minnesota power / 30 west superior street / duluth, minnesota 55802-2093 / 218-722-5642 / www.mnpower.com

December 20, 2013

VIA ELECTRONIC FILING

Dr. Burl W. Haar
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 Petition for Approval of Cost Recovery under Boswell Energy Center Unit 4 Emission Reduction Rider (BEC4 Rider)
Docket No. E015/M-13-___

Dear Dr. Haar:

Enclosed please find Minnesota Power's Petition to implement its Rider for Boswell Unit 4 Emission Reduction. Additionally, Minnesota Power submits this Petition in compliance with the Commission's November 5, 2013 Order approving the Boswell Energy Center Unit 4 mercury emission reduction project ("BEC4 Project") and authorizing rider recovery, and with Minn. Stat. § 216B.1692, subd. 6. that requires Minnesota Power to provide notification to the Commission and Minnesota Pollution Control Agency of the Company's intent to proceed with the BEC4 Project. Minnesota Power has included a Summary with this filing. As reflected in the attached Affidavit of Service, the Summary has been filed on the official general service list utilized by Minnesota Power.

Please contact me at (218) 355-3601 or lhoyum@mnpower.com with any questions related to this matter.

Yours truly,

Lori Hoyum

Lori Hoyum
Policy Manager

LH
Enc.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition for Approval of Cost Recovery Under Boswell Energy Center Unit 4 Emission Reduction Rider (BEC4 Rider)	Docket No. E015/M-13-_____ **PETITION TO IMPLEMENT BEC4 RIDER and COMPLIANCE FILING**

SUMMARY OF FILING

Minnesota Power submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. §§ 216B.6851; 216B.686, and 216B.682, subd. 3, seeking Commission approval of Minnesota Power's rate adjustment under its Boswell Energy Center Unit 4 Emission Reduction Rider. Additionally, Minnesota Power submits this Petition in compliance with Order Points 1.a. and 1.b. of the Commission's November 5, 2013 Order approving the Boswell Energy Center Unit 4 mercury emission reduction project and authorizing rider recovery. Through this Petition, Minnesota Power also provides notification to the Commission and Minnesota Pollution Control Agency of the Company's intent to proceed with the Project in compliance with Minn. Stat. § 216B.1692, subd. 6.

STATE OF MINNESOTA
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MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Petition for Approval of Cost Recovery Under Boswell Energy Center Unit 4 Emission Reduction Rider (BEC4 Rider)	Docket No. E015/M-13-_____ **PETITION TO IMPLEMENT BEC4 RIDER and COMPLIANCE FILING**

I. INTRODUCTION

Minnesota Power submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. §§ 216B.6851; 216B.686, and 216B.682, subd. 3, seeking Commission approval of Minnesota Power's rate adjustment under its Rider for Boswell Unit 4 Emission Reduction ("BEC4 Rider"). Additionally, Minnesota Power submits this Petition in compliance with Order Points 1.a. and 1.b. of the Commission's November 5, 2013 Order ("November 5, 2013 Order") in Docket No. E015/M-12-920 approving the Boswell Energy Center Unit 4 ("BEC4") mercury emission reduction project ("BEC4 Project") and authorizing rider recovery. Through this Petition, Minnesota Power also provides notification to the Commission and Minnesota Pollution Control Agency ("MPCA") of the Company's intent to proceed with the Project in compliance with Minn. Stat. § 216B.1692, subd. 6.

Minnesota Power is pleased to report that the current estimate for the BEC4 Project has decreased to approximately $306 million, a reduction of $44 million from an originally estimated approximately $350 million. Minnesota Power's initial cost estimates for the BEC4 Project were developed based on consulting engineers' like-kind project experience and vendor proposals, as well as the Company's engineering resources and experience. With approximately 80 percent of the contracts awarded and 80 percent of the engineering complete, Minnesota Power was able to refine the Project's total anticipated capital cost for the BEC4 Project. Many of these contracts were awarded for less than estimated amounts, which is one of the contributing factors to the decrease in the cost estimate. Additionally, once certain contracts were awarded, Minnesota Power was able to execute a more detailed engineering process than what could be done in the initial stages of the project. Through this detailed engineering process, Minnesota Power was able to reduce the impact to wetlands and construct a smaller footprint, as well as create additional engineering opportunities to decrease costs which all contributed to the savings. Minnesota Power's 80 percent ownership interest and the reasons for the decrease in total capital cost for the BEC4 Project are discussed in more detail in Section III.C.

On August 31, 2012, Minnesota Power submitted its Boswell Energy Center Unit 4 mercury emission reduction plan petition ("BEC4 Plan") in compliance with Minn. Stat. § 216B.6851 to the Commission and MPCA. The BEC4 Plan is a multi-pollutant solution for reducing mercury, particulate matter ("PM"), sulfur dioxide (SO_2), and other hazardous air pollutants being addressed by United States Environmental Protection Agency ("EPA") regulations while also reducing plant wastewater. Minnesota Power will install a semi-dry flue gas desulfurization system ("FGD"), fabric filter and powder activated carbon ("PAC") injection system to help achieve compliance with the Minnesota Mercury Emissions Reduction Act ("MERA"), the EPA Mercury and Air Toxics Rule, and other enacted or pending federal and state environmental rulemakings regulating air and water emissions and solid byproducts from coal-fired power plants. Through multi-pollutant control technology, Minnesota Power will cost-effectively achieve the mercury reduction required by MERA while ensuring compliance with other regulatory programs over the long term.

On March 7, 2013, Minnesota Power submitted its Petition seeking Commission approval pursuant to Minn. Stat. §§ 216B.683, subd. 1; 216B.686, subd. 2; and 216B.1692, subd. 3 to recover investments and expenditures associated with the BEC4 Project through the BEC4 Rider.

On November 5, 2013, the Commission issued an order approving Minnesota Power's BEC4 Project and BEC4 Rider. The Commission concluded that Minnesota Power's BEC4 Plan will come closest of the feasible alternatives to achieving a total mercury emissions reduction of 90 percent, and reducing emissions of pollutants other than mercury, in a manner that provides for increased environmental and public health benefits, does not impose excessive costs on Minnesota Power ratepayers, and will achieve at least the pollution control required by applicable state and federal regulations. The Order requires Minnesota Power to file biennial reports on the status of the project, with the first report due January 1, 2014 (see Order Point 1.a.). Additionally, Minnesota Power is to include an update on its discussions with the EPA to resolve the notice of violation and identify and explain any costs related to the notice of violation included in its rate factor adjustment filings or other rate proceedings (see Order Point 1.b). Minnesota Power provides the required information in this Petition in compliance with Order Points 1.a. and 1.b.

II. PROCEDURAL MATTERS

Pursuant to Stat. §§ 216B.683; 216B.1692; 216B.6851, 216B.686; and 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 a copy of this Petition on the Department of Commerce - Division of Energy Resources, the Minnesota Office of the Attorney General – Antitrust and Utilities Division and MPCA. 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. 4(A))

Minnesota Power
30 West Superior
Street Duluth, MN
55802 (218) 722-
2641

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

David Moeller
Senior Attorney
Minnesota Power
30 West Superior
Street Duluth, MN
55802 (218) 723-
3963
dmoeller@allete.com

5. Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Petition is being filed on December 20, 2013. The proposed effective date of the BEC4 Plan Adjustment is April 1, 2014.

6. Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 4(D))

This Petition is made pursuant to Minn. Stat. §§ 216B.683, 216B.1692, 216B.6851, 216B.686 and 216B.16. Minn. Stat. § 216B.1692 allows Minnesota Power to recover the costs of the BEC4 Plan through the Commission-approved BEC4 Rider. Minn. Stat. § 216B.16, subd. 1 requires a 60 day notice to the Commission of a proposed rate change, after which time the proposed rate change takes effect unless suspended.

This Petition falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rule 7829.0100, subp. 11 since no determination of Minnesota Power's general revenue requirement is necessary. Minn. Rule 7829.1400, subp. 1 and 4 respectively, permit comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed 10 days thereafter.

7. Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))

Lori Hoyum
Policy Manager
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(218) 355-3601
lhoyum@mnpower.com

8. Impact on Rates and Services (Minn. Rule 7829.1300, subp. 4(F))

The BEC4 Plan Adjustment will have no effect on Minnesota Power's base rates.

9. Service List (Minn. Rule 7829.0700)

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10. Modified Rates (Minn. Rule 7825.3600)

Minn. Rule 7825.3600 requires all proposed changes in rates be shown by filing revised or new pages to the rate book and by identifying those pages which were not changed. Minnesota Power's filing requires minor but identical references to the BEC4 Rider in the Adjustments section of its electric rate schedules. See Exhibit A. Upon approval of the requested rate adjustment, Minnesota Power will submit a compliance filing containing the final approved tariff pages.

III. PROJECT STATUS AND REQUIRED UPDATES

A. Project Status Notification - Minn. Stat. § 216B.1692, subd. 6

Minn. Stat. § 216B.1692, Subd. 6. states, "Within 60 days of a final commission order, the public utility shall notify the commission and the Pollution Control Agency whether it will proceed with the project." On November 5, 2013, the Commission issued an order approving Minnesota Power's BEC4 Project and BEC4 Rider. Minnesota Power is proceeding with the BEC4 Project and provides an update of the Project's progress in Section III.B.

B. Project Update

Minnesota Power provides the following project update in compliance with Order Point 1.a. of the Commission's November 5, 2013 Order in Docket No. E015/M-12-920 that requires Minnesota Power to "file biennial reports on the status of the Project, with the first report due January 1, 2014." Under the BEC4 Plan, Minnesota Power will install a proven, utility scale, commercially available semi-dry FGD system for the removal of SO_2, PM and mercury. In October 2012, Minnesota Power awarded the contract to Alstom. Alstom's circulating dry scrubber technology, referred to as the NID system ("NID"), will also further reduce emissions of acid gases, including hydrochloric acid and trace metals. Minnesota Power will also install a powder activated carbon injection system to capture flue gas mercury, in combination with the fabric filter integral to the NID to control PM and help optimize mercury removal performance.

Construction work is progressing slightly ahead of the project schedule presented in the BEC4 Plan Petition (see Table 2, page 29) submitted on August 31, 2012, and the subsequent March 7, 2013 Petition seeking Commission approval to establish the BEC4 Rider (see Table 1, page 9). Start of construction was postponed over two months due to the timing of air permit receipt from the MPCA. Through an accelerated construction schedule, Minnesota Power was able to make up the time lost due to the delay, and even worked ahead to complete the silo foundation, NID electrical building, and alleyway foundations this year, instead of in 2014. Completion of these sub-projects will lessen the concern of spring weather delays impacting the mechanical erection contract. Progress made over the past six months included installing:

- Approximately 39,000 linear feet of sheet pile,
- 1,406 16-inch displacement piles,

- 138 8-inch micro-piles, and
- 28 concrete foundations.

Construction activities were halted in late November until next spring, while engineering and purchasing efforts continue through the winter. Exhibit E contains pictures of the construction work at various stages of the project. Minnesota Power is very pleased to report that the BEC4 Project completed the first year of the project with zero injuries. With more than 150,000 hours worked on the major project already, there has not been a single reported first aid incident. Table 1 presents the projected schedules for implementation activities and status for activities to date.

Table 1 - Project Implementation Activity Update

Activity – Project Implementation	Timeline
Phase 1 – Conceptual Engineering Target Procurement Activities – Environmental Equipment [*Completed]	Apr 2012 – Dec 2012
Phase 2 – Final Design & Procurement Fabricate/Deliver – Fabric Filter/CDS [*In Progress]	Jul 2012 – May 2015
Phase 3 – Construction Site Preparation [*Completed] Pile construction [*Completed] Construction – Civil & Foundations [*In Progress] Construction – CDS/Fabric Filter and Ash Silo Construction – Electrical and Controls	 Apr 2013 – Jul 2013 Jul 2013 – Nov 2013 Apr 2013 – Sep 2014 Apr 2014 – Jul 2015 Nov 2014 – Jul 2015
Phase 4 – Start-Up Checkout & Commission for Tuning Final Plant Start-Up and Tuning	 Apr 2015 – Oct 2015 Oct 2015 – Jan 2016

Air and wetland/water permits from federal, state and local agencies, identified in Tables 3 and 4 on page 30 of the BEC4 Plan Petition, were required to begin construction of the BEC4 Project. Minnesota Power received all necessary permits.

C. Cost Containment Measures and Budget Estimate Update

Minnesota Power employs multiple steps to help ensure the lowest overall cost for the BEC4 Project. The Company uses its purchasing procedures to obtain competitive bids for as many purchases as possible, including equipment and labor packages, and award contracts to bidder(s) based on the best overall economic value for its customers. At this time, approximately 80 percent of the contracts have been awarded and engineering is 80 percent complete. Many of these contracts were awarded for less than the estimated amounts. Minnesota Power is pleased to report that the BEC4 Project total anticipated capital cost has decreased to a current estimate of approximately $306 million from an originally estimated approximately $350 million. The total capital cost reflects Minnesota Power's 80 percent[1] ownership interest in the equipment and facilities that comprise the BEC4 Project. The reasons for the decrease in total capital cost for the BEC4 Project are discussed below.

First, the initial Project cost estimates were based upon the design and footprint for a recent installation of a specific CDS technology at another utility's facility similar to BEC4. Through the request for proposal process it was determined that Alstom's NID layout fit the BEC4 site much better, with the constraints created by the location of Blackwater Lake, than the CDS technology used in the initial estimate. The NID layout offers many advantages including:

- Reducing the impact to wetlands by approximately 50 percent from the initial estimate;
- Reducing the amount of steel and erection costs due to the smaller footprint; and
- Creating additional engineering opportunities to reduce other costs.

Secondly, given the Alstom NID layout, the Company employed a detailed engineering process referred to as value engineering[2] which could not be performed in the initial design stage of the project used as a cost basis in the August 31, 2012 emission reduction plan and March 7, 2013 cost recovery filings. Through value engineering, Minnesota Power was able to:

[1] BEC4 is jointly owned by Minnesota Power and WPPI Energy. As a co-owner of BEC4, WPPI Energy will pay a proportionate share of the required capital and O&M associated with the BEC4 Project. Amounts reflected are net of WPPI's 20% ownership interest in BEC4. Amounts include approximately $3.4 million of AFUDC net of contra.

[2] Value engineering is a systematic and organized approach to provide the necessary functions in a project at the lowest cost. Value engineering promotes the substitution of materials and methods with less expensive alternatives, without sacrificing functionality. It is focused solely on the functions of various components and materials, rather than their physical attributes. This approach is also called a "value analysis."

- Decrease the quantity of ductwork and ductwork support steel (and associated foundations) required by 66 percent through the arrangement of equipment and ductwork layout;
- Eliminate approximately 400 feet of pipe rack and associated foundations as a result of relocating the lime handling and service building closer to the FGD;
- Decrease space required for lime handling and preparation equipment, while improving integration with the NID; and
- Reduce from the estimated two PAC storage silos to one PAC silo.

Finally, because nearly 80 percent of the contracts are awarded and costs determined, Minnesota Power is able to carry a lower contingency on the Project than what was included in the original estimate. Through Minnesota Power's diligent efforts, and those working on behalf of Minnesota Power, the Company has been successful to this point in working towards achieving the lowest overall cost for the BEC4 Project on behalf of its customers.

D. Notice of Violation Update

Minnesota Power provides the following project update in compliance with Order Point 1.b. of the Commission's November 5, 2013 Order in Docket No. E015/M-12-920 that requires Minnesota Power to "include in its annual rate factor adjustment filing an update on its discussions with the EPA to resolve the notice of violation and shall identify and explain any costs related to the notice of violation included in its rate factor adjustment filings or other rate proceeding." The Company continues to work on resolution with the EPA and will keep the Commission informed of notice of violation progress via annual rate factor adjustment filings.

IV. COST RECOVERY

A. BEC4 Rider - Revenue Requirements

Based upon the current estimated costs described in Section III.C., the revenue requirements for the BEC4 Project have been calculated according to the cost recovery terms detailed in Minnesota Power's Petition as approved by the November 5, 2013 Order. Subsequent to the November 5, 2013 Order, the Commission approved Minnesota Power's 2013 Renewable Resources Rider Adjustment Factors in Docket No. E015/M-13-410. In its Order dated December 3, 2013, the Commission, "Directed the Company for all future Renewable Resources Rider and other rider recovery filings, to remove capitalized internal costs when calculating the amount of AFUDC (allowance for funds used during construction) included in the rate base for rider recovery purposes, consistent with the terms of its prior rider filings." Consistent with this directive, Minnesota Power has excluded internal capitalized labor and the AFUDC on internal capitalized labor from the project costs and overall revenue requirements calculations for the BEC4 Project. Refer to Exhibit B-3 for these specific deductions from the project costs.

In addition to the adjustments discussed in the above paragraph, one other adjustment will be made to future revenue requirements. Equipment with Original Installed Cost ("OIC") of approximately $40 million will be retired from BEC4 prior to the BEC4 Project being placed into service. When this occurs, Minnesota Power will deduct the estimated jurisdictional revenue requirements associated with this equipment that is currently in base rates from the BEC4 rider jurisdictional revenue requirements. This credit will include a return on average rate base, depreciation expense and associated O&M (operations & maintenance) expenses. It is anticipated that this credit will begin with Minnesota Power's next BEC4 Rider Adjustment and continue until the BEC4 Project is rolled into base rates in Minnesota Power's subsequent rate case.

Minnesota Power proposes to include a total of $13.8 million in jurisdictional revenue requirements in the BEC4 Rider Adjustment Factors. The total revenue requirements for the BEC4 Rider Adjustment Factors consist of the projected 2013 Tracker Balance of $1.4 million and 2014 revenue requirements of $12.4 million. The 2013 Tracker Balance represents the revenue requirements beginning in October 2013, the month after Commission approval of the BEC4 Project. As discussed below, the BEC4 Rider Adjustment Factors are calculated to recover the revenue requirements over a twelve-month period. Refer to Exhibit B-1 for a summary of the revenue requirements and to Exhibit B-2 for the detailed revenue requirement calculations.

B. Cost Allocation and Rate Design

1. Jurisdictional and Class Allocation

The jurisdictional and class allocations of revenue requirements for the BEC4 Project have been calculated based on the methodology detailed in Minnesota Power's Petition and the subsequent Order.[3] Specifically, the revenue requirements have been allocated between jurisdictions using the Power Supply Production Demand (D-01) allocators as approved in Minnesota Power's 2009 rate case (Docket No. E015/GR-09-1151). Once revenue requirements are brought to jurisdiction, Minnesota Power utilized the Power Supply Production Demand (Peak & Average D-01) allocators, also approved in Minnesota Power's 2009 rate case (Docket No. E015/GR-09-1151), to allocate the revenue requirements to class. See Exhibit B-5 for further detail on these allocators.

2. Rate Design

As originally proposed in Minnesota Power's Petition, the Large Power ("LP") rate design for the Boswell 4 Plan Adjustment incorporates demand ($/kW-month) and energy (¢/kWh) adders that recover the costs in a manner that preserves LP base rate design. Specifically, the LP revenue requirements are split between demand and energy based on LP's 2010 base rate demand and energy revenue split of approximately 60 percent demand and 40 percent energy from the Company's most recent rate case (Docket No. E015/GR-09-1151). The LP demand rate adder is calculated as 60 percent of the projected LP revenue requirement divided by the LP class Billing Demand (kW-month) from the 2014 budget. The LP energy rate adder is calculated as 40 percent of the projected LP revenue requirement divided by the annual LP energy sales (kWh) from the 2014 budget. See Exhibit B-1, page 1 of 6, for further detail.

[3] Order Point 4 of the November 5, 2013 Order requires Minnesota Power to make annual rate factor adjustment filings, including adjusted retail allocation factors if any large power or wholesale customer's load changes by 10 megawatts or more.

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In Minnesota Power's Petition, the Company originally proposed a separate energy-based (kWh) rate adder for each of the remaining retail rate classes (non-LP). Subsequent to that Petition, the Commission approved Minnesota Power's 2013 Renewable Resources Rider Adjustment Factors on December 3, 2013 in Docket No. E105/M-13-410. In that Petition Minnesota Power had also proposed separate energy-based (kWh) rate adders for each of the remaining retail rate classes (non-LP). Based on a recommendation by the Department, it was determined that an equal average energy-based (kWh) rate adder would be more appropriate for the remaining retail rate classes (non-LP). Taking direction from that recommendation, the Company is therefore proposing an average energy-based (kWh) rate adder for the remaining retail rate classes (non-LP). This energy adder is calculated as an average energy (kWh) charge consisting of the projected non-LP revenue requirements divided by the annual non-LP kilowatt-hour sales from the 2014 budget. See Exhibit B-1, page 1 of 6, for further detail. Also, refer to Exhibit A for the proposed Rider for Boswell Unit 4 Emission Reduction tariff page and the thirteen affected service schedules identified on page 16 of Minnesota Power's March 7, 2013 Petition seeking Commission approval to recover investments and expenditures associated with the BEC4 Project through the BEC4 Rider. No other pages in the rate book were changed and, therefore, are not included in Exhibit A.

C. Customer Impact

1. Notice and Billing

The Boswell 4 Plan Adjustment will appear as a separate line item following the Transmission Adjustment on customers' bills. A sample customer bill with the Boswell 4 Plan Adjustment is attached as Exhibit C.

Minnesota Power proposes to notify customers of the BEC4 Rider through a bill insert prior to the application of the Boswell 4 Plan Adjustment. A draft of the notice is attached as Exhibit D. Minnesota Power will work with Commission Staff and the Department to finalize this customer notification.

2. Customer Impacts

Assuming the effective date is April 1, 2014, the rate impact for the average residential customer will be approximately $1.27 per month or a 1.59 percent increase during the first twelve months of cost recovery.

For Large Power customers, the rate impact will be approximately 0.144¢ per kWh of energy or an increase of 2.61 percent during the first twelve months of cost recovery.

Table 2 summarizes the estimated revenue requirements and rate impacts by customer class for the twelve months beginning April 1, 2014.

Table 2 - Estimated Customer Impact

Proposed Billing Factor Effective	**4/1/2014**
Retail Revenue Requirements	$13,787,338
Rate Class Impacts 1/	
Residential	
Average Rate (¢/kWh)	9.821
Increase (¢/kWh)	0.156
Increase (%)	1.59
Average Impact ($/month)	1.27
General Service	
Average Rate (¢/kWh)	9.816
Increase (¢/kWh)	0.156
Increase (%)	1.59
Average Impact ($/month)	4.33
Large Light & Power	
Average Rate (¢/kWh)	7.911
Increase (¢/kWh)	0.156
Increase (%)	1.97
Average Impact ($/month)	355.56
Large Power	
Average Rate (¢/kWh)	5.523
Increase (demand + energy combined) (¢/kWh)	0.144
Increase (%)	2.61
Average Impact ($/month)	79,983
Municipal Pumping	
Average Rate (¢/kWh)	8.981
Increase (¢/kWh)	0.156
Increase (%)	1.74
Average Impact ($/month)	18.91
Lighting	
Average Rate (¢/kWh)	15.507
Increase (¢/kWh)	0.156
Increase (%)	1.01
Average Impact ($/month)	0.23

Notes:
1/ Average current rates are 2014 estimated rates based on Final 2010 TY General Rates in 2009 Rate Case (E015/GR-09-1151) without riders, adjusted to include current rider rates. Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Conservation Program Adjustment, and estimated 2014 Fuel and Purchased Energy Adjustment. Average $/month impact based on 2014 budgeted billing units.

V. CONCLUSION

Minnesota Power respectfully requests that the Commission approve Minnesota Power's rate adjustment under its Rider for Boswell Unit 4 Emission Reduction. Additionally, Minnesota Power appreciates the opportunity to update the Commission and its stakeholders on the progress of the BEC4 Project and report on the Company's success in using value engineering and other measures to reduce the overall cost of the project on behalf of its customers.

Dated: December 20, 2013

Respectfully submitted,

By: Lori Hoyum

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EXHIBIT A

RIDER FOR BOSWELL UNIT 4 EMISSION REDUCTION

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:

Rate Class	**Boswell 4 Plan Adjustment**
~~Residential~~	~~0.000¢/kWh~~
~~General Service~~	~~0.000¢/kWh~~
~~Large Light & Power~~	~~0.000¢/kWh~~
~~Municipal Pumping~~	~~0.000¢/kWh~~
~~Lighting~~	~~0.000¢/kWh~~
Large Power	\$0.60~~00~~ per kW-month of Billing Demand and 0.057~~000~~¢/kWh
All other applicable Retail Rate Customers	0.156¢/kWh

RIDER FOR BOSWELL UNIT 4 EMISSION REDUCTION

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:

Rate Class	**Boswell 4 Plan Adjustment**
Large Power	$0.60 per kW-month of Billing Demand and 0.057¢/kWh
All other applicable Retail Rate Customers	0.156¢/kWh

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Filing Date December 20, 2013 **MPUC Docket No.**

Effective Date **Order Date**

Approved by:
Marcia A. Podratz
Director - Rates

RESIDENTIAL SERVICE

RATE CODES

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APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations and any applicable Riders.

A dwelling will be considered to be occupied seasonally when occupied as customer's principal dwelling place for eight months or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 or 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$8.00	$8.80
0 kwh to 300 kwh	5.098¢	
301 kwh to 500 kwh	6.735¢	
501 kwh to 750 kwh	8.168¢	
751 kwh to 1000 kwh	8.445¢	
Over 1000 kwh	8.937¢	
All kWh (¢/kWh)		8.235¢

Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

RESIDENTIAL SERVICE

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8~~7~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9~~8~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

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RESIDENTIAL SERVICE

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an extension agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 or 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$8.00
Energy Charge	
All kWh (per kWh)	5.178¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance wit the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8~~7~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an extension agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

3. The duration and frequency of interruptions shall be at the discretion of Company. Interruption will normally occur at such times:
   (a) when Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when Company expects to incur a new system peak,
   (c) at such other times when in Company's opinion the reliability of the system is endangered,
   (d) when Company performs necessary testing for certification of interruptibility of customers' loads.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. Company will provide, at customer's expense, and customer will install, as directed by Company, a load-break switch or circuit breaker. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$8.00
Energy Charge	
All kWh (per kWh)	4.332¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8~~7~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

<u>CUSTOMERS WITHOUT A DEMAND METER</u>	
Service Charge	$10.50
Energy Charge for all kWh	7.836¢
<u>CUSTOMERS WITH A DEMAND METER</u>	
Service Charge	$10.50
Demand Charge for all kW	$5.86
Energy Charge for all kWh	5.288¢

Plus any applicable Adjustments.

GENERAL SERVICE

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $1.75 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount of 0.284¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

GENERAL SERVICE

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8~~7~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9~~8~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 85% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

Filing Date ~~November 5, 2012~~ December 20, 2013 **MPUC Docket No.** ~~E015/GR-09-1151~~

Effective Date ~~January 1, 2013~~ **Order Date** ~~December 10, 2012~~

Approved by:

Marcia A. Podratz
Director - Rates

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, three phase, or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system).

RATE (Monthly)

Service Charge

Low Voltage Service	$10.50
High Voltage Service	$10.50

Energy Charge

Low Voltage Service	5.178¢ per kWh
High Voltage Service	4.791¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8~~7~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:
   (a) when Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when Company expects to incur a system peak in excess of its Mid-Continent Area Power Pool (MAPP) accredited generating capability,
   (c) when in Company's opinion the reliability of the system is endangered, or
   (d) when Company performs necessary testing of interruptibility of customer's loads.

Interruptions shall normally occur for capacity related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service (those loads that meet the requirements specified in the MAPP Procedure for the Certification of Interruptible Demand).

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. The customer will install, at its expense, a load-break switch, circuit breaker, or other means of allowing Company to automatically interrupt customer's Dual Fuel load by sending a command or signal. The Company reserves the right to inspect and approve the installation to ensure compliance and consistency with Company's interruption system. If Company's system cannot support automatic interruption, interruption shall be made in accordance with Service Condition 8. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

8. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, whenever the Company determines such interruption is necessary. Customers with existing provisions in their Electric Service Agreements for longer notice before interruption shall continue to have thirty (30) minutes to shed their interruptible loads through the term of their existing contracts or December 31, 1998, whichever is later.

9. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Mid-Continent Area Power Pool in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

(a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).

(b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer’s service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system), supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge

High Voltage Service	$10.50
Low Voltage Service	$10.50

Energy Charge

High Voltage Service	4.032¢ per kWh
Low Voltage Service	4.332¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8~~7~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

55 75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,100.00
All additional kW of Billing Demand ($/kW)	$9.30
Energy Charge	
All kWh (¢/kWh)	3.722¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $1.75 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will also be subject to a discount of 0.284¢ per kWh of Energy.

LARGE LIGHT AND POWER SERVICE

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8~~7~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9~~8~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

LARGE LIGHT AND POWER SERVICE

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the amount by which the greatest adjusted demand duringthe preceding eleven months exceeds 100 kW, but not more than 75% of such adjusted demand. However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 85% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

LARGE POWER SERVICE

RATE CODES

54 74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");

(b) The voltage level(s) at which service will be supplied;

(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;

(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;

(e) A confidentiality agreement; and

(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

LARGE POWER SERVICE

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company ("Confidential Information"), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term "Holidays" shall mean New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year's Eve Day.

For purposes of ESAs, the term "Office" shall mean the Minnesota Office of Energy Security or its successor organization.

LARGE POWER SERVICE

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$216,276
All additional kW of Firm Demand ($/kW)	$19.85

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.232¢

Excess Energy Charge

All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under " ENERGY"

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

2. Fuel and Purchased Power Adjustment / Conservation Adjustment / Resource Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Adjustment and a conservation program

adjustment will be determined in accordance with the Rider for Conservation Program Adjustment. The combination of the Fuel and Purchased Power adjustment and the Conservation Program Adjustment will be shown on customer's bill as the Resource Adjustment.

3. AREA Adjustment. An emissions-reduction adjustment will be determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

4. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

5. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

6. CARE Affordability Surcharge: There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. Boswell 4 Plan Adjustment: There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8~~7~~. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9~~8~~. City of Duluth Franchise Fee. An adjustment for customers located within the corporate limits of the City of Duluth as specified in the Rider for City of Duluth Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

LARGE POWER SERVICE

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be the greater of the kW of Customer's Adjusted Demand or such higher Firm Demand specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this amount shall be deemed to be the Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases, for all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

LARGE POWER SERVICE

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Energy Portion

For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

LARGE POWER SERVICE

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$259,531
All additional kW of Non-Contract Billing Demand ($/kW)	$23.82

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.232¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY"

Plus any applicable Adjustments.

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

NON-CONTRACT LARGE POWER SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment. Such Fuel Adjustment shall be applicable to Customer's Non-Contract Firm Energy only.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8~~7~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

NON-CONTRACT LARGE POWER SERVICE

The adjusted demand ("Adjusted Demand")_in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 58/78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

NON-CONTRACT LARGE POWER SERVICE

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

Capacity Portion

For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

Energy Portion

For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

NON-CONTRACT LARGE POWER SERVICE

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 54/74 for which a ten (10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 54/74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 54/74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes <u>no</u> responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Lamp Type & Size	CIS Code	Rate Per Lamp Per Month Option 1	Option 2	Option 3	Option 4
Sub rate code		_ _A	_ _B	_ _C	_ _D
			(Option 2 Closed to New Installation)	(Option 3 Closed to New Installation)	
Mercury Vapor Lamps					
7,000 Lumens (175 watts)	K	11.60	8.06		
20,000 Lumens (400 watts)	M/P	18.36	12.69		
55,000 Lumens (1,000 watts)	Q	34.38	24.57		
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	I	10.19	5.86	5.86	
14,000 Lumens (150 watts)	X	11.73	7.44		
23,000 Lumens (250 watts)	J/G	16.65	9.89	9.96	
45,000 Lumens (400 watts)	Z	22.22	13.23	10.59	
Metal Halide Lamps					
17,000 Lumens (250 watts)	R	16.44			
28,800 Lumens (400 watts)	S	20.12		11.84	
88,000 Lumens (1,000 watts)	U	33.39		22.42	
Pole Charge Each pole used for service under this schedule only	6	$4.70	$4.70	$4.70	
Energy Charge - Per kWh		Included	Included	Included	5.882¢

Plus any applicable adjustments

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

Filing Date ~~November 5, 2012~~ December 20, 2013 **MPUC Docket No.** ~~E015/GR-09-1151~~
Effective Date ~~January 1, 2013~~ **Order Date** ~~December 10, 2012~~

Approved by: ______________________
Marcia A. Podratz
Director - Rates

OUTDOOR AND AREA LIGHTING SERVICE

The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8~~7~~. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

OUTDOOR AND AREA LIGHTING SERVICE

ENERGY TABLE

Lamp CIS Code	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	4,200	462	379	367	302	264	233	252	294	336	401	435	475
					Monthly kWh usage per lamp by type								
G	1,224	135	110	107	88	77	68	73	86	98	117	127	138
I	504	56	46	44	36	32	28	30	35	40	48	52	57
J	1,224	135	110	107	88	77	68	73	86	98	117	127	138
K	888	98	80	78	64	56	49	53	62	71	85	92	100
M	1,932	213	174	169	139	121	107	116	135	155	184	200	219
P	1,932	213	174	169	139	121	107	116	135	155	184	200	219
Q	4,620	508	417	404	332	290	256	277	323	370	441	479	523
R	1,260	139	114	110	91	79	70	76	88	101	120	130	142
S	1,932	213	174	169	139	121	107	116	135	155	184	200	219
U	4,410	485	398	385	317	277	245	264	309	353	421	457	499
X	756	83	68	66	54	48	42	45	53	60	72	78	87
Z	2,016	222	182	176	145	127	112	121	141	161	192	209	228

Company shall furnish all electric energy required for service under this schedule.

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

<u>Option 1</u>

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, lamp, ballast, photo-electric control and wiring.

<u>Option 2</u>

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include, but not be limited to, the fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications.

Filing Date ~~November 5, 2012~~ December 20, 2013 **MPUC Docket No.** ~~E015/GR-09-1151~~

Effective Date ~~January 1, 2013~~ **Order Date** ~~December 10, 2012~~

Approved by: ______________________

Marcia A. Podratz
Director - Rates

OUTDOOR AND AREA LIGHTING SERVICE

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option, including poles, except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications. Company's point of delivery shall be on the Company's side of disconnect switch either at the weather head for overhead service or at the pad mount transformer for underground service.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

OUTDOOR AND AREA LIGHTING SERVICE

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, over and above those which would be required for a single standard bracket mounting, shall not exceed $15.00 per light. Additional required investment will be at Customer's expense.

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For lamps which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

OUTDOOR AND AREA LIGHTING SERVICE

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Materials charges per the Company's cost for lighting replacement equipment plus the then current Material Handling Expense and A&G expense per Company's Accounting Manual.

ERIE MINE SITE SERVICE

RATE CODES

72

TERRITORY

Applicable to customers located at or close to the former Erie Mine Site near Hoyt Lakes, Minnesota.

APPLICATION

To the electric service requirements of any new industrial, mining or manufacturing Customer(s) located at the former Erie Mine Site or, subject to the prior written approval of the Company, at any other location in or around Hoyt Lakes, Minnesota where service can be taken from the Company's 138 kV transmission line. Service hereunder is limited to Customers with total power requirements of at least 2,000 kilowatts (kW) per Customer and not more than 25,000 kW in total for all customers. Customer and Company shall execute an Electric Service Agreement having a minimum term of one (1) year and maximum term of six (6) years (subject to the early termination option of the Company set forth below). Any service under this Schedule must commence on or before January 1, 2008.

If, at any time after this Rate Schedule becomes effective, Company chooses to retire the Taconite Harbor generating station or convert the Taconite Harbor generating station to a fuel source other than coal, new service under this schedule shall immediately cease to be available, and, commencing on January 1 of the next calendar year after the date of retirement or conversion, any existing service under this rate schedule shall terminate. Company shall, in the event of such a retirement or conversion, provide timely written notice to any existing Customer taking service under this Rate Schedule. Existing Customer(s) shall choose an alternative Rate Schedule or be assigned to an applicable Rate Schedule by the Company.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, metered at Company's available transmission voltage of 115,000 or 138,000 volts.

ERIE MINE SITE SERVICE

RATE

Shall consist of the following components: A. Generation Capacity Charge, B. Energy Charge, C. Transmission Service Charge, and D. Billing/Customer Charge.

A. Generation Capacity Charge

The Generation Capacity Charge shall be $13.43 per kW per month for calendar year 2013. The Generation Capacity Charge for each subsequent year shall be recalculated annually by December 31 using budget data for the subsequent year. The Generation Capacity Charge shall be the sum of Company's budgeted: i) net book value of the Taconite Harbor facilities multiplied by Company's allowed retail pre-tax cost of long-term debt, ii) Taconite Harbor depreciation and amortization expense, iii) Taconite Harbor property tax expense, and iv) Taconite Harbor fixed operating and maintenance expense. The capital investment and incremental operating and maintenance costs that are recovered through Company's Rider for Arrowhead Regional Emission Abatement (AREA) shall be excluded from the preceding calculations. The above total shall be increased by 12% to account for reserve capacity supply, divided by the Taconite Harbor accredited capacity in kW, and averaged over 12 months to result in a monthly Generation Capacity Charge to be applied to each kW of Customer's Billing Demand.

B. Energy Charge

The Energy Charge shall be determined monthly based on a combination of the average monthly Taconite Harbor energy cost and Company's hourly incremental energy cost, as follows:

- During hours when at least two of the three Taconite Harbor units are available, the Energy Charge shall be equal to the average monthly Taconite Harbor energy cost.
- During hours when fewer than two of the three Taconite Harbor units are available, the Energy Charge shall be equal to 50% of the average monthly Taconite Harbor energy cost plus 50% of the Company's hourly incremental energy cost.

The Taconite Harbor energy cost for each month shall be the total cost of fuel consumed by the Taconite Harbor units during the month, plus all fixed and variable operating and maintenance expenses not included in the Generation Capacity Charge, divided by the net energy produced by the Taconite Harbor units during the month.

ERIE MINE SITE SERVICE

The Company's hourly incremental energy cost shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the energy, and shall be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customers including all inter-system pool sales which involve capacity on a firm or participation basis, and to all interruptible sales to Large Power, Large Light and Power, and General Service customers.

The Energy Charge shall be applicable to all kilowatt-hours (kWh) of energy taken by Customer in the month.

C. Transmission Service Charge

The Transmission Service Charge shall be equal to the Large Power transmission demand cost determined in Company's latest retail cost of service study approved by the Minnesota Public Utilities Commission (MPUC) as part of a general retail rate case, adjusted to exclude the estimated pre-tax return on equity component of costs associated with the transmission assets acquired from LTV. The Transmission Service Charge shall be applicable monthly to each kW of Billing Demand. This rate shall be $2.59 per kW per month.

D. Billing/Customer Charge

$5000/month

ADJUSTMENTS

1. If Customer is taking service from Company at the same location under an Electric Service Agreement or other Company Schedule that includes a Billing/Customer Charge as part of that Agreement or Schedule, then the Customer shall not be billed the Billing/Customer Charge contained in this Schedule.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

ERIE MINE SITE SERVICE

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. There shall be added to the monthly bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

METERED AND MEASURED DEMAND

The Metered Demand in the month shall be the kW measured during the 15-minute period of Customer's greatest use during the month.

The Measured Demand in the month shall be the Metered Demand increased by one kW for each 20 kvar of excess reactive demand where excess reactive demand shall be the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of metered demand plus 25% of all additional kW of Metered Demand.

BILLING DEMAND

1. Billing Demand in the month is the kW of demand specified in the Customer's Electric Service Agreement.

ERIE MINE SITE SERVICE

2. Company may increase the Billing Demand, at its option, after written notice to Customer, if the Customer's Measured Demand exceeds 110% of Customer's Billing Demand applicable at the time. Customer's increased Billing Demand shall be the sum of the Billing Demand in effect for the previous billing period and the amount by which the Measured Demand exceeds 110% of such Billing Demand. Any increased Billing Demand resulting under this paragraph shall be the Billing Demand for the remaining term of the Electric Service Agreement unless further revised in accordance with this paragraph and/or other terms and conditions of the Electric Service Agreement.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Company on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Company. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

SERVICE CONDITIONS

1. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional required facilities which are not supported by this rate.

2. Customer shall be responsible for any additional costs imposed on Company's system due to the operating characteristics of Customer's load, including, but not limited to, costs associated with regulation and frequency response (continuous balancing of resources with load to maintain scheduled interconnection frequency at sixty cycles per second) and reactive supply and voltage control (operation of generation facilities to produce or absorb reactive power in order to maintain transmission voltages within generally accepted limits).

MUNICIPAL PUMPING

RATE CODES

87

APPLICATION

To electric service supplied to a municipality for the operation of water pumping and sewage disposal facilities, where all such facilities are completely electrified and operated by service of Company, subject to Company's Electric Service Regulations and any applicable Riders. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$10.50
Energy Charge	
All kWh (¢/kWh)	7.836¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$10.50
Demand Charge	
All kW ($/kW)	$6.20
Energy Charge	
All kWh (¢/kWh)	5.163¢

Plus any applicable Adjustments.

MUNICIPAL PUMPING

MINIMUM CHARGE (Monthly)

Demand Charge per kW of Billing Demand but not less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8~~7~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9~~8~~. Bills for service to Municipalities other than City of Duluth within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

MUNICIPAL PUMPING

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $1.75 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will also be subject to a discount of 0.284¢ per kWh of Energy.

DETERMINATION OF BILLING DEMAND

The Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than 5 kW.

Demand will be adjusted by multiplying by 85% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

Maximum use created by the operation of fire pumps will be disregarded if Company is notified promptly.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Five years, automatically renewable for one year periods unless canceled by 30 days' written notice by either party to the other prior to any renewal date.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Rate Code 85 customers are limited to the corporate city limits of International Falls, Minnesota. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Lamp Type & Size Sub rate code	CIS Code	Rate Per Lamp Per Month Option 1 _ _A	Option 2 _ _B (Option 2 Closed to New Installation)	Option 3 _ _C Option 3 Closed to New Installation)	Option 4 _ _D
Mercury Vapor Lamps (Closed to New Installations)					
7,000 Lumens (175 watts)	K	15.94	8.33	8.06	
10,000 Lumens (250 watts)	L			10.18	
20,000 Lumens (400 watts)	M	21.33	14.23	13.76	
55,000 Lumens (1,000 watts)	O			25.22	
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	I	13.62	6.83	6.48	
14,000 Lumens (150 watts)	X	15.73	8.59	8.33	
14,000 Lumens (150 watts)	A			8.33	
20,500 Lumens (200 watts)	F	18.32	10.08	9.95	
23,000 Lumens (230 watts)	G	19.77	11.05	10.75	
45,000 Lumens (400 watts)	Z	24.22	14.95	14.09	
Metal Halide Lamps					
28,800 Lumens (400 watts)	S		13.11		
Energy Charge - Per kWh		Included	Included	Included	5.882¢

Plus any applicable adjustments

STREET AND HIGHWAY LIGHTING SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

2. There shall be add to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be add to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7~~6~~. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8~~7~~. Bills for service to parties other than the City of Duluth within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

STREET AND HIGHWAY LIGHTING SERVICE

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per lamp by type													
A	468	52	42	41	34	29	26	28	33	37	45	48	53
C	1,356	149	122	119	98	85	75	81	95	109	130	140	153
F	1,140	125	103	100	82	72	63	68	80	91	109	118	129
G	1,224	135	110	107	88	77	68	73	86	98	117	127	138
I	504	56	46	44	36	32	28	30	35	40	48	52	57
K	888	98	80	78	64	56	49	53	62	71	85	92	100
L	1,224	135	110	107	88	77	68	73	86	98	117	127	138
M	1,932	213	174	169	139	121	107	116	135	155	184	200	219
O	4,620	508	417	404	332	290	256	277	323	370	441	479	523
S	1,932	213	174	169	139	121	107	116	135	155	184	200	219
V	2052	226	185	179	147	129	114	123	144	164	196	213	232
X	756	83	68	66	54	48	42	45	53	60	72	78	87
Z	2,016	222	182	176	145	127	112	121	141	161	192	209	228

Company shall furnish all electric energy required for service under this schedule.

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1

COMPANY TO OWN AND MAINTAIN.

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and wiring.

STREET AND HIGHWAY LIGHTING SERVICE

Option 2

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's facilities. The equipment shall include, but not be limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications. In all cases, poles are owned by Company.

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls. Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, lamp, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out lamps and photo-electric controls and will clean or replace glassware at the time of lamp replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include

STREET AND HIGHWAY LIGHTING SERVICE

but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install in master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of lamps of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

STREET AND HIGHWAY LIGHTING SERVICE

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For lamps which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

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Approved by: Marcia A. Podratz
Marcia A. Podratz
Director - Rates

RESIDENTIAL SERVICE

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APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations and any applicable Riders.

A dwelling will be considered to be occupied seasonally when occupied as customer's principal dwelling place for eight months or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 or 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$8.00	$8.80
0 kwh to 300 kwh	5.098¢	
301 kwh to 500 kwh	6.735¢	
501 kwh to 750 kwh	8.168¢	
751 kwh to 1000 kwh	8.445¢	
Over 1000 kwh	8.937¢	
All kWh (¢/kWh)		8.235¢

Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

RESIDENTIAL SERVICE

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

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RESIDENTIAL SERVICE

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an extension agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 or 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

<u>Service Charge</u>	$8.00
<u>Energy Charge</u>	
All kWh (per kWh)	5.178¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance wit the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an extension agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

3. The duration and frequency of interruptions shall be at the discretion of Company. Interruption will normally occur at such times:
   (a) when Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
   (b) when Company expects to incur a new system peak,
   (c) at such other times when in Company's opinion the reliability of the system is endangered,
   (d) when Company performs necessary testing for certification of interruptibility of customers' loads.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. Company will provide, at customer's expense, and customer will install, as directed by Company, a load-break switch or circuit breaker. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

<u>Service Charge</u>	$8.00
<u>Energy Charge</u>	
All kWh (per kWh)	4.332¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER

Service Charge	$10.50
Energy Charge for all kWh	7.836¢

CUSTOMERS WITH A DEMAND METER

Service Charge	$10.50
Demand Charge for all kW	$5.86
Energy Charge for all kWh	5.288¢

Plus any applicable Adjustments.

GENERAL SERVICE

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $1.75 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount of 0.284¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

GENERAL SERVICE

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 85% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, three phase, or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system).

RATE (Monthly)

Service Charge

Low Voltage Service	$10.50
High Voltage Service	$10.50

Energy Charge

Low Voltage Service	5.178¢ per kWh
High Voltage Service	4.791¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:
   (a) when Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when Company expects to incur a system peak in excess of its Mid-Continent Area Power Pool (MAPP) accredited generating capability,
   (c) when in Company's opinion the reliability of the system is endangered, or
   (d) when Company performs necessary testing of interruptibility of customer's loads.

Interruptions shall normally occur for capacity related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service (those loads that meet the requirements specified in the MAPP Procedure for the Certification of Interruptible Demand).

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. The customer will install, at its expense, a load-break switch, circuit breaker, or other means of allowing Company to automatically interrupt customer's Dual Fuel load by sending a command or signal. The Company reserves the right to inspect and approve the installation to ensure compliance and consistency with Company's interruption system. If Company's system cannot support automatic interruption, interruption shall be made in accordance with Service Condition 8. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

8. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, whenever the Company determines such interruption is necessary. Customers with existing provisions in their Electric Service Agreements for longer notice before interruption shall continue to have thirty (30) minutes to shed their interruptible loads through the term of their existing contracts or December 31, 1998, whichever is later.

9. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Mid-Continent Area Power Pool in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

(a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).

(b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer’s service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system), supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge

High Voltage Service	\$10.50
Low Voltage Service	\$10.50

Energy Charge

High Voltage Service	4.032¢ per kWh
Low Voltage Service	4.332¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

55 75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,100.00
All additional kW of Billing Demand ($/kW)	$9.30
Energy Charge	
All kWh (¢/kWh)	3.722¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $1.75 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will also be subject to a discount of 0.284¢ per kWh of Energy.

LARGE LIGHT AND POWER SERVICE

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

LARGE LIGHT AND POWER SERVICE

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the amount by which the greatest adjusted demand duringthe preceding eleven months exceeds 100 kW, but not more than 75% of such adjusted demand. However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 85% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

LARGE POWER SERVICE

RATE CODES

54 74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");

(b) The voltage level(s) at which service will be supplied;

(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;

(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;

(e) A confidentiality agreement; and

(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

LARGE POWER SERVICE

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company ("Confidential Information"), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term "Holidays" shall mean New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year's Eve Day.

For purposes of ESAs, the term "Office" shall mean the Minnesota Office of Energy Security or its successor organization.

LARGE POWER SERVICE

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$216,276
All additional kW of Firm Demand ($/kW)	$19.85

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.232¢

Excess Energy Charge

All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under " ENERGY"

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

2. Fuel and Purchased Power Adjustment / Conservation Adjustment / Resource Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Adjustment and a conservation program

adjustment will be determined in accordance with the Rider for Conservation Program Adjustment. The combination of the Fuel and Purchased Power adjustment and the Conservation Program Adjustment will be shown on customer's bill as the Resource Adjustment.

3. AREA Adjustment. An emissions-reduction adjustment will be determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

4. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

5. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

6. CARE Affordability Surcharge: There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. Boswell 4 Plan Adjustment: There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. City of Duluth Franchise Fee. An adjustment for customers located within the corporate limits of the City of Duluth as specified in the Rider for City of Duluth Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

LARGE POWER SERVICE

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be the greater of the kW of Customer's Adjusted Demand or such higher Firm Demand specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this amount shall be deemed to be the Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases, for all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Energy Portion

For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$259,531
All additional kW of Non-Contract Billing Demand ($/kW)	$23.82

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.232¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY"

Plus any applicable Adjustments.

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

NON-CONTRACT LARGE POWER SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment. Such Fuel Adjustment shall be applicable to Customer's Non-Contract Firm Energy only.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

NON-CONTRACT LARGE POWER SERVICE

The adjusted demand ("Adjusted Demand")_in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 58/78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

NON-CONTRACT LARGE POWER SERVICE

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

<u>Capacity Portion</u>

For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

<u>Energy Portion</u>

For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

NON-CONTRACT LARGE POWER SERVICE

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 54/74 for which a ten (10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 54/74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 54/74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes no responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Lamp Type & Size	CIS Code	Rate Per Lamp Per Month: Option 1	Option 2	Option 3	Option 4
Sub rate code		_ _A	_ _B	_ _C	_ _D
			(Option 2 Closed to New Installation)	(Option 3 Closed to New Installation)	
Mercury Vapor Lamps					
7,000 Lumens (175 watts)	K	11.60	8.06		
20,000 Lumens (400 watts)	M/P	18.36	12.69		
55,000 Lumens (1,000 watts)	Q	34.38	24.57		
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	I	10.19	5.86	5.86	
14,000 Lumens (150 watts)	X	11.73	7.44		
23,000 Lumens (250 watts)	J/G	16.65	9.89	9.96	
45,000 Lumens (400 watts)	Z	22.22	13.23	10.59	
Metal Halide Lamps					
17,000 Lumens (250 watts)	R	16.44			
28,800 Lumens (400 watts)	S	20.12		11.84	
88,000 Lumens (1,000 watts)	U	33.39		22.42	
Pole Charge Each pole used for service under this schedule only	6	$4.70	$4.70	$4.70	
Energy Charge - Per kWh		Included	Included	Included	5.882¢

Plus any applicable adjustments

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

OUTDOOR AND AREA LIGHTING SERVICE

The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8. Bills for service within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

OUTDOOR AND AREA LIGHTING SERVICE

ENERGY TABLE

Lamp CIS Code	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per lamp by type													
G	1,224	135	110	107	88	77	68	73	86	98	117	127	138
I	504	56	46	44	36	32	28	30	35	40	48	52	57
J	1,224	135	110	107	88	77	68	73	86	98	117	127	138
K	888	98	80	78	64	56	49	53	62	71	85	92	100
M	1,932	213	174	169	139	121	107	116	135	155	184	200	219
P	1,932	213	174	169	139	121	107	116	135	155	184	200	219
Q	4,620	508	417	404	332	290	256	277	323	370	441	479	523
R	1,260	139	114	110	91	79	70	76	88	101	120	130	142
S	1,932	213	174	169	139	121	107	116	135	155	184	200	219
U	4,410	485	398	385	317	277	245	264	309	353	421	457	499
X	756	83	68	66	54	48	42	45	53	60	72	78	87
Z	2,016	222	182	176	145	127	112	121	141	161	192	209	228

Company shall furnish all electric energy required for service under this schedule.

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, lamp, ballast, photo-electric control and wiring.

Option 2

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include, but not be limited to, the fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications.

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option, including poles, except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications. Company's point of delivery shall be on the Company's side of disconnect switch either at the weather head for overhead service or at the pad mount transformer for underground service.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

OUTDOOR AND AREA LIGHTING SERVICE

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, over and above those which would be required for a single standard bracket mounting, shall not exceed $15.00 per light. Additional required investment will be at Customer's expense.

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For lamps which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

OUTDOOR AND AREA LIGHTING SERVICE

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Materials charges per the Company's cost for lighting replacement equipment plus the then current Material Handling Expense and A&G expense per Company's Accounting Manual.

ERIE MINE SITE SERVICE

RATE CODES

72

TERRITORY

Applicable to customers located at or close to the former Erie Mine Site near Hoyt Lakes, Minnesota.

APPLICATION

To the electric service requirements of any new industrial, mining or manufacturing Customer(s) located at the former Erie Mine Site or, subject to the prior written approval of the Company, at any other location in or around Hoyt Lakes, Minnesota where service can be taken from the Company's 138 kV transmission line. Service hereunder is limited to Customers with total power requirements of at least 2,000 kilowatts (kW) per Customer and not more than 25,000 kW in total for all customers. Customer and Company shall execute an Electric Service Agreement having a minimum term of one (1) year and maximum term of six (6) years (subject to the early termination option of the Company set forth below). Any service under this Schedule must commence on or before January 1, 2008.

If, at any time after this Rate Schedule becomes effective, Company chooses to retire the Taconite Harbor generating station or convert the Taconite Harbor generating station to a fuel source other than coal, new service under this schedule shall immediately cease to be available, and, commencing on January 1 of the next calendar year after the date of retirement or conversion, any existing service under this rate schedule shall terminate. Company shall, in the event of such a retirement or conversion, provide timely written notice to any existing Customer taking service under this Rate Schedule. Existing Customer(s) shall choose an alternative Rate Schedule or be assigned to an applicable Rate Schedule by the Company.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, metered at Company's available transmission voltage of 115,000 or 138,000 volts.

ERIE MINE SITE SERVICE

RATE

Shall consist of the following components: A. Generation Capacity Charge, B. Energy Charge, C. Transmission Service Charge, and D. Billing/Customer Charge.

A. Generation Capacity Charge

The Generation Capacity Charge shall be $13.43 per kW per month for calendar year 2013. The Generation Capacity Charge for each subsequent year shall be recalculated annually by December 31 using budget data for the subsequent year. The Generation Capacity Charge shall be the sum of Company's budgeted: i) net book value of the Taconite Harbor facilities multiplied by Company's allowed retail pre-tax cost of long-term debt, ii) Taconite Harbor depreciation and amortization expense, iii) Taconite Harbor property tax expense, and iv) Taconite Harbor fixed operating and maintenance expense. The capital investment and incremental operating and maintenance costs that are recovered through Company's Rider for Arrowhead Regional Emission Abatement (AREA) shall be excluded from the preceding calculations. The above total shall be increased by 12% to account for reserve capacity supply, divided by the Taconite Harbor accredited capacity in kW, and averaged over 12 months to result in a monthly Generation Capacity Charge to be applied to each kW of Customer's Billing Demand.

B. Energy Charge

The Energy Charge shall be determined monthly based on a combination of the average monthly Taconite Harbor energy cost and Company's hourly incremental energy cost, as follows:

- During hours when at least two of the three Taconite Harbor units are available, the Energy Charge shall be equal to the average monthly Taconite Harbor energy cost.
- During hours when fewer than two of the three Taconite Harbor units are available, the Energy Charge shall be equal to 50% of the average monthly Taconite Harbor energy cost plus 50% of the Company's hourly incremental energy cost.

The Taconite Harbor energy cost for each month shall be the total cost of fuel consumed by the Taconite Harbor units during the month, plus all fixed and variable operating and maintenance expenses not included in the Generation Capacity Charge, divided by the net energy produced by the Taconite Harbor units during the month.

ERIE MINE SITE SERVICE

The Company's hourly incremental energy cost shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the energy, and shall be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customers including all inter-system pool sales which involve capacity on a firm or participation basis, and to all interruptible sales to Large Power, Large Light and Power, and General Service customers.

The Energy Charge shall be applicable to all kilowatt-hours (kWh) of energy taken by Customer in the month.

C. Transmission Service Charge

The Transmission Service Charge shall be equal to the Large Power transmission demand cost determined in Company's latest retail cost of service study approved by the Minnesota Public Utilities Commission (MPUC) as part of a general retail rate case, adjusted to exclude the estimated pre-tax return on equity component of costs associated with the transmission assets acquired from LTV. The Transmission Service Charge shall be applicable monthly to each kW of Billing Demand. This rate shall be $2.59 per kW per month.

D. Billing/Customer Charge

$5000/month

ADJUSTMENTS

1. If Customer is taking service from Company at the same location under an Electric Service Agreement or other Company Schedule that includes a Billing/Customer Charge as part of that Agreement or Schedule, then the Customer shall not be billed the Billing/Customer Charge contained in this Schedule.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

ERIE MINE SITE SERVICE

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. There shall be added to the monthly bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

METERED AND MEASURED DEMAND

The Metered Demand in the month shall be the kW measured during the 15-minute period of Customer's greatest use during the month.

The Measured Demand in the month shall be the Metered Demand increased by one kW for each 20 kvar of excess reactive demand where excess reactive demand shall be the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of metered demand plus 25% of all additional kW of Metered Demand.

BILLING DEMAND

1. Billing Demand in the month is the kW of demand specified in the Customer's Electric Service Agreement.

ERIE MINE SITE SERVICE

2. Company may increase the Billing Demand, at its option, after written notice to Customer, if the Customer's Measured Demand exceeds 110% of Customer's Billing Demand applicable at the time. Customer's increased Billing Demand shall be the sum of the Billing Demand in effect for the previous billing period and the amount by which the Measured Demand exceeds 110% of such Billing Demand. Any increased Billing Demand resulting under this paragraph shall be the Billing Demand for the remaining term of the Electric Service Agreement unless further revised in accordance with this paragraph and/or other terms and conditions of the Electric Service Agreement.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Company on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Company. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

SERVICE CONDITIONS

1. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional required facilities which are not supported by this rate.

2. Customer shall be responsible for any additional costs imposed on Company's system due to the operating characteristics of Customer's load, including, but not limited to, costs associated with regulation and frequency response (continuous balancing of resources with load to maintain scheduled interconnection frequency at sixty cycles per second) and reactive supply and voltage control (operation of generation facilities to produce or absorb reactive power in order to maintain transmission voltages within generally accepted limits).

MUNICIPAL PUMPING

RATE CODES

87

APPLICATION

To electric service supplied to a municipality for the operation of water pumping and sewage disposal facilities, where all such facilities are completely electrified and operated by service of Company, subject to Company's Electric Service Regulations and any applicable Riders. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$10.50
Energy Charge	
All kWh (¢/kWh)	7.836¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$10.50
Demand Charge	
All kW ($/kW)	$6.20
Energy Charge	
All kWh (¢/kWh)	5.163¢

Plus any applicable Adjustments.

MUNICIPAL PUMPING

MINIMUM CHARGE (Monthly)

Demand Charge per kW of Billing Demand but not less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

2. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an Affordability Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service to Municipalities other than City of Duluth within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $1.75 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will also be subject to a discount of 0.284¢ per kWh of Energy.

DETERMINATION OF BILLING DEMAND

The Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than 5 kW.

Demand will be adjusted by multiplying by 85% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

Maximum use created by the operation of fire pumps will be disregarded if Company is notified promptly.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Five years, automatically renewable for one year periods unless canceled by 30 days' written notice by either party to the other prior to any renewal date.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Rate Code 85 customers are limited to the corporate city limits of International Falls, Minnesota. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Lamp Type & Size	CIS Code	Rate Per Lamp Per Month Option 1	Option 2	Option 3	Option 4
Sub rate code		_ _A	_ _B	_ _C	_ _D
			(Option 2 Closed to New Installation)	Option 3 Closed to New Installation)	
Mercury Vapor Lamps (Closed to New Installations)					
7,000 Lumens (175 watts)	K	15.94	8.33	8.06	
10,000 Lumens (250 watts)	L			10.18	
20,000 Lumens (400 watts)	M	21.33	14.23	13.76	
55,000 Lumens (1,000 watts)	O			25.22	
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	I	13.62	6.83	6.48	
14,000 Lumens (150 watts)	X	15.73	8.59	8.33	
14,000 Lumens (150 watts)	A			8.33	
20,500 Lumens (200 watts)	F	18.32	10.08	9.95	
23,000 Lumens (230 watts)	G	19.77	11.05	10.75	
45,000 Lumens (400 watts)	Z	24.22	14.95	14.09	
Metal Halide Lamps					
28,800 Lumens (400 watts)	S		13.11		
Energy Charge - Per kWh		Included	Included	Included	5.882¢

Plus any applicable adjustments

STREET AND HIGHWAY LIGHTING SERVICE

ADJUSTMENTS

1. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

   The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

2. There shall be add to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Arrowhead Regional Emission Abatement (AREA).

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be add to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, an emissions-reduction adjustment determined in accordance with the Rider for Boswell Unit 4 Emission Reduction.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8. Bills for service to parties other than the City of Duluth within the corporate limits of the City of Duluth shall include an upward adjustment as specified in the Rider for City of Duluth Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

STREET AND HIGHWAY LIGHTING SERVICE

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	4,200	462	379	367	302	264	233	252	294	336	401	435	475
					Monthly kWh usage per lamp by type								
A	468	52	42	41	34	29	26	28	33	37	45	48	53
C	1,356	149	122	119	98	85	75	81	95	109	130	140	153
F	1,140	125	103	100	82	72	63	68	80	91	109	118	129
G	1,224	135	110	107	88	77	68	73	86	98	117	127	138
I	504	56	46	44	36	32	28	30	35	40	48	52	57
K	888	98	80	78	64	56	49	53	62	71	85	92	100
L	1,224	135	110	107	88	77	68	73	86	98	117	127	138
M	1,932	213	174	169	139	121	107	116	135	155	184	200	219
O	4,620	508	417	404	332	290	256	277	323	370	441	479	523
S	1,932	213	174	169	139	121	107	116	135	155	184	200	219
V	2052	226	185	179	147	129	114	123	144	164	196	213	232
X	756	83	68	66	54	48	42	45	53	60	72	78	87
Z	2,016	222	182	176	145	127	112	121	141	161	192	209	228

Company shall furnish all electric energy required for service under this schedule.

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1

COMPANY TO OWN AND MAINTAIN.

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and wiring.

Option 2

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's facilities. The equipment shall include, but not be limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications. In all cases, poles are owned by Company.

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls. Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, lamp, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out lamps and photo-electric controls and will clean or replace glassware at the time of lamp replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include

but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install in master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of lamps of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

STREET AND HIGHWAY LIGHTING SERVICE

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For lamps which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

EXHIBIT B

Minnesota Power
BEC4 Rider: 2014 Factor Filing
Summary: Revenue Requirements, Cost Allocation and Rate Design

			Total
Projected 2013 Tracker Balance		$	1,666,156
2014 Net Revenue Requirements		$	15,144,186
Total 2014 Revenue Requirements 1/		$	16,810,342
	Allocators 2/		
MN Jurisdictional & Class Revenue Requirements	82.017%	$	13,787,338
Large Power	51.269%	$	8,618,494
All Other Retail Classes	30.748%	$	5,168,844

Billing Units 3/		
Large Power	kW - month	715,217
	kWh	5,998,692,000
All Other Retail Classes	kWh	3,310,820,000

Billing Factors 4/		**Proposed 4/1/2014**
Large Power	$/kW - month	0.60
	¢/kWh	0.057
All Other Retail Classes	¢/kWh	0.156

Notes:
1/ Refer to Exhibit B-1, page 2 of 6.
2/ Jurisdictional Power Supply Demand (D-01) allocator and Peak & Average (P&A) class allocators from 2009 MPUC rate case Docket No. E-015/GR-09-1151. Refer to Exhibit B-5, line 11.
3/ 2014 Budget.
4/ 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
BEC4 Rider
Summary: Projected 2013 Tracker Balance and 2014 Revenue Requirements

Projected 2013 Tracker Balance

Total 2013 Revenue Requirements ($)	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total
BEC 4 Environmental	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821	1,664,748
Boswell Ash Pond Phase 1	-	-	-	-	-	-	-	-	-	377	469	561	1,407
Boswell Ash Pond Phase 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 3	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 5	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Requirements	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
Revenue Credit for Basin's Share ($)													
BEC 4 Environmental	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
BEC 4 Base Rate Revenue Credit ($)	-	-	-	-	-	-	-	-	-	-	-	-	-
Net 2013 Revenue Requirements ($)													
BEC 4 Environmental	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821	1,664,748
Boswell Ash Pond Phase 1	-	-	-	-	-	-	-	-	-	377	469	561	1,407
Boswell Ash Pond Phase 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 3	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 5	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net 2013 Revenue Requirements 1/	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156

Total 2014 Revenue Requirements ($)	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
BEC 4 Environmental	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300	15,121,118
Boswell Ash Pond Phase 1	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159	23,068
Boswell Ash Pond Phase 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 3	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 5	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Requirements	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
Revenue Credit for Basin's Share ($)													
BEC 4 Environmental	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
BEC 4 Base Rate Revenue Credit ($)	-	-	-	-	-	-	-	-	-	-	-	-	-
Net 2014 Revenue Requirements ($)													
BEC 4 Environmental	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300	15,121,118
Boswell Ash Pond Phase 1	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159	23,068
Boswell Ash Pond Phase 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 3	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 4	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Ash Pond Phase 5	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net 2014 Revenue Requirements 2/	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186

1/ Refer to Exhibit B-1, page 4, line E-6.
2/ Refer to Exhibit B-1, page 6, line E-6.

Projected 2013 Tracker

Total Sum: All Projects

Section	Line	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total Year Dec-13
A	**Book Basis of Property**													
	0 CWIP (net of contra AFUDC & internal costs) 1/	-	-	-	-	-	-	-	-	44,370,763	51,026,641	57,975,510	66,742,073	66,742,073
	1 Plant in Service (net of contra AFUDC & Internal costs)	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
B	**Tax Basis of Property**													
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Bonus Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	5 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	-	-
	7 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%
	8 Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - Consolidated NOL**													
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	5 Current Return on CWIP /1	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	6 Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156

1/ Refer to Exhibit B-3, page 2.

Projected 2013 Tracker

Total Sum: All Projects

Section	Line	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total Year Dec-13
C-2	**Revenue Requirements - Stand Alone NOL**													
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	5 Current Return on CWIP 1/	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	6 Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
D	**Stand Alone Taxable Income or Loss (NOL)**													
	1 Revenue Requirements	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	2 Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Interest Expense (including on CWIP) /1	-	-	-	-	-	-	-	-	-	100,962	115,361	131,993	348,316
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	-	-	-	-	-	-	-	-	-	100,962	115,361	131,993	348,316
	7 Taxable Income (NOL)	-	-	-	-	-	-	-	-	-	381,987	436,463	499,390	1,317,840
	8 Current tax expense	-	-	-	-	-	-	-	-	-	158,028	180,564	206,598	545,190
		-	-	-	-	-	-	-	-	-	-	-	-	
E	**Summary: Revenue Requirements**													
	1 Revenue Requirement: Consolidated	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	2 Revenue Requirement: Stand Alone	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	3 Revenue Requirement: Rider 2/	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	4 Revenue Credit for Basin's Share /3	-	-	-	-	-	-	-	-	-	-	-	-	-
	5 BEC 4 Base Rate Revenue Credit 4/	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Net Revenue Requirements	-	-	-	-	-	-	-	-	-	482,949	551,823	631,383	1,666,156
	7 MN Jurisdictional Allocator /5	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.82017
	8 MN Jurisdictional Revenue Requirement	-	-	-	-	-	-	-	-	-	396,101	452,589	517,841	1,366,531
F	**Monthly Entry**													
	1 Monthly Entry needed	-	-	-	-	-	-	-	-	-	396,101	452,589	517,841	
	2 Cumulative Year	-	-	-	-	-	-	-	-	-	396,101	848,690	1,366,531	1,366,531
	3 Booked YTD	-	-	-	-	-	-	-	-	-	396,101	848,690	1,366,531	1,366,531
	4 Entry Needed	-	-	-	-	-	-	-	-	-	396,101	452,589	517,841	
G	**Projected 2013 Tracker**													
	1 Cash Collections	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Monthly (Over)/Under collection										396,101	452,589	517,841	1,366,531
	3 Cumulative (Over)/Under Balance										396,101	848,690	1,366,531	1,366,531

1/ Refer to Exhibit B-3, page 2.
2/ Lesser of E1 or E2.
3/ Details to follow in future filings as applicable.
4/ Details to follow in future filings as applicable.
5/ Refer to Exhibit B-5, line 11.

2014 Revenue Requirements

Total Sum: All Projects

Section	Line	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total Year Dec-14
A	**Book Basis of Property**													
	0 CWIP (net of contra AFUDC & internal costs) 1/	73,424,965	79,747,358	90,491,594	102,771,763	115,901,937	129,001,589	139,597,835	146,959,912	155,006,993	165,691,016	173,643,730	180,224,718	180,224,718
	1 Plant in Service (net of contra AFUDC & internal costs)	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
B	**Tax Basis of Property**													
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Bonus Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	5 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	-	-
	7 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%
	8 Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - Consolidated NOL**													
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	5 Current Return on CWIP 1/	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	6 Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186

1/ Refer to Exhibit B-3, page 2.

2014 Revenue Requirements

Total Sum: All Projects

Section	Line	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total Year Dec-14
C-2	**Revenue Requirements - Stand Alone NOL**													
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	5 Current Return on CWIP /1	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	6 Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
D	**Stand Alone Taxable Income or Loss (NOL)**													
	1 Revenue Requirements	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	2 Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	
	4 Interest Expense (including on CWIP) /1	148,343	162,107	180,170	204,537	231,430	259,190	284,268	303,274	319,582	339,405	359,129	374,511	3,165,945
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	148,343	162,107	180,170	204,537	231,430	259,190	284,268	303,274	319,582	339,405	359,129	374,511	3,165,945
	7 Taxable Income (NOL)	561,252	613,328	681,665	773,859	875,606	980,635	1,075,517	1,147,425	1,209,126	1,284,128	1,358,753	1,416,948	11,978,241
	8 Current tax expense	232,190	253,734	282,005	320,146	362,238	405,689	444,941	474,690	500,215	531,244	562,116	586,192	4,955,400
E	**Summary: Revenue Requirements**													
	1 Revenue Requirement: Consolidated	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	2 Revenue Requirement: Stand Alone	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	3 Revenue Requirement: Rider 2/	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	4 Revenue Credit for Basin's Share /3	-	-	-	-	-	-	-	-	-	-	-	-	-
	5 BEC 4 Base Rate Revenue Credit 4/	-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Net Revenue Requirements	709,596	775,435	861,835	978,396	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	15,144,186
	7 MN Jurisdictional Allocator /5	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.8202	0.82017
	8 MN Jurisdictional Revenue Requirement	581,989	635,988	706,851	802,451	907,957	1,016,867	1,115,255	1,189,819	1,253,800	1,331,574	1,408,955	1,469,301	12,420,807

1/ Refer to Exhibit B-3, page 2.
2/ Lesser of E1 or E2.
3/ Details to follow in future filings as applicable.
4/ Details to follow in future filings as applicable.
5/ Refer to Exhibit B-5, line 11.

Minnesota Power
BEC4 Rider
Revenue Requirements: Boswell 4 Environmental Retrofit

BEC 4 Environmental Retrofit
Project ID # 103698
In Service 12/31/2015

Section	Line	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
A	**Book Basis of Property**												
	0 CWIP (net of contra AFUDC & internal costs) 1/									44,338,072	50,984,869	57,924,659	66,682,042
	1 Plant in Service (net of contra AFUDC & Internal costs) 1/												
	2 Accumulated Depreciation 12/2015 Plant	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Depreciation Rate (24 yrs remaining life 2012)												
B	**Tax Basis of Property**												
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
	2 Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Bonus Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Net Depreciable 12/2015 Plant												
	6 Tax Depreciation Rate 12/2015 Plant 2/												
	7 Tax Depreciation 12/2015 Plant	-	-	-	-	-	-	-	-	-	-	-	-
	8 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	-
	9 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%
	10 Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	-
	11 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - Consolidated NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 5/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821

1/ Refer to Exhibit B-3.
2/ Refer to Exhibit B-6
3/ Minnesota Composite Income Tax Rate.
4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/15 (Avg. Monthly Rate Base x ROR% / 12).
5/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.

Minnesota Power
BEC4 Rider
Revenue Requirements: Boswell 4 Environmental Retrofit

BEC 4 Environmental Retrofit
Project ID # 103698
In Service 12/31/2015

Section	Line	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
C-2	**Revenue Requirements - Stand Alone NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 5/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
D	**Stand Alone Taxable Income or Loss (NOL)**												
	1 Revenue Requirements	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	2 Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-
	4 Interest Expense (including on CWIP) 4/	-	-	-	-	-	-	-	-	-	100,883	115,263	131,875
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	-	-	-	-	-	-	-	-	-	100,883	115,263	131,875
	7 Taxable Income (NOL)	-	-	-	-	-	-	-	-	-	381,689	436,092	498,946
	8 Current tax expense	-	-	-	-	-	-	-	-	-	157,905	180,411	206,414
E	**Summary: Revenue Requirements**												
	1 Revenue Requirement: Consolidated	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	2 Revenue Requirement: Stand Alone	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	3 Revenue Requirement: Rider 6/	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	4 Revenue Credit for Basin's Share 7/	-	-	-	-	-	-	-	-	-	-	-	-
	5 BEC 4 Base Rate Revenue Credit 8/	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Net Revenue Requirements	-	-	-	-	-	-	-	-	-	482,572	551,354	630,821
	7 MN Jurisdictional Allocator 9/	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017
	8 MN Net Jurisdictional Revenue Requirement	-	-	-	-	-	-	-	-	-	395,791	452,204	517,381

4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/15 (Avg. Monthly Rate Base x ROR% / 12).
5/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.
6/ Lesser of E1 or E2.
7/ Details to follow in future filings as applicable.
8/ Details to follow in future filings as applicable.
9/ Refer to Exhibit B-5, line 11.

Minnesota Power
BEC4 Rider
Revenue Requirements: Boswell 4 Environmental Retrofit

BEC 4 Environmental Retrofit
Project ID # 103698
In Service 12/31/2015

Section	Line	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
A	**Book Basis of Property**												
	0 CWIP (net of contra AFUDC & internal costs) 1/	73,356,249	79,678,642	90,422,878	102,662,574	115,752,276	128,811,454	139,367,549	146,689,146	154,694,954	165,378,977	173,331,691	179,912,679
	1 Plant in Service (net of contra AFUDC & Internal costs) 1/												
	2 Accumulated Depreciation 12/2015 Plant	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Depreciation Rate (24 yrs remaining life 2012)												
B	**Tax Basis of Property**												
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
	2 Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Bonus Depreciation												
	5 Net Depreciable 12/2015 Plant												
	6 Tax Depreciation Rate 12/2015 Plant 2/												
	7 Tax Depreciation 12/2015 Plant	-	-	-	-	-	-	-	-	-	-	-	-
	8 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	-
	9 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%
	10 Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	-
	11 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - Consolidated NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 5/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300

1/ Refer to Exhibit B-3.
2/ Refer to Exhibit B-6
3/ Minnesota Composite Income Tax Rate.
4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/15 (Avg. Monthly Rate Base x ROR% / 12).
5/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.

BEC 4 Environmental Retrofit
Project ID # 103698
In Service 12/31/2015

Section	Line	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
C-2	**Revenue Requirements - Stand Alone NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 5/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
D	**Stand Alone Taxable Income or Loss (NOL)**												
	1 Revenue Requirements	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	2 Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-
	4 Interest Expense (including on CWIP) 4/	148,207	161,962	180,024	204,349	231,156	258,830	283,823	302,743	318,965	338,745	358,469	373,850
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	148,207	161,962	180,024	204,349	231,156	258,830	283,823	302,743	318,965	338,745	358,469	373,850
	7 Taxable Income (NOL)	560,737	612,777	681,115	773,146	874,569	979,274	1,073,833	1,145,419	1,206,792	1,281,629	1,356,254	1,414,449
	8 Current tax expense	231,977	253,506	281,777	319,851	361,809	405,126	444,245	473,860	499,250	530,210	561,082	585,158
E	**Summary: Revenue Requirements**												
	1 Revenue Requirement: Consolidated	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	2 Revenue Requirement: Stand Alone	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	3 Revenue Requirement: Rider 6/	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	4 Revenue Credit for Basin's Share 7/	-	-	-	-	-	-	-	-	-	-	-	-
	5 BEC 4 Base Rate Revenue Credit 8/	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Net Revenue Requirements	708,944	774,739	861,139	977,495	1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300
	7 MN Jurisdictional Allocator 9/	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017
	8 MN Net Jurisdictional Revenue Requirement	581,454	635,418	706,280	801,712	906,883	1,015,456	1,113,509	1,187,739	1,251,380	1,328,982	1,406,364	1,466,710

4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/15 (Avg. Monthly Rate Base x ROR% / 12).
5/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.
6/ Lesser of E1 or E2.
7/ Details to follow in future filings as applicable.
8/ Details to follow in future filings as applicable.
9/ Refer to Exhibit B-5, line 11.

Boswell Ash Pond Phase 1
Project ID # 106072
In Service 12/31/2016

Minnesota Power
BEC4 Rider
Revenue Requirements: Boswell Ash Pond Phase 1

Section	Line	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
A	**Book Basis of Property**												
	0 CWIP (net of contra AFUDC & internal costs) 1/									32,692	41,772	50,851	60,030
	1 Plant in Service (net of contra AFUDC & Internal costs) 1/												
	2 Accumulated Depreciation 12/2016 Plant	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Depreciation Rate (24 yrs remaining life 2012)												
B	**Tax Basis of Property**												
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
	2 Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Bonus Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Net Depreciable 12/2015 Plant												
	6 Tax Depreciation Rate 12/2015 Plant 2/												
	7 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-
	8 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	-
	9 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%
	10 Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	-
	11 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - Consolidated NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	-	-	-	-	-	-	-	-	-	377	469	561
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense 5/	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 6/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	-	-	-	-	-	-	-	-	-	377	469	561

1/ Refer to Exhibit B-3.
2/ Refer to Exhibit B-6
3/ Minnesota Composite Income Tax Rate.
4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/16 (Avg. Monthly Rate Base x ROR% / 12).
5/ All O&M for Ash Pond projects included in Phase 1 project.
6/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.

Boswell Ash Pond Phase 1
Project ID # 106072
In Service 12/31/2016

Section	Line	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
C-2	**Revenue Requirements - Stand Alone NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	-	-	-	-	-	-	-	-	-	377	469	561
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense 5/	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 6/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	-	-	-	-	-	-	-	-	-	377	469	561
D	**Stand Alone Taxable Income or Loss (NOL)**												
	1 Revenue Requirements	-	-	-	-	-	-	-	-	-	377	469	561
	2 Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-
	4 Interest Expense (including on CWIP) 4/	-	-	-	-	-	-	-	-	-	79	98	117
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	-	-	-	-	-	-	-	-	-	79	98	117
	7 Taxable Income (NOL)	-	-	-	-	-	-	-	-	-	298	371	444
	8 Current tax expense	-	-	-	-	-	-	-	-	-	123	153	184
E	**Summary: Revenue Requirements**												
	1 Revenue Requirement: Consolidated	-	-	-	-	-	-	-	-	-	377	469	561
	2 Revenue Requirement: Stand Alone	-	-	-	-	-	-	-	-	-	377	469	561
	3 Revenue Requirement: Rider 7/	-	-	-	-	-	-	-	-	-	377	469	561
	4 Revenue Credit for Basin's Share 8/	-	-	-	-	-	-	-	-	-	-	-	-
	5 Total Net Revenue Requirements	-	-	-	-	-	-	-	-	-	377	469	561
	6 MN Jurisdictional Allocator 9/	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017
	7 MN Net Jurisdictional Revenue Requirement	-	-	-	-	-	-	-	-	-	309	385	460

4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/16 (Avg. Monthly Rate Base x ROR% / 12).
5/ All O&M for Ash Pond projects included in Phase 1 project.
6/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.
7/ Lesser of E1 or E2.
8/ Details to follow in future filings as applicable.
9/ Refer to Exhibit B-5, line 11.

Minnesota Power
BEC4 Rider
Revenue Requirements: Boswell Ash Pond Phase 1

Boswell Ash Pond Phase 1
Project ID # 106072
In Service 12/31/2016

Section	Line	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
A	**Book Basis of Property**												
	0 CWIP (net of contra AFUDC & internal costs) 1/	68,716	68,716	68,716	109,189	149,661	190,134	230,286	270,766	312,039	312,039	312,039	312,039
	1 Plant in Service (net of contra AFUDC & Internal costs) 1/												
	2 Accumulated Depreciation 12/2016 Plant	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Depreciation Rate (24 yrs remaining life 2012)												
B	**Tax Basis of Property**												
	1 Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-
	2 Accumulated Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	4 Bonus Depreciation												
	5 Net Depreciable 12/2015 Plant												
	6 Tax Depreciation Rate 12/2015 Plant 2/												
	7 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-
	8 Tax Book Difference	-	-	-	-	-	-	-	-	-	-	-	-
	9 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%
	10 Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	-	-	-
	11 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	-	-	-
C-1	**Revenue Requirements - Consolidated NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense 5/	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 6/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159

1/ Refer to Exhibit B-3.
2/ Refer to Exhibit B-6
3/ Minnesota Composite Income Tax Rate.
4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/16 (Avg. Monthly Rate Base x ROR% / 12).
5/ All O&M for Ash Pond projects included in Phase 1 project.
6/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.

Boswell Ash Pond Phase 1
Project ID # 106072
In Service 12/31/2016

Section	Line	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
C-2	**Revenue Requirements - Stand Alone NOL**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	3 Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	4 Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	5 Current Return on CWIP 4/	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	6 Return on Average Rate Base 4/												
	7 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-
	8 Income Tax Component	-	-	-	-	-	-	-	-	-	-	-	-
	9 Interest Expense Component	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-
	11 Operation & Maintenance Expense 5/	-	-	-	-	-	-	-	-	-	-	-	-
	12 Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Property Tax 6/	-	-	-	-	-	-	-	-	-	-	-	-
	14 Revenue Requirements	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
D	**Stand Alone Taxable Income or Loss (NOL)**												
	1 Revenue Requirements	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	2 Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	3 Property Tax	-	-	-	-	-	-	-	-	-	-	-	-
	4 Interest Expense (including on CWIP) 4/	136	145	145	188	274	360	445	530	617	660	660	660
	5 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	6 Total Tax Deduction	136	145	145	188	274	360	445	530	617	660	660	660
	7 Taxable Income (NOL)	516	550	550	712	1,036	1,361	1,683	2,006	2,334	2,499	2,499	2,499
	8 Current tax expense	213	228	228	295	429	563	696	830	965	1,034	1,034	1,034
E	**Summary: Revenue Requirements**												
	1 Revenue Requirement: Consolidated	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	2 Revenue Requirement: Stand Alone	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	3 Revenue Requirement: Rider 7/	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	4 Revenue Credit for Basin's Share 8/	-	-	-	-	-	-	-	-	-	-	-	-
	5 Total Net Revenue Requirements	652	696	696	901	1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159
	6 MN Jurisdictional Allocator 9/	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017	0.82017
	7 MN Net Jurisdictional Revenue Requirement	535	571	571	739	1,075	1,411	1,746	2,080	2,420	2,591	2,591	2,591

4/ Current Return on CWIP starts 10/1/13 (Avg. Monthly CWIP x ROR% / 12). Refer to Exhibit B-3 for CWIP calculations.
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.
Return on Average Rate Base starts 12/31/16 (Avg. Monthly Rate Base x ROR% / 12).
5/ All O&M for Ash Pond projects included in Phase 1 project.
6/ Project assumed to qualify for 100% property tax pollution control exemption per Tax Department.
7/ Lesser of E1 or E2.
8/ Details to follow in future filings as applicable.
9/ Refer to Exhibit B-5, line 11.

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	to date Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13 Start Return on CWIP	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14
BEC 4 Environmental Retrofit	**287,539,603**																
In Service 12/31/2015																	
BOM		0	21,108,392	23,585,552	26,251,077	30,284,697	33,404,597	34,568,293	36,797,083	40,774,456	44,338,072	50,984,869	57,924,659	66,682,042	73,356,249	79,678,642	90,422,878
CapEx	289,184,130	20,266,658	2,440,127	2,597,287	3,963,230	3,063,879	1,053,585	2,126,593	3,870,183	3,429,730	6,725,962	7,010,270	8,827,863	6,749,006	6,424,394	10,846,236	12,341,696
Less Internal Cost	-4,873,584	-959,447	-87,683	-70,052	-85,685	-119,029	-81,269	-97,510	-108,632	-101,637	-70,480	-70,480	-70,480	-74,800	-102,000	-102,000	-102,000
AFUDC	3,391,917	1,899,828	130,908	144,919	163,136	182,679	199,828	208,650	225,340	245,626	-8,996	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	-98,647	-6,192	-6,630	-7,061	-7,630	-8,447	-8,944	-9,518	-10,102	311	0	0	0	0	0	0
EOM		21,108,392	23,585,552	26,251,077	30,284,697	33,404,597	34,568,293	36,797,083	40,774,456	44,338,072	50,984,869	57,924,659	66,682,042	73,356,249	79,678,642	90,422,878	102,662,574
Return on CWIP																	
After Tax Return on Equity											223,784	255,681	292,532	328,760	359,271	399,337	453,295
Income Tax Component											157,905	180,411	206,414	231,977	253,506	281,777	319,851
Interest Expense Component											100,883	115,263	131,875	148,207	161,962	180,024	204,349
Total Return on CWIP											482,572	551,354	630,821	708,944	774,739	861,139	977,495
BEC 4 Ash Phase 1	**5,125,327**																
In Service 12/31/2016																	
BOM		0	0	423	426	429	431	5,452	14,532	23,612	32,692	41,772	50,851	60,030	68,716	68,716	68,716
CapEx	5,174,257	0	422	0	0	0	5,000	9,080	9,080	9,080	9,080	9,079	9,179	10,046	1,360	1,360	41,833
Less Internal Cost	-48,960	0	0	0	0	0	0	0	0	0	0	0	0	-1,360	-1,360	-1,360	-1,360
AFUDC	30	0	1	3	3	3	20	0	0	0	0	0	0	0	0	0	0
EOM		0	423	426	429	431	5,452	14,532	23,612	32,692	41,772	50,851	60,030	68,716	68,716	68,716	109,189
Return on CWIP																	
After Tax Return on Equity											175	217	260	302	323	323	418
Income Tax Component											123	153	184	213	228	228	295
Interest Expense Component											79	98	117	136	145	145	188
Total Return on CWIP											377	469	561	652	696	696	901
BEC 4 Ash Phase 2	**1,487,584**																
In Service 12/31/2020																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,552,864																
Less Internal Cost	-65,280																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 3	**1,852,400**																
In Service 12/31/2024																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 4	**2,170,800**																
In Service 12/31/2028																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	to date Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14
BEC 4 Ash Phase 5	**2,549,200**																
In Service 12/31/2032																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
Total	**300,724,914**																
BOM		0	21,108,392	23,585,975	26,251,503	30,285,126	33,405,028	34,573,745	36,811,615	40,798,068	44,370,763	51,026,641	57,975,510	66,742,073	73,424,965	79,747,358	90,491,594
CapEx	302,633,651	20,266,658	2,440,549	2,597,287	3,963,230	3,063,879	1,058,585	2,135,673	3,879,263	3,438,810	6,735,042	7,019,350	8,837,042	6,759,052	6,425,754	10,847,596	12,383,529
Less Internal Cost	-5,137,825	-959,447	-87,684	-70,052	-85,685	-119,029	-81,269	-97,510	-108,632	-101,637	-70,480	-70,480	-70,480	-76,160	-103,360	-103,360	-103,360
AFUDC	3,391,947	1,899,828	130,909	144,922	163,139	182,681	199,848	208,650	225,340	245,626	-8,996	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	-98,647	-6,192	-6,630	-7,061	-7,630	-8,447	-8,944	-9,518	-10,102	311	0	0	0	0	0	0
EOM		21,108,392	23,585,975	26,251,503	30,285,126	33,405,028	34,573,745	36,811,615	40,798,068	44,370,763	51,026,641	57,975,510	66,742,073	73,424,965	79,747,358	90,491,594	102,771,763
Return on CWIP																	
After Tax Return on Equity	21,378,832	0	0	0	0	0	0	0	0	0	223,959	255,898	292,792	329,062	359,594	399,660	453,713
Income Tax Component	15,085,169	0	0	0	0	0	0	0	0	0	158,028	180,565	206,598	232,190	253,734	282,005	320,146
Interest Expense Component	9,637,728	0	0	0	0	0	0	0	0	0	100,962	115,361	131,993	148,343	162,107	180,170	204,537
Total Return on CWIP	46,101,729	0	0	0	0	0	0	0	0	0	482,949	551,823	631,383	709,596	775,435	861,835	978,396

	Total Project	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15
BEC 4 Environmental Retrofit	287,539,603															
In Service 12/31/2015																
BOM		102,662,574	115,752,276	128,811,454	139,367,549	146,689,146	154,694,954	165,378,977	173,331,691	179,912,679	188,981,536	198,050,393	207,316,239	218,957,788	228,409,641	240,275,523
CapEx	289,184,130	13,191,702	13,161,178	10,658,094	7,423,597	8,107,808	10,786,023	8,122,714	6,682,988	9,170,857	9,170,857	9,367,846	11,743,549	9,560,653	11,974,682	13,178,192
Less Internal Cost	-4,873,584	-102,000	-102,000	-102,000	-102,000	-102,000	-102,000	-170,000	-102,000	-102,000	-102,000	-102,000	-102,000	-108,800	-108,800	-108,800
AFUDC	3,391,917	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		115,752,276	128,811,454	139,367,549	146,689,146	154,694,954	165,378,977	173,331,691	179,912,679	188,981,536	198,050,393	207,316,239	218,957,788	228,409,641	240,275,523	253,344,915
Return on CWIP																
After Tax Return on Equity		512,760	574,148	629,588	671,559	707,542	751,419	795,171	829,291	866,031	908,612	951,656	1,000,739	1,050,258	1,100,305	1,158,844
Income Tax Component		361,810	405,126	444,245	473,860	499,250	530,210	561,083	585,158	611,082	641,128	671,500	706,134	741,075	776,389	817,695
Interest Expense Component		231,156	258,830	283,823	302,743	318,965	338,745	358,469	373,850	390,413	409,609	429,013	451,140	473,464	496,025	522,415
Total Return on CWIP		1,105,725	1,238,104	1,357,656	1,448,162	1,525,757	1,620,374	1,714,723	1,788,300	1,867,527	1,959,349	2,052,169	2,158,012	2,264,798	2,372,719	2,498,953
BEC 4 Ash Phase 1	5,125,327															
In Service 12/31/2016																
BOM		109,189	149,661	190,134	230,286	270,766	312,039	312,039	312,039	312,039	448,039	584,039	779,125	974,210	1,169,296	1,364,381
CapEx	5,174,257	41,833	41,833	41,512	41,840	42,633	1,360	1,360	1,360	137,360	137,360	196,446	196,446	196,446	196,446	196,446
Less Internal Cost	-48,960	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		149,661	190,134	230,286	270,766	312,039	312,039	312,039	312,039	448,039	584,039	779,125	974,210	1,169,296	1,364,381	1,559,467
Return on CWIP																
After Tax Return on Equity		608	798	987	1,176	1,368	1,465	1,465	1,465	1,784	2,423	3,200	4,116	5,032	5,948	6,864
Income Tax Component		429	563	696	830	965	1,034	1,034	1,034	1,259	1,710	2,258	2,904	3,551	4,197	4,843
Interest Expense Component		274	360	445	530	617	660	660	660	804	1,092	1,443	1,856	2,269	2,681	3,094
Total Return on CWIP		1,310	1,720	2,128	2,537	2,950	3,159	3,159	3,159	3,848	5,225	6,901	8,876	10,851	12,827	14,802
BEC 4 Ash Phase 2	1,487,584															
In Service 12/31/2020																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,552,864															
Less Internal Cost	-65,280															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 3	1,852,400															
In Service 12/31/2024																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	2,170,800															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

	Total Project	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15
BEC 4 Ash Phase 5	2,549,200															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	**300,724,914**															
BOM		102,771,763	115,901,937	129,001,589	139,597,835	146,959,912	155,006,993	165,691,016	173,643,730	180,224,718	189,429,575	198,634,432	208,095,364	219,931,998	229,578,937	241,639,905
CapEx	302,633,651	13,233,534	13,203,011	10,699,606	7,465,437	8,150,441	10,787,383	8,124,074	6,684,348	9,308,217	9,308,217	9,564,292	11,939,994	9,757,098	12,171,128	13,374,638
Less Internal Cost	-5,137,825	-103,360	-103,360	-103,360	-103,360	-103,360	-103,360	-171,360	-103,360	-103,360	-103,360	-103,360	-103,360	-110,160	-110,160	-110,160
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		115,901,937	129,001,589	139,597,835	146,959,912	155,006,993	165,691,016	173,643,730	180,224,718	189,429,575	198,634,432	208,095,364	219,931,998	229,578,937	241,639,905	254,904,382
Return on CWIP																
After Tax Return on Equity	21,378,832	513,367	574,946	630,575	672,735	708,910	752,884	796,636	830,756	867,816	911,035	954,856	1,004,855	1,055,291	1,106,253	1,165,708
Income Tax Component	15,085,169	362,238	405,689	444,942	474,690	500,216	531,244	562,116	586,192	612,342	642,838	673,758	709,038	744,626	780,586	822,538
Interest Expense Component	9,637,728	231,430	259,190	284,268	303,274	319,582	339,405	359,129	374,511	391,217	410,701	430,456	452,996	475,732	498,707	525,509
Total Return on CWIP	46,101,729	1,107,036	1,239,824	1,359,785	1,450,699	1,528,707	1,623,534	1,717,882	1,791,459	1,871,375	1,964,574	2,059,070	2,166,889	2,275,649	2,385,545	2,513,755

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
BEC 4 Environmental Retrofit	287,539,603					In-Service										
In Service 12/31/2015						12/31/2015										
BOM		253,344,915	263,835,012	274,148,946	284,631,838	286,241,938										
CapEx	289,184,130	10,598,897	10,558,734	10,727,692	1,786,900	1,474,465										
Less Internal Cost	-4,873,584	-108,800	-244,800	-244,800	-176,800	-176,800										
AFUDC	3,391,917	0	0	0	0	0										
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0										
EOM		263,835,012	274,148,946	284,631,838	286,241,938	287,539,603										
Return on CWIP																
After Tax Return on Equity		1,214,153	1,262,994	1,311,817	1,340,207	671,994										
Income Tax Component		856,721	891,184	925,634	945,667	474,167										
Interest Expense Component		547,349	569,366	591,376	604,175	302,939										
Total Return on CWIP		2,618,223	2,723,544	2,828,828	2,890,048	1,449,100										
BEC 4 Ash Phase 1	5,125,327															
In Service 12/31/2016																
BOM		1,559,467	1,981,449	2,176,534	2,371,620	2,502,820	2,634,020	2,841,786	3,049,553	3,243,428	3,451,194	3,658,961	3,870,727	4,082,494	4,294,260	4,502,027
CapEx	5,174,257	423,342	196,446	196,446	132,560	132,560	209,127	209,127	195,234	209,127	209,127	213,126	213,126	213,126	209,127	209,127
Less Internal Cost	-48,960	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		1,981,449	2,176,534	2,371,620	2,502,820	2,634,020	2,841,786	3,049,553	3,243,428	3,451,194	3,658,961	3,870,727	4,082,494	4,294,260	4,502,027	4,709,793
Return on CWIP																
After Tax Return on Equity		8,313	9,761	10,677	11,443	12,059	12,855	13,831	14,774	15,717	16,692	17,677	18,671	19,666	20,651	21,626
Income Tax Component		5,866	6,888	7,534	8,075	8,509	9,071	9,759	10,424	11,090	11,778	12,473	13,175	13,876	14,571	15,260
Interest Expense Component		3,747	4,401	4,813	5,159	5,436	5,795	6,235	6,660	7,085	7,525	7,969	8,417	8,865	9,309	9,749
Total Return on CWIP		17,926	21,050	23,025	24,677	26,005	27,721	29,825	31,858	33,892	35,995	38,119	40,263	42,407	44,531	46,635
BEC 4 Ash Phase 2	1,487,584															
In Service 12/31/2020																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,552,864															
Less Internal Cost	-65,280															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 3	1,852,400															
In Service 12/31/2024																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	2,170,800															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

	Total Project	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	**300,724,914**															
BOM		254,904,382	265,816,461	276,325,481	287,003,458	288,744,758	290,173,623	290,381,390	290,589,156	290,783,031	290,990,797	291,198,564	291,410,330	291,622,097	291,833,863	292,041,630
CapEx	302,633,651	11,022,238	10,755,180	10,924,138	1,919,460	1,607,025	209,127	209,127	195,234	209,127	209,127	213,126	213,126	213,126	209,127	209,127
Less Internal Cost	-5,137,825	-110,160	-246,160	-246,160	-178,160	-178,160	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		265,816,461	276,325,481	287,003,458	288,744,758	290,173,623	290,381,390	290,589,156	290,783,031	290,990,797	291,198,564	291,410,330	291,622,097	291,833,863	292,041,630	292,249,397
Return on CWIP																
After Tax Return on Equity	21,378,832	1,222,466	1,272,755	1,322,494	1,351,651	684,053	12,855	13,831	14,774	15,717	16,692	17,677	18,671	19,666	20,651	21,626
Income Tax Component	15,085,169	862,587	898,072	933,168	953,741	482,676	9,071	9,759	10,424	11,090	11,778	12,473	13,175	13,876	14,571	15,260
Interest Expense Component	9,637,728	551,096	573,767	596,190	609,334	308,376	5,795	6,235	6,660	7,085	7,525	7,969	8,417	8,865	9,309	9,749
Total Return on CWIP	46,101,729	2,636,149	2,744,594	2,851,853	2,914,725	1,475,105	27,721	29,825	31,858	33,892	35,995	38,119	40,263	42,407	44,531	46,635

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18
BEC 4 Environmental Retrofit	**287,539,603**															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	**5,125,327**		In-Service													
In Service 12/31/2016			12/31/2016													
BOM		4,709,793	4,917,560													
CapEx	5,174,257	209,127	209,127													
Less Internal Cost	-48,960	-1,360	-1,360													
AFUDC	30	0	0													
EOM		4,917,560	5,125,327													
Return on CWIP																
After Tax Return on Equity		22,602	11,545													
Income Tax Component		15,948	8,146													
Interest Expense Component		10,189	5,204													
Total Return on CWIP		48,738	24,895													
BEC 4 Ash Phase 2	**1,487,584**															
In Service 12/31/2020																
BOM		0	0	0	11,551	23,102	34,654	46,205	58,344	74,544	90,744	106,944	123,144	139,344	155,544	171,744
CapEx	1,552,864			12,911	12,911	12,911	12,911	13,499	17,560	17,560	17,560	17,560	17,560	17,560	17,560	94,451
Less Internal Cost	-65,280			-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	0			0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		0	0	11,551	23,102	34,654	46,205	58,344	74,544	90,744	106,944	123,144	139,344	155,544	171,744	264,835
Return on CWIP																
After Tax Return on Equity				27	81	136	190	245	312	388	464	540	616	692	768	1,025
Income Tax Component				19	57	96	134	173	220	274	327	381	435	488	542	723
Interest Expense Component				12	37	61	86	111	141	175	209	244	278	312	346	462
Total Return on CWIP				58	175	292	409	529	673	837	1,001	1,165	1,329	1,493	1,657	2,210
BEC 4 Ash Phase 3	**1,852,400**															
In Service 12/31/2024																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	**2,170,800**															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

	Total Project	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18
Total	**300,724,914**															
BOM		292,249,397	292,457,163	292,664,930	292,676,481	292,688,032	292,699,583	292,711,135	292,723,274	292,739,474	292,755,674	292,771,874	292,788,074	292,804,274	292,820,474	292,836,674
CapEx	302,633,651	209,127	209,127	12,911	12,911	12,911	12,911	13,499	17,560	17,560	17,560	17,560	17,560	17,560	17,560	94,451
Less Internal Cost	-5,137,825	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		292,457,163	292,664,930	292,676,481	292,688,032	292,699,583	292,711,135	292,723,274	292,739,474	292,755,674	292,771,874	292,788,074	292,804,274	292,820,474	292,836,674	292,929,765
Return on CWIP																
After Tax Return on Equity	21,378,832	22,602	11,545	27	81	136	190	245	312	388	464	540	616	692	768	1,025
Income Tax Component	15,085,169	15,948	8,146	19	57	96	134	173	220	274	327	381	435	488	542	723
Interest Expense Component	9,637,728	10,189	5,204	12	37	61	86	111	141	175	209	244	278	312	346	462
Total Return on CWIP	46,101,729	48,738	24,895	58	175	292	409	529	673	837	1,001	1,165	1,329	1,493	1,657	2,210

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
BEC 4 Environmental Retrofit	287,539,603															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	5,125,327															
In Service 12/31/2016																
BOM																
CapEx	5,174,257															
Less Internal Cost	-48,960															
AFUDC	30															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 2	1,487,584															
In Service 12/31/2020																
BOM		264,835	357,926	451,018	544,109	637,200	730,291	823,382	916,474	1,009,565	1,102,656	1,195,747	1,283,424	1,300,064	1,316,704	1,333,344
CapEx	1,552,864	94,451	94,451	94,451	94,451	94,451	94,451	94,451	94,451	94,451	94,451	89,037	18,000	18,000	18,000	18,000
Less Internal Cost	-65,280	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		357,926	451,018	544,109	637,200	730,291	823,382	916,474	1,009,565	1,102,656	1,195,747	1,283,424	1,300,064	1,316,704	1,333,344	1,349,984
Return on CWIP																
After Tax Return on Equity		1,462	1,899	2,336	2,773	3,210	3,647	4,085	4,522	4,959	5,396	5,820	6,065	6,143	6,221	6,299
Income Tax Component		1,032	1,340	1,648	1,957	2,265	2,574	2,882	3,191	3,499	3,807	4,107	4,280	4,335	4,390	4,445
Interest Expense Component		659	856	1,053	1,250	1,447	1,644	1,841	2,038	2,235	2,432	2,624	2,734	2,769	2,805	2,840
Total Return on CWIP		3,153	4,095	5,038	5,980	6,923	7,865	8,808	9,751	10,693	11,636	12,551	13,079	13,247	13,416	13,584
BEC 4 Ash Phase 3	1,852,400															
In Service 12/31/2024																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	2,170,800															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	**300,724,914**															
BOM		292,929,765	293,022,856	293,115,947	293,209,039	293,302,130	293,395,221	293,488,312	293,581,403	293,674,495	293,767,586	293,860,677	293,948,354	293,964,994	293,981,634	293,998,274
CapEx	302,633,651	94,451	94,451	94,451	94,451	94,451	94,451	94,451	94,451	94,451	94,451	89,037	18,000	18,000	18,000	18,000
Less Internal Cost	-5,137,825	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		293,022,856	293,115,947	293,209,039	293,302,130	293,395,221	293,488,312	293,581,403	293,674,495	293,767,586	293,860,677	293,948,354	293,964,994	293,981,634	293,998,274	294,014,914
Return on CWIP																
After Tax Return on Equity	21,378,832	1,462	1,899	2,336	2,773	3,210	3,647	4,085	4,522	4,959	5,396	5,820	6,065	6,143	6,221	6,299
Income Tax Component	15,085,169	1,032	1,340	1,648	1,957	2,265	2,574	2,882	3,191	3,499	3,807	4,107	4,280	4,335	4,390	4,445
Interest Expense Component	9,637,728	659	856	1,053	1,250	1,447	1,644	1,841	2,038	2,235	2,432	2,624	2,734	2,769	2,805	2,840
Total Return on CWIP	46,101,729	3,153	4,095	5,038	5,980	6,923	7,865	8,808	9,751	10,693	11,636	12,551	13,079	13,247	13,416	13,584

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20
BEC 4 Environmental Retrofit	287,539,603																
In Service 12/31/2015																	
BOM																	
CapEx	289,184,130																
Less Internal Cost	-4,873,584																
AFUDC	3,391,917																
Less AFUDC on Internal Cost	-162,860																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 1	5,125,327																
In Service 12/31/2016																	
BOM																	
CapEx	5,174,257																
Less Internal Cost	-48,960																
AFUDC	30																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 2	1,487,584																
In Service 12/31/2020																	
BOM		1,349,984	1,366,624	1,383,264	1,399,904	1,416,544	1,433,184	1,449,824	1,466,464	1,483,104	1,483,104	1,483,104	1,483,104	1,483,104	1,484,224	1,485,344	1,486,464
CapEx	1,552,864	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	1,360	1,360	1,360	1,360	2,480	2,480	2,480	2,480
Less Internal Cost	-65,280	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		1,366,624	1,383,264	1,399,904	1,416,544	1,433,184	1,449,824	1,466,464	1,483,104	1,483,104	1,483,104	1,483,104	1,483,104	1,484,224	1,485,344	1,486,464	1,487,584
Return on CWIP																	
After Tax Return on Equity		6,378	6,456	6,534	6,612	6,690	6,768	6,846	6,925	6,964	6,964	6,964	6,964	6,966	6,971	6,977	6,982
Income Tax Component		4,500	4,555	4,610	4,666	4,721	4,776	4,831	4,886	4,914	4,914	4,914	4,914	4,915	4,919	4,923	4,927
Interest Expense Component		2,875	2,910	2,946	2,981	3,016	3,051	3,086	3,122	3,139	3,139	3,139	3,139	3,140	3,143	3,145	3,148
Total Return on CWIP		13,753	13,921	14,090	14,258	14,427	14,595	14,764	14,932	15,016	15,016	15,016	15,016	15,022	15,033	15,045	15,056
BEC 4 Ash Phase 3	1,852,400																
In Service 12/31/2024																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 4	2,170,800																
In Service 12/31/2028																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20
BEC 4 Ash Phase 5	**2,549,200**																
In Service 12/31/2032																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
Total	**300,724,914**																
BOM		294,014,914	294,031,554	294,048,194	294,064,834	294,081,474	294,098,114	294,114,754	294,131,394	294,148,034	294,148,034	294,148,034	294,148,034	294,148,034	294,149,154	294,150,274	294,151,394
CapEx	302,633,651	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	1,360	1,360	1,360	1,360	2,480	2,480	2,480	2,480
Less Internal Cost	-5,137,825	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360	-1,360
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		294,031,554	294,048,194	294,064,834	294,081,474	294,098,114	294,114,754	294,131,394	294,148,034	294,148,034	294,148,034	294,148,034	294,148,034	294,149,154	294,150,274	294,151,394	294,152,514
Return on CWIP																	
After Tax Return on Equity	21,378,832	6,378	6,456	6,534	6,612	6,690	6,768	6,846	6,925	6,964	6,964	6,964	6,964	6,966	6,971	6,977	6,982
Income Tax Component	15,085,169	4,500	4,555	4,610	4,666	4,721	4,776	4,831	4,886	4,914	4,914	4,914	4,914	4,915	4,919	4,923	4,927
Interest Expense Component	9,637,728	2,875	2,910	2,946	2,981	3,016	3,051	3,086	3,122	3,139	3,139	3,139	3,139	3,140	3,143	3,145	3,148
Total Return on CWIP	46,101,729	13,753	13,921	14,090	14,258	14,427	14,595	14,764	14,932	15,016	15,016	15,016	15,016	15,022	15,033	15,045	15,056

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
BEC 4 Environmental Retrofit	**287,539,603**															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	**5,125,327**															
In Service 12/31/2016																
BOM																
CapEx	5,174,257															
Less Internal Cost	-48,960															
AFUDC	30															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 2	**1,487,584**				In-Service											
In Service 12/31/2020					12/31/2020											
BOM		1,487,584	1,487,584	1,487,584	1,487,584											
CapEx	1,552,864	1,360	1,360	1,360	1,360											
Less Internal Cost	-65,280	-1,360	-1,360	-1,360	-1,360											
AFUDC	0	0	0	0	0											
EOM		1,487,584	1,487,584	1,487,584	1,487,584											
Return on CWIP																
After Tax Return on Equity		6,985	6,985	6,985	3,492											
Income Tax Component		4,928	4,928	4,928	2,464											
Interest Expense Component		3,149	3,149	3,149	1,574											
Total Return on CWIP		15,062	15,062	15,062	7,531											
BEC 4 Ash Phase 3	**1,852,400**															
In Service 12/31/2024																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	**2,170,800**															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
BEC 4 Ash Phase 5	2,549,200															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	300,724,914															
BOM		294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514
CapEx	302,633,651	1,360	1,360	1,360	1,360	0	0	0	0	0	0	0	0	0	0	0
Less Internal Cost	-5,137,825	-1,360	-1,360	-1,360	-1,360	0	0	0	0	0	0	0	0	0	0	0
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514
Return on CWIP																
After Tax Return on Equity	21,378,832	6,985	6,985	6,985	3,492	0	0	0	0	0	0	0	0	0	0	0
Income Tax Component	15,085,169	4,928	4,928	4,928	2,464	0	0	0	0	0	0	0	0	0	0	0
Interest Expense Component	9,637,728	3,149	3,149	3,149	1,574	0	0	0	0	0	0	0	0	0	0	0
Total Return on CWIP	46,101,729	15,062	15,062	15,062	7,531	0	0	0	0	0	0	0	0	0	0	0

	Total Project	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23
BEC 4 Environmental Retrofit	**287,539,603**															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	**5,125,327**															
In Service 12/31/2016																
BOM																
CapEx	5,174,257															
Less Internal Cost	-48,960															
AFUDC	30															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 2	**1,487,584**															
In Service 12/31/2020																
BOM																
CapEx	1,552,864															
Less Internal Cost	-65,280															
AFUDC	0															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 3	**1,852,400**															
In Service 12/31/2024																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,650
CapEx	1,902,400		1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	38,067	38,067
Less Internal Cost	-50,000		-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,417	-1,417
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	36,650	73,300
Return on CWIP																
After Tax Return on Equity			0	0	0	0	0	0	0	0	0	0	0	0	86	258
Income Tax Component			0	0	0	0	0	0	0	0	0	0	0	0	61	182
Interest Expense Component			0	0	0	0	0	0	0	0	0	0	0	0	39	116
Total Return on CWIP			0	0	0	0	0	0	0	0	0	0	0	0	186	557
BEC 4 Ash Phase 4	**2,170,800**															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

	Total Project	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	**300,724,914**															
BOM		294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,189,164
CapEx	302,633,651	0	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	38,067	38,067
Less Internal Cost	-5,137,825	0	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,417	-1,417
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,152,514	294,189,164	294,225,814
Return on CWIP																
After Tax Return on Equity	21,378,832	0	0	0	0	0	0	0	0	0	0	0	0	0	86	258
Income Tax Component	15,085,169	0	0	0	0	0	0	0	0	0	0	0	0	0	61	182
Interest Expense Component	9,637,728	0	0	0	0	0	0	0	0	0	0	0	0	0	39	116
Total Return on CWIP	46,101,729	0	0	0	0	0	0	0	0	0	0	0	0	0	186	557

	Total Project	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24
BEC 4 Environmental Retrofit	**287,539,603**															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	**5,125,327**															
In Service 12/31/2016																
BOM																
CapEx	5,174,257															
Less Internal Cost	-48,960															
AFUDC	30															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 2	**1,487,584**															
In Service 12/31/2020																
BOM																
CapEx	1,552,864															
Less Internal Cost	-65,280															
AFUDC	0															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 3	**1,852,400**															
In Service 12/31/2024																
BOM		73,300	109,950	146,600	183,250	219,900	256,550	293,200	329,850	366,500	403,150	439,800	557,516	675,233	792,950	910,666
CapEx	1,902,400	38,067	38,067	38,067	38,067	38,067	38,067	38,067	38,067	38,067	38,067	119,133	119,133	119,133	119,133	119,133
Less Internal Cost	-50,000	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417
AFUDC	0															
EOM		109,950	146,600	183,250	219,900	256,550	293,200	329,850	366,500	403,150	439,800	557,516	675,233	792,950	910,666	1,028,383
Return on CWIP																
After Tax Return on Equity		430	602	774	946	1,119	1,291	1,463	1,635	1,807	1,979	2,341	2,894	3,447	3,999	4,552
Income Tax Component		304	425	546	668	789	911	1,032	1,154	1,275	1,396	1,652	2,042	2,432	2,822	3,212
Interest Expense Component		194	272	349	427	504	582	659	737	815	892	1,055	1,305	1,554	1,803	2,052
Total Return on CWIP		928	1,299	1,670	2,041	2,412	2,783	3,154	3,525	3,896	4,267	5,049	6,241	7,433	8,625	9,816
BEC 4 Ash Phase 4	**2,170,800**															
In Service 12/31/2028																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	**300,724,914**															
BOM		294,225,814	294,262,464	294,299,114	294,335,764	294,372,414	294,409,064	294,445,714	294,482,364	294,519,014	294,555,664	294,592,314	294,710,030	294,827,747	294,945,464	295,063,180
CapEx	302,633,651	38,067	38,067	38,067	38,067	38,067	38,067	38,067	38,067	38,067	38,067	119,133	119,133	119,133	119,133	119,133
Less Internal Cost	-5,137,825	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		294,262,464	294,299,114	294,335,764	294,372,414	294,409,064	294,445,714	294,482,364	294,519,014	294,555,664	294,592,314	294,710,030	294,827,747	294,945,464	295,063,180	295,180,897
Return on CWIP																
After Tax Return on Equity	21,378,832	430	602	774	946	1,119	1,291	1,463	1,635	1,807	1,979	2,341	2,894	3,447	3,999	4,552
Income Tax Component	15,085,169	304	425	546	668	789	911	1,032	1,154	1,275	1,396	1,652	2,042	2,432	2,822	3,212
Interest Expense Component	9,637,728	194	272	349	427	504	582	659	737	815	892	1,055	1,305	1,554	1,803	2,052
Total Return on CWIP	46,101,729	928	1,299	1,670	2,041	2,412	2,783	3,154	3,525	3,896	4,267	5,049	6,241	7,433	8,625	9,816

	Total Project	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
BEC 4 Environmental Retrofit	287,539,603																
In Service 12/31/2015																	
BOM																	
CapEx	289,184,130																
Less Internal Cost	-4,873,584																
AFUDC	3,391,917																
Less AFUDC on Internal Cost	-162,860																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 1	5,125,327																
In Service 12/31/2016																	
BOM																	
CapEx	5,174,257																
Less Internal Cost	-48,960																
AFUDC	30																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 2	1,487,584																
In Service 12/31/2020																	
BOM																	
CapEx	1,552,864																
Less Internal Cost	-65,280																
AFUDC	0																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 3	1,852,400							In-Service									
In Service 12/31/2024								12/31/2024									
BOM		1,028,383	1,146,100	1,263,816	1,381,533	1,499,250	1,616,966	1,734,683									
CapEx	1,902,400	119,133	119,133	119,133	119,133	119,133	119,133	119,133									
Less Internal Cost	-50,000	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417									
AFUDC	0																
EOM		1,146,100	1,263,816	1,381,533	1,499,250	1,616,966	1,734,683	1,852,400									
Return on CWIP																	
After Tax Return on Equity		5,105	5,658	6,210	6,763	7,316	7,868	4,072									
Income Tax Component		3,602	3,992	4,382	4,772	5,162	5,552	2,874									
Interest Expense Component		2,301	2,550	2,800	3,049	3,298	3,547	1,836									
Total Return on CWIP		11,008	12,200	13,392	14,584	15,776	16,968	8,782									
BEC 4 Ash Phase 4	2,170,800																
In Service 12/31/2028																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25
BEC 4 Ash Phase 5	**2,549,200**								
In Service 12/31/2032									
BOM		0	0	0	0	0	0	0	0
CapEx	2,599,200								
Less Internal Cost	-50,000								
AFUDC	0								
EOM		0	0	0	0	0	0	0	0
Return on CWIP									
After Tax Return on Equity									
Income Tax Component									
Interest Expense Component									
Total Return on CWIP									
Total	**300,724,914**								
BOM		295,180,897	295,298,614	295,416,330	295,534,047	295,651,764	295,769,480	295,887,197	296,004,914
CapEx	302,633,651	119,133	119,133	119,133	119,133	119,133	119,133	119,133	0
Less Internal Cost	-5,137,825	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	0
AFUDC	3,391,947	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0
EOM		295,298,614	295,416,330	295,534,047	295,651,764	295,769,480	295,887,197	296,004,914	296,004,914
Return on CWIP									
After Tax Return on Equity	21,378,832	5,105	5,658	6,210	6,763	7,316	7,868	4,072	0
Income Tax Component	15,085,169	3,602	3,992	4,382	4,772	5,162	5,552	2,874	0
Interest Expense Component	9,637,728	2,301	2,550	2,800	3,049	3,298	3,547	1,836	0
Total Return on CWIP	46,101,729	11,008	12,200	13,392	14,584	15,776	16,968	8,782	0

	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
BEC 4 Ash Phase 5								
In Service 12/31/2032								
BOM	0	0	0	0	0	0	0	0
CapEx								
Less Internal Cost								
AFUDC								
EOM	0	0	0	0	0	0	0	0
Return on CWIP								
After Tax Return on Equity								
Income Tax Component								
Interest Expense Component								
Total Return on CWIP								
Total								
BOM	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914
CapEx	0	0	0	0	0	0	0	0
Less Internal Cost	0	0	0	0	0	0	0	0
AFUDC	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	0	0	0	0	0	0	0	0
EOM	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914
Return on CWIP								
After Tax Return on Equity	0	0	0	0	0	0	0	0
Income Tax Component	0	0	0	0	0	0	0	0
Interest Expense Component	0	0	0	0	0	0	0	0
Total Return on CWIP	0	0	0	0	0	0	0	0

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27
BEC 4 Environmental Retrofit	**287,539,603**																
In Service 12/31/2015																	
BOM																	
CapEx	289,184,130																
Less Internal Cost	-4,873,584																
AFUDC	3,391,917																
Less AFUDC on Internal Cost	-162,860																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 1	**5,125,327**																
In Service 12/31/2016																	
BOM																	
CapEx	5,174,257																
Less Internal Cost	-48,960																
AFUDC	30																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 2	**1,487,584**																
In Service 12/31/2020																	
BOM																	
CapEx	1,552,864																
Less Internal Cost	-65,280																
AFUDC	0																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 3	**1,852,400**																
In Service 12/31/2024																	
BOM																	
CapEx	1,902,400																
Less Internal Cost	-50,000																
AFUDC	0																
EOM																	
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	
BEC 4 Ash Phase 4	**2,170,800**																
In Service 12/31/2028																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,220,800				1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	44,800
Less Internal Cost	-50,000				-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,417
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43,383
Return on CWIP																	
After Tax Return on Equity					0	0	0	0	0	0	0	0	0	0	0	0	102
Income Tax Component					0	0	0	0	0	0	0	0	0	0	0	0	72
Interest Expense Component					0	0	0	0	0	0	0	0	0	0	0	0	46
Total Return on CWIP					0	0	0	0	0	0	0	0	0	0	0	0	220

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27
BEC 4 Ash Phase 5	**2,549,200**																
In Service 12/31/2032																	
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200																
Less Internal Cost	-50,000																
AFUDC	0																
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																	
After Tax Return on Equity																	
Income Tax Component																	
Interest Expense Component																	
Total Return on CWIP																	

	Total Project	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27
Total	**300,724,914**																
BOM		296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914
CapEx	302,633,651	0	0	0	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	44,800
Less Internal Cost	-5,137,825	0	0	0	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,333	-1,417
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,004,914	296,048,297
Return on CWIP																	
After Tax Return on Equity	21,378,832	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	102
Income Tax Component	15,085,169	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72
Interest Expense Component	9,637,728	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	46
Total Return on CWIP	46,101,729	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	220

	Total Project	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28
BEC 4 Environmental Retrofit	**287,539,603**															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	**5,125,327**															
In Service 12/31/2016																
BOM																
CapEx	5,174,257															
Less Internal Cost	-48,960															
AFUDC	30															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 2	**1,487,584**															
In Service 12/31/2020																
BOM																
CapEx	1,552,864															
Less Internal Cost	-65,280															
AFUDC	0															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 3	**1,852,400**															
In Service 12/31/2024																
BOM																
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	**2,170,800**															
In Service 12/31/2028																
BOM		43,383	86,767	130,150	173,533	216,917	260,300	303,683	347,067	390,450	433,833	477,217	520,600	658,117	795,633	933,150
CapEx	2,220,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	138,933	138,933	138,933	138,933
Less Internal Cost	-50,000	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417
AFUDC	0															
EOM		86,767	130,150	173,533	216,917	260,300	303,683	347,067	390,450	433,833	477,217	520,600	658,117	795,633	933,150	1,070,667
Return on CWIP																
After Tax Return on Equity		306	509	713	917	1,120	1,324	1,528	1,731	1,935	2,139	2,343	2,767	3,413	4,059	4,704
Income Tax Component		216	359	503	647	791	934	1,078	1,222	1,365	1,509	1,653	1,953	2,408	2,864	3,319
Interest Expense Component		138	230	321	413	505	597	689	781	872	964	1,056	1,247	1,539	1,830	2,121
Total Return on CWIP		659	1,098	1,537	1,977	2,416	2,855	3,294	3,734	4,173	4,612	5,051	5,967	7,360	8,752	10,144

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	**300,724,914**															
BOM		296,048,297	296,091,680	296,135,064	296,178,447	296,221,830	296,265,214	296,308,597	296,351,980	296,395,364	296,438,747	296,482,130	296,525,514	296,663,030	296,800,547	296,938,064
CapEx	302,633,651	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	44,800	138,933	138,933	138,933	138,933
Less Internal Cost	-5,137,825	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		296,091,680	296,135,064	296,178,447	296,221,830	296,265,214	296,308,597	296,351,980	296,395,364	296,438,747	296,482,130	296,525,514	296,663,030	296,800,547	296,938,064	297,075,580
Return on CWIP																
After Tax Return on Equity	21,378,832	306	509	713	917	1,120	1,324	1,528	1,731	1,935	2,139	2,343	2,767	3,413	4,059	4,704
Income Tax Component	15,085,169	216	359	503	647	791	934	1,078	1,222	1,365	1,509	1,653	1,953	2,408	2,864	3,319
Interest Expense Component	9,637,728	138	230	321	413	505	597	689	781	872	964	1,056	1,247	1,539	1,830	2,121
Total Return on CWIP	46,101,729	659	1,098	1,537	1,977	2,416	2,855	3,294	3,734	4,173	4,612	5,051	5,967	7,360	8,752	10,144

	Total Project	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29
BEC 4 Environmental Retrofit	287,539,603															
In Service 12/31/2015																
BOM																
CapEx	289,184,130															
Less Internal Cost	-4,873,584															
AFUDC	3,391,917															
Less AFUDC on Internal Cost	-162,860															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 1	5,125,327															
In Service 12/31/2016																
BOM																
CapEx	5,174,257															
Less Internal Cost	-48,960															
AFUDC	30															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 2	1,487,584															
In Service 12/31/2020																
BOM																
CapEx	1,552,864															
Less Internal Cost	-65,280															
AFUDC	0															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 3	1,852,400															
In Service 12/31/2024																
BOM																
CapEx	1,902,400															
Less Internal Cost	-50,000															
AFUDC	0															
EOM																
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
BEC 4 Ash Phase 4	2,170,800								In-Service							
In Service 12/31/2028									12/31/2018							
BOM		1,070,667	1,208,183	1,345,700	1,483,217	1,620,733	1,758,250	1,895,767	2,033,283							
CapEx	2,220,800	138,933	138,933	138,933	138,933	138,933	138,933	138,933	138,933							
Less Internal Cost	-50,000	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417							
AFUDC	0															
EOM		1,208,183	1,345,700	1,483,217	1,620,733	1,758,250	1,895,767	2,033,283	2,170,800							
Return on CWIP																
After Tax Return on Equity		5,350	5,996	6,641	7,287	7,933	8,578	9,224	102							
Income Tax Component		3,775	4,231	4,686	5,142	5,597	6,053	6,509	72							
Interest Expense Component		2,412	2,703	2,994	3,285	3,576	3,867	4,158	46							
Total Return on CWIP		11,537	12,929	14,321	15,714	17,106	18,498	19,891	220							

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29
BEC 4 Ash Phase 5	2,549,200															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CapEx	2,599,200															
Less Internal Cost	-50,000															
AFUDC	0															
EOM		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Return on CWIP																
After Tax Return on Equity																
Income Tax Component																
Interest Expense Component																
Total Return on CWIP																
Total	300,724,914															
BOM		297,075,580	297,213,097	297,350,614	297,488,130	297,625,647	297,763,164	297,900,680	298,038,197	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714
CapEx	302,633,651	138,933	138,933	138,933	138,933	138,933	138,933	138,933	138,933	0	0	0	0	0	0	0
Less Internal Cost	-5,137,825	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	-1,417	0	0	0	0	0	0	0
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		297,213,097	297,350,614	297,488,130	297,625,647	297,763,164	297,900,680	298,038,197	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714
Return on CWIP																
After Tax Return on Equity	21,378,832	5,350	5,996	6,641	7,287	7,933	8,578	9,224	102	0	0	0	0	0	0	0
Income Tax Component	15,085,169	3,775	4,231	4,686	5,142	5,597	6,053	6,509	72	0	0	0	0	0	0	0
Interest Expense Component	9,637,728	2,412	2,703	2,994	3,285	3,576	3,867	4,158	46	0	0	0	0	0	0	0
Total Return on CWIP	46,101,729	11,537	12,929	14,321	15,714	17,106	18,498	19,891	220	0	0	0	0	0	0	0

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29	Jan-30	Feb-30	Mar-30	Apr-30	May-30	Jun-30	Jul-30	Aug-30	Sep-30	Oct-30
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		0	0	0	0	0	0	611	1,222	1,833	2,444	3,056	3,667	4,278	4,889	5,500
CapEx	2,599,200						2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Less Internal Cost	-50,000						-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389
AFUDC	0															
EOM		0	0	0	0	0	611	1,222	1,833	2,444	3,056	3,667	4,278	4,889	5,500	6,111
Return on CWIP																
After Tax Return on Equity							1	4	7	10	13	16	19	22	24	27
Income Tax Component							1	3	5	7	9	11	13	15	17	19
Interest Expense Component							1	2	3	5	6	7	8	10	11	12
Total Return on CWIP							3	9	15	22	28	34	40	46	53	59

	Total Project	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29	Jan-30	Feb-30	Mar-30	Apr-30	May-30	Jun-30	Jul-30	Aug-30	Sep-30	Oct-30
Total	**300,724,914**															
BOM		298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,176,325	298,176,936	298,177,547	298,178,158	298,178,769	298,179,380	298,179,991	298,180,602	298,181,214
CapEx	302,633,651	0	0	0	0	0	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Less Internal Cost	-5,137,825	0	0	0	0	0	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		298,175,714	298,175,714	298,175,714	298,175,714	298,175,714	298,176,325	298,176,936	298,177,547	298,178,158	298,178,769	298,179,380	298,179,991	298,180,602	298,181,214	298,181,825
Return on CWIP																
After Tax Return on Equity	21,378,832	0	0	0	0	0	1	4	7	10	13	16	19	22	24	27
Income Tax Component	15,085,169	0	0	0	0	0	1	3	5	7	9	11	13	15	17	19
Interest Expense Component	9,637,728	0	0	0	0	0	1	2	3	5	6	7	8	10	11	12
Total Return on CWIP	46,101,729	0	0	0	0	0	3	9	15	22	28	34	40	46	53	59

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Nov-30	Dec-30	Jan-31	Feb-31	Mar-31	Apr-31	May-31	Jun-31	Jul-31	Aug-31	Sep-31	Oct-31	Nov-31	Dec-31	Jan-32
BEC 4 Ash Phase 5	**2,549,200**															
In Service 12/31/2032																
BOM		6,111	6,722	7,333	57,744	108,156	158,567	208,978	259,389	309,800	360,211	410,622	461,033	511,444	561,856	612,267
CapEx	2,599,200	2,000	2,000	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	162,800
Less Internal Cost	-50,000	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389
AFUDC	0															
EOM		6,722	7,333	57,744	108,156	158,567	208,978	259,389	309,800	360,211	410,622	461,033	511,444	561,856	612,267	773,678
Return on CWIP																
After Tax Return on Equity		30	33	153	389	626	863	1,100	1,336	1,573	1,810	2,046	2,283	2,520	2,756	3,254
Income Tax Component		21	23	108	275	442	609	776	943	1,110	1,277	1,444	1,611	1,778	1,945	2,296
Interest Expense Component		14	15	69	176	282	389	496	602	709	816	923	1,029	1,136	1,243	1,467
Total Return on CWIP		65	71	329	840	1,350	1,861	2,371	2,882	3,392	3,902	4,413	4,923	5,434	5,944	7,016

	Total Project	Nov-30	Dec-30	Jan-31	Feb-31	Mar-31	Apr-31	May-31	Jun-31	Jul-31	Aug-31	Sep-31	Oct-31	Nov-31	Dec-31	Jan-32
Total	**300,724,914**															
BOM		298,181,825	298,182,436	298,183,047	298,233,458	298,283,869	298,334,280	298,384,691	298,435,102	298,485,514	298,535,925	298,586,336	298,636,747	298,687,158	298,737,569	298,787,980
CapEx	302,633,651	2,000	2,000	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	51,800	162,800
Less Internal Cost	-5,137,825	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		298,182,436	298,183,047	298,233,458	298,283,869	298,334,280	298,384,691	298,435,102	298,485,514	298,535,925	298,586,336	298,636,747	298,687,158	298,737,569	298,787,980	298,949,391
Return on CWIP																
After Tax Return on Equity	21,378,832	30	33	153	389	626	863	1,100	1,336	1,573	1,810	2,046	2,283	2,520	2,756	3,254
Income Tax Component	15,085,169	21	23	108	275	442	609	776	943	1,110	1,277	1,444	1,611	1,778	1,945	2,296
Interest Expense Component	9,637,728	14	15	69	176	282	389	496	602	709	816	923	1,029	1,136	1,243	1,467
Total Return on CWIP	46,101,729	65	71	329	840	1,350	1,861	2,371	2,882	3,392	3,902	4,413	4,923	5,434	5,944	7,016

Minnesota Power
BEC 4 Rider
Plant Additions, AFUDC and Return on CWIP

	Total Project	Feb-32	Mar-32	Apr-32	May-32	Jun-32	Jul-32	Aug-32	Sep-32	Oct-32	Nov-32	Dec-32 In-Service 12/31/2032
BEC 4 Ash Phase 5	2,549,200											
In Service 12/31/2032												
BOM		773,678	935,089	1,096,500	1,257,911	1,419,322	1,580,733	1,742,144	1,903,556	2,064,967	2,226,378	2,387,789
CapEx	2,599,200	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800
Less Internal Cost	-50,000	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389
AFUDC	0											
EOM		935,089	1,096,500	1,257,911	1,419,322	1,580,733	1,742,144	1,903,556	2,064,967	2,226,378	2,387,789	2,549,200
Return on CWIP												
After Tax Return on Equity		4,012	4,769	5,527	6,285	7,043	7,801	8,559	9,317	10,075	10,832	5,606
Income Tax Component		2,831	3,365	3,900	4,435	4,970	5,504	6,039	6,574	7,109	7,643	3,955
Interest Expense Component		1,808	2,150	2,492	2,833	3,175	3,517	3,858	4,200	4,542	4,883	2,527
Total Return on CWIP		8,651	10,285	11,919	13,553	15,188	16,822	18,456	20,091	21,725	23,359	12,088

Total	**300,724,914**											
BOM		298,949,391	299,110,802	299,272,214	299,433,625	299,595,036	299,756,447	299,917,858	300,079,269	300,240,680	300,402,091	300,563,502
CapEx	302,633,651	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800	162,800
Less Internal Cost	-5,137,825	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389	-1,389
AFUDC	3,391,947	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-162,860	0	0	0	0	0	0	0	0	0	0	0
EOM		299,110,802	299,272,214	299,433,625	299,595,036	299,756,447	299,917,858	300,079,269	300,240,680	300,402,091	300,563,502	300,724,914
Return on CWIP												
After Tax Return on Equity	21,378,832	4,012	4,769	5,527	6,285	7,043	7,801	8,559	9,317	10,075	10,832	5,606
Income Tax Component	15,085,169	2,831	3,365	3,900	4,435	4,970	5,504	6,039	6,574	7,109	7,643	3,955
Interest Expense Component	9,637,728	1,808	2,150	2,492	2,833	3,175	3,517	3,858	4,200	4,542	4,883	2,527
Total Return on CWIP	46,101,729	8,651	10,285	11,919	13,553	15,188	16,822	18,456	20,091	21,725	23,359	12,088

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.

Minnesota Power
BEC 4 Rider
2010 Rate Case Allocators

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
MP Exhibit (SJS) Rebuttal Schedule 2, page 9 of 15
Docket No. E-015/GR-09-1151

		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.

Minnesota Power
BEC4 Rider
Tax Depreciation Table

BEC4 Environmental Retrofit Project

	20 yr PUP 40% Weighting 1/	Pollution Control 60% Weighting 2/	Weighted Average
Year 1	0.938%	1.1905%	1.0895%
Year 2	7.430%	14.2857%	11.5434%
Year 3	6.872%	14.2857%	11.3202%
Year 4	6.357%	14.2857%	11.1142%
Year 5	5.880%	14.2857%	10.9234%
Year 6	5.439%	14.2857%	10.7470%
Year 7	5.031%	14.2857%	10.5838%
Year 8	4.654%	13.095%	9.7187%
Year 9	4.458%	0.000%	1.7832%
Year 10	4.458%	0.000%	1.7832%
Year 11	4.458%	0.000%	1.7832%
Year 12	4.458%	0.000%	1.7832%
Year 13	4.458%	0.000%	1.7832%
Year 14	4.458%	0.000%	1.7832%
Year 15	4.458%	0.000%	1.7832%
Year 16	4.458%	0.000%	1.7832%
Year 17	4.458%	0.000%	1.7832%
Year 18	4.459%	0.000%	1.7836%
Year 19	4.458%	0.000%	1.7832%
Year 20	4.459%	0.000%	1.7836%
Year 21	3.901%	0.000%	1.5604%
	100.000%	100.000%	100.000%

Weighting allocation per Internal Revenue Code Regulation 1.169-4.
1/ 40% weighting is 20 year PUP tax table, mid 4th quarter
2/ 60% weighting of pollution control portion is 84 month straight line.
Plant in-service in December, so one month depreciation taken in first year and eleven months taken in final year.

Boswell Ash Pond Projects

	20 yr PUP 40% Weighting 1/	Pollution Control 60% Weighting 2/	Weighted Average
Year 1	3.750%	1.1905%	2.2143%
Year 2	7.219%	14.2857%	11.4590%
Year 3	6.677%	14.2857%	11.2422%
Year 4	6.177%	14.2857%	11.0422%
Year 5	5.713%	14.2857%	10.8566%
Year 6	5.285%	14.2857%	10.6854%
Year 7	4.888%	14.2857%	10.5266%
Year 8	4.522%	13.095%	9.6659%
Year 9	4.462%	0.000%	1.7848%
Year 10	4.461%	0.000%	1.7844%
Year 11	4.462%	0.000%	1.7848%
Year 12	4.461%	0.000%	1.7844%
Year 13	4.462%	0.000%	1.7848%
Year 14	4.461%	0.000%	1.7844%
Year 15	4.462%	0.000%	1.7848%
Year 16	4.461%	0.000%	1.7844%
Year 17	4.462%	0.000%	1.7848%
Year 18	4.461%	0.000%	1.7844%
Year 19	4.462%	0.000%	1.7848%
Year 20	4.461%	0.000%	1.7844%
Year 21	2.231%	0.000%	0.8924%
	100.000%	100.000%	100.000%

Weighting allocation per Internal Revenue Code Regulation 1.169-4.
1/ 40% weighting is 20 year PUP tax table, half-year
2/ 60% weighting of pollution control portion is 84 month straight line.
Plant in-service in December, so one month depreciation taken in first year and eleven months taken in final year.

EXHIBIT C

P00002-0000002

Name: JOHN E DOE
Account: 9876

Bill Number: 34374175
Bill Date: 09/25/2012

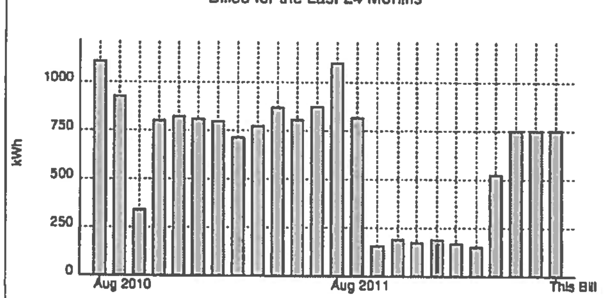
123 MAIN ST
ESKO MN

Residential Service Rate: A20
30 days

Next Scheduled Meter Read: 09/03/2012

Meter #	Start Date	Start Read	Read Code	End Date	End Read	Read Code	Usage
196099	06/30/12	7,964	regular	07/30/12	8,714	regular	750 Kilowatt Hours (kWh) used

Billed for the Last 24 Months



Service Charge		8.00
300 kWh @ $0.05116	15.35	
200 kWh @ $0.06753	13.51	
250 kWh @ $0.08186	20.47	
Total Energy Charge for 750 kWh		49.33
Affordability Surcharge		0.65
Renewable Adjustment 750 kWh @ $0.00149		1.12
Transmission Adjustment 750 kWh @ $0.00033		0.25
Boswell 4 Plan Adjustment 750 KWH @ $0.00156		1.17
Resource Adjustment		10.62
Minnesota Sales Tax (6.875%)		4.89
Total charge this service agreement		76.03

The average kWh per day for this meter is 25
For the same period last year it was 30
The average daily cost for this meter is $2.53

Fuels used to generate electricity have different costs, reliability and air emissions. For more information, call Minnesota Power at 218-722-2625 or 1-800-228-4966, or visit www.mnpower.com. You may also contact the Minnesota Department of Commerce at www.commerce.state.mn.us; or the Minnesota Pollution Control Agency at www.pca.state.mn.us/programs/electricity.html.

MOVING? Please call 1-800-228-4966 in advance. Thank you!

Changing your name, phone number, or just the mailing address?
Please fill out and check box on reverse side.

Name change:______________ Reason why______

New phone number:______________

New mailing address:______________

City__________ State______ Zip code______

REQUIRED: Home #:__________ Cell #:__________

Work #:__________ Account#:__________

EXHIBIT D

minnesota power
AN ALLETE COMPANY

Notice to Minnesota Power Customers

On November 5, 2013, the Minnesota Public Utilities Commission (MPUC) approved Minnesota Power's Boswell Energy Center Unit 4 (BEC4) Mercury Emission Reduction Plan (BEC4 Plan). The BEC4 Plan addresses the Mercury Emission Reduction Act of 2006, the Mercury and Air Toxics Standard Rule, as well as other new state and federal emission control regulations. Beginning in 2016, Minnesota Power will significantly reduce emissions from its largest coal-based generation unit in Northern Minnesota. The BEC4 Plan is a multi-pollutant solution for reducing mercury, particulate matter (PM), sulfur dioxide (SO_2), and other hazardous air pollutants being addressed by the United States Environmental Protection Agency while also significantly reducing wastewater from BEC4 operations at BEC4 in Cohasset, Minnesota.

The BEC4 Plan balances emission reductions and environmental/health benefits with customer costs.

Minnesota Power will add a line item adjustment to your monthly electric bills to recover the costs of these environmental retrofits. This Boswell 4 Plan Adjustment will result in an average rate increase of approximately X.XX percent in [Month] 2014 to X.XX percent in [Month] 2016. For more information, please call Minnesota Power at 218-722-2625 or 1-800-228-4966, or visit www.mnpower.com.

EXHIBIT E

Boswell - July 30, 2013

Sheet Pile Wall

Sheet Pile Wall & NID Site

Piling Work

Early Foundations in South Alleyway

Electrical Room Foundation

Ash Silo Pilings

Ash Silo Pour

STATE OF MINNESOTA) AFFIDAVIT OF SERVICE VIA
) ss ELECTRONIC FILING
COUNTY OF ST. LOUIS)

Susan Romans of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 20th day of December, 2013, she served Minnesota Power's Petition to Implement Boswell Energy Center Unit 4 Emission Reduction Rider and Compliance Filing to the Minnesota Public Utilities Commission via electronic filing. The persons on the attached General Service List were served as requested.

/s/ Susan Romans
Susan Romans

Subscribed and sworn to before
me this 20th day of December, 2013.

/s/ Jodi Nash
Jodi Nash, Notary Public
Commission Expires on Jan 31, 2015

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_GEN_SL_Minnesota Power_Minnesota Power General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Margaret	Hodnik	mhodnik@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	Yes	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Thomas	Scharff	thomas.scharff@newpagecorp.com	New Page Corporation	P.O. Box 8050 610 High Street Wisconsin Rapids, WI 544958050	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Karen	Turnboom	karen.turnboom@newpagecorp.com	NewPage Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List
Laurance R.	Waldoch	lwaldoch@lindquist.com	Lindquist & Vennum	4200 IDS Center 80 South 8th Street Minneapolis, MN 554022274	Paper Service	No	GEN_SL_Minnesota Power_GEN_SL_Minnesota Power_Minnesota Power General Service List