AN ALLETE COMPANY

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June 5, 2018

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Renewable Resources Rider and 2018 Renewable Factor
Docket No. E015/M-18-___

Dear Mr. Wolf:

Minnesota Power hereby submits the attached Petition seeking Minnesota Public Utilities Commission approval of its 2018 Renewable Factor. This Petition is filed pursuant to Minn. Stat. § 216B.1645, subd. 2a for cost recovery of investments, expenditures and costs related to the development of the Thomson Hydroelectric Restoration Project through Minnesota Power's Renewable Resources Rider, along with certain reimbursements and true-ups.

Minnesota Power has included a Summary with this filing. As reflected in the Affidavit of Service, the Summary has been filed on the general service list utilized by Minnesota Power.

Please contact me at 218-355-3586 with any questions related to this matter.

Respectfully yours,

Susan Ludwig

SL:sr
Attach

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Renewable Resources Rider and 2018 Renewable Factor

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INITIAL FILING

SUMMARY

Minnesota Power submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. § 216B.1645 and Minn. Rules 7829.1300. Minnesota Power is seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd 2a to update cost recovery of investments, expenditures and costs related to the Thomson Hydroelectric Restoration Project, and other true-ups and reimbursements to customers as directed by the Commission, through Minnesota Power's Commission-approved Rider for Renewable Resources.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Renewable Resources Rider and 2018 Renewable Factor	Docket No. E015/M-18-___ **INITIAL FILING**

I. INTRODUCTION

Minnesota Power submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. § 216B.1645 and Minn. Rules 7829.1300. Minnesota Power ("the Company") is seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 2a to update cost recovery of incurred investments, expenditures and costs related to the development of the Thomson Hydroelectric Restoration Project ("Thomson Project"), through Minnesota Power's Commission-approved Rider for Renewable Resources ("Renewable Resources Rider" or "RRR"). The Thomson Project is a 71 MW hydroelectric restoration project. The Company also updates the Renewable Resources Rider tracker balance and includes certain reimbursements and true-ups as directed by the Commission. Specifically, the Company is requesting:

- Commission approval to implement the updated Renewable Resources Rider factor shown in Exhibit A-1 coincident with the implementation of final rates in Minnesota Power's current general rate case.[1]
- Commission provisional approval to zero out the rider sub-factor for the Large Power ("LP") class effective July 1, 2018.

On November 2, 2016, Minnesota Power filed a request with the Commission to increase its rates for electric utility service. For the general rate case, most of the RRR project costs were rolled into base rates. Also, the Company split the current 2017 RRR bill factor into two sub-factors: a base rate sub-factor and a rider sub-factor. The split in the bill factor was based on the originally-designed rate and the original revenue requirements as shown in Exhibit A-2, page 1.

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[1] Docket No. E015/GR-16-664. In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota. Implementation of final rates is expected in fourth quarter 2018.

This allowed the base rate sub-factor revenue to largely offset the RRR costs rolled into base rates, while at the same time it allowed the rider sub-factor revenue to be treated as continuing rider revenue to credit the continuing rider revenue requirements and tracker balance.[2]

Although the Company currently requests to zero out the LP rider sub-factor, the Company will continue to bill customers using the base rate sub-factor and credit that revenue to base rate revenue until implementation of final rates in the rate case. With the implementation of final rates, the base rate sub-factors for all customers will be zeroed out as the related revenue requirements become part of base rates. In the rate case, the Company included an estimated budget of $94.9 million in base rate rider cash collections in the 2017 test year for three current cost recovery riders: BEC4 Environmental Rider, Renewable Resources Rider, and Transmission Cost Recovery Rider. As shown in Exhibit A-2, page 2, the actual cash collection for all three riders for 2017 was $90.9 million. As summarized in the rate review Staff Briefing Papers,[3] Volume 1, page 259, the under-or over-collection in actual base rate cash collection will be addressed in each rider after final rates are implemented and the final base rate cash collections are known (Docket No. E015/GR-16-664).

As shown in Exhibit B-1, page 2, by the end of 2017, the Company collected the revenue requirements and tracker balance that had accumulated in the rider from 2015 to 2017, and is now slightly over-collected. As shown in Exhibit B-1, page 1, the 2018 Factor also includes two credits that offset rider revenue requirements totaling $4.4 million as discussed in detail below. Because of the slight over-collection and the revenue credits, the 2018 RRR Factor will be a negative factor and return approximately $7.6 million in one year to customers.

To avoid over-collection from the LP class and minimize the overcollection of the rider while waiting for the implementation of final rates, the Company believes it is appropriate to zero out the rider sub-factor. This would provide the LP customers with an immediate 5.3 percent rate decrease. Then, coincident with the implementation of final rates, the newly proposed 2018 RRR Factor would be implemented and result in a further rate reduction for the LP customers, resulting in a total decrease of about 6.5 percent compared to present rates (not including the interim rate increase).

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[2] The rider sub-factor is not subject to an interim and general rate increase. Refer to Herbert G. Minke's Direct Testimony, pages 3 to 4, filed on November 2, 2016.

[3] Staff Briefing Papers for the January 11, 2018 agenda.

Presently, all customers aside from the LP class ("Non-LP" customers) are receiving a revenue credit because they have a negative rider sub-factor that was implemented with the 2017 RRR Factors on January 1, 2017 at the beginning of the Company's rate case.[4] When the 2017 RRR Factors were implemented, the LP class experienced about a 1.5 increase in rates before considering interim rates, while the average residential customer experienced about a 5.3 percent decrease in rates before considering interim rates. Because the proposed 2018 RRR factor for Non-LP customers is almost the same as the current rider sub-factor, the Company believes it is appropriate to maintain the current rider sub-factor until the proposed factor can be implemented coincident with final rates. Coincident with the implementation of final rates, the newly proposed 2018 RRR Factor for Non-LP customers would be implemented and result in a rate reduction of about $0.04 per month for an average residential customer compared to present rates (not including the interim rate increase).

In order to provide timely rate relief for Large Power customers and to avoid over-collection while waiting for implementation of final rates, Minnesota Power requests that the Commission waive the requirements of Minn. Rule 7825.3200, which requires that utilities serve notice to the Commission at least 90 days prior to the proposed effective date of modified rates. The Company is requesting that the Commission waive the 90-day requirement and grant provisional approval of its request in this petition to zero out the rider sub-factor effective July 1, 2018. Because this will result in a substantial decrease in Large Power customer bills and avoid over-collection, the Company believes it is appropriate to grant provisional approval, with the understanding that a final decision would be made subsequent to a comment period in which parties may conduct a thorough review of the petition. Under Minn. Rule 7829.3200, the Commission shall grant a variance to its rules when it determines that the following requirements are met:

a. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;

b. granting the variance would not adversely affect the public interest; and

c. granting the variance would not conflict with standards imposed by law.

[4] Docket No. E015/M-16-776.

In this instance, enforcement of the rule would obviate Minnesota Power's desire to achieve the lower rates for LP customers as of July 1, 2018, on a provisional basis and subject to full Commission review and approval. Enforcement of the Rule requiring 90-day notice would impose an excessive burden, considering that Minnesota Power can true-up any differences in approved rates under a future RRR Factor. Minnesota Power believes that granting the variance in this instance would directly benefit LP customers and is not aware of any reason why it would adversely affect the public interest. If provisional approval is not granted to zero out the rider sub-factor on July 1, 2018, the Company estimates it will over-collect an additional $8.3 million from the Large Power class, assuming the new 2018 billing factors will be implemented on December 1, 2018. The additional $8.3 million in over-collection would go to the tracker balance and would not be returned to customers until the subsequent 2019 billing factors are implemented. Granting of the variance would also not conflict with standards imposed by law or rules governing the Commission's actions and is consistent with prior Commission decisions.

A provisional approval was granted in Minnesota Power's petition for approval of its 2017 Renewable Resource Rider (Docket No. E015/M-16-776), as well as Otter Tail Power Company's petition for approval of its environmental upgrades cost recovery rider (Docket No. E017/M-16-373) and transmission cost recovery rider annual adjustment (Docket No. E017/M-16-374). In these dockets, Minnesota Power and Otter Tail Power Company requested cost recovery factors which would decrease rates for customers. And in these dockets, the Minnesota Department of Commerce Division of Energy Resources ("Department") ultimately supported the utilities' requests for provisional approval of the reduced rates. A provisional approval was also requested in Minnesota Power's recent 2018 Boswell Unit 4 Emmissions Reduction Factor filing. While this request is on the Commission agenda for June 14, 2018, the Department recently recommended approval of the request, stating, *"[t]he Department generally does not support the implementation of new rider rates on a provisional basis, however, given the overlap between riders and base rates, and the interconnection between this petition and MP's recent rate case, the Department supports MP's request to zero-out the rider sub-factor, effective June 1, 2018 or on the first day of the month following Commission approval, whichever is later, on a provisional basis prior to the Commission's final determination in the instant docket"."*[5]

[5] Page 2 of the Department's Letter dated May 16, 2018, in Docket No. E015/M-18-264.

A. Background of the Renewable Resources Rider

On May 11, 2007, the Commission established Minnesota Power's Renewable Resources Rider through an order approving recovery of investments and expenditures for potential transmission upgrades for the Oliver Wind II power purchase agreement with FPL Energy allowed under Minn. Stat. § 216B.1645.[6] The Company subsequently utilized the RRR for the Company's Bison Wind Energy Center ("Bison Wind"). Bison Wind is Minnesota Power's 496.6 MW wind facility located in central North Dakota and developed over time in stages: Bison 1 (81.8 MW), Bison 2 (105 MW), Bison 3 (105 MW), and Bison 4 (204.8 MW).

The initial Bison 1 project cost recovery began in 2010, additional Bison 1, 2 and 3 cost recoveries started in late 2013, Bison 4 cost recovery started in June 2015, and Thomson Project cost recovery began in April 2016.

The Company's most recent Renewable Resources Rider Factor Filing ("2017 Factor Filing") was filed on November 2, 2016.[7] Because the proposed 2017 RRR factor resulted in a decrease in customer bills for most customers, and to allow cost recovery for RRR projects to be synchronized with the Company's rate case (also filed November 2, 2016), the Commission waived the 90-day requirement of Minn. Rule 7825.3200 and granted provisional approval of the 2017 renewable factor on Decmber 21, 2016, with implementation effective January 1, 2017. In an Order dated November 8, 2017 the Commission granted final approval of the the 2017 Factor Filing.

B. Current 2018 Renewable Resources Rider

In the Company's recent rate case, all of the Bison projects and most of the projects associated with the Thomson Project were rolled into base rates and are no longer included in the Renewable Resources Rider. Minnesota Power now seeks approval to adjust this Rider for recovery of updated tracker balance, updated investments and expenditures related to the two remaining projects associated with the Thomson Project and for certain true-ups and reimbursements as directed by the Commission and described below:

1. True-up of actual production tax credits, as directed in the Commission's March 12, 2018 Order in the Company's rate case at Order Point 37.

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[6] Docket No. E015/M-07-216.
[7] Docket No. E015/M-16-776.

2. Reimbursements of sums related to the Bison 6 Large Generator Interconnection Agreement ("LGIA"), as directed in the Commission's March 16, 2018 Order in the Company's Affiliated Interest Agreement petition (Docket No. E015/AI-17-304).

Because the 2018 RRR calcuations include an update to the 2016 tracker balances for Bison and Thomson projects which have been moved to base rates, descriptions of these projects are included in this filing.

Costs related to the Company's Camp Ripley Solar Project and the Community Solar Garden projects are not included in RRR bill factors. These costs will be included in a new Solar Renewable Factor in the future. The Commission approved a new Solar Renewable Factor as part of the Camp Ripley Solar project filing in Docket No. E015/M-15-773, in order to appropriately allocate costs to customers as set out in Minnesota's Solar Energy Standard ("SES"). The SES includes a provision[8] that exempts certain customers from paying costs to meet the SES. Because of this, all solar-related costs incurred in an effort to meet the SES have been excluded from the 2017 RRR rider calculations.

The Company's current proposed RRR will result in a rate reduction for all customer classes. The impact for the average residential customer will be a modest reduction of about 0.06 percent. The Large Power average class rate will decrease by about 6.54 percent.

C. <u>Bison 1 Project</u>

On March 23, 2009, Minnesota Power submitted a petition[9] seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 1 Project and associated transmission upgrades through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 1 Project is an 81.8 MW wind facility located southwest of Center, North Dakota, with the wind energy applied towards Minnesota Power's requirements under the Renewable Energy Standard ("RES").[10] The Bison 1 Project included upgrading Minnesota Power's existing DC Line between the Square Butte Substation in Center, North Dakota, and Minnesota Power's

[8] Minn. Stat. § 216B.1691, subd. 2f(f)
[9] Docket No. E015/M-09-285.
[10] Minn. Stat. § 216B.1691.

Arrowhead Substation near Duluth.[11] The upgrade increased the DC Line capacity from 500 MW to 550 MW, facilitating the deliverability and reliability of the Bison 1 Project.

On July 7, 2009, the Commission issued an order finding that Minnesota Power's Bison 1 Project, including transmission related components, qualifies as an eligible technology under Minn. Stat. § 216B.1691, its generated energy is a reasonable means by which to meet Minnesota Power's renewable energy standard obligations, and the project is prudent and reasonable when compared to alternative approaches for meeting these obligations.

D. Bison 2 Project

On March 24, 2011, Minnesota Power submitted a petition[12] seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 2 Project through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 2 Project is a 105 MW wind facility located in Oliver and Morton Counties in central North Dakota, with the wind energy applied towards Minnesota Power's requirements under the RES.

On September 8, 2011, the Commission issued an order finding that Minnesota Power's Bison 2 Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

E. Bison 3 Project

On June 21, 2011, Minnesota Power submitted a petition[13] seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 3 Project through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 3 Project is also a 105 MW wind facility located in Oliver and Morton Counties in central North Dakota, with the wind energy applied towards Minnesota Power's requirements under the RES.

On November 2, 2011, the Commission issued an order finding that Minnesota Power's Bison 3 Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

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[11] Docket No. E015/PA-09-526.
[12] Docket No. E015/M-11-234.
[13] Docket No. E015/M-11-626.

F. Bison 4 Project

On September 27, 2013, Minnesota Power submitted a petition[14] seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 4 Project through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 4 Project is a 204.8 MW wind facility located in Oliver County in central North Dakota, with the wind energy applied towards Minnesota Power's requirements under the RES. The Bison 4 Project included expanding the existing Bison Substation, constructing a new Tri-County Substation, constructing 11 miles of 230 kV transmission line connecting the two substations, and integrating software to enhance voltage regulation. In addition, a component of this project involved upgrading the capacity of the Center-Heskett 230 kV transmission line that runs between Center and Mandan, North Dakota to support the injection of additional wind energy onto the alternating current (AC) system.

On January 17, 2014, the Commission issued an order finding that Minnesota Power's Bison 4 Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

G. Thomson Project

On July 3, 2014, Minnesota Power filed a petition[15] with the Commission seeking approval to include costs of a hydroelectric restoration project at the Company's Thomson Hydroelectric Facility through the Renewable Resources Rider. The Thomson Project was developed to restore 71 MW of renewable energy to the hydroelectric facility after it was severely damaged in record rainfall and flooding in June 2012. On March 5, 2015, the Commission issued an order finding that the Thomson Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

[14] Docket No. E015/M-13-907.
[15] Docket No. E015/M-14-577.

II. PROCEDURAL MATTERS

A. General Filing Information

Pursuant to Minn. Stat. § 216B.16, subd. 1 and Minn. Rule 7829.1300, Minnesota Power provides the following required general filing information.

1. **Summary of Filing (Minn. Rule 7829.1300, subp.1)**

A one-paragraph summary accompanies this Petition.

2. **Service on Other Parties (Minn. Rule 7829.1300, subp. 2)**

Pursuant to Minn. Stat. § 216.17, subd. 3 and Minn. Rules 7829.1300, subp. 2, Minnesota Power eFiles the Petition on the Minnesota Department of Commerce Division of Energy Resources and the Minnesota Office of the Attorney General – Antitrust and Utilities Division. A summary of the filing prepared in accordance with Minn. Rules 7829.1300, subp. 1 is being served on Minnesota Power's general service list.

3. **Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 3(A))**

Minnesota Power
30 West Superior Street
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(218) 722–2641

4. **Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 3(B))**

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5. **Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 3(C))**

This Petition is being filed on June 5, 2018. Minn. Rule 7825.3200 requires that utilities serve notice to the Commission at least 90 days prior to the proposed effective date of modified rates. However, the Company is requesting the Commission waive the 90-day requirement and grant provisional approval to zero out the Large Power class rider sub-factor effective July 1, 2018 and then implement the new 2018 Renewable Factors for all classes coincident with implementation of final rates in the Company's current rate case. This will allow for a timely rate reduction for the Large Power class and avoid further over collection. However, a final Commission decision on implementing the 2018 Renewable Resources Factor would be made subsequent to a comment period in which parties conduct a thorough review of the petition.

6. **Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 3(D))**

This Petition is made pursuant to Minn. Stat. § 216B.1645, subd. 2a. Minn. Rule 7825.3200 requires that utilities serve notice to the Commission at least 90 days prior to the proposed effective date of modified rates. Furthermore, Minnesota Power's proposed 2018 Renewable Resources Factor falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4 permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

7. **Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 3(E))**

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8. **Impact on Rates and Services (Minn. Rule 7829.1300, subp. 3(F))**

The 2018 Renewable Resources Factor will have no effect on Minnesota Power's base rates. The additional information required under Minn. Rule 7829.1300, subp. 3(F) is included throughout this Petition.

9. **Service List (Minn. Rule 7829.0700)**

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III. RENEWABLE RESOURCES RIDER AUTHORIZATION

Minn. Stat. § 216B.1645, subd. 2a allows the Commission to approve a 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 Minn. Stat. § 216B.1645, subd. 2a, 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; and

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

IV. 2018 RENEWABLE RESOURCES FACTOR

A. Description of Facilities (Minn. Stat. § 216B.1645, subd. 2a(b)(1))

As detailed in Minnesota Power's July 3, 2014, Petition, the Thomson Project is a 71 MW hydroelectric restoration project located at the Thomson Development in Minnesota Power's St. Louis River Hydro System. The Thomson facility was severely damaged and brought offline by record rainfall and flooding in June 2012. The project was to restore the facility from the damages and upgrade Thomson to meet current safety and engineering standards. Specifically, the project included reconstruction of the forebay canal, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system, and construction of additional spillway facilities at the Thomson main dam.

Most of the projects associated with the Thomson Project were completed by the time of the Company's recent rate case and were moved into base rates. Only two projects remain and are still included the Renewable Resources Rider – the Thomson Spill Capacity project and the Thomson Dam 6 refurbishment. The Thomson Spill Capacity project was completed and placed into service at the end of 2017. The Thomson Dam 6 project is well underway and is expected to be placed in-service by the end of 2018. All permits and approvals required for construction have been acquired and all major stakeholders (including the Federal Energy Regulatory Commission and the State Historic Preservation Office) have been appropriately involved throughout the project.

The Company is pleased to report that the Thomson Project has resulted in improved efficiency of the units resulting in an increase of generation capability from pre-reconstruction levels. The Thomson station is now capable of nearly 75 MW at peak production.

B. Project Schedule (Minn. Stat. § 216B.1645, subd. 2a(b)(2))

As described above, most of the Thomson Project has been completed. The Spill Capacity project was completed at the end of 2017 and the Dam 6 project is anticipated to be completed by the end of 2018.

C. Minnesota Power's Costs (Minn. Stat. § 216B.1645, subd. 2a(b)(3 & 4))

Minnesota Power has employed multiple steps to help ensure the lowest costs to customers on projects recoverable through the Renewable Resources Rider. Minn. Stat. § 216B.1645, subd. 2a(b)(4). Minnesota Power utilized its standard purchasing procedures to obtain competitive quotations for most major purchases and awarded contracts to the lowest bidder(s), unless a better overall value could be obtained. In some cases, contracts were awarded on a single source basis to qualified contractors based on utilizing existing partnering agreements or based upon original equipment manufacturer considerations. Minnesota Power will provide any additional information deemed necessary, as part of notice and comment, for the Commission to conclude that "the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred." Minn. Stat. § 216B.1645, subd. 2a(b)(4).

Based on the original Petition, Minnesota Power anticipated that the Thomson Project would cost approximately $90.4 million, net of insurance proceeds. Currently the Company estimates the overall project costs will be finalized at about $95.7 million, net of insurance proceeds. In order to remain within the maximum level of capital expenditures approved in the original Petition, capital expenditures, net of insurance proceeds, were capped in both the 2017 and current 2018 Renewable Resources Factors at $90.4 million. After deducting internal costs, AFUDC on internal costs, and wholesale AFUDC, the capital expenditures for calculating revenue requirements was capped at $84.1 million, which is equal to the amount of capital expenditures utilized for calculating revenue requirements in the original Petition. Refer to Exhibit B-3 for additional detail on Thomson Project expenditures utilized in calculating the revenue requirements.

In addition to revenue requirements on project costs and updated tracker balance, the calculation of the 2018 Renewable Resources Rider includes other amounts as directed by the Commission and described below.

1. Production Tax Credit True-ups

The Commission's March 12, 2018 Order in the Company's rate case directed Minnesota Power to perform an annual true-up of actual production tax credits through the Renewable Resources Rider (see Order Point 37). Those amounts have been included in the calculation of the RRR factor as shown in Exhibit B-1, page 1, and are shown in detail in Exhibit B-2, page 8.

2. Reimbursements related to the Bison 6 LGIA

The Commission's March 16, 2018 Order in the The Company's Affiliate Interest Agreement petition between ALLETE, Inc. and ALLETE Clean Energy Inc.[16] directed Minnesota Power to use the Renewable Resources Rider to reimburse its ratepayers for certain costs associated with the Bison 6 LGIA transfer. On April 17, 2018 and May 7, 2018, the Company filed Compliance Filings with the Commission which provided the detail of these cost amounts. The 2018 RRR calculations include reimbursements as documented in the Company's April 17 and May 7 Compliance Filings. Those amounts have been included in the calculation of the RRR factor as shown in Exhibit B-1, page 1, and are shown in detail in Exhibit B-2, page 7.

D. Revenue Requirements

The total recoverable retail revenue requirements for the 2018 Renewable Resources Rider is -$7.6 million, consisting of a -$4 million 2017 tracker balance, $0.8 million in projected revenue requirements for 2018 for the Thomson Projects, a revenue credit of $1.5 million for the 2018 Bison LGIA reimbursement, and a revenue credit of $2.9 million for the 2017 PTC true-up. As shown in Exhibit B-1, page 1, the 2018 RRR factor will return about $4.6 million to Large Power customers and about $3 million to Non-LP customers.

The 2018 RRR Factors shown in Exhibit A-1 are calculated assuming they are effective on December 1, 2018, or coincident with implementation of final rates in the Company's rate

[16] Docket No. E015/AI-17-304.

case. Supporting documentation for revenue requirement calculations is included in exhibits as described below:

- Exhibit B-1, page 1, summarizes the revenue requirements, cost allocation, and rate design for all projects.
- Exhibit B-1, page 2, provides a summary of the 2015, 2016 and 2017 ending trackers.
- Exhibit B-1, pages 3 to 7 shows the 2016 and 2017 trackers for the Bison Projects and Thomson projects.
- Exhibit B-1, page 8, shows the 2018 tracker for the two remaining Thomson projects.
- Exhibit B-2 includes the revenue requirement calculations for each Thomson project.
- Exhibit B-2 also includes the Thomson base rate revenue credits, as well as the Bison 6 LGIA credit, PTC true-up credit, and the prorata accumulated deferred income taxes ("ADIT") calculation.
- Exhibit B-3 details capital expenditure and construction work in progress ("CWIP") calculation for the Thomson projects.
- Exhibit B-4 shows the details of the authorized rates of return utilized in the revenue requirements.
- Exhibit B-5 provides background on the allocation factors.

A description of the revenue requirement components is provided below.

1. Return on Construction Work in Progress

Minnesota Power will record capital expenditures related to the Renewable Resources Rider in Federal Energy Regulatory Commission ("FERC") Account 107 – CWIP. Minnesota Power is requesting a current return on CWIP on the components that are not yet placed in-service beginning when cost recovery under the Rider is approved by the Commission. A return on CWIP will be the only component of revenue requirements recovered under the Rider until the components not yet in-service are placed in-service. Consistent with the terms of the 2011 Transmission Cost Recovery Factor Filing[17] and subsequent filings, internal capitalized costs are excluded from the CWIP balances as shown in Exhibit B-3. In compliance with the terms of the

[17] Docket No. E015/M-11-695.

2013 Renewable Resources Factor Filing,[18] allowance for funds used during construction ("AFUDC") on internal capitalized costs is excluded from CWIP balances as shown in Exhibits B-3.

a) Allowance for Funds Used During Construction

The Company will calculate AFUDC and record an offsetting regulatory liability (referred to as a "contra" entry) equaling 100 percent of the RRR projects' AFUDC and include that regulatory liability as a reduction to rate base through an entry to "Pre-funded AFUDC Regulatory Liability." After the projects are placed in-service, the amount of the Pre-funded AFUDC Regulatory Liability will be amortized over the lives of the projects.

In a December 2010 Order, FERC prescribed specific accounting treatment, which requires the Company to record the Pre-funded AFUDC Regulatory Liability by debiting Account 407.3, Regulatory Debits, and crediting Account 254, Other Regulatory Liabilities, in accordance with the instructions of those accounts. In addition, the Company will amortize the Pre-funded AFUDC Regulatory Liability as an offset to depreciation expense by debiting Account 254 and crediting Account 407.4, Regulatory Credits. The Company will maintain all necessary controls to ensure the amount of the Pre-funded AFUDC Regulatory Liability recorded in Account 254 includes the total amount of AFUDC accrued on the projects. This FERC-approved methodology for the application of AFUDC is currently being applied to all Minnesota Power current cost recovery rider projects.

b) Return on Investment – CWIP

Revenue requirements during the construction phase of the projects will be based on the average monthly CWIP balance of the RRR projects. The Return on Investment – CWIP will be calculated on the average of the beginning and ending monthly CWIP balance until the projects are placed in-service. The components of the revenue requirement will include an after-tax return on equity component, current and deferred income taxes, and interest expense. The total annual revenue requirements are the sum of the monthly current return on CWIP calculations until the projects are placed in-service. At that time, the ending CWIP balance is transferred to plant in-service and Minnesota Power will begin to recover full revenue requirements. Internal

[18] Docket No. E015/M-13-410.

capitalized costs and AFUDC on internal costs are excluded from the CWIP balances as shown in Exhibits B-3.

(i) Return on Equity Component

The return on investment will be based on Minnesota Power's last retail rate case.[19] Minnesota Power will use the average monthly CWIP balance multiplied by the after-tax equity return rate and the equity percentage of the allowed capital structure from the last rate case to calculate the return on equity component of the revenue requirement calculation.

[Return on Equity Component = Average Monthly CWIP Balance X After-Tax Equity Return Rate X Capital Structure Equity Percentage]

(ii) Income Tax Expense Component

Minnesota Power will include a component of the revenue requirement calculation to recover the effective rate of taxes.[20] This represents both current and deferred income taxes. The income tax amount will be based upon the Return on Equity component of the revenue requirement to equate it to a pretax amount.

[Income Taxes = Return on Equity Component X 1/(1-41.37%) X 41.37%]

(iii) Interest Expense Component

Minnesota Power will include a component of the revenue requirement calculation to recover an equivalent amount of interest expense that would be incurred given the investment in the RRR projects. The interest component will be calculated based on the average monthly CWIP balance times the debt rate approved in the last rate case times the debt percentage of the allowed capital structure from the last rate case.

[Interest Expense = Average Monthly CWIP Balance X Debt Rate X Capital Structure Debt Percentage]

[19] Docket No. E015/GR-09-1151. Minnesota Power will update the return on equity and jurisdictional allocator amounts determined in the Company's current rate case (Docket No. E015/GR-16-664) once final rates are implemented. These amounts will be incorporated into the tracker coincident with final rates and will be reflected in the next RRR filing.
[20] The tax calculations do not reflect changes due to the 2017 Federal Tax Act. Once determinations have been made in the Commission's Investigation Regarding the Tax Cuts and Jobs Act of 2017 (Docket No. E, G-999/CI-17-895), the Company will update the RRR tracker and incorporate the impacts in the subsequent factor filing.

(iv) Thomson Base Rate Revenue Credit

The Minnesota Jurisdictional Revenue Requirements include a credit for plant equipment that was retired as a result of the Thomson Project. Equipment with original installed cost of approximately $3.1 million was retired as part of the Thomson Project. The jurisdictional revenue requirements associated with this equipment that were in base rates were deducted from the Thomson Project jurisdictional revenue requirements. This credit includes a return on average rate base, depreciation expense, and associated property tax. This credit began with the start of revenue requirements in February 2015 following Commission approval of the Thomson Project and continued until the Thomson projects and retirements were rolled into base rates starting January 1, 2017. Refer to Exhibit B-2, page 5 for this credit that was applied to the 2015 and 2016 revenue requirements. Beginning December 1, 2017 with the retirement of plant associated with one of the last projects remaining in the rider, a new base rate revenue credit is applied and will continue until this final project is rolled into base rate rates in a subsequent rate case. The calculation of this new revenue credit is shown in Exhibit B-2, page 6.

(v) Property Taxes

Any Minnesota property taxes that Minnesota Power is required to pay on CWIP that is in-place will be included in the project revenue requirements.

2. Full Revenue Requirements – In-service

Full revenue requirements will be based on the Original Installed Cost ("OIC") when the final Thomson project is placed in-service. Internal capitalized costs and AFUDC on internal costs are excluded from the OIC balances as shown in Exhibits B-3. As described in greater detail below, the in-service revenue requirements will be calculated using the adjusted average monthly rate base for the projects plus related expenses. The components of the revenue requirements will include an after-tax return on investment, current and deferred income taxes, interest expense, depreciation expense, and property taxes. Revenue requirements will additionally include an applicable true-up of the PTCs and North Dakota Investment Tax Credits ("ND ITC") when utilized.

a) Adjusted Average Rate Base

Adjusted average rate base will be calculated using the monthly balance of the RRR projects' OIC reduced by the accumulated depreciation for the projects. The adjusted average rate base will also be adjusted for any differences between book and tax depreciation expense through accumulated deferred income taxes.

b) Return on Equity Component

The return on investment calculation will be based on Minnesota Power's last retail rate case.[21] Minnesota Power will use the average monthly adjusted rate base multiplied by the after-tax equity return rate and the equity percentage of the allowed capital structure from the last rate case to calculate the return on equity component of revenue requirements.

[Return on Equity Component = Average Monthly Adjusted Rate Base X After-tax Equity Return Rate X Capital Structure Equity Percentage]

c) Income Tax Expense Component

Minnesota Power will include a component of the revenue requirement calculation to recover the effective rate of taxes.[22] This represents both current and deferred income taxes. The income tax amount will be based upon the Return on Equity component of the revenue requirement to equate it to a pre-tax amount.

[Income Taxes = Return on Equity Component X 1/(1-41.37%) X 41.37%]

d) Interest Expense Component

Minnesota Power will include a component of the revenue requirement calculation to recover an equivalent amount of interest expense that would be incurred given the investment in the RRR projects. The interest component will be calculated based on the average monthly adjusted rate base times the debt rate approved in the last rate case times the debt percentage of the allowed capital structure from the last rate case.

[21] Docket No. E015/GR-09-1151. Minnesota Power will update the return on equity determination from the Company's current rate case (Docket No. E015/GR-16-664) once final rates are implemented. These amounts will be incorporated into the tracker coincident with final rates and will be reflected in the next RRR filing.
[22] The tax calculations do not reflect changes due to the 2017 Federal Tax Act. Once determinations have been made in the Commission's Investigation Regarding the Tax Cuts and Jobs Act of 2017 (Docket No. E, G-999/CI-17-895), the Company will update the RRR tracker and incorporate the impacts in the subsequent factor filing.

[Interest Expense = Average Monthly Adjusted Rate Base X Debt Rate X Capital Structure Debt Percentage]

e) Depreciation Expense Component

Once the assets are placed in service, depreciation on the RRR projects will be recovered through the Rider. Depreciation expense will be calculated on a straight line basis over the lives of the projects on the components and will begin as the assets are placed in-service.

f) Property Tax Component

Property tax on wind generation assets in North Dakota is a combination of wind generation rated capacity and actual kilowatt hours generated. Property taxes on the Thomson projects are included based upon the value of the property and applicable tax rates.

g) O&M Expense Component

Any O&M expenses related to the RRR pprojects would also be recovered through the Rider. However, since there are no incremental O&M expenses related to the Thomson Project, there are no O&M expenses included in the calculation of revenue requirements for the 2018 Renewable Resources Factor.

h) Production Tax Credits

The PTCs generated from the Bison wind projects were rolled into base rates starting January 1, 2017 in the Company's current rate case. As discussed previously, the 2018 RRR Factor includes a PTC true-up for the amount included in base rates compared to the 2017 amounts. This true-up in shown in Exhibit B-2, page 8.

i) North Dakota Investment Tax Credits[23]

The Bison Projects qualify for the ND ITC. Currently no North Dakota income taxes are charged to revenue requirements. To the extent Minnesota Power generates taxable income in North Dakota in the future, any resulting income taxes will be offset by the use of this nonrefundable credit. Minnesota Power will offset future Renewable Resources Rider revenue requirements with ND ITC once they have been realized. Based upon Minnesota Power's

[23] In an Order dated December 7, 2017, in the Company's 2015 Factor Filing (Docket No. E015/M-14-962), the Commission allowed Minnesota Power to reflect in its revenue requirements the North Dakota ITCs that the Company would realize on a separate-return basis.

current estimates of corporate North Dakota income taxes, it is not anticipated that the Company will be able to fully utilize these tax credits.

j) Thomson Investment Tax Credits

Federal investment tax credits ("ITCs") are currently available for qualified renewable energy projects and the Commission has directed Minnesota Power to return any amortization of the ITCs associated with the Thomson Project to ratepayers through future RRR filings until they can be included in base rates in a subsequent rate case.[24] The Thomson Project qualified for $22.3 million of federal ITCs under Internal Revenue Service ("IRS") guidance pertaining to when a rebuilt renewable asset will qualify as a new asset for purposes of earning a tax credit. As a result of Minnesota Power's net operating losses ("NOLs"), the cash benefit of the federal ITCs from this project will not be realized in the year generated, but deferred for future utilization. Under IRS normalization rules, Minnesota Power cannot begin to amortize this new federal ITC until it is utilized in a subsequent tax year. Minnesota Power currently anticipates fully utilizing the NOL carryforward in approximately 2024, and at that time will begin using the Minnesota Power tax credit carryforwards. Once the federal ITC is utilized, Minnesota Power will begin amortizing these federal ITCs to reduce regulatory tax expense in a future rate case, or revenue requirements in a future factor filing. The Thomson ITCs have no impact on revenue requirements in this filing; they are included in the filing discussion to provide full transparency of the full costs and benefits generated from this project.

k) Thomson Base Rate Revenue Credit

The Minnesota jurisdictional revenue requirements include a credit for plant equipment that was retired as a result of the Thomson Project. Equipment with original installed cost of approximately $3.1 million was retired as part of the Thomson Project. The jurisdictional revenue requirements associated with this equipment that were in base rates were deducted from the Thomson Project jurisdictional revenue requirements. This credit includes a return on average rate base, depreciation expense, and associated property tax. This credit began with the start of revenue requirements in February 2015, following Commission approval of the Thomson Project, and continued until the Thomson projects and retirements were rolled into base rates

[24] See the Commission's November 8, 2017 Order at Point 3 in Minnesota Power's 2017 Renewable Resources Rider petition, Docket No. E015/M-16-776.

starting January 1, 2017. Refer to Exhibit B-2, page 5 for this credit that was applied to the 2015 and 2016. Beginning December 1, 2017 with the retirement of plant associated with one of the last projects remaining in the rider, a new base rate revenue credit is applied and will continue until this final project is rolled into base rate rates in a subsequent rate case. The calculation of this new revenue credit is shown in Exhibit B-2, page 6.

l) Deferred Income Taxes

Under Internal Revenue Code Section 167(l), rate-regulated utilities that utilize accelerated tax depreciation are required to use a normalization method of accounting. If a future test year, or a part historical and part future test year are utilized when determining the reserve for deferred taxes for the reduction of rate base, then a specific pro rata calculation must be utilized to avoid a normalization violation. In this RRR current cost recovery filing, the Company is utilizing a 2018 test year. As discussed above in Section D. Revenue Requirements, the 2018 Renewable Adjustment Factors shown in Exhibit A-1 are proposed to be effective on December 1, 2018, or coincident with implementation of final rates in the Company's rate case. This results in a part historical and part future test year, with the future test year estimated to be the month of December 2018. As discussed in recent electric utility rate proceedings, the IRS has issued several Private Letter Rulings on this issue in the past few years, which give guidance on the proper treatment to avoid a normalization violation. In 2017 the IRS issued PLR 201741004, which addressed a situation in which a taxpayer had three state cost recovery riders which had an annual filing to set the projected rate, with a following true-up filing. The IRS determined that the projected rates employed a future test period and, therefore, required the proration calculation. The IRS also determined that the true-up calculation employed a historical test period and, therefore, was not subject to the proration requirement. The Company has followed IRS guidance and included the prorata deferred tax calculation in this filing for one month, resulting in a minimal impact on the deferred tax liability.

Refer to Exhibit B-2, page 9, for the calculation of the prorata ADIT.

m) Impact of 2017 Federal Tax Act

The 2018 revenue requirements do not reflect any changes due to the 2017 Federal Tax Act. Once determinations have been made in the Commission's Investigation Regarding the Tax

Cuts and Jobs Act of 2017,[25] the Company will update the RRR tracker and incorporate the impacts in the subsequent factor filing. The anticipated updates are the removal of 40 percent bonus tax depreciation on projects placed in service, and the reduction in the federal tax rate from 35 percent to 21 percent.

n) Application of Rate Case Authorized Rate of Return and Jurisdictional and Class Alloctors

Assuming final rates in the Company's current rate review will be implemented on December 1, 2018, the rider revenue requirements were calculated utilizing the rate of return from the Commission's March 12, 2018, rate review Findings of Fact, Conclusions, and Order starting December 1, 2018. Refer to Exhibit B-4. Similarly, the jurisdictional and class allocators from the Company's rate review were utilized starting on December 1, 2018, Refer to Exhibit B-5.

E. Rate Calculation and Customer Impact

Minnesota Power has calculated its proposed 2018 Renewable Adjustment Factors as shown in Exhibit A-1. Minn. Stat. § 216B.1645, subd. 2a(b)(3). Exhibit B-1, page 1, summarizes the revenue requirements, tracker balance, cost allocation, and rate design for the 2018 Renewable Adjustment Factors. Minnesota Power proposes to maintain the current Renewable Adjustment Factor rate design that incorporates demand ($/kW-month) and energy (¢/kWh) adders for the LP class and an average energy (¢/kWh) adder that is applied to all other retail classes. Specifically, the LP revenue requirements are split between demand and energy based on LP's base rate demand and energy revenue split of approximately 56 percent demand and 44 percent energy as currently drafted in the Company's upcoming Compliance Filing in its current rate case (Docket No. E015/GR-16-664). The LP demand rate adder will be calculated as 56 percent of the projected LP revenue requirement divided by the LP class Billing Demand (kW-month) from Minnesota Power's most recent budget. The LP energy rate adder will be calculated as 44 percent of the projected LP revenue requirement divided by the LP energy (kWh) sales from Minnesota Power's most recent budget. The Renewable Adjustment Factor for the other Non-LP classes will continue to be calculated as an average energy-based (¢/kWh)

[25] Docket No. E, G-999/CI-17-895.

charge consisting of the projected revenue requirements divided by the total energy (kWh) sales of the other Non-LP classes from Minnesota Power's most recent budget.

Minnesota Power has utilized the appropriate authorized rates of return, the jurisdictional Power Supply Production Demand allocators, and the jurisdictional Power Supply Transmission Demand allocators, based on those approved by the Commission in Minnesota Power's last retail rate case[26] and as approved in previous Renewable Resources Rider Factor filings. Refer to Exhibit B-4 for authorized rates of return, and to Exhibit B-5 for the allocation factors from Minnesota Power's last retail rate case. As mentioned above, the authorized rate of return and jurisdictional and class allocators from the Company's current rate case are applied December 1, 2018, assuming this is coincident with implementation of final rates in the Company's current rate review.

1. Customer Impact

Table 1 below summarizes the estimated rate impacts by customer class assuming the 2018 Renewable Adjustment Factors are implemented on December 1, 2018 or coincident with implementation of final rates in the Compnay's current rate case. The rate decrease in cents per kWh shown in Table 1 below is the incremental change between the current 2017 rider sub-factors and the 2018 Renewable Factors in this filing.

Based on the above assumptions, all of the Non-LP classes would have an average rate decrease of about 0.006 cents per kWh. For an average residential customer this would be about a 0.06 percent reduction or about $0.04 less per month. The LP average class rate would decrease about 0.442 cents per kWh or a decrease of about 6.54 percent.

If the Commission approves the Company's proposal to immediately zero out the current Large Power rider sub-factor effective July 1, 2018, the LP class would see about a 5.29 percent rate reduction compared to current rates (not including interim rate increase).

[26] Docket Nos. E015/GR-09-1151.

Table 1. Estimated Customer Impact

Proposed Effective Date	**1/1/2018**	**7/1/2017**
Rate Class Impacts 1/		
Residential		
Average Current Rate (¢/kWh)	10.697	na
Increase (Decrease) (¢/kWh)	(0.006)	na
Increase (Decrease) (%)	(0.06%)	na
Average Impact ($/month)	($0.04)	na
General Service		
Average Current Rate (¢/kWh)	10.609	na
Increase (Decrease) (¢/kWh)	(0.006)	na
Increase (Decrease) (%)	(.06%)	na
Average Impact ($/month)	($0.16)	na
Large Light & Power		
Average Current Rate (¢/kWh)	8.117	na
Increase (Decrease) (¢/kWh)	(0.006)	na
Increase (Decrease) (%)	(0.07%)	na
Average Impact ($/month)	($15.58)	na
Large Power		
Average Current Rate (¢/kWh)	6.759	6.759
Increase (Decrease) (demand + energy combined) (¢/kWh)	(0.442)	(0.358)
Increase (Decrease) (%)	(6.54%)	(5.29%)
Average Impact ($/month)	($276,047)	($223,563)
Municipal Pumping		
Average Rate (¢/kWh)	10.290	na
Increase (Decrease) (¢/kWh)	(0.006)	na
Increase (Decrease) (%)	(0.06%)	na
Average Impact ($/month)	($0.32)	na
Lighting		
Average Rate (¢/kWh)	16.226	na
Increase (Decrease) (¢/kWh)	(0.006)	na
Increase (Decrease) (%)	(0.04%)	na
Average Impact ($/month)	($0.02)	na

Notes:
1/ Average current rates are 2017 Test Year Preent Rates with all riders from MP's 2016 Rate Case (E015/GR-16-664) Average $/month impact based on 2018 budgeted billing units. The increase/decrease in cents/kWh is the incremental decrease due to the new factor being implemented (new 2018 Renewable Factor minus the current 2017 Renewable rider sub-factors).

F. Project Benefits in Promoting Renewable Energy (Minn. Stat. § 216B.1645, subd. 2a(b)(5))

The project benefits in promoting renewable energy were described in Minnesota Power's initial plan filings for each of the projects and confirmed by Commission Order for the Bison and Thomson Projects. Together these projects are key components of Minnesota Power's proactive renewable plan to cost effectively meet Minnesota's 25 percent by 2025 RES.

V. CONCLUSION

Minnesota Power believes the Renewable Resources Rider will appropriately recover the current costs associated with the RRR projects and respectfully requests that the Commission approve Minnesota Power's 2018 Renewable Factor. The Company further requests that the Commission waive the 90-day requirement under Minn. Rule 7825.3200 and grant provisional approval to zero out the Large Power rider sub-factor beginning July 1, 2018, with the understanding that a final decision will be made subsequent to a comment period in which parties may conduct a thorough review of the petition.

Dated: June 5, 2018

Respectfully submitted,

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RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	-$0.33~~4.61~~ per kW-month for all Billing Demand kW
	and
	-0.037~~0.450~~¢ per kWh for all kWh
All other applicable Retail Rate Customers	-0.096~~0.598~~¢ per kWh for all kWh

RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	-$0.33 per kW-month for all Billing Demand kW and -0.037¢ per kWh for all kWh
All other applicable Retail Rate Customers	-0.096¢ per kWh for all kWh

REPRODUCED FROM:
MP Exihibt ____(HGM) Schedule 3
Docekt No. E015/GR-16-664
Page 1 of 2

Minnesota Power
Renewable Resources Rider (RRR)
Development of Sub-Factors

			RRR Sub-Factors	
2016 Estimated Tracker Balance ($) 2/		Total 1/	Base Rates	Rider
MN Jurisdiction		14,683,084	-	14,683,084
Large Power		17,788,537	-	17,788,537
All Other Retail Classes		(3,105,453)	-	(3,105,453)
2017 Revenue Requirements Bison 1-4 ($) 3/				
MN Jurisdiction		51,169,983	51,169,983	-
Large Power		31,986,464	31,986,464	-
All Other Retail Classes		19,183,518	19,183,518	-
2017 Revenue Requirements Thomson ($) 4/				
MN Jurisdiction		9,605,152	9,187,179	417,973
Large Power		6,004,180	5,742,905	261,275
All Other Retail Classes		3,600,972	3,444,274	156,698
Total 2017 Factor Revenue Requirements ($)				
MN Jurisdiction		75,458,218	60,357,162	15,101,057
Large Power		55,779,181	37,729,369	18,049,812
All Other Retail Classes		19,679,037	22,627,792	(2,948,755)
Billing Units 5/				
Large Power	kW - month	605,385	605,385	605,385
	kWh	4,961,473,000	4,961,473,000	4,961,473,000
All Other Retail Classes	kWh	3,290,254,000	3,290,254,000	3,290,254,000

			RRR Sub-Factors	
			Base Rates	Rider
Billing Factors 6/		**1/1/2017**	**1/1/2017**	**1/1/2017**
Large Power	$/kW - month	4.61	3.12	1.49
	¢/kWh	0.450	0.304	0.146
All Other Retail Classes	¢/kWh	0.598	0.688	-0.090

Notes:
1/ 2017 RRR Factor Filing, Exhibit B-1, page 1 (Docket E015/M16-776)
2/ Tracker balance to continue in rider
3/ All Bison revenue revenue requirements are rolling into base rates.
4/ Two Thomson projects are staying in rider. See MP Exhibt___(HGM), Schedule 3, page 2 for details.
5/ 2017 budget.
6/ The LP rate design is a demand rate adder ($/kW-month) and an energy adder (¢/kWh). The LP allocated costs are to be split between demand and energy on the 2010 base rate demand and energy revenue split of approximately 60% demand and 40% energy per results of MP's most recent MPUC rate case (Docket No. E015/GR-09-1151). All other retail classes will have an energy adder (¢/kWh).

Minnesota Power
Renewable Resources Rider (RRR)
Base Rate Rider Cash Collections

	2017 Test Year Budget		2017 Actual	Over / (Under) Collection
BEC4 Environmental Rider	18,951,906	1/	18,060,619	(891,287)
Renewable Resources Rider	63,805,127	2/	61,205,036	(2,600,091)
Transmission Rider	12,174,515	3/	11,600,892	(573,624)
Total	94,931,548		90,866,546	(4,065,002)

1/ MP Exhibit 019 (MAP) Supplemental Direct, Schedule E-2, page 83 of 104 (Docket E015/GR-16-664).
2/ MP Exhibit 019 (MAP) Supplemental Direct, Schedule E-2, page 71 of 104 (Docket E015/GR-16-664).
3/ MP Exhibit 019 (MAP) Supplemental Direct, Schedule E-2, page 77 of 104 (Docket E015/GR-16-664).

Minnesota Power
2018 Renewable Resources Rider
Summary: Revenue Requirements, Cost Allocation and Rate Design

			MN Jurisdictional Amounts Total
2017 Continuing Rider Ending Tracker Balance (Over) / Under Collection 1/			
MN Jurisdictional & Class Tracker		$	(4,012,935)
Large Power		$	(2,345,392)
All Other Retail Classes		$	(1,667,543)
2018 Net Revenue Requirements 2/			
MN Jurisdictional & Class Revenue Requirements		$	808,944
Large Power		$	505,143
All Other Retail Classes		$	303,801
2018 Bison 6 LGIA Revenue Credit 3/	Allocators 4/		
MN Jurisdictional & Class Revenue Requirements	100.00%	$	(1,476,686)
Large Power	61.68%	$	(910,760)
All Other Retail Classes	38.32%	$	(565,926)
2017 PTC True-Up 5/	Allocators		
MN Jurisdictional & Class Revenue Requirements	100.00%	$	(2,953,879)
Large Power	61.68%	$	(1,821,832)
All Other Retail Classes	38.32%	$	(1,132,047)
2018 Prorata ADIT Revenue Requirement 6/	Allocators		
MN Jurisdictional & Class Revenue Requirements	100.00%	$	299
Large Power	61.68%	$	184
All Other Retail Classes	38.32%	$	115
Total 2018 RRR Factor Revenue Requirements			
MN Jurisdictional & Class Revenue Requirements		$	(7,634,257)
Large Power		$	(4,572,656)
All Other Retail Classes		$	(3,061,602)
Billing Units 7/			
Large Power	kW - month		647,437
	kWh		5,465,342,000
All Other Retail Classes	kWh		3,189,902,000

Billing Factors 8/		**Proposed 12/1/2018**
Large Power	$/kW - month	(0.33)
	¢/kWh	(0.037)
All Other Retail Classes	¢/kWh	(0.096)

		Current Rider Sub-Factor 9/	Proposed	Change
Large Power	($/kW - month)	1.49	(0.33)	(1.820)
	(¢/kWh)	0.146	(0.037)	(0.183)
All Other Classes	(¢/kWh)	(0.090)	(0.096)	(0.006)

Notes:
1/ Refer to Exhibit B-1, page 2.
2/ Refer to Exhibit B-1, page 8, line C24 and C25.
3/ Refer to Exhibit B-2, page 7, line C19. First year credit only.
4/ Refer to Exhibit B-5, page 1.
5/ Refer to Exhibit B-2, page 8.
6/ Refer to Exhibit B-2, page 9.
7/ 2018 Budget.
8/ The LP rate design is a demand rate adder ($/kW-month) and an energy adder (¢/kWh). The LP allocated costs are split between demand and energy on the 2017 base rate demand and energy revenue split of approximately 56% demand and 44% energy per results of MP's 2017 MPUC rate case (Docket No. E015/GR-16-664). All other retail classes will have an energy adder (¢/kWh).
9/ Refer to Exhibit A-2, page 1 of 2.

Minnesota Power
Renewable Resources Rider: 2018 Factor Filing
Tracker Summary

2015 Ending Tracker Bison & Thomson 1/			
Total		$	40,263,802
Large Power		$	28,450,993
All Other Retail Classes		$	11,812,809
2016 Revenue Requirements Bison 2/	Allocators 3/		
MN Jurisdictional & Class Revenue Requirements	100.00%	$	47,453,223
Large Power	62.51%	$	29,663,010
All Other Retail Classes	37.49%	$	17,790,213
2016 Revenue Requirements Thomson 4/	Allocators 3/		
MN Jurisdictional & Class Revenue Requirements	100.00%	$	9,457,562
Large Power	62.51%	$	5,911,922
All Other Retail Classes	37.49%	$	3,545,640
2016 Cash Collections			
Total		$	(82,123,042)
Large Power			(46,740,922)
All Other Retail Classes			(35,382,119)
2016 Ending Tracker Bison & Thomson			
Total			15,051,546
Large Power			17,285,002
All Other Retail Classes			(2,233,457)
2017 Continuing Rider Revenue Requirements 5/	Allocators 3/		
MN Jurisdictional & Class Revenue Requirements	100.00%		418,380
Large Power	62.51%	$	261,529
All Other Retail Classes	37.49%	$	156,851
2017 Continuing Rider Cash Collections			
Total		$	(19,482,861)
Large Power		$	(19,891,924)
All Other Retail Classes		$	409,063
2017 Continuing Rider Ending Tracker (Over)/Under Collection			
MN Jurisdictional Tracker		$	(4,012,935)
Large Power		$	(2,345,392)
All Other Retail Classes		$	(1,667,543)

Notes:
1/ 2017 Renewable Resources Rider, Docket E015/M-16-776, Exhibit B-1, page 2.
2/ Refer to Exhibit B-1, page 4, line E4.
3/ Refer to Exhibit B-5, page 1.
4/ Refer to Exhibit B-1, page 6, line E6.
5/ Refer to Exhibit B-1, page 7, line C20.

2016 Bison Tracker: Total Sum All Projects

Section	Line	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total Year 2016
A	**Book Basis of Property**													
	0 CWIP (net of contra AFDC & internal costs)	-	-	-	-	-	-	-	-	-	-	-	-	-
	1 Plant in Service (net of contra AFDC & Internal costs)	795,598,194	795,606,434	795,613,112	795,613,117	795,617,425	795,618,416	795,620,280	795,595,677	795,596,367	795,596,597	795,596,827	795,597,057	795,597,057
	2 Total Accumulated Depreciation	59,876,824	61,760,980	63,645,153	65,529,334	67,413,520	69,297,712	71,181,908	73,066,078	74,950,222	76,834,366	78,718,511	80,602,656	80,602,656
	3 Net Plant	735,721,370	733,845,455	731,967,960	730,083,784	728,203,906	726,320,704	724,438,372	722,529,600	720,646,146	718,762,232	716,878,317	714,994,402	714,994,402
	4 Total Depreciation	1,882,532	1,884,155	1,884,173	1,884,181	1,884,186	1,884,192	1,884,196	1,884,170	1,884,143	1,884,144	1,884,145	1,884,145	22,608,364
	5 Book Depreciation Rate (35 year book life)	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	
B	**Tax Basis of Property**													
	1 Plant in Service	795,598,194	795,606,434	795,613,112	795,613,117	795,617,425	795,618,416	795,620,280	795,595,677	795,596,367	795,596,597	795,596,827	795,597,057	795,597,057
	2 Accumulated Depreciation	661,546,410	666,096,635	670,646,146	675,192,321	679,740,694	684,287,422	688,834,618	693,368,412	697,914,869	702,461,103	707,007,349	711,553,618	711,553,618
	3 Net Plant	134,051,784	129,509,799	124,966,966	120,420,797	115,876,732	111,330,994	106,785,662	102,227,266	97,681,499	93,135,495	88,589,479	84,043,439	84,043,439
	4 Bonus Depreciation	290,389	4,120	3,339	3	2,154	495	932	(12,301)	345	115	115	115	289,821
	5 Total Tax Depreciation (including bonus)	4,836,430	4,550,225	4,549,511	4,546,175	4,548,373	4,546,728	4,547,196	4,533,793	4,546,457	4,546,235	4,546,246	4,546,269	54,843,638
	6 Accumulated Tax Depreciation	661,546,410	666,096,635	670,646,146	675,192,321	679,740,694	684,287,422	688,834,618	693,368,412	697,914,869	702,461,103	707,007,349	711,553,618	711,553,618
	7 Tax Book Difference	601,669,586	604,335,656	607,000,993	609,662,987	612,327,174	614,989,710	617,652,710	620,302,333	622,964,647	625,626,737	628,288,838	630,950,962	630,950,962
	8 Income Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	9 Accumulated Deferred Income Tax Liability	248,910,708	250,013,661	251,116,311	252,217,578	253,319,752	254,421,243	255,522,926	256,619,075	257,720,474	258,821,781	259,923,092	261,024,413	261,024,413
	10 Deferred Tax Expense debit / (Credit)	1,222,028	1,102,953	1,102,650	1,101,267	1,102,174	1,101,491	1,101,683	1,096,149	1,101,399	1,101,307	1,101,311	1,101,321	13,335,733
	11 ADITA for NOL Carryforward	65,376,454	65,513,733	65,650,947	65,788,160	65,925,373	66,062,586	66,199,799	66,335,939	66,473,147	66,610,354	66,747,561	66,884,769	66,884,769
	12 Carryforeward utilized	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 ADITA - NOL	174,319,687	174,328,152	174,336,550	174,344,949	174,353,348	174,361,747	174,370,146	174,377,471	174,385,864	174,394,257	174,402,650	174,411,043	174,411,043
	14 Energy (MWh)	119,550	120,155	175,606	170,439	137,565	150,451	123,398	128,902	150,206	150,328	157,030	167,735	1,751,365
	15 Fed Production Tax Credit ($/MWh)	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00
	16 Fed Production Tax Credit ($)	2,749,650	2,763,565	4,038,938	3,920,097	3,163,995	3,460,373	2,838,154	2,964,746	3,454,738	3,457,544	3,611,690	3,857,905	40,281,395
	17 Utilized PTC	-	-	-	-	-	-	-	-	-	-	-	-	-
	18 ADITA for PTC	87,475,861	90,239,426	94,278,364	98,198,461	101,362,456	104,822,829	107,660,983	110,625,729	114,080,467	117,538,011	121,149,701	125,007,606	125,007,606
C-1	**Revenue Requirements - Consolidated NOL**													
	1 Net Plant	735,721,370	733,845,455	731,967,960	730,083,784	728,203,906	726,320,704	724,438,372	722,529,600	720,646,146	718,762,232	716,878,317	714,994,402	714,994,402
	2 Less: ADITL - Def Taxes	(248,910,708)	(250,013,661)	(251,116,311)	(252,217,578)	(253,319,752)	(254,421,243)	(255,522,926)	(256,619,075)	(257,720,474)	(258,821,781)	(259,923,092)	(261,024,413)	(261,024,413)
	3 Plus: ADITA - NOL	174,319,687	174,328,152	174,336,550	174,344,949	174,353,348	174,361,747	174,370,146	174,377,471	174,385,864	174,394,257	174,402,650	174,411,043	174,411,043
	4 Plus: ADITA - PTC	87,475,861	90,239,426	94,278,364	98,198,461	101,362,456	104,822,829	107,660,983	110,625,729	114,080,467	117,538,011	121,149,701	125,007,606	125,007,606
	5 Rate Base	748,606,210	748,399,372	749,466,563	750,409,617	750,599,958	751,084,037	750,946,575	750,913,725	751,392,003	751,872,719	752,507,576	753,388,638	753,388,638
	6 Average Rate Base	748,539,502	748,502,791	748,932,968	749,938,090	750,504,787	750,841,998	751,015,306	750,930,150	751,152,864	751,632,361	752,190,147	752,948,107	750,594,089
	7 Current Return on CWIP	2,940	-	-	-	-	-	-	-	-	-	-	-	2,940
	8 Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	9 After Tax Return on Equity	3,514,605	3,514,433	3,516,452	3,521,172	3,523,833	3,525,416	3,526,230	3,525,830	3,526,876	3,529,127	3,531,746	3,535,305	42,291,023
	10 Income Tax Component	2,479,949	2,479,827	2,481,252	2,484,582	2,486,460	2,487,577	2,488,151	2,487,869	2,488,607	2,490,196	2,492,044	2,494,555	29,841,069
	11 Interest Expense Component	1,584,409	1,584,331	1,585,241	1,587,369	1,588,568	1,589,282	1,589,649	1,589,469	1,589,940	1,590,955	1,592,136	1,593,740	19,065,090
	12 Total Return on Average Rate Base	7,578,962	7,578,591	7,582,946	7,593,123	7,598,861	7,602,275	7,604,030	7,603,168	7,605,423	7,610,278	7,615,925	7,623,600	91,197,182
	13 Operation & Maintenance Expense	1,104,761	1,066,375	1,193,180	1,233,274	1,193,045	1,155,281	1,205,669	1,250,482	1,214,211	1,373,543	1,233,603	1,261,350	14,484,774
	14 Depreciation Expense	1,882,532	1,884,155	1,884,173	1,884,181	1,884,186	1,884,192	1,884,196	1,884,170	1,884,143	1,884,144	1,884,145	1,884,145	22,608,364
	15 Property Tax	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	2,232,720
	16 Federal Production Tax Credit	(4,689,835)	(4,713,568)	(6,888,859)	(6,686,162)	(5,396,546)	(5,902,052)	(4,840,788)	(5,056,705)	(5,892,441)	(5,897,227)	(6,160,140)	(6,580,087)	(68,704,409)
	17 ND Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
	18 Revenue Requirements	6,065,420	6,001,613	3,957,500	4,210,476	5,465,606	4,925,757	6,039,167	5,867,175	4,997,396	5,156,798	4,759,593	4,375,068	61,821,571

2016 Bison Tracker: Total Sum All Projects

Section	Line	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total Year 2016
C-2	**Revenue Requirements - Stand Alone NOL**													
	1 Net Plant	735,721,370	733,845,455	731,967,960	730,083,784	728,203,906	726,320,704	724,438,372	722,529,600	720,646,146	718,762,232	716,878,317	714,994,402	714,994,402
	2 Less: ADITL - Def Taxes	(248,910,708)	(250,013,661)	(251,116,311)	(252,217,578)	(253,319,752)	(254,421,243)	(255,522,926)	(256,619,075)	(257,720,474)	(258,821,781)	(259,923,092)	(261,024,413)	(261,024,413)
	3 Plus: ADITA - NOL (Stand Alone)	211,795,107	212,243,354	213,586,846	214,837,502	215,550,449	216,468,049	216,943,942	217,502,222	218,408,356	219,311,822	220,319,070	221,493,965	221,493,965
	4 Plus: ADITA - PTC	87,475,861	90,239,426	94,278,364	98,198,461	101,362,456	104,822,829	107,660,983	110,625,729	114,080,467	117,538,011	121,149,701	125,007,606	125,007,606
	5 Rate Base	786,081,630	786,314,574	788,716,859	790,902,169	791,797,059	793,190,339	793,520,371	794,038,475	795,414,495	796,790,284	798,423,996	800,471,560	800,471,560
	6 Average Rate Base	785,689,585	786,198,102	787,515,717	789,809,514	791,349,614	792,493,699	793,355,355	793,779,423	794,726,485	796,102,389	797,607,140	799,447,778	792,339,567
	7 Current Return on CWIP	2,940	-	-	-	-	-	-	-	-	-	-	-	2,940
	8 Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	9 After Tax Return on Equity	3,689,035	3,691,423	3,697,609	3,708,379	3,715,611	3,720,982	3,725,028	3,727,019	3,731,466	3,737,926	3,744,992	3,753,634	44,643,105
	10 Income Tax Component	2,603,029	2,604,714	2,609,079	2,616,678	2,621,781	2,625,571	2,628,426	2,629,831	2,632,969	2,637,527	2,642,512	2,648,610	31,500,727
	11 Interest Expense Component	1,663,043	1,664,119	1,666,908	1,671,763	1,675,023	1,677,445	1,679,269	1,680,166	1,682,171	1,685,083	1,688,268	1,692,164	20,125,425
	12 Total Return on Average Rate Base	7,955,107	7,960,256	7,973,597	7,996,821	8,012,415	8,023,999	8,032,723	8,037,017	8,046,606	8,060,537	8,075,772	8,094,409	96,269,257
	13 Operation & Maintenance Expense	1,104,761	1,066,375	1,193,180	1,233,274	1,193,045	1,155,281	1,205,669	1,250,482	1,214,211	1,373,543	1,233,603	1,261,350	14,484,774
	14 Depreciation Expense	1,882,532	1,884,155	1,884,173	1,884,181	1,884,186	1,884,192	1,884,196	1,884,170	1,884,143	1,884,144	1,884,145	1,884,145	22,608,364
	15 Property Tax	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	2,232,720
	16 Federal Production Tax Credit	(4,689,835)	(4,713,568)	(6,888,859)	(6,686,162)	(5,396,546)	(5,902,052)	(4,840,788)	(5,056,705)	(5,892,441)	(5,897,227)	(6,160,140)	(6,580,087)	(68,704,409)
	17 ND Investment Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
	18 Revenue Requirements	6,441,565	6,383,278	4,348,151	4,614,174	5,879,160	5,347,480	6,467,860	6,301,024	5,438,579	5,607,057	5,219,440	4,845,877	66,893,646
D	**Stand Alone Taxable Income or Loss (NOL)**													
	1 Revenue Requirements	6,441,565	6,383,278	4,348,151	4,614,174	5,879,160	5,347,480	6,467,860	6,301,024	5,438,579	5,607,057	5,219,440	4,845,877	66,893,646
	2 Tax Depreciation	4,836,430	4,550,225	4,549,511	4,546,175	4,548,373	4,546,728	4,547,196	4,533,793	4,546,457	4,546,235	4,546,246	4,546,269	54,843,638
	3 Property Tax	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	186,060	2,232,720
	4 Interest Expense (including on CWIP)	1,663,658	1,664,119	1,666,908	1,671,763	1,675,023	1,677,445	1,679,269	1,680,166	1,682,171	1,685,083	1,688,268	1,692,164	20,126,040
	5 Operation & Maintenance Expense	1,104,761	1,066,375	1,193,180	1,233,274	1,193,045	1,155,281	1,205,669	1,250,482	1,214,211	1,373,543	1,233,603	1,261,350	14,484,774
	6 Total Tax Deduction	7,790,909	7,466,780	7,595,659	7,637,272	7,602,501	7,565,514	7,618,194	7,650,502	7,628,899	7,790,921	7,654,178	7,685,844	91,687,172
	7 Taxable Income (NOL)	(1,349,343)	(1,083,502)	(3,247,508)	(3,023,098)	(1,723,341)	(2,218,034)	(1,150,334)	(1,349,478)	(2,190,320)	(2,183,864)	(2,434,737)	(2,839,966)	(24,793,526)
	8 Current tax expense	(558,224)	(448,243)	(1,343,494)	(1,250,657)	(712,947)	(917,600)	(475,893)	(558,278)	(906,134)	(903,464)	(1,007,252)	(1,174,894)	(10,257,080)
	9 Taxable Income (NOL)	(1,349,343)	(1,083,502)	(3,247,508)	(3,023,098)	(1,723,341)	(2,218,034)	(1,150,334)	(1,349,478)	(2,190,320)	(2,183,864)	(2,434,737)	(2,839,966)	(28,528,168)
	10 NOL carryforward	(510,604,022)	(511,953,366)	(513,036,867)	(516,284,375)	(519,307,474)	(521,030,815)	(523,248,849)	(524,399,184)	(525,748,661)	(527,938,981)	(530,122,845)	(532,557,582)	(510,601,704)
	11 Taxable Income after NOL carryforward	(511,953,366)	(513,036,867)	(516,284,375)	(519,307,474)	(521,030,815)	(523,248,849)	(524,399,184)	(525,748,661)	(527,938,981)	(530,122,845)	(532,557,582)	(535,397,548)	(539,129,872)
	12 Expected stand alone ADITA NOL	211,795,107	212,243,354	213,586,846	214,837,502	215,550,449	216,468,049	216,943,942	217,502,222	218,408,356	219,311,822	220,319,070	221,493,965	221,493,965
	9 Annual Fed Production Tax Credit ($)	2,749,650	2,763,565	4,038,938	3,920,097	3,163,995	3,460,373	2,838,154	2,964,746	3,454,738	3,457,544	3,611,690	3,857,905	40,281,395
	10 Utilized PTC	-	-	-	-	-	-	-	-	-	-	-	-	-
	11 ADITA for PTC	87,475,861	90,239,426	94,278,364	98,198,461	101,362,456	104,822,829	107,660,983	110,625,729	114,080,467	117,538,011	121,149,701	125,007,606	125,007,606
E	**Summary: Revenue Requirements**													
	1 Revenue Requirement: Consolidated	6,065,420	6,001,613	3,957,500	4,210,476	5,465,606	4,925,757	6,039,167	5,867,175	4,997,396	5,156,798	4,759,593	4,375,068	61,821,571
	2 Revenue Requirement: Stand Alone	6,441,565	6,383,278	4,348,151	4,614,174	5,879,160	5,347,480	6,467,860	6,301,024	5,438,579	5,607,057	5,219,440	4,845,877	66,893,646
	3 Revenue Requirement: Rider 1/	5,773,851	5,706,227	3,660,865	3,915,116	5,169,659	4,627,990	5,738,889	5,563,150	4,690,807	4,848,747	4,450,349	4,065,759	58,211,409
	4 MN Jurisdictional Revenue Requirement	4,710,738	4,655,390	2,977,960	3,186,604	4,215,657	3,771,510	4,682,750	4,538,733	3,823,383	3,953,033	3,626,391	3,311,074	47,453,223

Notes:

1/ Lesser of E1 or E2. For the sum of all projects, E3 does not equal the lesser of E1 or E2. This is due to the limitation and utilization of NOL carryforwards under both methods results in each individual projects' lower requirement changing from stand-alone to consolidated at different times.

Section	Line	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total Year Dec-16
A	**Book Basis of Property**													
	0 CWIP	1,726,670	1,808,489	1,858,888	1,492,894	1,550,861	1,527,047	1,584,291	1,625,535	1,722,190	1,822,651	1,925,586	2,109,833	2,109,833
	1 Plant in Service	78,027,613	78,034,291	77,919,748	78,301,306	78,318,170	77,559,096	77,574,502	77,478,036	77,480,982	77,495,668	77,505,290	77,520,850	77,520,850
	2 Total Accumulated Depreciation	1,959,504	2,092,671	2,225,743	2,359,047	2,492,697	2,625,703	2,758,063	2,890,325	3,022,479	3,154,649	3,286,849	3,419,078	3,419,078
	3 Net Plant	76,067,911	75,939,909	75,692,293	75,940,547	75,823,761	74,931,681	74,814,727	74,585,998	74,456,792	74,339,307	74,224,728	74,108,060	74,108,060
	4 Total Depreciation	133,117	133,167	133,072	133,304	133,650	133,006	132,360	132,262	132,154	132,170	132,200	132,229	1,592,692
	5 Book Depreciation Rate (35 year book life)													
B	**Tax Basis of Property**													
	1 Investment Tax Credit (30%)	23,143	545	(40,034)	(1,697)	5,093	(182,265)	-	(28,965)	884	4,406	3,925	4,658	(210,308)
	2 Reduction to Book and Tax Basis (ITC x 50%)	11,571	272	(20,017)	(849)	2,546	(91,133)	-	(14,482)	442	2,203	1,963	2,329	(105,154)
	3 Adjusted Book and Tax Basis for Deferred Taxes	40,698	6,406	(94,526)	382,406	14,318	(667,942)	15,406	(81,984)	2,505	12,483	7,659	13,232	(349,339)
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	66,734,981	66,741,387	66,646,860	67,029,267	67,043,585	66,375,643	66,391,049	66,309,065	66,311,570	66,324,053	66,331,712	66,344,944	66,344,944
	5 Book Style Depreciation for Deferred Taxes	114,185	114,225	114,152	114,405	114,749	114,197	113,646	113,565	113,472	113,486	113,504	113,521	1,367,108
	6 Accum Book Style Depreciation for Deferred Taxes	1,677,675	1,791,900	1,906,051	2,020,456	2,135,206	2,249,403	2,363,049	2,476,613	2,590,086	2,703,572	2,817,076	2,930,597	2,930,597
	7 Accumulated Tax Depreciation	36,328,553	36,525,586	36,671,976	37,057,629	37,259,272	37,150,062	37,350,334	37,494,188	37,687,761	37,887,265	38,085,274	38,285,649	38,285,649
	8 Net Plant for Tax	30,406,428	30,215,801	29,974,884	29,971,637	29,784,313	29,225,582	29,040,715	28,814,878	28,623,809	28,436,789	28,246,438	28,059,295	28,059,295
	9 Bonus Depreciation	20,111	3,203	(47,263)	191,203	7,159	(301,732)	7,703	(48,233)	1,473	7,343	5,707	7,780	(145,546)
	10 Total Tax Depreciation (including bonus)	213,931	197,033	146,390	385,653	201,643	(109,210)	200,273	143,853	193,574	199,503	198,010	200,375	2,171,027
	11 Tax Book Difference	99,745	82,809	32,238	271,248	86,893	(223,407)	86,627	30,289	80,101	86,017	84,505	86,854	803,920
	12 Income Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference	41,265	34,258	13,337	112,215	35,948	(92,424)	35,838	12,530	33,138	35,585	34,960	35,931	332,582
	14 Total Accumulated Deferred Income Tax Liability	14,335,068	14,369,326	14,382,663	14,494,878	14,530,826	14,438,403	14,474,240	14,486,771	14,519,908	14,555,494	14,590,454	14,626,385	14,626,385
	15 Deferred Tax Expense debit / (Credit)	41,265	34,258	13,337	112,215	35,948	(92,424)	35,838	12,530	33,138	35,585	34,960	35,931	332,582
	16 Cum Investment Tax Credit (30% on Qualifing Costs)	22,585,264	22,585,809	22,545,775	22,544,078	22,549,170	22,366,905	22,366,905	22,337,940	22,338,824	22,343,230	22,347,155	22,351,813	22,351,813
	17 Amortization of ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
	18 Gross-up of Amoritized ITC for revenue requirements	-	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - MP Regulated NOL**													
	1 Net Plant	76,067,911	75,939,909	75,692,293	75,940,547	75,823,761	74,931,681	74,814,727	74,585,998	74,456,792	74,339,307	74,224,728	74,108,060	74,108,060
	2 Less: ADITL - Def Taxes	(14,335,068)	(14,369,326)	(14,382,663)	(14,494,878)	(14,530,826)	(14,438,403)	(14,474,240)	(14,486,771)	(14,519,908)	(14,555,494)	(14,590,454)	(14,626,385)	(14,626,385)
	3 Plus: ADITA - NOL	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	61,732,843	61,570,583	61,309,630	61,445,668	61,292,935	60,493,278	60,340,487	60,099,228	59,936,883	59,783,813	59,634,274	59,481,675	59,481,675
	5 Average Rate Base	61,793,899	61,651,713	61,440,106	61,377,649	61,369,301	60,893,107	60,416,883	60,219,857	60,018,056	59,860,348	59,709,044	59,557,974	59,557,974
	6 Current Return on CWIP	17,416	17,897	18,566	16,968	15,409	15,582	15,751	16,250	16,948	17,946	18,975	20,429	208,137
	7 Return on Average Rate Base													
	8 After Tax Return on Equity	290,140	289,472	288,479	288,185	288,146	285,910	283,674	282,749	281,802	281,061	280,351	279,642	3,419,612
	9 Income Tax Component	204,726	204,255	203,554	203,347	203,320	201,742	200,164	199,511	198,843	198,320	197,819	197,319	2,412,921
	10 Interest Expense Component	130,797	130,496	130,048	129,916	129,898	128,890	127,882	127,465	127,038	126,704	126,384	126,064	1,541,585
	11 Total Return on Average Rate Base	625,663	624,224	622,081	621,449	621,364	616,543	611,721	609,726	607,683	606,086	604,554	603,024	7,374,118
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	133,117	133,167	133,072	133,304	133,650	133,006	132,360	132,262	132,154	132,170	132,200	132,229	1,592,692
	14 Property Tax	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	2,603,522
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	993,157	992,248	990,680	988,681	987,383	982,090	976,792	975,198	973,745	973,162	972,690	972,643	11,778,469

Section	Line	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total Year Dec-16
C-2	**Revenue Requirements - Stand Alone NOL**													
	1 Net Plant	76,067,911	75,939,909	75,692,293	75,940,547	75,823,761	74,931,681	74,814,727	74,585,998	74,456,792	74,339,307	74,224,728	74,108,060	74,108,060
	2 Less: ADITL - Def Taxes	(14,332,266)	(14,366,537)	(14,379,886)	(14,492,113)	(14,528,073)	(14,433,287)	(14,469,132)	(14,481,670)	(14,514,816)	(14,550,409)	(14,585,376)	(14,621,315)	(14,621,315)
	3 Plus: ADITA - NOL (Stand Alone)	10,239,903	10,030,611	9,801,735	9,666,744	9,461,723	9,159,128	8,958,340	8,735,623	8,534,887	8,338,642	8,144,183	7,951,817	7,951,817
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	71,975,548	71,603,983	71,114,142	71,115,177	70,757,411	69,657,522	69,303,934	68,839,951	68,476,863	68,127,540	67,783,535	67,438,562	67,438,562
	5 Average Rate Base	72,138,181	71,789,765	71,359,063	71,114,660	70,936,294	70,207,466	69,480,728	69,071,943	68,658,407	68,302,202	67,955,538	67,611,048	67,611,048
	6 Current Return on CWIP	17,416	17,897	18,566	16,968	15,409	15,582	15,751	16,250	16,948	17,946	18,975	20,429	208,137
	7 Return on Average Rate Base													
	8 After Tax Return on Equity	338,709	337,073	335,051	333,903	333,066	329,644	326,232	324,312	322,371	320,698	319,071	317,453	3,937,583
	9 Income Tax Component	238,997	237,843	236,416	235,606	235,015	232,601	230,193	228,839	227,469	226,289	225,140	223,999	2,778,408
	10 Interest Expense Component	152,692	151,955	151,043	150,526	150,148	148,606	147,068	146,202	145,327	144,573	143,839	143,110	1,775,090
	11 Total Return on Average Rate Base	730,399	726,871	722,511	720,036	718,230	710,851	703,492	699,353	695,166	691,560	688,050	684,562	8,491,081
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	133,117	133,167	133,072	133,304	133,650	133,006	132,360	132,262	132,154	132,170	132,200	132,229	1,592,692
	14 Property Tax	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	2,603,522
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	1,097,892	1,094,895	1,091,109	1,087,269	1,084,249	1,076,398	1,068,564	1,064,826	1,061,228	1,058,636	1,056,185	1,054,180	12,895,432
D	**Stand Alone Taxable Income or Loss (NOL)**													
	1 Revenue Requirements	1,097,892	1,094,895	1,091,109	1,087,269	1,084,249	1,076,398	1,068,564	1,064,826	1,061,228	1,058,636	1,056,185	1,054,180	12,895,432
	2 Tax Depreciation	213,931	197,033	146,390	385,653	201,643	(109,210)	200,273	143,853	193,574	199,503	198,010	200,375	2,171,027
	3 Property Tax	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	216,960	2,603,522
	4 Interest Expense (including on CWIP)	156,333	155,696	154,925	154,073	153,370	151,863	150,360	149,599	148,870	148,325	147,806	147,381	1,818,602
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	587,224	569,690	518,275	756,687	571,973	259,613	567,593	510,413	559,404	564,788	562,776	564,716	6,593,151
	7 Taxable Income (NOL)	510,668	525,205	572,834	330,582	512,277	816,785	500,970	554,413	501,824	493,848	493,409	489,464	6,302,281
	8 Current tax expense	211,262	217,278	236,981	136,763	211,931	337,905	207,253	229,363	207,605	204,305	204,124	202,494	2,607,264
	9 Taxable Income (NOL)	510,668	525,205	572,834	330,582	512,277	816,785	500,970	554,413	501,824	493,848	493,409	489,464	
	10 NOL carryforward	(25,243,043)	(24,752,001)	(24,246,102)	(23,692,858)	(23,366,556)	(22,870,976)	(22,139,539)	(21,654,194)	(21,115,841)	(20,630,621)	(20,156,256)	(19,686,200)	
	11 Taxable Income after NOL carryforward	(24,732,374)	(24,226,796)	(23,673,268)	(23,349,975)	(22,854,280)	(22,054,190)	(21,638,568)	(21,099,781)	(20,614,017)	(20,136,773)	(19,662,847)	(19,196,736)	
	12 Expected stand alone ADITA NOL	10,239,903	10,030,611	9,801,735	9,666,744	9,461,723	9,159,128	8,958,340	8,735,623	8,534,887	8,338,642	8,144,183	7,951,817	7,951,817
E	**Summary: Revenue Requirements**													
	1 Revenue Requirement: Consolidated	993,157	992,248	990,680	988,681	987,383	982,090	976,792	975,198	973,745	973,162	972,690	972,643	11,778,469
	2 Revenue Requirement: Stand Alone	1,097,892	1,094,895	1,091,109	1,087,269	1,084,249	1,076,398	1,068,564	1,064,826	1,061,228	1,058,636	1,056,185	1,054,180	12,895,432
	3 Revenue Requirement: Rider 1/	993,157	992,248	990,680	988,681	987,383	982,090	976,792	975,198	973,745	973,162	972,690	972,643	11,778,469
	4 Base Rate Revenue Credit	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(18,047)	(216,565)
	5 Total Net Revenue Requirements	975,109	974,201	972,633	970,634	969,336	964,043	958,745	957,151	955,697	955,115	954,642	954,596	11,561,903
	6 **MN Jurisdictional Revenue Requirement**	797,619	796,877	795,596	793,961	792,901	788,564	784,223	782,942	781,777	781,302	780,917	780,883	9,457,562

Notes:

1/ Lesser of E1 or E2. For the sum of all projects, E3 may not equal the lesser of E1 or E2 if there is utilization of NOL carryforwards that result in each individual projects' lower requirement changing from stand-alone to consolidated at different times.

2017 Thomson Tracker: Total Sum All Projects

Section	Line	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total Year Dec-17
A	**Book Basis of Property**													
	0 CWIP	2,163,743	2,252,219	2,319,190	2,332,746	2,554,413	2,818,689	3,395,349	3,772,786	4,757,113	6,510,348	6,536,723	6,536,723	6,536,723
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	6,122,046	6,122,046
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	5,427	5,427
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	6,116,619	6,116,619
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	5,427	5,427
	5 Book Depreciation Rate (35 year book life)													
B	**Tax Basis of Property**													
	1 Investment Tax Credit (30%)	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	6,122,046	6,122,046
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	6,122,046	6,122,046
	5 Book Style Depreciation for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	5,427	5,427
	6 Accum Book Style Depreciation for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	5,427	5,427
	7 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	3,175,811	3,175,811
	8 Net Plant for Tax	-	-	-	-	-	-	-	-	-	-	-	2,946,235	2,946,235
	9 Bonus Depreciation	-	-	-	-	-	-	-	-	-	-	-	3,061,023	3,061,023
	10 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	3,175,811	3,175,811
	11 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	3,170,384	3,170,384
	12 Income Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference	-	-	-	-	-	-	-	-	-	-	-	1,311,588	1,311,588
	14 Total Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	1,311,588	1,311,588
	15 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	1,311,588	1,311,588
C	**Revenue Requirements**													
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	6,116,619	6,116,619
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	(1,311,588)	(1,311,588)
	3 Plus: ADITA - NOL	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	-	-	-	-	-	-	-	-	-	-	-	4,805,031	4,805,031
	5 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	2,402,515	2,402,515
	6 Current Return on CWIP	21,635	22,356	23,143	23,550	24,741	27,201	31,459	36,289	43,183	57,042	66,051	35,191	411,840
	7 Return on Average Rate Base													
	8 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	11,280	11,280
	9 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	7,960	7,960
	10 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	5,085	5,085
	11 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	24,325	24,325
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	5,427	5,427
	14 Property Tax	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	5,732	68,786
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	27,367	28,088	28,875	29,283	30,473	32,933	37,191	42,021	48,915	62,774	71,783	70,676	510,379
	17 Base Rate Revenue Credit /1	-	-	-	-	-	-	-	-	-	-	-	(265)	(265)
	18 Total Revenue Requirements	27,367	28,088	28,875	29,283	30,473	32,933	37,191	42,021	48,915	62,774	71,783	70,411	510,114
	19 MN Jurisdictional Allocator /2	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	
	20 MN Jurisdictional Revenue Requirement	22,446	23,037	23,682	24,017	24,993	27,011	30,503	34,464	40,118	51,485	58,874	57,749	418,380

Notes:
1/ Refer to Exhibit B-2, page 6.
2/ Refer to Exhibit B-5, page 1.

2018 Thomson Tracker: Total Sum All Projects

Section	Line	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total Year 2018
A	**Book Basis of Property**													
	0 CWIP	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	-	-
	1 Plant in Service	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,536,723	6,536,723
	2 Total Accumulated Depreciation	16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	113,974	124,829	136,059	136,059
	3 Net Plant	6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,008,072	5,997,217	6,400,664	6,400,664
	4 Total Depreciation	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	11,230	130,632
	5 Book Depreciation Rate (35 year book life)													
B	**Tax Basis of Property**													
	1 Investment Tax Credit (30%)	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	414,677	414,677
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,536,723	6,536,723
	5 Book Style Depreciation for Deferred Taxes	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	11,230	130,632
	6 Accum Book Style Depreciation for Deferred Taxes	16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	113,974	124,829	136,059	136,059
	7 Accumulated Tax Depreciation	3,194,226	3,212,641	3,231,055	3,249,470	3,267,884	3,286,299	3,304,714	3,323,128	3,341,543	3,359,958	3,378,372	3,571,988	3,571,988
	8 Net Plant for Tax	2,927,820	2,909,406	2,890,991	2,872,576	2,854,162	2,835,747	2,817,333	2,798,918	2,780,503	2,762,089	2,743,674	2,964,735	2,964,735
	9 Bonus Depreciation	-	-	-	-	-	-	-	-	-	-	-	165,871	165,871
	10 Total Tax Depreciation (including bonus)	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	193,616	396,176
	11 Tax Book Difference	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	182,385	265,544
	12 Income Tax Rate	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	75,453	109,856
	14 Total Accumulated Deferred Income Tax Liability	1,314,715	1,317,843	1,320,971	1,324,098	1,327,226	1,330,353	1,333,481	1,336,608	1,339,736	1,342,863	1,345,991	1,421,444	1,421,444
	15 Deferred Tax Expense debit / (Credit)	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	75,453	109,856
C	**Revenue Requirements**													
	1 Net Plant	6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,008,072	5,997,217	6,400,664	6,400,664
	2 Less: ADITL - Def Taxes	(1,314,715)	(1,317,843)	(1,320,971)	(1,324,098)	(1,327,226)	(1,330,353)	(1,333,481)	(1,336,608)	(1,339,736)	(1,342,863)	(1,345,991)	(1,421,444)	(1,421,444)
	3 Plus: ADITA - NOL	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	4,791,049	4,777,066	4,763,084	4,749,102	4,735,120	4,721,138	4,707,155	4,693,173	4,679,191	4,665,209	4,651,226	4,979,220	4,979,220
	5 Average Rate Base	4,798,040	4,784,058	4,770,075	4,756,093	4,742,111	4,728,129	4,714,146	4,700,164	4,686,182	4,672,200	4,658,218	4,815,223	4,815,223
	6 Current Return on CWIP	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	1,827	48,012
	7 Return on Average Rate Base													
	8 After Tax Return on Equity	22,528	22,463	22,397	22,331	22,266	22,200	22,134	22,069	22,003	21,937	21,872	19,975	264,174
	9 Income Tax Component	15,896	15,850	15,803	15,757	15,711	15,665	15,618	15,572	15,526	15,479	15,433	14,095	186,404
	10 Interest Expense Component	10,156	10,126	10,097	10,067	10,037	10,008	9,978	9,949	9,919	9,889	9,860	8,370	118,457
	11 Total Return on Average Rate Base	48,580	48,439	48,297	48,155	48,014	47,872	47,731	47,589	47,448	47,306	47,164	42,440	569,036
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	11,230	130,632
	14 Property Tax	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	239,646
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	83,604	83,462	83,321	83,179	83,038	82,896	82,755	82,613	82,471	82,330	82,188	75,469	987,326
	17 Jurisdictional Allocator /1	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.84360	
	18 Jurisdictional Revenue Requirements	68,569	68,453	68,337	68,221	68,105	67,989	67,873	67,757	67,641	67,524	67,408	63,665	811,543
	19 Jurisdictional Base Rate Revenue Credit /2	(217)	(217)	(217)	(217)	(217)	(217)	(217)	(217)	(217)	(217)	(217)	(209)	(2,599)
	20 Net Jurisdictional Revenue Requirements	68,352	68,236	68,120	68,004	67,888	67,772	67,655	67,539	67,423	67,307	67,191	63,456	808,944
	21 Large Power Class Allocation 1/	0.62510	0.62510	0.62510	0.62510	0.62510	0.62510	0.62510	0.62510	0.62510	0.62510	0.62510	0.61676	
	22 Large Power Class Revenue Requirements	42,727	42,654	42,582	42,509	42,437	42,364	42,292	42,219	42,146	42,074	42,001	39,137	505,143
	23 All Other Class Revenue Requirements /3	25,625	25,582	25,538	25,494	25,451	25,407	25,364	25,320	25,277	25,233	25,190	24,319	303,801

Notes:
1/ Refer to Exhibit B-5, page 1.
2/ Refer to Exhibit B-2, page 6.
3/ Line C20 - Line C22.

THM Replace/Refurbish Dam 6
Project ID # 106069
In Service 12/31/2018

Section	Line	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
A	**Book Basis of Property**												
	0 CWIP	243,819	249,813	260,878	262,182	327,474	327,990	370,663	398,892	407,413	414,677	414,677	414,677
	1 Plant in Service												
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Depreciation Rate 1/												
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) 2/	-	-	-	-	-	-	-	-				
	2 Reduction to Book and Tax Basis (ITC x 50%)												-
	3 Adjusted Book and Tax Basis for Deferred Taxes												-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes												-
	5 Book Style Depreciation for Deferred Taxes												-
	6 Accum Book Style Depreciation for Deferred Taxes												-
	7 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-				-
	8 Net Plant for Tax	-	-	-	-	-	-	-	-				-
	9 Bonus Depreciation 40% in 2018												
	10 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-
	7.6 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	11 Tax Book Difference	-	-	-	-	-	-	-	-				-
	12 Income Tax Rate 3/	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference	-	-	-	-	-	-	-	-				-
	14 Total Accumulated Deferred Income Tax Liability												-
	15 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-				-
C	**Revenue Requirements**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes												-
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	6 Current Return on CWIP 4/	2,403	2,499	2,585	2,648	2,985	3,318	3,537	3,896	4,082	4,162	4,199	4,199
	7 Return on Average Rate Base 4/												
	8 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	9 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	11 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	14 Property Tax	623	623	623	623	623	623	623	623	623	623	623	623
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	3,026	3,122	3,208	3,271	3,608	3,941	4,160	4,519	4,705	4,785	4,821	4,821

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
3/ Minnesota Composite Income Tax Rate.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664 starting 12/1/2018. Refer to Exhibit B-4.

THM Replace/Refurbish Dam 6
Project ID # 106069
In Service 12/31/2018

Section	Line	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
A	**Book Basis of Property**												
	0 CWIP	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	
	1 Plant in Service												414,677
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	376
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	414,301
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	376
	5 Book Depreciation Rate 1/												0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) 2/												-
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	414,677
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	414,677
	5 Book Style Depreciation for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	376
	6 Accum Book Style Depreciation for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	376
	7 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	175,201
	8 Net Plant for Tax	-	-	-	-	-	-	-	-	-	-	-	239,476
	9 Bonus Depreciation 40% in 2018												165,871
	10 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	175,201
	7.6 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	175,201
	11 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	174,825
	12 Income Tax Rate 3/	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference	-	-	-	-	-	-	-	-	-	-	-	72,325
	14 Total Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	72,325
	15 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	72,325
C	**Revenue Requirements**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	414,301
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	(72,325)
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	-	-	-	-	-	-	-	-	-	-	-	341,976
	5 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	170,988
	6 Current Return on CWIP 4/	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	1,827
	7 Return on Average Rate Base 4/												
	8 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	709
	9 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	501
	10 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	297
	11 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	1,507
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	376
	14 Property Tax	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	5,581	5,581	5,581	5,581	5,581	5,581	5,581	5,581	5,581	5,581	5,581	5,093

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
3/ Minnesota Composite Income Tax Rate.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664 starting 12/1/2018. Refer to Exhibit B-4.

THM Spill Capacity
Project ID # 106794
In Service 12/31/2017

Section	Line	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
A	**Book Basis of Property**												
	0 CWIP	1,919,924	2,002,405	2,058,312	2,070,564	2,226,939	2,490,700	3,024,686	3,373,894	4,349,700	6,095,671	6,122,046	6,122,046
	1 Plant in Service												6,122,046
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	5,427
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	6,116,619
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	5,427
	5 Book Depreciation Rate 1/												0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) /2	-	-	-	-	-	-	-	-				-
	2 Reduction to Book and Tax Basis (ITC x 50%)												-
	3 Adjusted Book and Tax Basis for Deferred Taxes												6,122,046
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes												6,122,046
	5 Book Style Depreciation for Deferred Taxes												5,427
	6 Accum Book Style Depreciation for Deferred Taxes												5,427
	7 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-				3,175,811
	8 Net Plant for Tax	-	-	-	-	-	-	-	-				2,946,235
	9 Bonus Depreciation 50% in 2017												3,061,023
	10 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	3,175,811
	7.6 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	3,175,811
	11 Tax Book Difference	-	-	-	-	-	-	-	-	-			3,170,384
	12 Income Tax Rate 3/	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference												1,311,588
	14 Total Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-			1,311,588
	15 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-			1,311,588
C	**Revenue Requirements - MP Regulated NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	6,116,619
	2 Less: ADITL - Def Taxes												(1,311,588)
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	-	-	-	-	-	-	-	-	-	-	-	4,805,031
	5 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	2,402,515
	6 Current Return on CWIP 4/	19,232	19,857	20,557	20,902	21,756	23,883	27,922	32,393	39,101	52,880	61,852	30,993
	7 Return on Average Rate Base /												
	8 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	11,280
	9 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	7,960
	10 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	5,085
	11 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	24,325
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	5,427
	14 Property Tax	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	24,341	24,966	25,667	26,012	26,866	28,992	33,031	37,502	44,210	57,989	66,962	65,855

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
3/ Minnesota Composite Income Tax Rate.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664 starting 12/1/2018. Refer to Exhibit B-4.

THM Spill Capacity
Project ID # 106794
In Service 12/31/2017

Section	Line	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
A	**Book Basis of Property**												
	0 CWIP												
	1 Plant in Service	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046
	2 Total Accumulated Depreciation	16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	113,974	124,829	135,684
	3 Net Plant	6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,008,072	5,997,217	5,986,363
	4 Total Depreciation	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	5 Book Depreciation Rate 1/	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) /2												
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046
	5 Book Style Depreciation for Deferred Taxes	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	6 Accum Book Style Depreciation for Deferred Taxes	16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	113,974	124,829	135,684
	7 Accumulated Tax Depreciation	3,194,226	3,212,641	3,231,055	3,249,470	3,267,884	3,286,299	3,304,714	3,323,128	3,341,543	3,359,958	3,378,372	3,396,787
	8 Net Plant for Tax	2,927,820	2,909,406	2,890,991	2,872,576	2,854,162	2,835,747	2,817,333	2,798,918	2,780,503	2,762,089	2,743,674	2,725,259
	9 Bonus Depreciation 50% in 2017												
	10 Total Tax Depreciation (including bonus)	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415
	7.6 Accumulated Tax Depreciation	3,194,226	3,212,641	3,231,055	3,249,470	3,267,884	3,286,299	3,304,714	3,323,128	3,341,543	3,359,958	3,378,372	3,396,787
	11 Tax Book Difference	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560
	12 Income Tax Rate 3/	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%	41.37%
	13 Deferred Income Tax on Timing Difference	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128
	14 Total Accumulated Deferred Income Tax Liability	1,314,715	1,317,843	1,320,971	1,324,098	1,327,226	1,330,353	1,333,481	1,336,608	1,339,736	1,342,863	1,345,991	1,349,118
	15 Deferred Tax Expense debit / (Credit)	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128	3,128
C	**Revenue Requirements - MP Regulated NOL**												
	1 Net Plant	6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,008,072	5,997,217	5,986,363
	2 Less: ADITL - Def Taxes	(1,314,715)	(1,317,843)	(1,320,971)	(1,324,098)	(1,327,226)	(1,330,353)	(1,333,481)	(1,336,608)	(1,339,736)	(1,342,863)	(1,345,991)	(1,349,118)
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	4,791,049	4,777,066	4,763,084	4,749,102	4,735,120	4,721,138	4,707,155	4,693,173	4,679,191	4,665,209	4,651,226	4,637,244
	5 Average Rate Base	4,798,040	4,784,058	4,770,075	4,756,093	4,742,111	4,728,129	4,714,146	4,700,164	4,686,182	4,672,200	4,658,218	4,644,235
	6 Current Return on CWIP 4/												
	7 Return on Average Rate Base /												
	8 After Tax Return on Equity	22,528	22,463	22,397	22,331	22,266	22,200	22,134	22,069	22,003	21,937	21,872	19,266
	9 Income Tax Component	15,896	15,850	15,803	15,757	15,711	15,665	15,618	15,572	15,526	15,479	15,433	13,594
	10 Interest Expense Component	10,156	10,126	10,097	10,067	10,037	10,008	9,978	9,949	9,919	9,889	9,860	8,073
	11 Total Return on Average Rate Base	48,580	48,439	48,297	48,155	48,014	47,872	47,731	47,589	47,448	47,306	47,164	40,933
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	14 Property Tax	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	78,023	77,881	77,739	77,598	77,456	77,315	77,173	77,032	76,890	76,748	76,607	70,376

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
3/ Minnesota Composite Income Tax Rate.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664 starting 12/1/2018. Refer to Exhibit B-4.

Thosmson Base Rate Revenue Credit through 1/1/2017.

Property Retirements in Base Rates

Section	Line		2009	Base Rates 2010
A		**Book Basis of Retired Property**		
	1	Plant in Service	3,068,658	3,124,620
	2	Total Accumulated Depreciation	1,919,500	1,975,208
	3	Net Plant	1,149,158	1,149,412
	4	Depreciation Expense		55,708
B		**Tax Basis of Retired Property**		
	1	Plant in Service	3,068,658	3,124,620
	2	Accumulated Depreciation	2,982,953	3,057,308
	3	Net Plant	85,705	67,312
	4	Total Tax Depreciation		74,355
	5	Tax Book Difference	1,063,453	1,082,100
	6	Income Tax Rate 1/	41.37%	41.37%
	7	Accumulated Deferred Income Tax Liability	439,951	447,665
	8	Deferred Tax Expense debit / (Credit)		7,714
C		**Revenue Requirements in Base Rates**		
	1	Net Plant	1,149,158	1,149,412
	2	Less: ADITL - Def Taxes	(439,951)	(447,665)
	3	Rate Base	709,208	701,747
	4	Average Rate Base		705,477
	5	Return on Average Rate Base 2/		
	6	After Tax Return on Equity		39,749
	7	Income Tax Component		28,047
	8	Interest Expense Component		17,919
	9	Total Return on Average Rate Base		85,715
	10	Operation & Maintenance Expense Associated with Retired Plant		-
	11	Depreciation Expense		55,708
	12	Property Tax		75,142
	13	Revenue Requirements in Base Rates Associated with Retired Property		216,565
	14	Monthly Credit for Revenue Requirements in Base Rates		(18,047)
	15	MN Jurisdictional Allocator 3/		0.82017
	16	Monthly MN jurisdictional Credit for Revenue Requirements in Base Rates 4/		(14,802)

Notes:

1/ Minnesota Composite Income Tax Rate.

2/ Pre-tax rate of return is 12.15% from 2009 MPUC rate case, Docket No. E-015/GR-09-1151. Refer to Exhibit B-4 rate of return components.

3/ Refer to Exhibit B-5.

4/ This monthly revenue requirement credit is needed beginning the month MPUC approves cost recovery and until 1/1/2017 when the retirements and the Thomson projects were rolled into base rates in 2016 rate case .

Thosmson Base Rate Revenue Credit for 12/1/2017 and forward

Property Retirements in Base Rates

Section	Line		2009	Base Rates 2010	
A		**Book Basis of Retired Property**			
	1	Plant in Service	121,484	121,484	
	2	Total Accumulated Depreciation	98,145	99,718	
	3	Net Plant	23,339	21,766	
	4	Depreciation Expense		1,573	
B		**Tax Basis of Retired Property**			
	1	Plant in Service	121,484	121,484	
	2	Accumulated Depreciation	121,484	121,484	
	3	Net Plant	-	-	
	4	Total Tax Depreciation		-	
	5	Tax Book Difference	23,339	21,766	
	6	Income Tax Rate 1/	41.37%	41.37%	
	7	Accumulated Deferred Income Tax Liability	9,655	9,004	
	8	Deferred Tax Expense debit / (Credit)		(651)	
C		**Revenue Requirements in Base Rates**			
	1	Net Plant	23,339	21,766	
	2	Less: ADITL - Def Taxes	(9,655)	(9,004)	
	3	Rate Base	13,683	12,761	
	4	Average Rate Base		13,222	
				Starting 12/1/2017	Starting 12/1/2018
	5	Return on Average Rate Base 2/			
	6	After Tax Return on Equity		745	658.21
	7	Income Tax Component		526	464.44
	8	Interest Expense Component		336	275.82
	9	Total Return on Average Rate Base		1,607	1,398
	10	Operation & Maintenance Expense Associated with Retired Plant		-	-
	11	Depreciation Expense		1,573	1,573
	12	Property Tax		-	-
	13	Revenue Requirements in Base Rates Associated with Retired Property		3,180	2,972
	14	Monthly Credit for Revenue Requirements in Base Rates 3/		(265)	(248)
	15	MN Jurisdictional Allocator 4/		0.82017	0.84360
	16	MN Jurisdictional Revenue Credit		(217)	(209)

Notes:

1/ Minnesota Composite Income Tax Rate.

2/ Refer to Exhibit B-4 rate of return components.

3/ This monthly revenue requirement credit is needed beginning with the retirement in 12/2017 and until the retirements and the project #106794 are incorporated into base rates in a subsequent rate case.

4/ Refer to Exhibit B-5.

Minnesota Power
Renewable Resources Rider: 2018 RRR Factor Filing

Base Rate Revenue Credit for Bison 6 LGIA Transaction /1

Section	Line	2016	Base Rates 2017
A	**Book Basis of Bison 6 LGIA Related Property**		
	1 Plant in Service	52,073,893	52,073,893
	2 Total Accumulated Depreciation	5,708,846	7,424,287
	3 Net Plant	46,365,047	44,649,606
	4 Depreciation Expense		1,715,440
B	**Tax Basis**		
	1 Plant in Service	52,073,893	52,073,893
	2 Accumulated Depreciation	36,586,965	37,960,242
	3 Net Plant	15,486,928	14,113,651
	4 Total Tax Depreciation		1,373,277
	5 Tax Book Difference	30,878,119	30,535,955
	6 Income Tax Rate	41.37%	41.37%
	7 Accumulated Deferred Income Tax Liability	12,774,278	12,632,725
	8 Deferred Tax Expense debit / (Credit)		(141,553)
C	**Revenue Requirements in Base Rates**		
	1 Net Plant	46,365,047	44,649,606
	2 Less: ADITL - Def Taxes	(12,774,278)	(12,632,725)
	3 Rate Base	33,590,769	32,016,882
	4 Average Rate Base		32,803,825
	5 Return on Average Rate Base /2		
	6 After Tax Return on Equity		1,632,976
	7 Income Tax Component		1,152,244
	8 Interest Expense Component		684,288
	9 Total Return on Average Rate Base		3,469,508
	10 Depreciation Expense		1,715,440
	11 Total Return on Average Rate Base and Depreciation Expense in Base Rates		5,184,948
	12 Bison 6 LGIA share of allocated plant costs		28.504%
	13 Bison 6 LGIA allocated Return on Rate Base and Depreciation Expense		1,477,941
	14 Allocated Operation & Maintenance Expense associated with Bison 6 LGIA		159,148
	15 Annual Base Rate Revenue Credit		1,637,089
	16 MN Jurisdictional Allocator		0.82713
	17 MN Jurisdictional Annual Base Rate Revenue Credit 3/		1,354,085
	18 Single Lump Sum Related to Transaction Costs 4/		122,601
	19 Total Base Rate Revenue Credit for first 12 months /5		1,476,686

Notes:
1/ For source document and support, refer to Docket E015/AI-17-304, filed 4/17/2018, and Attachment 1 as revised.
2/ Pre-tax rate of return is 10.577% from 2016 MPUC rate case, Docket No. E-015/GR-16-664. Refer to Exhibit B-4 for rate of return components.
3/ This revenue requirement credit is needed beginning 2/4/2019 until the Company's next rate case.
4/ This is a single lump sum that should only be credited for one year.
5/ This revenue requirement credit is needed beginning 2/4/2018 until 2/4/2019 when it would be replace with credit on line 17.

Minnesota Power
Renewable Resources Rider: 2018 RRR Factor Filing
PTC True-Up: 2017

Line	Description		Amount	Note
1	2017 Test Year Budget		1,742,923	MWh
		$	23	$/MWh
		$	40,087,240	1/
2	Rebuttal Adjustment		1,742,923	MWh
		$	1	$/MWh
			1,742,923	2/
3	Total PTC in Rate Case	$	41,830,163	3/
4	2017 Actual		1,832,070	MWh
		$	24	$/MWh
		$	43,969,680	
5	PTC Over-Budget	$	2,139,517	4/
6	Deferred tax expense impact	$	(2,139,517)	5/
7	Grossup		1.705611	6/
8	Revenue requirement impact	$	(3,649,183)	7/
9	Increase to average rate base		1,069,758	8/
10	Rate of return on rate base		7.064%	9/
11	Return on rate base		75,568	10/
12	Grossup		1.705611	6/
13	Rate base revenue requirement impact	$	128,889	11/
14	Total Revenue requirement impact		(3,520,294)	12/
15	MN Jurisdictional allocator		0.83910	13/
16	MN Jurisdictional Revenue Requirement True-Up	$	(2,953,879)	14/

Notes:
1/ MP Exhibit 074 Jago Direct, Table 1, page 16.
2/ MP Exhibit 075 Jago Direct, page 5, line 9.
3/ Line 1 + Line 2.
4/ Line 4 - Line 3.
5/ Line 5 x -1.
6/ 1/(1 - 41.37 tax rate)
7/ Line 6 x Line 7
8/ Line 6 / -2
9/ Refer to Exhibit B-4.
10/ Line 9 x Line 10
11/ Line 11 x Line 12
12/ Line 8 + Line 13
13/ MP Exhibit 019 Supplemental Direct Volume 4, (SJS) Supplemental Direct C-1, page 15, line 18, column (3) / column (1).
14/ Line 14 x Line 15

Minnesota Power
Renewable Resources Rider: 2018 RRR Factor Filing
Prorata Accumulated Deferred Income Taxes
Year Ended December 31, 2018

Rate Year = *Projected 2018*

Line	A	B	C	D	E	F	G	H	
1	**Account 190**								
2	**Days in Period**					**Averaging with Proration - Projected**			
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
3	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity 1/	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)	
4									
5	November 30th balance Prorated Items							1,345,991	2/
6	December	31	1	31	3.23%	75,453	2,434	1,348,425	3/
7	Total					75,453	2,434		
8	November DTL (nonprorated)							1,345,991	4/
9	December DTL (nonprorated)							1,421,444	5/
10	Average (nonprorated)							1,383,717	6/
11	Change in Rate Base							35,292	7/
12	Rate of Return on Rate Base							7.064%	8/
13	Return on Rate Base							2,493	9/
14	Grossup							1.70561	10/
15	Annual Prorata ADIT Revenue Requirement							4,252	11/
16	Number of Months New Rate Effective in 2018							1	
17	Prorata ADIT Revenue Requirement							354	12/
18	MN Jurisdctional allocator							0.8432	13/
19	Prorata ADIT Revenue Requirement in Projected Rate							299	14/

Notes:

1/ Refer to Exhibit B-2, pages 1 and 2, line B15, December 2018
2/ Refer to Exhibit B-2, pages 1 and 2, line B14, November 2018.
3/ Lines 5H + Line 6G.
4/ Refer to Exhibit B-2, pages 1 and 2, line B14, November 2018.
5/ Refer to Exhibit B-2, pages 1 and 2, line B14, December 2018.
6/ Lines (8 + 9)/2.
7/ Line 11 - Line 6
8/ Refer to Exhibit B-4.
9/ Line 11 x Line 12.
10/ 1/(1 - 41.37 tax rate)
11/ Line 13 x Line 14.
12/ Line 15 x (1/12).
13/ MP Exhibit 019 Supplemental Direct Volume 4, (SJS) Supplemental Direct C-1, page 15, line 17, column (3) / column (1).
14/ Line 17 x Line 18.

Minnesota Power
2016 Renewable Resources Rider: Thomson Hydro
Plant Additions, AFUDC and Return on CWIP

	Total Project	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Replace/Refurbish Dam 6	414,677												
ID# 106069													
In Service 12/31/2018												CAPPED	
BOM		230,834	243,819	249,813	260,878	262,182	327,474	327,990	370,663	398,892	407,413	414,677	414,677
CapEx	467,229	20,196	7,698	11,969	5,290	74,848	2,663	44,689	31,650	10,456	7,489		
Less Internal Cost	-52,552	-7,211	-1,703	-904	-3,986	-9,556	-2,147	-2,016	-3,421	-1,934	-225		
AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		243,819	249,813	260,878	262,182	327,474	327,990	370,663	398,892	407,413	414,677	414,677	414,677
Return on CWIP													
After Tax Return on Equity		1,114	1,159	1,199	1,228	1,384	1,539	1,640	1,807	1,893	1,930	1,947	1,947
Income Tax Component		786	818	846	866	977	1,086	1,157	1,275	1,336	1,362	1,374	1,374
Interest Expense Component		502	522	540	554	624	694	739	814	853	870	878	878
Total Return on CWIP		2,403	2,499	2,585	2,648	2,985	3,318	3,537	3,896	4,082	4,162	4,199	4,199
Thomson Spill Capacity	6,122,046												In-Service
ID# 106794													
In Service 12/31/2017												CAPPED	12/31/2017
BOM		1,878,999	1,919,924	2,002,405	2,058,312	2,070,564	2,226,939	2,490,700	3,024,686	3,373,894	4,349,700	6,095,671	6,122,046
CapEx	6,512,178	63,970	96,306	80,083	31,344	180,038	286,200	556,041	377,971	1,021,454	1,778,708	53,196	
Less Internal Cost	-441,417	-23,045	-13,825	-24,176	-19,092	-23,663	-22,439	-22,054	-28,763	-45,648	-32,737	-26,821	
AFUDC	53,042	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-1,756	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		1,919,924	2,002,405	2,058,312	2,070,564	2,226,939	2,490,700	3,024,686	3,373,894	4,349,700	6,095,671	6,122,046	6,122,046
Return on CWIP													
After Tax Return on Equity		8,919	9,208	9,533	9,693	10,089	11,075	12,948	15,022	18,132	24,522	28,683	14,372
Income Tax Component		6,293	6,497	6,727	6,840	7,119	7,815	9,136	10,599	12,794	17,303	20,239	10,141
Interest Expense Component		4,021	4,151	4,298	4,370	4,548	4,993	5,837	6,772	8,174	11,055	12,930	6,479
Total Return on CWIP		19,232	19,857	20,557	20,902	21,756	23,883	27,922	32,393	39,101	52,880	61,852	30,993
Total	84,057,574												
BOM		79,630,683	79,684,594	79,773,069	79,840,041	79,853,597	80,075,264	80,339,540	80,916,200	81,293,637	82,277,964	84,031,199	84,057,574
CapEx	107,971,672	86,402	104,348	92,052	36,635	254,886	288,863	600,730	409,621	1,031,909	1,786,197	53,196	0
Less Internal Cost	-7,075,092	-32,492	-15,872	-25,081	-23,078	-33,219	-24,587	-24,070	-32,183	-47,582	-32,962	-26,821	0
AFUDC	4,602,876	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-297,252	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	-21,144,630	0	0	0	0	0	0	0	0	0	0	0	0
EOM		79,684,594	79,773,069	79,840,041	79,853,597	80,075,264	80,339,540	80,916,200	81,293,637	82,277,964	84,031,199	84,057,574	84,057,574
Return on CWIP													
After Tax Return on Equity	745,873	10,033	10,367	10,732	10,921	11,473	12,614	14,588	16,828	20,025	26,452	30,630	16,319
Income Tax Component	526,297	7,079	7,315	7,573	7,706	8,096	8,901	10,294	11,874	14,130	18,665	21,613	11,515
Interest Expense Component	336,245	4,523	4,674	4,838	4,923	5,172	5,687	6,577	7,586	9,027	11,925	13,808	7,357
Total Return on CWIP	1,608,414	21,635	22,356	23,143	23,550	24,741	27,201	31,459	36,289	43,183	57,042	66,051	35,191

Minnesota Power
2016 Renewable Resources Rider: Thomson Hydro
Plant Additions, AFUDC and Return on CWIP

	Total Project	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Replace/Refurbish Dam 6	414,677												In-Service
ID# 106069													
In Service 12/31/2018													12/30/2018
BOM		414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677
CapEx	467,229												
Less Internal Cost	-52,552												
AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677
Return on CWIP													
After Tax Return on Equity		1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	860
Income Tax Component		1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	607
Interest Expense Component		878	878	878	878	878	878	878	878	878	878	878	360
Total Return on CWIP		4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	1,827
Thomson Spill Capacity	6,122,046												
ID# 106794													
In Service 12/31/2017													
BOM													
CapEx	6,512,178												
Less Internal Cost	-441,417												
AFUDC	53,042												
Less AFUDC on Internal Cost	-1,756												
Less Insurance Proceeds	0												
EOM													
Return on CWIP													
After Tax Return on Equity													
Income Tax Component													
Interest Expense Component													
Total Return on CWIP													
Total	84,057,574												
BOM		84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574
CapEx	107,971,672	0	0	0	0	0	0	0	0	0	0	0	0
Less Internal Cost	-7,075,092	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC	4,602,876	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-297,252	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	-21,144,630	0	0	0	0	0	0	0	0	0	0	0	0
EOM		84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574
Return on CWIP													
After Tax Return on Equity	745,873	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	860
Income Tax Component	526,297	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	607
Interest Expense Component	336,245	878	878	878	878	878	878	878	878	878	878	878	360
Total Return on CWIP	1,608,414	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	4,199	1,827

Minnesota Power
MPUC Docket E015/GR-09-1151
Rate of Return / Cost of Capital Summary
(thousands of dollars)
Commission Decision (9/29/2010)

	Average for 13 months Ended 12/31/10						
		Amount	% of Total	Component Cost	Weighted Cost	Pre-tax Rate	After-Tax Rate
Long Term Debt	$	696,677	45.71%	5.56%	2.540%	2.540%	1.490%
Common Equity	$	827,534	54.29%	10.38%	5.640%	9.610%	5.640%
	$	1,524,211	100.00%		8.180%	12.150%	7.130%

Federal & State Income Tax Rate	41.37%	
Pretax "Gross-up" Factor	1.70560	
After Tax Return on Equity	5.6343%	1/
Income Tax Component	3.9757%	2/
Interest Expense Component	2.5400%	
Pre-tax Return	12.1500%	

1/ Rounding forced to equity.
2/ Shown here as a component of the pretax rate of return. Can also be computed as 70.56% gross up on After Tax Return on Equity.

MPUC Docket E015/GR-16-664
Rate of Return / Cost of Capital Summary
(thousands of dollars)
Supplemental Direct
Used Starting 12/1/2018 Coincident with Final Rates

	Average for 13 months Ended 12/31/17						
		Amount	% of Total	Component Cost	Weighted Cost	Pre-tax Rate	After-Tax Rate
Long Term Debt	$	1,228,550	46.189%	4.52%	2.0860%	2.0860%	1.220%
Common Equity	$	1,431,272	53.811%	9.25%	4.9780%	8.4905%	4.978%
	$	2,659,822	100.00%		7.0640%	10.5765%	6.198%

Federal & State Income Tax Rate	41.37%	
Pretax "Gross-up" Factor	1.70560	
After Tax Return on Equity	4.9780%	1/
Income Tax Component	3.5125%	2/
Interest Expense Component	2.0860%	
Pre-tax Return	10.5765%	

1/ Rounding forced to equity.
2/ Shown here as a component of the pretax rate of return. Can also be computed as 70.56% gross up on After Tax Return on Equity.

Minnesota Power
Renewable Resources Rider
Allocation Factors

Allocation factors used beginning 4/1/2011

	D-01		D-02	
	Rate Case	Normalized	Rate Case	Normalized
MN Jurisdiction	0.82017	1.0000	0.77570	1.0000
Residential	0.11259	0.1373	0.10649	0.1373
General Service	0.06213	0.0758	0.05876	0.0758
Large Light & Power	0.12471	0.1521	0.11795	0.1521
Large Power	0.51269	0.6251	0.48489	0.6251
Municipal Pumping	0.00568	0.0069	0.00537	0.0069
Lighting	0.00237	0.0029	0.00224	0.0029

The D-01 and D-02 allocators from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151 were applied in 2011 Factor Filing begining April 2011.
Because the revenue tracker amounts are 100% MN Jurisdictional, the factors are normalized to obtain class allocations.
Refer to Exhibit B-5, page 2.

Allocation factors used beginning 12/1/2018

	D-01		D-02	
	Rate Case	Normalized	Rate Case	Normalized
MN Jurisdiction	0.84360	1.0000	0.82713	1.0000
Residential	0.10655	0.1263	0.10449	0.1263
General Service	0.06625	0.0785	0.06495	0.0785
Large Light & Power	0.14604	0.1731	0.14318	0.1731
Large Power	0.52030	0.6168	0.51014	0.6168
Municipal Pumping	0.00193	0.0023	0.00189	0.0023
Lighting	0.00253	0.0030	0.00248	0.0030
check	-	-	-	-

The D-01 and D-02 allocators from MP's 2016 MPUC rate case Docket No. E-015/GR-16-664 are applied begining 12/1/2018 assumed to be coincident with Final Rate implementation in rate case.
Because the revenue tracker amounts are 100% MN Jurisdictional, the factors are normalized to obtain class allocations.
Refer to Exhibit B-5, page 3.

Minnesota Power
Docket No. E-015/GR-09-1151
Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
Test Year 2010 Rebuttal Customer Budget
Revised from original work paper AF-3, page 14.

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses)	8,973,590	1,164,063	645,945	1,311,171	5,768,410	61,116	22,885
2	Average Demand	1,024,382	132,884	73,738	149,677	658,494	6,977	2,612
3	Percent	100.000	12.972	7.198	14.611	64.282	0.681	0.255
4	Annual CP Demand (loss adjusted)	1,267,035	214,342	116,138	224,399	697,256	9,334	5,567
5	Percent	100.000	16.917	9.166	17.711	55.031	0.737	0.439
6	Annual Load Factor (Line 2 / Line 4)	0.80849						
7	1.0 - Load Factor	0.19151						
8	Average Factor (Line 3 x Line 6 total)	80.849	10.488	5.820	11.813	51.971	0.551	0.206
9	Peak Factor (Line 5 x Line 7 total)	19.151	3.240	1.755	3.392	10.539	0.141	0.084
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	13.728	7.575	15.205	62.510	0.692	0.290
11	Power Supply Production - D-01 Adjusted for Jurisditional Split (Line 10 x .82017)	82.017	11.259	6.213	12.471	51.269	0.568	0.237
12	Power Supply Transmission - D-02 Adjusted for Jurisditional Split (Line 10 x .77570)	77.570	10.649	5.876	11.795	48.489	0.537	0.224

Notes:
Residential, General Service, Large Light and Power and Municipal Pumping CP demands per customer from load research multiplied by budgeted number of customers and adjusted for losses. Large Power CP demand based on 2008 CP adjusted for losses and ratio of 2008 to Test Year average demand. Large Light and Power and Large Power loads normalized to reflect three cusomters that moved from Large Power to Large Light and Power. Lighting CP is average load based on Test Year budgeted total energy and 4,200 burning hours and adjusted for losses.

Allete, Inc., d/b/a Minnesota Power
Docket No. E-015/GR-16-664
Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
2017 Test Year 2/28/2017 Supplemental Filing

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses, excl. dual fuel)	8,795,413	1,048,806	682,004	1,544,886	5,477,638	18,171	23,907
2	Average Demand	1,004,043	119,727	77,854	176,357	625,301	2,074	2,729
3	Percent	100.000	11.924	7.754	17.565	62.278	0.207	0.272
4	Annual CP Demand (loss adjusted)	1,142,421	203,013	97,884	176,764	654,612	4,413	5,734
5	Percent	100.000	17.770	8.568	15.473	57.300	0.386	0.502
6	Annual Load Factor (Line 2 / Line 4)	0.87887						
7	1.0 - Load Factor	0.12113						
8	Average Factor (Line 3 x Line 6 total)	87.887	10.479	6.815	15.437	54.735	0.182	0.239
9	Peak Factor (Line 5 x Line 7 total)	12.113	2.152	1.038	1.874	6.941	0.047	0.061
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	12.631	7.853	17.311	61.676	0.229	0.300
11	Power Supply Production - D-01 Adjusted for Jurisdictional Split (Line 10 x .84360)	84.360	10.655	6.625	14.604	52.030	0.193	0.253
12	Power Supply Transmission - D-02 Adjusted for Jurisdictional Split (Line 10 x .82713)	82.713	10.449	6.495	14.318	51.014	0.189	0.248

Notes:

Residential, General Service, Large Light and Power and Municipal Pumping CP demands per customer from load research multiplied by number of customers and adjusted for losses. Large Power CP demand estimated based on 2017 budgeted average demand and the ratio of Large Power CP demand to Large Power average demand from 2012 -2015. Lighting CP is average load based on 2017 Test Year energy and 4,200 burning hours and adjusted for losses.

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING

SUSAN ROMANS of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **5th** day of **June, 2018**, she served Minnesota Power's Petition seeking Approval of its 2018 Renewable Factor on the Minnesota Public Utilities Commission and the Minnesota Department of Commerce via electronic filing. Parties on Minnesota Power's General Service List were served as requested.

Susan Romans

Susan Romans

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	Yes	GEN_SL_Minnesota Power_MPs General Service List
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