale and retail customers;

(5) terminates recovery when costs have been fully recovered or have otherwise been reflected in a utility's rates.

(b) A petition filed under this subdivision must include:

(1) a description of the facilities for which costs are to be recovered;

(2) an implementation schedule for the facilities;

(3) the utility's costs for the facilities;

(4) a description of the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred; and

(5) a description of the benefits of the project in promoting the development of renewable energy in a manner consistent with this chapter.

Subd. 3. Applicability to recovery of other costs.

Nothing in this section shall be construed to determine the manner or extent to which revenues derived from other generation facilities of the utility may be considered in determining the recovery of the approved cost or expenses associated with the mandated contracts, investments, or expenditures in the event there is retail competition for electric energy.

Subd. 4. Settlement with Mdewakanton Dakota Tribal Council at Prairie Island.

The commission shall approve a rate schedule providing for the automatic adjustment of charges to recover the costs or expenses of a settlement between the public utility that owns the Prairie Island nuclear generation facility and the Mdewakanton Dakota Tribal Council at Prairie Island, resolving outstanding disputes regarding the provisions of Laws 1994, chapter 641, article 1, section 4. The settlement must provide for annual payments, not to exceed $2,500,000 annually, by the public utility to the Prairie Island Indian Community, to be used for, among other purposes, acquiring up to 1,500 contiguous or noncontiguous acres of land in Minnesota within 50 miles of the tribal community's reservation at Prairie Island to be taken into trust by the federal government for the benefit of the tribal community for housing and other residential purposes. The legislature acknowledges that the intent to purchase land by the tribe for relocation purposes is part of the settlement agreement and Laws 2003, First Special Session chapter 11. However, the state, through the governor, reserves the right to support or oppose any particular application to place land in trust status.

From:	Addonizio, Craig (COMM)
To:	Hetherington, Raymond (PUC)
Subject:	RE: MP"s Renewable Resource Rider 19-523
Date:	Monday, August 03, 2020 3:02:55 PM

Hi Ray,

Yes, the Department is done commenting on this docket.

The Department does not have strong objections to updating the revenue requirements, but from a purely practical standpoint, I do have some concerns about the volume and nature of the issues MP wants to deal with in a compliance filing. I obviously have not seen any 2020 revenue requirements calculations, and there is a small but non-negligible chance that I'll have to issue an IR or two in order to determine that whatever MP ends up filing is reasonable. Similarly, I would not expect MP's PTC true-up to be overly complicated, but it is not just a simple true-up of a historical period, and thus there is again a non-negligible chance I'll have to ask an IR or two about it.

Lastly, I note that unless the PTC true-up amount is quite large, or for some reason there is a significant change to the Thomson-related revenue requirements, the 2020 dollar amounts shouldn't be significantly different than the 2019 dollar amounts, so I think that the rider factor calculated using the data we currently have in the record should be pretty close to what the factor would be if we updated everything, and for that reason I don't see a lot of benefit to adding the additional process.

Please let me know if you have any other questions.

Thanks
Craig

From: Hetherington, Raymond (PUC) <raymond.hetherington@state.mn.us>
Sent: Monday, August 03, 2020 2:17 PM
To: Addonizio, Craig (COMM) <craig.addonizio@state.mn.us>
Subject: MP's Renewable Resource Rider 19-523

Hi, Craig

Are you and the Department done commenting on this docket? MP's last response indicated they want to update revenue requirements for the Thomson projects, Bison 6 LGIA, and true-up of PTC's. Does the Department object?

Thanks,
Ray

Raymond Hetherington
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