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Direct Testimony and Schedules
Marcia A. Podratz

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
for Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-19-442

Exhibit ________

REVENUE REQUIREMENTS AND RATE DESIGN

November 1, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Marcia A. Podratz, and my business address is 30 West Superior Street, Duluth, Minnesota, 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). I am the Director – Rates for Minnesota Power.

Q. Please describe your educational background and work experience with Minnesota Power.

A. I have a Bachelor of Arts degree with a double major in Economics and Mathematics from the University of Minnesota – Duluth. I have been employed by Minnesota Power in a variety of positions since 1987. My previous positions at Minnesota Power include Rate Engineer/Analyst, Energy Resource Planner, Marketing and Pricing Analyst, Strategic Account Support Manager, and Customer Solutions Manager. In 2007, I became Manager – Rates, and in 2008, I was promoted to Director – Rates.

Q. What are your present duties at Minnesota Power?

A. My primary responsibilities include management of Minnesota Power's cost-of-service, revenue requirements, and rate design functions, and preparation of information for regulatory filings. I supervise the work of employees in the Rate Department, which includes determining load characteristics of customers and classes of customers, determining allocation factors for cost-of-service purposes, and obtaining other information relating to and used for developing rates. I am also responsible for designing and revising Minnesota Power's rate schedules; interpreting rate schedules and checking for proper rate application; and preparing material and data relating to rates, cost recovery riders, electric service agreements, and electric service regulations for submission to regulatory authorities.

Q. Have you previously testified before regulatory bodies?

A. Yes. I previously testified in Minnesota Power's 2008, 2009, and 2016 Minnesota rate cases in Minnesota Public Utilities Commission ("MPUC" or "Commission") Dockets E015/GR-08-415, E015/GR-09-1151, and E015/GR-16-664. I also submitted cost-of-service, rate design, and fuel clause testimony to the Federal Energy Regulatory Commission ("FERC") on behalf of Minnesota Power in 2007 in FERC Docket No. ER08-397-000, and I submitted testimony presenting Minnesota Power's electric power supply formula rate for its wholesale electric customers in 2008 in FERC Docket No. ER09-226-000.

Q. What is the purpose and scope of your testimony?

A. The purpose of my testimony is to support Minnesota Power's revenue requirements and rate design for the 2020 test year. My testimony addresses the determination of rate base and operating income and summarizes the treatment of adjustments made in the General Rate cost-of-service study used to determine the total Minnesota jurisdictional operating income and the revenue increase required by Minnesota Power to earn its requested rate of return.

My testimony discusses the adjustments specific to the Company's Interim Rate request, and supports the Company's Interim Rate increase request.

Next, I explain how the Company's riders and trackers bear on our 2020 test year cost of service, building on the detailed testimony of Company witness Mr. Stewart J. Shimmin. In particular, I support the Company's Conservation Improvement Program ("CIP") tracker and base rate totals, as well as the calculation of the Company's test year average cost of Fuel and Purchased Energy ("FPE"), which Minnesota Power proposes to remove from base rates effective with the start of interim rates and recover entirely through the FPE Charge as part of the Resource Adjustment on customer bills. At its October 17, 2019 hearing in Docket No. E999/CI-03-802 ("the Fuel Clause Docket"), the Commission approved Minnesota Power's proposed changes related to the base cost of fuel and purchased energy and required Minnesota Power to demonstrate in this rate case filing that its proposed base rates do not include any amount of FPE costs.

In addition, my testimony summarizes the results of Minnesota Power's class cost of service study ("CCOSS") sponsored by Mr. Shimmin, supports the data linkage between the CCOSS and the cost of service and rate design, and explains the Company's approach to rate design. Mr. Shimmin discusses the classification and functional assignment of costs and the cost allocation between jurisdictions and customer classes that are used in the determination of the revenue requirements by class.

Next, I address the distribution of increased revenue requirements among the classes of service; the design of the Company's proposed rates for Minnesota Power's retail classes (Residential, General Service, Large Light and Power, Large Power, and Lighting); and billing comparisons reflecting present and proposed rates. Because Minnesota Power is proposing a significant change to the structure of its Residential rates, I summarize the Company's stakeholder engagement process and explain the proposed new rate design in detail.

Finally, I address several compliance items from other dockets.

Q. What exhibits are you sponsoring in your testimony?

A. I am sponsoring the following schedules that immediately follow my testimony and are identified as:

- MP Exhibit ___ (Podratz), Direct Schedule 1 – Present Rate Revenues, Revenue Deficiency, and Rate Increase Summary (General Rates and Interim Rates)
- MP Exhibit ___ (Podratz), Direct Schedule 2 – Basin Electric Power Sale

Pro Forma Adjustment

- MP Exhibit ___ (Podratz), Direct Schedule 3 – Rate Case Expenses
- MP Exhibit ___ (Podratz), Direct Schedule 4 – Credit Card Processing Fee Over-Recovery Amortization
- Exhibit ___ (Podratz), Direct Schedule 5, 2020 Test Year Operating Revenue Adjustments to Budget
- Exhibit ___ (Podratz), Direct Schedule 6, Revenue Credits Summary (Trade Secret)
- Exhibit ___ (Podratz), Direct Schedule 7, Summary Calculation of Test Year Average Cost of Fuel and Purchased Energy
- Exhibit ___ (Podratz), Direct Schedule 8, Test Year Cost of Fuel and Purchased Energy Excluded from Base Rates (Interim and General Rates)
- Exhibit ___(Podratz), Direct Schedule 9, Minnesota Power 2019 Residential Rate Design Stakeholder Process Summary
- Exhibit ___ (Podratz), Direct Schedule 10, Class Revenue Apportionment
- Exhibit ___ (Podratz), Direct Schedule 11, Summary of Proposed Rate Increases by Rate Class
- Exhibit ___ (Podratz), Direct Schedule 12, Residential Present Rate Impact of Inclining Block Rates to Flat Rates Structure Change
- Exhibit ___ (Podratz), Direct Schedule 13, Residential Annual Profile Impacts with Present Revenue Requirement (IBR to Phase 2 Flat)
- Exhibit ___ (Podratz), Direct Schedule 14, Residential Phased Flat Rates with Proposed Rates Bill Impact
- Exhibit ___ (Podratz), Direct Schedule 15, Residential Annual Bill Comparison with Proposed Phase 2 Rates
- Exhibit ___ (Podratz), Direct Schedule 16, Residential Phase 2 Structure Change and Revenue Change Impact Summary
- Exhibit ___ (Podratz), Direct Schedule 17, Residential Phase 2 Billing Comparison Summary

- Exhibit ___ (Podratz), Direct Schedule 18, Summary of Present and Proposed General Rates

II. RATE CHANGE REQUEST

Q. Please summarize Minnesota Power's revenue deficiency in this proceeding.

A. Minnesota Power proposes an overall annual Interim Rate increase of $47.9 million (7.70 percent) for the retail jurisdiction and an average General Rate increase of $65.9 million (10.59 percent). The total retail General Rate and Interim Rate revenue requirements, revenue deficiency, and proposed rate increase percentage are summarized on MP Exhibit ___ (Podratz), Direct Schedule 1 to my testimony. Additionally, Volume 1, Schedule A-1 (IR) summarizes Minnesota Power's Interim Rate revenue deficiency for the test year, and Volume 3, Schedule A-1, summarizes Minnesota Power's proposed General Rate revenue deficiency for the test year.

Q. Please summarize Minnesota Power's cost allocation results and proposed change in rates.

A. Our 2020 test year CCOSS indicates that the Company's test year General Rate revenue deficiency should result in a 36 percent change for Residential customers and a 7 percent change for Large Power customers (our two largest individual customer classes). However, Minnesota Power proposes an overall increase of $15.5 million (15.00 percent) for Residential, $7.5 million (10.35 percent) for General Service, $11.1 million (10.35 percent) for Large Light and Power, $33.7 million (10.35 percent) for Large Power, and $0.5 million (15.00 percent) for Lighting. In addition, Minnesota Power proposes a decrease of $2.4 million (22.6 percent) for Residential and Commercial/Industrial Dual Fuel service. The proposed increases by customer class and supporting calculations are shown in detail on Schedule E-1 in Volume 3 and discussed in Section IX below.

Q. Is Minnesota Power also proposing to move amounts already being recovered from customers through existing cost recovery riders to base rates?

A. Yes. Minnesota Power is moving some cost recovery rider projects to base rates in this case, but the number of projects and associated dollar amounts (approximately $1 million revenue requirement) are much smaller than in the Company's last rate case (Docket No. E015/GR-16-664) (the "2016 Rate Case") and the Company's proposal for addressing rider projects in the rate case is simpler. As described in the testimony of Mr. Shimmin, the Company proposes to move the Dog Lake project that is currently in the Rider for Transmission Cost Recovery ("TCR Rider") and the final two Thomson Hydro projects that are currently in the Rider for Renewable Resources ("RRR") to base rates at the beginning of the rate case, so their revenue requirements are incorporated in the interim and final rate requests. This proposal is consistent with Order Point 47 from the Commission's Findings of Fact, Conclusions, and Order in Docket No. E015/GR-16-664, which required that in future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate case at the end of the rate case if Minnesota Power wants to continue rider recovery.

Minnesota Power also proposes to move the Excess Accumulated Deferred Income Tax ("ADIT") credit to base rates and cancel the Tax Cut Refund Rider effective with final rates, as described in Section VII.D below.

Q. What are the results of the test year allocated cost-of-service study before this rate change?

A. Volume 3, Schedule E-3, Page 2 of 87 summarizes the results of the allocated cost-of-service study for the test year and shows the rate of return, based on present revenue levels, earned for the Minnesota jurisdiction to be 5.21 percent. Based on test year return requirements of 7.4737 percent on rate base, this produces the revenue deficiency of $65.9 million during the test year ending December 31, 2020.

III. TEST YEAR AND DATA PROVIDED

Q. What test period did Minnesota Power use for the cost-of-service study?

A. Minnesota Power uses a forward-looking calendar year test year that begins January 1, 2020, and ends December 31, 2020. The 2020 test year information is based on Minnesota Power's 2020 budget that was finalized in October 2019.

Q. Please identify the fiscal periods for which Minnesota Power is providing financial data in Volumes 1 and 3 of this filing.

A. Financial data is provided for calendar year 2018[1] as the most recent fiscal year; for calendar year 2019[2] as the projected fiscal year; and for calendar year 2020 as the proposed test year.[3] Consistent with Minnesota Rules, the Company provides unadjusted average rate base, unadjusted operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for 2018 and 2019. The Company also provides this information for the 2020 test year, and identifies adjustments reflecting changes to costs, prior regulatory outcomes, and other updates.

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[1] Minn. Rule 7825.3100, Subp. 10 defines "Most recent fiscal year" as "the utility's prior fiscal year unless notice of a change in rates is filed with the commission within the last three months of the current fiscal year and at least nine months of historical data is available for presentation of current fiscal year financial information, in which case the most recent fiscal year is deemed to be the current fiscal year." ALLETE's 2019 Third Quarter financial results will be released on November 6, 2019, which is after the date of this filing. Therefore, 2018, the prior fiscal year, is the most recent fiscal year for which nine months of historical data is available, consistent with Minn. R. 7825.3100, Subd. 10. If the Commission believes it is necessary to grant a variance to utilize this definition of the "most recent fiscal year," the Company requests a variance under Minn. R. 7829.3200, because (i) it would be an excessive burden on the utility to have to wait to file a case until nine months of 2019 data is available, given the amount of time required to prepare a rate case filing; (ii) the variance would not adversely affect the public interest given that the Rule contemplates using the prior calendar year as the most recent fiscal year, and this has been Minnesota Power's practice for decades; and (iii) the variance would not conflict with standards imposed by law because it is consistent with Minn. R. 7825.3100 and with past practice.

[2] Minn. Rule 7825.3100, Subp. 12 defines "Projected fiscal year" as "the fiscal year immediately following the most recent fiscal year."

[3] Minn. Rule 7825.3100, Subp. 17 defines "Test year" as "the 12-month period selected by the utility for the purpose of expressing its need for a change in rates."

Q. Why is the 2020 calendar year the appropriate test year for this proceeding?

A. The test year begins on the proposed effective date for interim rates, which is January 1, 2020. Use of this test year results in appropriate matching of Minnesota Power's costs with the revenues that are proposed to be collected under interim and final rates. Use of a budgeted prospective test year is also consistent with what the Commission approved in Minnesota Power's most recent retail rate case (Docket No. E015/GR-16-664; calendar year 2017). Further, Minnesota Power has presented a projected test year in all nine of its prior retail rate cases in Minnesota, including Docket Nos. E015/GR-09-1151 (calendar year 2010), E015/GR-08-415 (July 1, 2008 through June 30, 2009), E015/GR-94-001 (calendar year 1994), E015/GR-87-223 (July 1, 1987 through June 30, 1988), E015/GR-81-250 (July 1, 1981 through June 30, 1982), E015/GR-80-76 (May 1, 1980 through April 30, 1981), E015/GR-78-514 (July 1, 1978 through June 30, 1979), E015/GR-77-360 (May 1, 1977 through April 30, 1978), and E015/GR-76-408 (calendar year 1976).

IV. RATE BASE

Q. Please generally discuss the development of test year rate base.

A. Test year rate base was developed using costs from calendar year 2018 (most recent fiscal year), and updated costs for 2019 (projected fiscal year) with actuals through February 2019. Minnesota Power witness Mr. Joshua G. Rostollan explains Minnesota Power's methodology for overall budget development in his Direct Testimony.

Q. What are the major capital additions that are included in the 2020 construction budget and the test year cost-of-service study?

A. Minnesota Power's 2020 capital budget includes a total of approximately $103.6 million of 2020 capital additions (not including those that are in cost recovery riders). The test year cost-of-service study includes non-rider recoverable capital additions that have occurred since the Company's 2017 test year used in the 2016 Rate Case. These consist of generation investments not related to environmental or renewable projects, base transmission and distribution investments to maintain reliability of the power delivery system, general plant, and intangible investments, such as software. They are discussed in the Direct Testimony of Company witnesses Mr. Joshua Skelton (generation) and Mr. Daniel Gunderson (transmission and distribution). In addition, capital investments for cost recovery rider projects that are being moved to base rates for cost recovery are included in the test year cost-of-service study as discussed by Mr. Shimmin. Capital investments for rider projects that will remain in riders are excluded from the test year.

Q. Please list the major components of the test year rate base.

A. The major components of rate base are: Plant in Service, Accumulated Depreciation and Amortization, Construction Work in Progress ("CWIP"), and Working Capital (including Fuel Inventory, Materials and Supplies, Prepayments, and Cash Working Capital). These components are discussed in more detail below and as part of the adjustments to budget in Section IV.C. In addition, rate base includes several smaller items: Workers' Compensation Deposit, Unamortized WPPI Transmission Amortization, Unamortized UMWI Transaction Cost, Customer Advances and Deposits, Other Deferred Credits – Hibbard, Wind Performance Deposit, and ADIT. Details of the functional assignment of rate base are discussed in the Direct Testimony of Mr. Shimmin.

A. <u>Test Year Plant in Service</u>

Q. How was the test year rate base related to plant in service developed?

A. Plant in service in rate base is measured at original cost depreciated and based on the average of beginning and ending balances for the test year. Plant in service for the test year was developed beginning with December 2018 plant balances by major function. Added to these amounts were forecast additions and retirements for 2019 and 2020 from the 2020 construction budget to arrive at average plant balances. These plant additions and retirements are also the basis for development of test year depreciation expense and, therefore, the accumulated provision for depreciation and amortization. CWIP was also obtained from actual December 2018 balances adjusted for additions to CWIP and transfers to plant for 2019 and 2020 from the construction budget information. All associated rate base items for projects that will be recovered via current cost recovery riders during the test year have been adjusted out of the test year rate base.

B. Cash Working Capital Allowance

Q. Please provide a general summary of your testimony regarding the cash working capital component of rate base included in this filing.

A. The cash working capital requirement included in rate base is based on a lead-lag study prepared by the Company for calendar year 2017 and included in Volume 4, Workpaper OS-2. In all significant aspects, the 2017 study and resulting working capital calculation are consistent with the approach and methodology filed by the Company and approved by the Commission in the 2016 Rate Case, which was based on a 2012 lead-lag study.

Q. How have you defined cash working capital?

A. Working capital for purposes of this proceeding is defined as the amount of capital investors must provide to the Company, in addition to their investment in utility rate base, to meet cash payment requirements during the period after expenditures are made to provide service and before the collection of revenues for that service. Thus, cash working capital represents an amount of money needed to meet current operating expenses incurred prior to collecting revenues for the service provided.

When investors supply these funds, they are entitled to a return on these advances. To the extent these funds are supplied by customers, they are entitled to have their contribution recognized as a rate base deduction. This is accomplished by including an appropriate cash working capital requirement in rate base. The elements of working capital included in this proceeding are consistent with those allowed by the Commission in each of the Company's most recent retail rate cases. As stated in its June 14, 1982, <u>Statement of Policy on Cash Working Capital</u>, the Commission recognizes that the most precise method of determining the cash working capital requirements is to perform a lead-lag study.

Q. What procedures were followed in the preparation of the lead-lag study utilized in this proceeding?

A. The procedures used in the lead-lag study were initially developed to support the Company's request for a cash working capital allowance in Docket No. E015/GR-78-514, which the Commission approved. The same lead-lag study methodology, adjusted to reflect various minor changes in procedures such as required payment due dates, was also the basis for the determination of cash working capital in Docket Nos. E015/GR-80-76, E015/GR-81-250, E015/GR-87-223, E015/GR-94-001, E015/GR-08-415, E015/GR-09-1151, and E015/GR-16-664. The cash working capital allowances were approved in these seven dockets with minor or no adjustments.

For this proceeding, the established lead-lag periods were determined based on a detailed study of the actual lead days and lag days experienced by the Company during calendar year 2017. Patterns in the payment of expenses and receipt of revenues do not vary significantly from one year to another. The Company reviewed procedures currently in effect and identified no significant changes in policies or procedures that would affect the validity of the lead-lag periods experienced during 2018, 2019, or the 2020 test year.

Q. How have the results of the Company's lead-lag study been used in this proceeding?

A. The results of this study have been applied to the 2020 test year data to determine the working capital component of rate base for the Interim Rate and General Rate cost-of-service studies.

Q. Do you anticipate any changes to the working capital calculation during the course of the rate case proceeding?

A. Yes. As in Minnesota Power's previous retail rate cases, cash working capital will need to be recalculated to reflect any changes in the Company's request during the course of the case, as well as for the Commission-approved financial adjustments that impact operations and maintenance ("O&M") expenses, rate base, and capital structure. As such, cash working capital is likely to change over the course of this proceeding.

In addition, during the course of final reconciliations the Company determined that its cash working capital calculation inadvertently did not include certain FERC accounts. As I discuss later in my testimony, Minnesota Power has corrected the calculation for interim rates and will incorporate the appropriate revisions to cash working capital, as well as necessary updates described above, in the normal course of the proceeding.

C. Rate Base Adjustments to Budget

Q. What is the purpose of this section of your testimony?

A. In this section, I walk through the several adjustments to budgeted rate base that have been made in the cost-of-service study to reflect prior Commission decisions and items for which Minnesota Power is not requesting recovery in this proceeding.

Q. Please describe the adjustments to the budgeted rate base items included in the cost-of-service study.

A. These adjustments include:

1. Removal of Asset Retirement Obligations ("ARO") related to the decommissioning of certain long-lived assets and incorporation of decommissioning treatment as ordered by the Commission in Minnesota Power's 2008 retail rate case;
2. Boswell Unit 3 environmental project adjustments pursuant to the settlement approved by the Commission in Minnesota Power's 2009 retail rate case;
3. An adjustment to the December 2017 accumulated depreciation and

amortization reserve balance, to reflect the Boswell Energy Center Unit 3 ("BEC3") and Boswell Common Facilities depreciation expense adjustment ordered by the Commission in Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544).

4. Addition of a regulated asset, accumulated amortization reserve balance, and the associated ADIT to reflect recovery for the retired Boswell Energy Center Units 1 & 2 ("BEC 1&2") through 2022, pursuant to Commission approvals in Docket Nos. E015/GR-09-1151 and E015/D-18-544.
5. Removal of plant in service, depreciation reserve, CWIP, and ADIT associated with projects that will remain in riders with separate line items for cost recovery on customer bills:
6. Exclusion of prepaid pension asset in working capital (Interim Rates only) and the associated ADIT credit;
7. Exclusion of ADIT associated with prepayments for other post-employment benefits ("OPEB") from working capital;
8. Removal of plant in-service, depreciation reserve, and costs of the corporate aircraft hangar;
9. Basin Electric Power Cooperative ("Basin') sale pro forma ADIT;
10. An adjustment for the cost of UIPlanner software project costs below budget in 2019; and
11. Cash working capital adjustments resulting from other ratemaking adjustments to budget.

The adjustments are summarized in Volume 3, Schedule B-6, and each of them is described below.

1. <u>Asset Retirement Obligations (ARO) and Decommissioning</u>

Q. What is the adjustment for ARO?

A. In Minnesota Power's 2008 retail rate case (Docket No. E015/GR-08-415), the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision, and consistent with handling in the 2009 rate case, these items have been removed from the 2020 budget. As shown in Volume 3, Schedule B-6, Page 1 of 2, columns 3, 4, and 5, the removal of ARO, Cost to Retire ARO Reclass, and related decommissioning adjustment reduces rate base by $15.5 million Total Company ($16.2 MN Jurisdictional).

2. <u>BEC3 Environmental Project</u>

Q. What is the adjustment for the BEC3 environmental project?

A. In Minnesota Power's 2009 Rate Case (Docket No. E015/GR-09-1151), the Commission approved a settlement specifying that Minnesota Power may recover $223 million of Total Company costs associated with the BEC3 environmental retrofit, but no more, for regulatory purposes. The Commission also approved capitalization of the BEC3 environmental project cost recovery tracker balance of $20.5 million Total Company ($16.8 million MN Jurisdictional). As shown in Volume 3, Schedule B-6, Page 1 of 2, column 9, these adjustments and the associated ADIT adjustment reduce rate base by $6.9 million Total Company ($6.0 MN Jurisdictional).

3. <u>BEC3 and Common Depreciation Adjustment</u>

Q. What is the adjustment for BEC3 and Common depreciation?

A. In Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544), the Commission ordered Minnesota Power to record supplemental depreciation expense of $2.0 million for the Boswell Common Facilities, and $0.8 million for Boswell Unit 3 in 2017, spread over 36 months starting in 2018. An adjustment was made to the December 2017 accumulated depreciation and amortization reserve balance, increasing it by $2.8 million to reflect the BEC3 and Common depreciation expense adjustment related to 2017. The Commission also ordered Minnesota Power to include in any future request for cost recovery all adjustments necessary to ensure that ratepayers bear no additional expense as a result of the errors in the 2017 depreciation accruals for BEC3 and the Boswell Common

Facilities. Additional depreciation expense of approximately $0.9 million in 2018 through 2020 is therefore being adjusted out. The resulting accumulated depreciation adjustment decreases each year through 2020. As shown in Volume 3, Schedule B-6, Page 1 of 2, column 8, this adjustment reduces rate base by $0.3 million Total Company ($0.3 MN Jurisdictional), including the ADIT impact.

4. <u>BEC 1&2 Regulated Asset and Accumulated Amortization</u>

Q. What is the adjustment for the BEC 1&2 Regulated Asset and Accumulated Amortization?

A. In Minnesota Power's 2009 Rate Case and in Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544) the Commission approved an end of life of 2022 for BEC1 & 2. When Minnesota Power retired BEC 1&2 in December 2018, a regulated asset was set up to reflect this continued cost recovery, with amortization through 2022. The adjustments for the regulated asset and accumulated amortization reserve balance for BEC 1&2 are shown in Volume 3, Schedule B-6, Page 1 of 2, column 7. These adjustments decreased rate base by $1.2 million Total Company ($1.1 MN Jurisdictional), including the ADIT impact.

5. <u>Continuing Cost Recovery Riders</u>

Q. What are the adjustments for cost recovery rider items?

A. Several projects in the 2020 budget will be included or remain in the TCR Rider or the RRR for cost recovery, as discussed further in the Direct Testimony of Mr. Shimmin. Therefore, these projects must be removed from rate base in the cost-of-service study to avoid double recovery of the revenue requirements. These projects include Great Northern Transmission Line ("GNTL") transmission project, the Camp Ripley solar project, and the Community Solar Garden renewable (solar factor) project. The combined adjustments applicable for these projects are listed on Volume 3, Schedule B-6, Page 2 of 2, column 10. Including the impact of ADIT, these adjustments reduce rate base by $318.3 million Total Company ($274.6 MN Jurisdictional).

6. Prepaid Pension Asset and ADIT

Q. What is the proposed adjustment for Minnesota Power's Prepaid Pension Asset?

A. As explained in the Direct Testimony of Mr. Patrick L. Cutshall, Minnesota Power is proposing to include its pension plan accumulated contributions in excess of net periodic benefit cost (or prepaid pension asset), which is a balance sheet asset in the 2020 budget, as a component of working capital in rate base. Minnesota Power's estimated 2020 test year 13-month average prepaid pension asset is already included in budget rate base, which is the same treatment as for other working capital prepayments. Therefore, no General Rate adjustment is needed. However, an adjustment to interim rates has been made to remove the asset and associated ADIT, as I describe in Section VI.A of my Direct Testimony.

7. Prepaid OPEB Asset

Q. What is the adjustment for other post-employment benefit (OPEB) prepayments?

A. As described in the Direct Testimony of Company witness Mr. Cutshall, Minnesota Power is not requesting to include the prepaid OPEB asset in rate base. Prepayments for OPEB are not included in working capital in the 2020 budget, and therefore no adjustment is required for prepayments. However, an adjustment is required to remove budgeted ADIT associated with prepaid OPEB from rate base. This adjustment increases rate base by $1.4 million Total Company ($1.2 MN Jurisdictional) is shown on Volume 3, Schedule B-6, Page 2 of 2, column 11.

8. Corporate Aircraft Hangar

Q. How are the costs associated with the Company's corporate aircraft hangar treated in this rate case?

A**.** Company witness Mr. Rostollan explains in his Direct Testimony that Minnesota Power has decided to forego recovery of any costs associated with the corporate aircraft and hangar in this rate case. The corporate aircraft that was previously owned by Minnesota Power was retired, and the new corporate aircraft is owned by ALLETE Enterprises as a non-regulated asset. The aircraft hangar is the only asset related to the aircraft still included in the Company's regulated plant balance. Therefore, the net plant balance of $1.1 million Total Company ($1.0 MN Jurisdictional) for the aircraft hangar and associated ADIT is removed from rate base, as shown on Volume 3, Schedule B-6, Page 1 of 1, column 2.

9. Basin Electric Power Cooperative ("Basin") Sale Pro Forma ADIT

Q. What is the test year pro forma adjustment for the Basin sale?

A. The Basin sale and test year pro forma expense adjustments are discussed in detail in Section V.A.18 below, and test revenue adjustments are discussed in Section V.B.6. In addition to those adjustments, there is an ADIT adjustment that increases rate base by $1.4 million Total Company ($1.2 MN Jurisdictional), because it affects the amount of Production Tax Credits the Company is able to use for tax purposes. This adjustment is shown on Volume 3, Schedule B-6, Page 1 of 2, column 6.

10. UIPlanner Software Project

Q. What is the adjustment for UIPlanner Software project costs?

A. As described in the testimony of Mr. Shimmin, in 2019 Minnesota Power acquired and implemented a new CCOSS software model known as UIPlanner. The project cost was estimated at $2.4 million in Minnesota Power's 2019 capital budget. However, the actual project cost is now expected to be $1.8 million. The reduced project cost in 2019 affects 2020 plant in service, accumulated amortization, and ADIT and reduces rate base by $0.3 million Total Company ($0.3 million MN Jurisdictional), as shown on Volume 3, Schedule B-6, Page 2 of 2, column 12.

11. Cash Working Capital

Q. What is the adjustment for cash working capital?

A. Cash working capital is adjusted to reflect the impact of the various O&M expense adjustments to the test year budget, including those required by Commission policies for advertising expense, economic development, charitable contributions, and organizational dues and other expense adjustments. In addition, state and federal income taxes in cash working capital reflect interest synchronization and the tax impact of the revenue deficiency. This adjustment is a reduction to rate base of $0.4 million Total Company ($0.4 million MN Jurisdictional) shown on Volume 3, Schedule B-6, Page 2 of 2, column 13.

In addition, while finalizing the initial filing in this rate case, Minnesota Power discovered that its cash working capital adjustment was missing the impacts of certain other O&M adjustments, which would reduce the Company's rate base. The Company has corrected cash working capital for purposes of interim rates, as I discuss in Section VI.A of my testimony.

V. TEST YEAR OPERATING INCOME

Q. Please explain the basis for test year revenues and expenses.

A. The 2020 Operating Budget provides the basis for energy sales, revenues, O&M expenses, property taxes, depreciation expense, allowance for funds used during construction ("AFUDC"), interest expense, and income taxes. Retail revenues from electricity sales used in the test year cost-of-service study reflect the final rates ordered in Docket No. E015/GR-16-664 and were developed based on budgeted sales of electricity in the 2020 Revenue Budget. O&M expenses, depreciation and amortization expenses, and other taxes are based on the 2020 Operating Budget. Income taxes are based on test year operating revenues and expenses, plus necessary adjustments to pretax income. The adjustments to pretax income, along with deferred income taxes and the investment tax credit, were developed by the Company's Tax Department based on 2020 budget data reflected in the cost-of-service study. Finally, AFUDC reflects interest charged on CWIP projects during the test year.

A. Expense Budget Adjustments

Q. Have you made any adjustments to expense items included in the 2020 budget to develop a normalized level of test year expense?

A. Yes, specific adjustments were made to the budgeted expense amounts in the test year for: ARO accretion and depreciation; BEC3 environmental project depreciation expense; cost recovery rider adjustments; BEC3 and Common depreciation expense; amortization expense for BEC 1&2 regulated asset; continuing cost recovery riders and rider-related internal labor; aircraft hangar depreciation expense; incentive compensation; conservation, economic development, charitable contributions, advertising expense, organization dues, research expense, employee and Board of Directors expenses, lobbying, investor relations expenses; Basin contract expiration; rate case expenses, Bison 6; UIPlanner costs; Itasca Rail Initiative project amortization; Aurora and Chisholm Service Center sales; credit card processing fees; cash working capital; and interest synchronization. Each of these adjustments is described in more detail below.

A summary of the expense adjustments, which also includes the state and federal income tax impacts of each adjustment, is included on Volume 3, Schedule C-10.

1. <u>Asset Retirement Obligations (ARO) and Decommissioning Expense</u>

Q. Please explain the expense adjustment for test year Asset Retirement Obligations (ARO) expense.

A. In accordance with the Commission's May 4, 2009 Order in Minnesota Power's 2008 retail rate case, as described in Section IV.C.1 above, Minnesota Power adjusted the depreciation expense by $0.3 million Total Company ($0.3 MN Jurisdictional) and accretion expense by $0.7 million Total Company ($0.6 MN Jurisdictional). These adjustments are shown on Volume 3, Schedule C-10, Page 1 of 6, column 4. The related decommissioning adjustment to increase depreciation expense by $0.8 million Total Company ($0.7 million MN Jurisdictional) is shown on Volume 3, Schedule C-10, Page 1 of 6, column 5.

2. BEC3 Environmental Project Expense

Q. What is the expense adjustment for the BEC3 environmental project?

A. Along with the rate base adjustments described in Section IV.C.2 above, there is an associated adjustment to reduce depreciation expense by $0.6 million Total Company ($0.5 MN Jurisdictional), as shown on Volume 3, Schedule C-10, Page 2 of 6, column 9.

3. BEC3 and Common Depreciation Expense

Q. What is the adjustment for BEC3 and Common depreciation expense?

A. Along with the rate base adjustments described in Section IV.C.3 above, there is an associated adjustment to reduce depreciation expense by $0.9 million Total Company ($0.8 MN Jurisdictional), as shown on Volume 3, Schedule C-10, Page 2 of 6, column 8.

4. BEC1&2 Regulated Asset and Accumulated Amortization

Q. What is the adjustment for the BEC1&2 Regulated Asset and Accumulated Amortization?

A. Along with the rate base adjustments described in Section IV.C.4 above, there is an associated adjustment to increase amortization expense for BEC 1&2 regulated asset by $7.3 million Total Company ($6.4 MN Jurisdictional), as shown on Volume 3, Schedule C-10, Page 1 of 6, column 7.

5. Continuing Cost Recovery Riders Expense

Q. What are the expense adjustments associated with continuing cost recovery riders?

A. Along with the rate base adjustments described in Section IV.C.5 above, there are associated adjustments to operating expense, depreciation expense, and taxes as shown on Volume 3, Schedule C-10, Page 3 of 6, column 18. These adjustments remove solar O&M expense of $0.9 million Total Company ($0.7 MN Jurisdictional) and GNTL O&M expense of $0.1 million Total Company ($0.1 million MN Jurisdictional), reverse Multi-Value Project ("MVP") transmission credit of $0.1 million Total Company ($0.1 million MN Jurisdictional), remove MISO Regional Expansion Criteria and Benefits ("RECB") expense from transmission and regional market expense of $39.7 million Total Company ($34.1 million MN Jurisdictional), remove depreciation expense of $4.8 million Total Company ($4.1 million MN Jurisdictional), remove MN Solar Production Tax expense and property tax expense for projects with costs recovered in riders of $9.3 million Total Company ($7.9 million MN Jurisdictional).

6. <u>Rider-Related Internal Labor</u>

Q. How are internal labor costs associated with projects that are eligible for rider cost recovery treated in this rate case?

A. In the Commission's May 11, 2011 Order in Minnesota Power's TCR Rider docket (Docket No. E015/M-10-799), the Commission ordered Minnesota Power to exclude capitalized internal labor costs from collection through cost recovery riders. As described further in the Direct Testimony of Mr. Shimmin, there are consequently some internal labor costs that are not included in either the cost recovery rider rate calculations or in the 2020 test year after capital costs associated with continuing rider projects are backed out. These costs are added to budgeted transmission expenses for 2020, consistent with what the Commission approved in Minnesota Power's 2016 Rate Case. As shown in Volume 3, Schedule C-10, Page 5 of 6, column 30, these adjustments increase operating expenses by $2.3 million Total Company ($1.9 MN Jurisdictional).

7. <u>Aircraft Hangar Depreciation Expense</u>

Q. How are the costs associated with the Company's corporate aircraft hangar and aircraft expenses treated in this rate case?

A. As mentioned above in Section IV.C.8, Minnesota Power is not seeking recovery of any costs associated with the corporate aircraft. No corporate aircraft expense was included in test year regulated administrative and general expense, and thus no adjustment is required. However, $24,000 Total Company ($22,000 MN Jurisdictional) is removed from depreciation expense related to the aircraft hangar, as shown on Volume 3, Schedule C-10, Page 1 of 6, column 3.

8. Incentive Compensation

Q. What types of incentive compensation expense require adjustment for ratemaking purposes?

A. Based on prior Commission practice and Orders in Minnesota Power's previous rate cases and other utility rate cases, Minnesota Power has made adjustments to exclude a portion of the budgeted expense for its Annual Incentive Program ("AIP"), and all of the budgeted expense for its Long-Term Incentive Plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP"), Executive Deferral Plan, and Legacy Employment Agreements. These adjustments are explained in more detail below, and the incentive compensation plans are described in the Direct Testimony of Company witness Ms. Laura E. Krollman. The incentive compensation expense reductions total $7.2 million Total Company ($6.4 million MN Jurisdictional) and are shown on Volume 3, Schedule C-10, Page 4 of 6, column 22. The detail of these individual adjustments is included in Volume 4, Workpaper ADJ-IS-21.

Q. Please describe the adjustment for the Company's AIP.

A. Consistent with the Commission-ordered treatment for incentive compensation in the Company's 2009 and 2016 retail rate cases, Minnesota Power has excluded the budgeted amount of compensation expense for the AIP that exceeds 20 percent of base pay for General and Interim Rates. The AIP adjustment reduces test year Administrative and General ("A&G") expense by $1.2 million Total Company ($1.0 million MN Jurisdictional).

Q. Please describe the adjustment for the LTIP.

A. Consistent with prior Commission practice and orders, Minnesota Power has excluded the entire budgeted amount of regulated expense associated with its LTIP for General and Interim Rates. The LTIP adjustment reduces test year A&G expense by $2.6 million Total Company ($2.3 million MN Jurisdictional).

Q. Please describe the adjustment for the SERP.

A. Also consistent with prior Commission practice and orders, Minnesota Power has excluded the entire budgeted amount of regulated expense associated with its SERP retirement and annual restoration plans for General and Interim Rates. The SERP adjustment reduces test year A&G expense by $1.4 million Total Company ($1.3 million MN Jurisdictional).

Q. Please describe the adjustment for Executive Deferral Plan.

A. Also consistent with prior Commission practice and orders, Minnesota Power has excluded the entire budgeted amount of regulated expense associated with its Executive Deferral Plan for General and Interim Rates. This includes budgeted line items for Executive Deferral Account, Executive Investment Plan, and Legacy Employment Agreements. The adjustment reduces test year A&G expense by $2.0 million Total Company ($1.8 million MN Jurisdictional).

9. <u>Conservation Expense</u>

Q. Please explain the adjustment for test year conservation expense.

A**.** For accounting purposes, Minnesota Power records conservation expense (Account 908) each month as its conservation expenditures and charges that are accumulated in the CIP tracker are recovered from customers. Cost recovery is achieved through a combination of the Conservation Cost Recovery Charge ("CCRC") in base rates and the Conservation Program Adjustment ("CPA"). The CCRC and CPA are discussed further in Section VII.B of my testimony. The CPA is modified each year as part of Minnesota Power's CIP Consolidated Filing. The modified CPA is based on projected CIP spending levels, the amount recovered through base rates, carrying charges, financial incentives, and the CIP tracker account balance at the end of the prior year. Minnesota Power's 2020 budgeted conservation expense of $6.7 million (Total

Company and MN Jurisdictional) in Account 908 thus includes recovery of conservation expenditures that are not limited to what Minnesota Power expects to spend on conservation programs during the test year.

Consistent with how conservation expenses were handled in Minnesota Power's 2008, 2009, and 2016 rate cases, it is appropriate to include the projected conservation expenditures for CIP programs in the test year, based on proposed annual CIP budgets filed with the Minnesota Department of Commerce. Test year conservation expense has been adjusted to remove the $6.7 million in Minnesota Power's 2020 budget for Account 908 and instead include projected 2020 expenditures of $10.5 million based on Minnesota Power's 2020 extension of its 2017-2019 CIP Triennial plan, as filed on July 1, 2019 in Docket No. E015/CIP-16-117. This is an increase of $3.8 million Total Company and MN Jurisdictional. Minnesota Power's CIP is entirely for retail customers, so the Total Company and MN Jurisdictional adjustments are the same. The rate adjustment is shown in Volume 3, Schedule C-10, page 2 of 6, column 12. For Interim and General Rates, an updated CCRC was calculated based on the 2020 CIP Budget and divided by test year retail energy sales of 2,715,161 MWh excluding CIP-exempt customers.

10. <u>Economic Development Expense</u>

Q. Please explain the adjustment for test year economic development expense.

A. Minnesota Power is proposing the recovery of a portion of Economic and Community Development costs in both Interim and General Rates consistent with Minn. Stat. §216B.16, subd. 13. The Commission allowed recovery of 50 percent of this expense in Minnesota Power's last three rate cases (2008, 2009, and 2016). Consistent with this treatment, the Company has included 50 percent of its Economic and Community Development costs in both Interim Rates and proposed General Rates. The Company is requesting 50 percent recovery of its test year Economic and Community Development costs of $0.7 million, or a total of $0.4 million Total Company ($0.3 million MN Jurisdictional) in proposed rates. Volume 3, Schedule G-5 provides details regarding the Company's Economic and Community Development Costs. The test year adjustment to exclude 50 percent of the expense is $0.4 million Total Company $0.3 million MN Jurisdictional), as shown in Volume 3, Schedule C-10, page 3 of 6, column 20.

11. Charitable Contributions

Q. How are charitable contributions handled in the test year cost of service?

A. Consistent with Minn. Stat. § 216B.16., subd. 9 and the Commission's June 14, 1982 Statement of Policy on Charitable Contributions, and the treatment allowed by the Commission in the Company's 2016 Rate Case, 50 percent of qualifying contributions have been included in the test year. The Commission's Policy Statement requires that a qualifying charitable contribution (1) serve the utility's Minnesota service area, (2) be nondiscriminatory in selecting recipients, and (3) not promote a political or special interest group. A detailed listing of qualifying 2018 charitable contributions is provided in Volume 4,Workpaper ADJ-IS-10.

Based on the Commission's March 12, 2018 Order in Minnesota Power's 2016 Rate Case, which allowed rate recovery based on 50 percent of the Company's actual charitable giving for the previous three years, and which disallowed recovery of administrative costs, Minnesota Power has excluded administrative cost of $77,756,[4] Total Company ($69,552 MN Jurisdictional) and has calculated its charitable contributions based on 50 percent of average actual expense for the three years 2016 through 2018. The average annual qualified charitable contributions for these three years was $0.7 million Total Company $0.6 million MN Jurisdictional), and 50 percent of this is $0.3 million Total Company ($0.3 million MN Jurisdictional), as shown in Volume 3, Schedule G-2.

[4] Excluded administrative costs are found in Direct Schedule G-2 for $11,429, average of costs for 2016-2018, page 1 of 1 and in Workpaper Schedule G-1 ADJ-IS-01, cost types 1100, 1200, 9100 and 9101, for $66,327.

Minnesota Power's Charitable Contributions – Foundation, are budgeted in Account 426.1, and the amount budgeted for 2020 is $0.8 million. The 2020 budget amount is consistent with the Company's historical average budgeting level. However, based on the three-year average smoothing methodology described above, the budgeted amount was reduced by $0.5 million Total Company ($0.4 million MN Jurisdictional) for ratemaking purposes to leave $0.3 million Total Company ($0.3 million MN Jurisdictional) of charitable contribution expense in the test year. The adjustment is shown in Volume 3, Direct Schedule C-10, page 2 of 6, column 11.

Minnesota Power reports its donations to the Minnesota Power Foundation ("MP Foundation") in account 426.1 on FERC Form 1 for each respective prior year 2016, 2017, and 2018. Each yearly amount includes Minnesota Power's lump sum contributions to the MP Foundation, plus some smaller other Minnesota Power direct donations. The account also includes Minnesota Power sponsorships, donation expenses, and donations outside of Minnesota Power's territory. For this reason, donation amounts in FERC Form 1 for each year will not equal the exact amounts of MP Foundation individual grants awarded in any given year.

The detailed listing of donations included in this filing is provided as an illustration of the types of organization, amounts, and service territory locations to which the MP Foundation typically makes contributions and shows Minnesota Power's compliance with the Commission's Statement of Policy on Charitable Contributions.

12. Advertising Expense

Q. Please explain the adjustment for test year advertising expense.

A. Certain advertising expenses have been included in the test year cost of service in compliance with Minn. Stat. § 216B.16, subd. 8 and the Commission's June 14, 1982 Statement of Policy on Advertising, and to be consistent with the treatment allowed in our 2016 Rate Case. Recovery is allowed only for advertising designed to: (1) encourage energy conservation; (2) promote safety; (3) inform and educate consumers on the utility's financial services; and (4) disseminate information on a utility's corporate affairs to its owners. A summary of the advertising expenses included in the test year, the excluded expense detail calculation (used for determination of the percent of disallowed test year expense), and the 2018 media summary list designating allowed and disallowed advertising is provided in Volume 3, Schedule G-1, and Volume 4, Workpaper ADJ-IS-01. This workpaper also includes examples of advertisements. The 2020 budget includes a total of $0.4 million Total Company ($0.3 million MN Jurisdictional) for advertising expense, and $0.2 million Total Company ($0.2 million MN Jurisdictional) of this has been excluded based on Commission policy. The adjustment is shown in Volume 3, Direct Schedule C-10, page 1 of 6, column 2.

13. Organization Dues

Q. Please explain the adjustment for test year organization dues expense.

A. Certain organizations' dues not related to lobbying have been included in the test year in compliance with the Commission's Statement of Policy on Organization Dues issued June 14, 1982, and to be consistent with the treatment allowed in the Company's 2016 Rate Case. Non-allowable items have been excluded from the cost-of-service studies. A detailed listing of organization dues and the calculation of the excluded amount, which consists of lobbying expenses that were billed along with other organization dues, is provided in Volume 4, Workpaper ADJ-IS-25. The test year adjustment to exclude organizational dues that are disallowed based on the Commission's policy statement is $0.1 million Total Company ($0.1 million MN Jurisdictional), as shown on Volume 3, Direct Schedule C-10, page 4 of 6, column 26.

14. Research Expenses

Q. Is there any adjustment associated with test year research expenses?

A. Yes, an adjustment of $0.1 million Total Company ($0.1 million MN Jurisdictional) to the 2020 budgeted amount is required due to a budgeting omission. The Company normally includes research expense in its annual budgets but inadvertently did not include any research expense in the 2020 budget due to a change in the area of the

Company responsible for budgeting and overseeing research activities. As shown in Volume 3, Direct Schedule G-4, research expense of $0.1 million was intended to be budgeted and is therefore added to the 2020 budget for this rate request. An itemized list of budgeted 2020 research expenses (all of which are for the Electric Power Research Institute ("EPRI")) is included in Volume 4. A description of the research and support for the benefits that are expected to accrue to Minnesota Power customer's over time is also included in Volume 3, Schedule G-4. Inclusion of the EPRI research expense is consistent with the treatment of research expenses in the Company's previous rate cases in 2008, 2009, and 2016. This adjustment to increase expense is shown in Volume 3, Schedule C-10, page 4 of 6, column 28.

15. <u>Employee and Board of Directors Expenses</u>

Q. Please explain the adjustment for test year employee and Board of Directors expenses.

A. Minnesota Power has excluded $0.1 million Total Company for Board of Directors expenses and $0.3 million Total Company for employee expenses from the test year cost of service. The total combined adjustment of $0.4 million Total Company ($0.4 million MN Jurisdictional) is shown on Volume 3, Schedule C-10, Page 3 of 6, column 21. The methodology for determining specific items to be excluded and calculation of the adjustment is provided in the testimony of Company witness Mr. Rostollan and shown in detail on Direct Schedule H-1.

16. <u>Lobbying Expenses</u>

Q. Please explain the adjustment for test year lobbying expenses.

A. Consistent with the Commission's decision in the Company's 2016 Rate Case, Minnesota Power has excluded all legislative lobbying expenses from its test year cost of service. Most lobbying expenses are recorded in Account 426.4, which is not a part of regulated expense. However, as described in the testimony of Mr. Rostollan, the Company's analysis determined that some lobbying-related expenses were included in other employee expense accounts. Therefore, an adjustment of $48,000 Total

Company was made to exclude those lobbying expenses. This adjustment is included in the $0.4 million Total Company adjustment for employee expenses described above in Section V.A.16 and also shown on Direct Schedule H-1.

17. Investor Relations Expenses

Q. Please explain the adjustment for test year investor relations expenses.

A. Consistent with recent Commission decisions, Minnesota Power has excluded 50 percent, or $0.3 million Total Company ($0.3 million MN Jurisdictional), of investor relations expense from the test year cost of service, as shown on Volume 3, Direct Schedule C-10, Page 4 of 6, column 23. Company witness Mr. Rostollan discusses this adjustment in more detail.

18. Basin Sale Pro Forma Expense Adjustments

Q. What is the test year pro forma adjustment for the Basin sale?

A. Minnesota Power has a 10-year 100 MW power sale contract with Basin that ends in April 2020 (the Large Market Contract, or "LMC"). The LMC started on May 1, 2010, which was in the middle of the calendar 2010 test year in Minnesota Power's 2009 Rate Case. Minnesota Power requested that the LMC be included in the test year per the contract schedule, to start May 1, 2010. However, during the course of the rate case, it was determined that an adjustment would be made to Minnesota Power's asset-based wholesale margins to reflect LMC in effect for the entire 2010 test year, even though the sale contract and revenues did not start until May 1, 2010.[5] Consistent with the inclusion of four extra months of wholesale margins at the beginning of the LMC sale in 2010, Minnesota Power has removed the budgeted LMC sale revenues and expenses for the first four months of the 2020 test year. This pro forma adjustment reflects a known and measurable change so that test year wholesale margins will be reflective of expected margins going forward while rates are in effect.

[5] *In the Matter of Application of Minn. Power for Auth. To Increase Elec. Serv. Rates in Minn.,* Docket E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 6 dated November 2, 2010 and Docket E015/GR-09-1151 Direct Testimony of Nancy A. Campbell dated March 31, 2010.

The expense budget portion of this adjustment reduces total budgeted fuel and purchased power expense by $6.7 million Total Company ($5.8 million MN Jurisdictional), as shown on MP Exhibit ___ (Podratz), Direct Schedule 2. The revenue budget portion of this adjustment is discussed in Section V.B.6 below. Company witness Ms. Julie I. Pierce discusses the LMC and the adjustment in more detail in her Direct Testimony.

19. Rate Case Expenses

Q. How were the projected rate case expenses determined?

A. The Company included in rate case expense projections the directly assignable costs associated with preparing and filing the rate case, including outside legal fees, expert witnesses and consultants, state agency fees, and administrative costs. Rate case expense does not include any Company labor and overheads, consistent with previous filings, and a portion of the total cost is allocated to non-regulated activities, consistent with the methodology approved by the Commission in Minnesota Power's previous retail rate cases (I discuss the non-regulated portion below). A summary of the projected rate case expenses compared to actual expenses for Minnesota Power's 2016 Rate Case is provided on MP Exhibit __ (Podratz), Direct Schedule 3, page 1.

Projected rate case expenses were based on examining actual expenditures in the Company's 2016 Rate Case as updated for current expectations. Projections for contract and professional services expenses were based on estimates of the fees for expert witnesses, consultants, and outside legal counsel who are anticipated to be used in this proceeding. These projections total approximately $2.2 million, compared with actual professional services expenditures of approximately $2.9 million in Minnesota Power's 2016 Rate Case. Similarly, projected MPUC/regulatory assessments of $1.4 million for this case were based on actual assessments of $1.3 million for the 2016 Rate Case. Projected "other costs" total $0.1 million and include employee-related expenses associated with the rate case and expenses such as printing/copying charges and preparation and mailing of notices to customers.

Q. Please provide a comparison of the Company's actual expenses for the 2016 Rate Case to its projected costs that were authorized for recovery by the Commission in that case.

A. In the 2016 Rate Case, Minnesota Power projected its rate case expenses for that case, excluding Company labor and overheads, to be $2.6 million. Of that amount, $0.1 million was allocated to non-regulated operations, resulting in a net $2.5 million of total cost, which was approved by the Commission. Total actual 2016 Rate Case expenses, excluding Company labor and overheads, were $4.4 million, as detailed on Exhibit **___** (Podratz), Direct Schedule 3, pages 1 and 3. The difference between the projected and actual amounts, approximately $1.8 million, was expensed by the Company and not recovered through rates charged to customers. Expenses in the 2016 Rate Case were higher than projected partially because of the length of the case, need for a Supplemental Filing to reflect a large customer load change that became known shortly after the initial filing, complex issues, the amount of discovery, and unexpected court appeals.

Q. How do Minnesota Power's projected 2020 Rate Case expenses compare to expenses for the Company's 2016 Rate Case?

A. Total projected 2020 Rate Case expenses of $3.7 million (before allocation to non-regulated operations) are approximately 15 percent lower than the actual expenses of $4.4 million for the Company's 2016 Rate Case.

Q. What adjustment have you made to recognize the impact of non-regulated activities on rate case expenses?

A. Using the apportionment methodology that was approved by the Commission in Minnesota Power's last three rate cases,[6] 4.04 percent of the total rate case expenses is allocated to the Company's non-regulated operations. As illustrated by Exhibit ___ (Podratz), Direct Schedule 3, pages 1 and 5, the 4.04 percent allocation is the result of dividing Minnesota Power's test year non-regulated corporate support services costs by the sum of Minnesota Power's test year regulated and non-regulated corporate support services costs. After subtracting the $0.2 million of expense allocated to non-regulated operations, the total cost allocated to Minnesota Power regulated business is $3.6 million (same amount for Total Company and MN Jurisdictional).

Q. How were rate case expenses included in the 2017 test year amortized and recovered in the Company's 2016 Rate Case?

A. In its 2016 Rate Case, Minnesota Power was allowed to amortize its test year regulated rate case expenses over a three-year period starting in 2017 (the test year). However, $2.7 million of accumulated prior rate case expense credit from the Company's 2009 rate case was netted against the 2016 Rate Case expense of $2.5 million. The three-year amortization of the net credit for these prior rate case expenses ends in December 2019, immediately before the start of the current rate case test year in January 2020.

Q. What amortization period do you propose for rate case expenses in this case, and why is your proposal reasonable?

A. Although it has been three years since the Company's 2016 Rate Case filing, Minnesota Power's preliminary analysis of key drivers of rate case timing currently indicate a need to file its next rate case in approximately two years, using a 2022 test year. Based on this, two years is a reasonable estimate of the amount of time until Minnesota Power files its next retail rate case, and two-year amortization would allow full recovery of

[6] MPUC Docket Nos. E015/GR-08-415, E015/GR-09-1151, and E015/GR-16-664.

the rate case expenses for this case. Therefore, Minnesota Power proposes amortizing the $3.6 million (Total Company and MN Jurisdictional) over two years, resulting in annual rate case expense of $1.8 million Total Company and $1.6 million MN Jurisdictional, as shown on Volume 3, Direct Schedule C-10, Page 4 of 6, column 27.

Q. Is there anything different about how the adjustment for rate case expenses is handled in this case compared to previous rate cases?

A. Yes, there is one difference. Minnesota Power discovered while doing its final review before filing this case that the test year rate case adjustment to include rate case expenses was allocated partially to the FERC resale jurisdiction, instead of being entirely retail. This resulted in approximately $200,000 of test year rate case expense amortization being incorrectly excluded from the retail rate request, as illustrated by the difference between Total Company and Minnesota jurisdictional expenses noted above. It was not practicable this late in the filing preparation process to correct the error, so Minnesota Power voluntarily foregoes the ability to collect this amount of the rate case expense for this case.

20. <u>Bison 6 Large Generator Interconnection Agreement ("LGIA")</u>

Q. What is the adjustment for the Bison 6 LGIA O&M payment from ALLETE Clean Energy ("ACE") to Minnesota Power?

A. As discussed in the Direct Testimony of Company witness Mr. Shimmin, there is a payment from ACE to Minnesota Power related to ongoing O&M of the shared Bison 6 LGIA. The payment for this shared facility was inadvertently left out of Minnesota Power's 2020 budget, but should be included in the test year. This adjustment increases revenue to offset the O&M for the facility that Minnesota Power's retail customers pay for in rates, to ensure that retail customers pay for only a portion of the O&M for the shared facility. This results in an increase to miscellaneous operating revenue of approximately $34,000 Total Company and MN Jurisdictional, as shown on Volume 3, Direct Schedule C-10, Page 4 of 6, column 25.

21. UIPlanner Software Costs

Q. What is the adjustment for UIPlanner Software project costs?

A. Along with the rate base adjustments described in Section IV.C.10 above, there is an associated adjustment to reduce test year amortization expense by $0.1 million Total Company ($0.1 million MN Jurisdictional), as shown on Volume 3, Direct Schedule C-10, Page 5 of 6, column 32.

22. Itasca (Iron Range) Rail Initiative Project Amortization

Q. Please explain Minnesota Power's proposed adjustment for Itasca (Iron Range) Project Amortization.

A. Company witness Mr. Joshua J. Skelton explains in his Direct Testimony that the capital costs incurred for the Itasca Rail Initiative Project provided leverage for BNSF rail contract negotiations, leading to fuel clause savings for Minnesota Power customers due to decreased coal delivery costs. Minnesota Power proposes recovery of the $2.0 million Total Company of capital costs incurred for the cancelled Itasca Rail Initiative Project as a regulatory asset, with amortization of the project costs over five years. This results in an annual test year amortization expense of $0.4 million Total Company ($0.4 million MN Jurisdictional), as shown on Volume 3, Direct Schedule C-10, Page 4 of 6, column 24.

23. Aurora and Chisholm Service Center Sales

Q. Please provide some background on the Company's Aurora and Chisholm service center sales.

A. On June 1, 2017, in the middle of the test year for its 2016 Rate Case, Minnesota Power filed a request for approval of four transactions, including the sale of its Aurora Service Center to Lakehead Constructors, Inc.[7] and the sale of its Chisholm Service Center to the United Way of Northeastern Minnesota, Inc. In its February 8, 2018, Order

[7] *In the Matter of the Petition of Minnesota Power for Approval of a Purchase Agreement for the Sale of the Aurora Service Center to Lakehead Constructors, Inc.*, Docket No. E015/PA-17-457, and *In the Matter of the Petition of Minnesota Power for Approval of a Purchase Agreement for the Sale of the Chisolm Service Center to United Way of Northeastern Minnesota, Inc.*, Docket No. E015/PA-17-459.

Approving Purchases and Sales with Conditions, the Commission approved the transactions and required that Minnesota Power use deferred accounting to create regulatory liabilities for these transactions as recommended by the Minnesota Department of Commerce.

Q. What other compliance requirements were associated with these transactions?

A. The Commission also required the Company to submit a compliance filing within 60 days of closing each transaction that included a detailed explanation and schedules for the regulatory liabilities established in connection to these four transactions and appropriate journal entries.[8] The Aurora Service Center sale closed on December 27, 2017, and Minnesota Power submitted its compliance filing on February 26, 2018. The regulatory liability through December 2019 is $0.2 million Total Company. The Chisholm Service Center sale closed on January 17, 2018, and Minnesota Power submitted its compliance filing on March 9, 2018. The regulatory liability through December 2019 is $0.2 million Total Company.

Q. What treatment does the Company propose for the regulatory liability?

A. Minnesota Power proposes to amortize the regulatory liability balances over two years beginning January 1, 2020, the start of the test year in this rate case, and return to ratepayers as a credit to Other Operating Revenue. Two years is the expected time until Minnesota Power's next rate case and would therefore return the total amount to customers by the start of the anticipated test year (2022) for that rate case. It also matches the amortization period proposed for rate case expenses and the over-recovery of credit card processing fees, which are discussed further below. The total combined regulatory liability balance for both service centers is $0.4 million Total Company. Amortizing this balance over two years results in an annual revenue credit of $0.2 million Total Company ($0.2 million MN Jurisdictional), as shown on Volume 3, Direct Schedule C-10, Page 5 of 6, column 31.

[8] MPUC Order Approving Purchases and Sales with Conditions, February 8, 2018, page 6.

24. Credit Card Processing Fees

Q. What rate case adjustment is Minnesota Power proposing for credit or debit card processing fees?

A. In the 2016 Rate Case, the Commission approved the Company's proposed removal of the per-transaction fee each customer incurred when making bill payments by credit or debit card, and instead including the costs of accepting card payments as part of Minnesota Power's overall operating expense. The Company's estimated annual increase in costs incurred for credit card processing fees was $350,000 (Total Company and MN Jurisdictional).

Q. What compliance requirement did the Commission impose along with its approval of the Company's test year expense for credit or debit card processing fees?

A. Recognizing the uncertainty in the amount of actual credit or debit card processing fees, since Minnesota Power had never before offered customers the option to pay their bills via credit card without incurring a fee, the Commission required the Company to track over- or under-collections for true-up in a future rate case.[9]

Q. How has Minnesota Power complied with this Commission requirement?

A. After October 2018, when Minnesota Power implemented the no-fee credit or debit card payment option for retail customers following Commission approval, Minnesota Power began tracking the difference between the amount collected in rates and the actual expenses paid by Minnesota Power. The net difference is currently an over-recovery and thus is recorded on our books as a regulatory liability. The projected balance of the regulatory liability on the proposed interim rate effective date of January 1, 2020 is $148,000 (Total Company and MN Jurisdictional).

[9] Docket No. E015/GR-16-664, MPUC March 12, 2018 Findings of Fact, Conclusions, and Order, pages 31 and 110 (Order Point 19).

Q. How does the Company propose to handle this accumulated regulatory liability for over-recovery of credit or debit card processing fees in the current rate case?

A. Minnesota Power proposes that the $148,000 (Total Company and MN Jurisdictional) accumulated over-recovery for credit or debit card processing fees, as shown on Exhibit___(Podratz), Direct Schedule 4, be returned to customers in this rate case as a negative expense amortized over two years. Two years is the amount of time until the Company plans to file its next retail rate case and matches the amortization period for rate case expenses described in section V.A.19 above. The annualized total credit or debit card fee over-recovery amortization amount for the test year is $74,000 (Total Company and MN Jurisdictional). This adjustment is shown on Volume 3, Direct Schedule C-10, Page 3 of 6, column 19.

25. Cash Working Capital

Q. Please explain the adjustment for test year cash working capital.

A. As previously discussed, cash working capital is calculated as a secondary calculation after determination of the Company's rate base and operating income. The operating income adjustment of approximately $26,000 in general rates is included on Volume 3, Direct Schedule C-10, Page 5 of 6, column 33.

26. Interest Synchronization

Q. Please explain the adjustment for test year interest synchronization.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt multiplied by the average rate base. The combined test year adjustment of $2.0 million Total Company ($1.8 million MN Jurisdictional) for interest synchronization is included on Volume 3, Direct Schedule C-10, Page 5 of 6, column 34. This calculation must be updated whenever a change in rate base, weighted cost of debt, or operating income occurs. Minnesota Power will therefore recalculate the interest synchronization expense after the final adjustments to rate base, weighted cost of debt, and operating income are determined in this case.

B. Revenue Budget Adjustments

Q. Please explain the development of test year revenues for use in the cost-of-service study.

A. Minnesota Power started with test year total operating revenues from the 2020 budget revenue model and made adjustments as required to arrive at appropriate revenues for use in the class cost-of-service study. Exhibit ___ (Podratz), Direct Schedule 5 summarizes the operating revenues and adjustments, which are described below. The purpose of the adjustments is to develop normalized test year revenue from sales of electricity by retail customer class. Revenues that are budgeted for retail sales of electricity but which are not related to retail rate classes for cost-of-service purposes are adjusted out of sales of electricity. Additional adjustments are also made to normalize revenues and match test year revenues with test year expenses. The total present rate revenue including all adjustments is shown in column 11. This adjusted revenue by customer class was included in the cost-of-service study, and it also matches the total present rate revenue by customer class in Volume 3, Schedule E-1(other than rounding). The adjustments in each column of Exhibit ___ (Podratz), Direct Schedule 5 are described below.

1. Revenue Types for Which No Adjustment is Needed

Q. What types of revenue have historically required adjustments to the budget in Minnesota Power rate cases but no longer need adjustment in this rate case?

Some categories of revenue, including Large Power Incremental Production Service ("IPS"), Industrial Economy and Non-firm Energy, Replacement Firm Power Service ("RRPS"), and Service Fees previously required rate case budget adjustments to transfer them to the appropriate category. However, Minnesota Power's Unadjusted Test Year 2020 budget (column 1 on Exhibit ___ (Podratz), Direct Schedule 5) already includes these revenues in the applicable line for Intersystem Sales (LP Econ/Non-firm/RFPS), so no adjustment is needed.

Q. Please describe the Industrial Service Fees and Economy customers and revenue.

A. Economy/Non-firm energy revenue and RFPS Fees are separate from the Large Power rate class because these revenues are not associated with providing service under the Large Power Service Schedule or any other retail rate schedule. The Economy and RFPS customers have their own generation, which they use to serve a portion of their load. Minnesota Power accredits this generation with the Midcontinent Independent System Operator ("MISO") under the requirements of MISO's Module E Resource Adequacy Program. This is similar to Minnesota Power's own generation accreditation with MISO and enables Minnesota Power to include the generation to meet system capacity reserve requirements even when it is not operating. This allows the customers to avoid buying standby service from Minnesota Power to cover generating unit outages, and it also allows Minnesota Power to use the customer generating capability to cover general system load when the large industrial customer's load is reduced. Customers with their own generation can also buy Economy/Non-firm energy from Minnesota Power in lieu of operating their own generation when it is cost-effective to do so (i.e., when the Economy energy price is lower than the customer generation operating cost).

Q. Please describe Large Power IPS and RFPS.

A. Large Power IPS is an interruptible energy product that is priced at Minnesota Power's incremental cost plus $10 per MWh. Large Power customers may utilize IPS for a small portion of their load (currently less than 10 percent of total load) that exceeds the firm service requirement. Because IPS is non-firm incremental-cost based energy, it has historically been excluded from the Large Power class in the cost-of-service study. Similarly, customers with generation who have entered into Power Purchase Agreements with Minnesota Power are able to buy economy energy/non-firm energy, which is priced at Minnesota Power's incremental cost plus an energy surcharge.

Customers may purchase economy/non-firm energy up to the available unused capacity of the units less reserves. If the units are unavailable, then the customer may purchase RFPS, which is priced at the greater of 120 percent of MP's incremental cost or $30/MWh.

Q. How are Wheeling Revenues handled in the Unadjusted Test Year budget and COS study?

A. Wheeling revenues from Minnesota Power's wholesale transmission customers Staples, Wadena, and Great River Energy are included in the Resale rate class as FERC-jurisdictional wheeling revenues for cost-of-service purposes.

2. CIP Incentive and Carrying Charge Adjustments

Q. Please describe the adjustments in columns 2 and 3 for CIP carrying charge and CIP incentive.

A. In Minnesota Power's annual CIP Consolidated Filings, the Commission has permitted Minnesota Power to collect financial incentives for its CIP achievements and also to collect a carrying charge on its CIP Tracker Account balance. Because these revenues are intended to provide an incentive to the Company and to provide a return on outstanding tracker account balances, they are subtracted from total operating revenues for ratemaking purposes.

3. CIP Revenue Adjustments

Q. What are the CPA adjustments in columns 4 and 5?

A. This is a two-part adjustment. First, the CPA Incentive adjustment in column 4 is the portion of revenue for the CIP incentive that is included in the CPA on customer bills. CIP incentive revenue was subtracted from Other Revenue in the adjustment shown in column 2. This is recovered over two years and represents the average of 2019 and 2020 CIP incentive revenue. This is added back to the budget numbers in column 4 in order to account for all CPA revenue in one place. Second, in the adjustment in column

5 the Total CPA revenue is removed because the CPA Rider will continue on customer bills outside of base rates.

Q. What is the CCRC adjustment in column 6?

A. The CCRC credit amount related to the four CIP-exempt Large Light and Power customers included in the 2020 budget is backed out of revenue because the CCRC credit amount is contained in the CIP tracker and corresponding rates are adjusted outside of base rates.

4. Customer Affordability of Residential Electricity ("CARE") Rider Adjustments

Q. Please describe the adjustments in column 7 for the CARE Rider.

A. Minnesota Power's Rider for Customer Affordability of Electricity ("CARE Rider") provides discounted rates to qualified low income Residential customers and is funded by an Affordability Surcharge assessed to other customers. The CARE Rider discounts and surcharge collections are accumulated in a tracker and adjusted as necessary between rate cases. Therefore, the Residential class discount and surcharge revenue from all customer classes is removed from retail sales of electricity for cost-of-service purposes.

Q. What changes to the CARE Program were recently approved by the Commission?

A. In its October 30, 2019, Order Accepting Report and Approving Program Changes in Docket No. E015/M-11-409, the Commission approved CARE program changes that are intended to benefit low income customers in northern Minnesota using a combination of a low-barrier, automated flat $15 discount component and an affordability discount targeting a 3 percent of income "energy burden" to provide more meaningful rate relief for higher-usage low income customers. In conjunction with these program changes, the Commission approved an increase in the CARE Program annual budget from roughly $1 million to $1.75 million and corresponding changes to the Affordability Surcharge for each rate class. The changes are to be effective January 1, 2020.

Q. How have you handled these recent changes in this rate case?

A. The CARE Rider and any changes to the CARE Program are authorized in a separate docket, with required annual reports through which the CARE discount amounts and surcharge revenues are tracked and adjusted when warranted. The CARE Rider discounts and surcharges are separate from Minnesota Power's base rates and not subject to change in this rate case. In the Schedule E billing comparisons and operating revenue summary, they are included in a separate section for continuing rider revenue. Therefore, it is not necessary to reflect the recent changes to the CARE Program in the test year revenue budget or Schedule E billing comparisons.

5. <u>Cost Recovery Rider Adjustments</u>

Q. What are the cost recovery rider adjustments in column 8?

A. There are two revenue components to these cost recovery rider adjustments, and both involve removing solar rider-related revenue from retail sales for cost-of-service purposes. The first component is the Solar Energy Adjustment ("SEA"). Revenue from the SEA charge is removed from the COS because solar cost recovery and credits are handled separately, as specified in the existing Rider for Fuel and Purchased Energy and the Rider for Solar Energy Adjustment. The second component is the Community Solar Garden ("CSG") Adjustment. Pricing and cost recovery associated with existing customer subscriptions to Minnesota Power's CSG Pilot Program[1] are handled separately pursuant to the Pilot Rider for Community Solar Garden Subscription and will continue in the rider following the conclusion of this rate case. Therefore, the CSG revenues are also removed from retail sales of electricity for cost-of-service purposes.

[1] MPUC Docket E015/M-15-825.

As discussed by witness Mr. Shimmin, the related solar rate base costs are also removed along with all other continuing rider costs from the cost of service as shown on Direct Schedule B-5, column 10, at page 2 of 2. The other associated solar costs on the income statement are also removed along with all other continuing rider cost from the cost of service as shown on Direct Schedule C-9, column 18, at page 3 of 6. The other costs not being recovered through the SEA charge will be included and recovered in the future Solar Renewable Factor in the Renewable Resources Rider.

6. Basin Sale Pro Forma Revenue Adjustments

Q. What are the pro forma revenue adjustments for the Basin sale in column 9?

A. Along with the Basin sale pro forma expense adjustment described above in Section V.A.18, there is a corresponding revenue adjustment to remove the wholesale off-system power sale revenue budgeted for January through April 2020 for the Basin sale. In addition, because the changes to fuel and purchased power expense associated with the Basin pro forma adjustment affect the test year budgeted FPE Charge, IPS, RFPS, Economy, and Non-firm power supply costs, there are also minor changes to these energy revenues for each applicable customer class. This amount is also detailed in Exhibit ___ (Podratz), Direct Schedule 2.

7. Corrections to Budgeted Rates and Revenues

Q. Please describe the adjustments in column 10 for revenue budget corrections.

A. As Minnesota Power developed the Volume 3, Schedule E-1 billing comparison schedules based on budgeted billing units and current rates, Company personnel discovered several minor instances where the incorrect billing units were used in the 2020 budget revenue model for certain types of retail service. These adjustments reflect the correct present rates and revenues. For Residential Electric Vehicle service, the on and off-peak energy usage was reversed, resulting in more energy used during on-peak rather than off-peak hours, and overstating revenue by $851. For Lighting Rate 80, the service charge calculation incorrectly multiplied the number of service agreements by a factor of 24 rather than 12. This overstated revenue by $45,912. For

Large Light and Power, the Service Voltage adjustment was incorrectly applied to one customer's Interruptible demand (kW) in addition to the firm demand (kW). This understated revenue by $138,455. See Volume 4, Workpaper ADJ-IS-28 for calculation details.

8. Total Revenue Including All Adjustments

Q. What does the total in column 11 represent?

A. Column 11 is the adjusted present rate revenue that includes all adjustments to the original 2020 test year budget. The total retail revenues from sales of electricity (and Dual Fuel) in this column match the total revenues in Schedule E-1 and also match the present rate revenues in the class cost-of-service study with very minor differences of roughly $20 due to rounding in the detailed calculations within the various schedules.

C. Revenue Credits

Q. Please summarize the revenue credits that are included in the cost-of-service study.

A. The revenue credits for the 2020 test year total approximately $240.2 million Total Company and are summarized in Exhibit ___ (Podratz), Direct Schedule 6, Page 1. There are several major categories of revenue credits, including:

1) Off-system wholesale power sales (Sales for Resale), shown on line 5, which total $102.2 million Total Company for the test year. Related to this, a pro forma adjustment to the test year budget for one of the long-term sales that ends in early 2020 is described below.
2) Other Operating Revenue, shown on line 11, which totals $92.1 million Total Company for the test year. This includes production-related revenue of $11.9 million Total Company (line 6), transmission-related revenue of $77.9 million (line 7), and about $2 million in miscellaneous categories (lines 8-10).
3) Various types of retail non-firm and other industrial power sales, or "intersystem sales" (line 4), which total about $35.6 million Total Company and Residential and

Commercial/Industrial Dual Fuel sales (lines 1-2) of about $10.3 million (Total Company).

These are discussed further in the sections below.

1. Off-System Wholesale Power Sales

Q. What are Minnesota Power's projected revenues from off-system wholesale power sales (non-requirements capacity and energy sales revenue) in the 2020 test year budget?

A. As shown on Podratz Direct Schedule 6, Page 2, budgeted capacity revenues from sales to various counterparties and the wholesale market are $35.0 million Total Company in the test year. These revenues come from off-system sales to Minnkota, Oconto, Basin, NextEra, MISO, and Other. The energy revenue of $67.2 million Total Company comes from a combination of specifically identified bilateral sales and sales to the MISO market, including sales to AEP Energy Partners, Basin, Minnkota Power Liquidation, Market Sales, NextEra, Oconto, and Non-MP Station Service. The Total Company revenue credit is thus $102.2 million Total Company before the pro forma adjustment for the Basin sale described below. The sale transactions, associated energy expenses, and net margin calculations are explained in the Direct Testimony of Ms. Julie Pierce.

Q. What is the difference between the off-system sales for resale included in Exhibit __ (Podratz), Direct Schedule 6 and those included in Exhibit ___ (Pierce), Direct Schedule 3?

A. There are several types of sales on my Schedule 6 that either do not generate margins for Minnesota Power or are credited back to customers in a different way. The Basin Emissions Recovery is credited through the Boswell 4 Emissions Reduction Rider. Non-MP Station Service does not have a margin; Oconto Transmission is transmission is a direct pass through that also has no margin.

The sales to Minnkota are a pass through per the sale contract and do not have margins. Minnesota Power is selling approximately 28 percent of its 50 percent output entitlement from Square Butte to Minnkota, under a power sales agreement with Minnkota that commenced June 1, 2014. Minnkota's net entitlement increases and Minnesota Power's net entitlement decreases until Minnesota Power's share is eliminated at the end of 2025.

Q. What adjustments have you included for the 2020 test year budget wholesale power sales?

A. I have included an adjustment related to Minnesota Power's 10-year power sale contract with Basin Electric Power Cooperative that ends on April 30, 2020, as described above in sections V.A.18 and V.B.6. As shown on Exhibit ___ (Podratz), Direct Schedule 2, the Basin sale pro forma adjustment decreases operating revenue by $18.8 million Total Company and reduces operating expenses by $6.7 million Total Company, for a net reduction to operating income before taxes of $12.1 million Total Company. After consideration of tax effects, the total net reduction to income is $8.6 million Total Company.

2. Other Electric Revenue

Q. What are the main revenue credit items shown under Other Operating Revenue on Exhibit ___ (Podratz), Direct Schedule 6?

A. The main categories included in the total revenue credits of $92.1 million (all Total Company) for Other Operating Revenue are:

1) Production-related revenue (line 6) of $11.9 million, primarily made up of steam sales and clean coal solutions revenue.
2) Transmission revenue (line 7) of $77.9 million, shown in more detail on Podratz Direct Schedule 6, Page 3, and primarily made up of various types of MISO revenues, Direct Current (DC) line revenue, Manitoba Hydro must-take fee, and Manitoba Hydro operating expense payments. Some of these revenues are backed

out of the rate case and handled in the TCR Rider or RRR instead, as indicated on Podratz Direct Schedule 6, Page 3.

3) Distribution revenue (line 8) of $1.1 million, including late fees, joint use pole attachment revenue, and miscellaneous service revenue.
4) General Plant revenue (line 9) of $1.0 million, for items such as rents and leases.
5) Gains from disposition of allowances and utility plant (line 10) of about $58,000.

3. Retail Non-firm and Other Industrial

Q. What types of sales are included in the revenue credits for retail non-firm and other industrial power sales?

A. The total revenue credits of $46.9 million (Total Company) on line 3 and 4 of Exhibit ___ (Podratz), Direct Schedule 6 include $10.3 million from interruptible sales to Minnesota Power's Residential and Commercial/Industrial Dual Fuel customers and $35.6 million for Large Power Incremental Production Service (IPS), Replacement Firm Power Service (RFPS), Economy/Non-firm energy sales, and RFPS Service Fees for customers who own generation that is capable of serving part of their electric needs. As described further in the Revenue Budget Adjustments section above (V.B.1), these revenues are removed from the Large Power rate class, and they are instead treated as revenue credits.

VI. ADJUSTMENTS SPECIFIC TO INTERIM RATES

A. Interim and General Rate Cost-of-Service Studies

Q. Are there any rate base or expense items that Minnesota Power proposes to handle differently for Interim Rates and General Rates?

A. Yes, there are several differences between Minnesota Power's proposed Interim Rate and General Rate cost-of-service studies, resulting in lower interim rates than the Company is requesting for final rates. The Company seeks different treatment of the following items, each of which is summarized below, in final General Rates compared to Interim Rates:

- Prepaid pension asset in rate base (and associated ADIT)

- Pro rata ADIT methodology
- Return on Equity
- Cash Working Capital

Q. How is the prepaid pension asset handled in the Interim Rate and General Rate cost-of-service studies?

A. Because Minnesota Power's pension plan accumulated contributions in excess of net periodic benefit cost (or prepaid pension asset) was not previously included in the Company's rate base, the Company has excluded these costs and the associated prepaid pension asset ADIT from its interim rate calculations. As explained by Mr. Cutshall, they are included in the General Rate calculations. Removing these amounts reduces our Interim Rate request by $87.8 million ($78.5 million MN jurisdictional) for the prepaid pension asset, with an offsetting $33.0 million ($29.6 million MN jurisdictional) for the associated ADIT.[10] These adjustments are set forth in Volume 1, Schedule B-4 (IR), Page 2 of 2, columns 12 and 13.

Q. What is the difference between Interim Rates and final General Rates for pro rata ADIT?

A. As described in the Direct Testimony of Company witness Mr. Cutshall, an IRS normalization requirement governs utilities that use forecast test years for determination of rates, which requires calculation of average accumulated deferred income taxes using a pro rata method. In the Company's 2016 Rate Case, the application of this normalization requirement was clarified as applying for interim rates but not final rates. Minnesota Power intends to adopt this methodology for recurring Minnesota retail rate proceedings, including this one. Thus, the pro rata ADIT methodology is reflected in the Interim Rate calculations but not the General Rate calculations. The -$0.2 million Total Company (-$0.2 MN Jurisdictional) ADIT

[10] These jurisdictional numbers will differ slightly from those in the Direct Testimony of Mr. Cutshall due to the effects of cash working capital.

proration adjustment, which reduces rate base for purposes of Interim Rates, is shown on Volume 1, Schedule B-4 (IR), Page 2 of 2, column 14.

Q. What return on equity does Minnesota Power propose to use for Interim Rates, and why?

A. The Commission authorized Minnesota Power to earn a 9.25 percent return on common equity in the 2016 Rate Case. Under Minn. Stat. §216B.16, subd. 3, unless the Commission finds that exigent circumstances exist, the utility shall include in Interim Rates a rate of return on common equity ("ROE") equal to that authorized by the Commission in the utility's most recent rate proceeding. For General Rates, the Company is requesting approval from the Commission of a return on common equity of 10.05 percent as supported by the Direct Testimony of Ms. Ann E. Bulkley. Because the requested ROE is higher than that authorized in Minnesota Power's most recent rate proceeding, the Company uses the previously authorized lower ROE for Interim Rates. The Company's interim total cost of capital is included on Volume 1, Schedule C-6 (IR).

Q. Please discuss the Cash Working Capital adjustment for interim rates.

A. As previously discussed, cash working capital is a secondary calculation that will typically differ between interim and final rates and must be updated through the course of a rate proceeding. Further, as described earlier in my testimony, the Company determined during final reconciliations that its cash working capital calculation inadvertently did not include certain FERC accounts. Minnesota Power has adjusted Interim Rates to ensure that customers receive the full benefit of the correct calculation, and will also update cash working capital for this and other changes during Rebuttal. The Cash Working Capital included in Interim Rates is set forth on Volume 1, Schedule B-4 (IR), Page 2 of 2, column 16, and Schedule B-8 (IR), Page 5 of 6, column 33. The adjustment from General to Interim Rates is reconciled on Volume 4, Workpapers ADJ-IS-32 and ADJ-RB-12.

Q. As a result of these differences, was it necessary to conduct different cost-of service-studies to determine appropriate rate levels for Interim and General Rates?

A. Yes. Minnesota Power is presenting separate cost-of-service studies for the test year for Interim Rates and General Rates. The two cost-of-service studies will be the same except for the adjustment items described above.

Q. Does this result in a request for the Commission to set Interim Rates which differ from General Rates?

A. Yes. The overall revenue deficiency for Interim Rates is $47.9 million, compared with $65.9 million for general rates.

B. <u>Application of Interim Rates</u>

Q. Is Minnesota Power requesting any exceptions to the application of Interim Rates?

A. No. As described in the Company's Petition for Interim Rates in Volume 1, Minnesota Power requests that the proposed interim rate increase be applied to all classes of Minnesota Power's retail electric customers, consistent with the rate design established in the Company's 2016 Rate Case and Minn. Stat. § 216B.16, subd. 3. As noted in the Company's Petition for Interim Rates, however, the interim rate increase is not applied to Large Power IPS, Economy/Non-firm, RFPS, and service fees. Revenue associated with these rate components is not considered part of the Large Power class revenue in the cost-of-service studies, and these services are priced based on Minnesota Power's hourly incremental energy cost or other separately negotiated terms.

VII. COST RECOVERY RIDERS AND TRACKERS

A. Cost Recovery Riders

Q. Please explain how Minnesota Power's cost recovery riders are handled in this rate case.

A. As Company witness Mr. Shimmin describes in his Direct Testimony, Minnesota Power currently recovers the costs of several emission control, transmission, and renewable resource projects through riders whose rates were determined in separate dockets based on individual project revenue requirement calculations. Minnesota Power summarizes its proposed rate case treatment of rider projects in the testimony of Company witness Mr. Shimmin.

By way of summary, completed projects moving to base rates will be rolled in beginning January 1, 2020, and as such their revenue requirements will be included in the test year, and excluded from rider recovery effective at the same time. For projects that will remain in the riders, cost recovery will continue through the applicable rider. As noted earlier in my testimony, appropriate rate base and income statement adjustments have been made to exclude projects remaining in riders from rate base and their associated expenses from test year expenses so no over-recovery of costs takes place. Revenue to be collected through the continuing riders has also been excluded from total revenues for cost-of-service purposes.

Treatment of individual cost recovery riders is also described in more detail in the testimony of Mr. Shimmin.

B. Conservation Improvement Program

Q. How has the Company historically treated Conservation Improvement Program ("CIP") costs?

A. The Commission approved a deferred debit accounting mechanism and established a Conservation Cost Tracker Account (CIP Tracker Account) in the Company's 1987 general rate case (Docket No. E015/GR-87-223). Conservation expenditures and costs are entered into the CIP Tracker Account. These charges are recovered through a combination of base rates and the Conservation Program Adjustment (CPA). Funds in the CIP Tracker Account are subject to a carrying charge utilizing the rate from Minnesota Power's multi-year credit facility. The Commission approves the rate of recovery of the CIP Tracker Account balances in the Company's annual CIP filings, the latest of which was filed on April 1, 2019 (Docket No. E015/M-19-31).

In the Company's 2016 Rate Case, $8,777,230 of CIP expense was included in O&M expense for the 2017 test year. This amount was based on Minnesota Power's 2017 CIP budgets.

Q. What is the current and future status of the Conservation Tracker Account?

A. The CIP Tracker Account balance was $(1.5) million[11] as of December 31, 2018. It is anticipated that the CIP Tracker Account will continue to be used in a manner consistent with recent years in that the entry of CIP-related charges and cost recovery amounts will be made to this account and reported in the annual CIP filing.

Q. Please describe the existing conservation recovery mechanism.

A. Minnesota Power's conservation costs are recovered through a combination of the per-kWh CCRC included in base rates, and the CPA adder on customer bills. The current CCRC that was determined in Minnesota Power's 2016 rate case is $0.003299105 per kWh. In an Order dated July 19, 2019 (Docket No. E015/M-19-31), the Commission approved Minnesota Power's CIP recovery mechanism which utilizes a line item on the customer bill called the "Resource Adjustment." Projected conservation spending levels, the amount recovered through base rates, carrying charges, financial incentives, and the CIP Tracker account balance at the end of the prior year together determine the CPA included in the "Resource Adjustment." The current CPA portion of the "Resource Adjustment" approved in that docket is -$0.000137 per kWh.

[11] Docket E015/M-19-31, April 1, 2019 filing, Exhibit 1, page 1 of 5.

Q. What is the CIP expense level included in the test year?

A. The CIP expense level for the 2020 test year is $10,518,770. This expense level is based on projected CIP expenditures as filed with the Department of Commerce in Minnesota Power's 2017-2019 CIP Extension Through 2020 filing (Docket No. E015/CIP-16-117).

The Company plans to continue utilizing the Conservation Tracker Account and CPA mechanism to correct for over- and under-collections through base rates. Pursuant to the Commission's decision in Docket No. E015/GR-94-001, no prior tracker balances are included in the test year for recovery in base rates.

Q. What is the proposed revised CCRC to be included in base rates?

A. Based on test year conservation expenses of $10,518,770 and 2,715,160 MWh of energy sales subject to the CCRC, Minnesota Power proposes a revised CCRC of $0.003874087 per kWh to be applicable for the test year. The calculation of the revised CCRC is shown in Volume 3, Direct Schedule I-1.

Q. How will the CCRC be applied to customers who are exempt from the CIP requirements?

A. Consistent with currently authorized treatment, the CCRC will not apply to several large customers who have been allowed exemptions from participation in CIP, Economy energy, or customers taking service under Company's Competitive Rate Schedules. In the 2008 rate case (Docket E015/GR-08-415), Minnesota Power revised the CCRC methodology so that it excludes the test year energy sales for exempt Large Power customers and thus more accurately reflects the test year retail sales subject to the CCRC. The same methodology for Large Power customers continues to be followed here. For LLP customers with CIP exemptions, the CCRC amount is refunded to them because it is built into their base rates. The test year conservation expense is allocated to retail rate classes based on each class's MWh of energy subject to the CCRC.

C. Fuel and Purchased Energy Rider

Q. What changes are proposed for Minnesota Power's Rider for Fuel and Purchased Energy ("FPE Rider")?

A. In conjunction with the Commission's June 12, 2019 Order Approving Additional Details of New Fuel Clause Adjustment Process in the Fuel Clause Docket, Minnesota Power submitted its base cost of energy compliance filing on July 23, 2019 and a clarification letter on August 23, 2019. In those submittals, the Company proposed the following changes:

1. Zero out the fuel and purchased energy ("FPE") costs included in the base cost of energy in the Company's next general rate case (which is this case) and include all such energy costs in a new FPE Charge;
2. Continue to include the FPE Charge under the Resource Adjustment line on customer bills until final rates are implemented;
3. Show the FPE Charge as a separate line on customer bills effective with final rates; and
4. Forego filing a separate Base Cost of Energy filing in future general rate cases (including this one).

Q. What is the status of these changes requested by Minnesota Power?

A. At its October 17, 2019 hearing in Docket No. E999/CI-03-802, the Commission approved Minnesota Power's proposed changes related to the base cost of fuel and purchased energy.

Q. What is Minnesota Power's current base cost of fuel and purchased energy that is included in energy rates?

A. Minnesota Power's current average FPE cost that was set in the Company's 2016 Rate Case is 2.121¢ per kWh ($21.21 per MWh). Under Minnesota Power's existing FPE

Rider, the class-specific Base Cost of Energy for each rate class is obtained by multiplying 2.121¢/kWh by the applicable Class Cost Factor. The resulting class-specific Base Cost of Energy ranges from 1.75135¢ per kWh for Lighting to 2.19562¢ per kWh for General Service customers.

Q. What specific change does Minnesota Power propose for interim rates?

A. Minnesota Power proposes to remove (or "zero out") the entire amount of FPE cost included in base rates, by subtracting the class-specific Base Cost of Energy from the energy charge in each individual rate effective with interim rates on January 1, 2020. Along with this, we propose that the entire cost of fuel and purchased energy be recovered in a separate FPE Charge, which would be combined with the CPA in the Resource Adjustment line item on customer bills during the interim rate period.

Q. What specific change does Minnesota Power propose for final rates?

A. Effective with final rates, Minnesota Power proposes to show the FPE Charge as a separate line item on customer bills. Because the Department of Commerce was previously concerned about having the CPA as a stand-alone line item on customer bills, Minnesota Power also proposes to combine its other existing state energy policy-related cost recovery rider line items with the CPA in the Resource Adjustment effective with final rates. The other currently applicable cost recovery riders include the TCR Rider, RRR, and Boswell Energy Center Unit 4 Emission Reduction Rider. These rider adjustment line items recover a portion of the total costs for their respective categories, similar to the CPA, and it therefore makes sense to combine them rather than continuing to show them separately. Conversely, part of the purpose of the forward-looking fuel clause and projected FPE costs is to allow for more customer transparency for these costs. This increased visibility is promoted by showing the FPE Charge as a separate line item rather than continuing to include a portion in base rates and the rest in a separate adjustment factor.

Q. What are the proposed modifications to the FPE Rider to reflect these changes?

A. Redlined and clean versions of the Rider for Fuel and Purchased Energy, Minnesota Power Electric Rate Book, Section V, Page No. 50, that reflect the proposed changes are provided in the Tariff Pages for Change in Rates in Volume 3.

Q. What is Minnesota Power's proposed base cost of fuel and purchased energy for the 2020 test year?

A. Minnesota Power's average FPE cost in the unadjusted 2020 test year budget is 2.432¢ per kWh ($24.32 per MWh). With inclusion of the fuel and purchased energy expense impacts associated with the Basin sale pro forma adjustment discussed in Section V.A.18 above, the adjusted 2020 test year budget average FPE cost is 2.441¢ per kWh ($24.41 per MWh). The calculations of the unadjusted and adjusted test year average FPE costs are shown on Exhibit ___ (Podratz), Direct Schedule 7, Summary Calculation of Test Year Average Cost of Fuel and Purchased Energy.

Q. What compliance requirement was included in the Fuel Clause Docket decision related to FPE costs?

A. The Commission decided at its October 17, 2019 hearing to "Require Minnesota Power to demonstrate in its upcoming initial rate case filing that its proposed base rates do not include any amount of FCA[12] costs." The Commission's Order has not yet been issued; however, Minnesota Power is complying with this requirement in this proceeding.

Q. How has Minnesota Power met this requirement in this rate case?

A. A summary showing the exclusion of the existing class-specific FPE costs from interim rates is included on Exhibit ___ (Podratz), Direct Schedule 8, Test Year Cost of Fuel and Purchased Energy Excluded from Base Rates. The exclusion of FPE costs from

[12] FCA is the abbreviation for "fuel clause adjustment." The terms FCA and FPE have been used interchangeably to refer to the Rider for Fuel and Purchased Energy Adjustment and associated costs and rate adjustments.

base rates for interim rates is shown on Page 1, and the exclusion of FPE costs from base rates for proposed general rates is shown on Page 2.

D. Tax Cut Refund Rider

Q. What is the Rider for 2017 Federal Tax Cut Refund ("Tax Cut Refund Rider")?

A. In the Commission's December 5, 2018 Order in Docket No. E, G-999/CI-17-895 ("Tax Cut Docket"), the Commission established methods for rate-regulated utilities to incorporate into rates the tax cost savings resulting from the Tax Cuts and Jobs Act ("TCJA"). Minnesota Power's Tax Cut Refund Rider returns to customers the protected Excess ADIT, amortized using Average Rate Assumption Method ("ARAM") as early as Internal Revenue Service provisions allow, plus unprotected Excess ADIT, amortized over ten years. It was approved by the Commission in Docket No. E, G-999/CI-17-895, with an effective date of January 1, 2019. The Excess ADIT refund factor is applied as a percent of customer bills.

Q. What change does Minnesota Power propose to the Tax Cut Refund Rider in this rate case?

A. Minnesota Power proposes to include the Excess ADIT credit in base rates and cancel the Tax Cut Refund Rider effective with final rates. Mr. Cutshall discusses the 2020 amortization amounts related to including the Excess ADIT in base rates. The Tax Cut Refund Rider will remain in place during the interim rate period.

VIII. COST OF SERVICE, STAKEHOLDER INPUT, AND RATE DESIGN PROCESS

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I correlate the total cost of service for the 2020 test year to the class cost of service study (CCOSS) provided by Company witness Mr. Shimmin, and then present how the Company utilized the CCOSS and other considerations to develop its proposed rate design in this proceeding.

Q. What is Minnesota Power's test year revenue deficiency for final General Rates?

A. Volume 3, Schedule A-1, summarizes Minnesota Power's proposed General Rate revenue deficiency for the test year. The revenue deficiency is $65.9 million, indicating that an 10.59 percent overall rate increase for Minnesota jurisdictional customers is required.

A. <u>Data Linkage Between Cost of Service and Rate Design</u>

Q. What is the importance of data linkage between the Company's sales forecast, revenue calculations, cost of service study, and rate design?

A. In the Company's 2009 Rate Case, the Commission required the Company to continue working with the Department to improve the electronic linkage between its CCOSS, forecasting processes, and revenue models. It is not clear that this order point remains applicable; however, I discuss improved linkages we have implemented since that time.

Q. How does Minnesota Power integrate its sales forecast and revenue calculations with its financial schedules, rate design information, and class cost-of-service study?

A. Volume 3, Schedule E-1 (Comparison of Operating Revenues) and Volume 3, Schedule E-2 (Supporting Information) are in a single electronic spreadsheet file that includes numerous supporting spreadsheets containing detailed Company budget information such as monthly billing units and rates for each rate class and individually budgeted customers. Schedule E-2 also includes "frequency distribution" sheets that are used to convert revenue class (e.g., residential, commercial, industrial) forecast information into rate class (e.g., residential, General Service, Large Light and Power) billing units to which the various rates can be applied. The electronic versions of both of these schedules contain multiple linked spreadsheet tabs with Excel formulas that perform the calculations, rather than having values such as present rate revenues entered from the Company budget. Schedule E-1 and E-2 are in a similar format to what the Company included in its 2016 Rate Case filing.

Q. How did Minnesota Power then use the results of the CCOSS and test year billing units to develop proposed final/general rates?

A. The revenue requirements by customer class from the cost-of-service study for proposed General Rates are shown in Volume 3, Schedule E-2. These revenue requirements and the associated customer class billing units from Schedule E-1 were used to determine unit costs for customer, energy, and demand components. Minnesota Power also considered other factors such as rate stability and overall customer billing impacts in determining the rate changes to propose.

Q. Please describe the electronic linkage between CCOSS, forecasting process and revenue models.

A. The 2018 Advance Forecast Report ("AFR") uses econometric modeling to inform the budget on the number of customers and billing units for total revenue classes (e.g. commercial, residential, etc.). The frequency distribution is then applied to the AFR results to determine the number of customers and billing units on particular rates within each revenue class, which in turn determine budget revenue by rate. The revenue by rate is then totaled to provide revenue by rate class. Direct Schedules E-1 and E-2 in Volume 3 (in particular Direct Schedule E-2) demonstrate this process. Direct Schedule E-2 contains overview pages outlining the steps in the process of converting the AFR numbers into budgeted revenue by rate. The 2020 budget is then input into the CCOSS (with the previously discussed adjustments). Minnesota Power goes through a rigorous verification process to ensure that the Direct Schedule E and CCOSS present rate revenues by class match.

B. <u>Stakeholder Input on Residential Rate Design</u>

Q. What did Minnesota Power do prior to preparing this rate case to get a better understanding of key stakeholder interests related to residential rate design?

A. Minnesota Power conducted a series of three stakeholder meetings between July and September 2019 with attendees representing low income customers, local governments, environmental and renewable energy advocates, and state agencies charged with protecting the public interest and that of residential customers. The meetings were facilitated by Great Plains Institute ("GPI") and Center for Energy and Environment ("CEE"). Minnesota Power also engaged Navigant Consulting rate design expert Mr. Lon Huber to provide rate design background information at the meetings and assist with analysis specific to Minnesota Power's residential rates and customer load profile. Mr. Huber recently assisted with evaluation of Minnesota Power's residential time-of-day rate alternatives and previously did similar work for Xcel Energy in Minnesota, so he is familiar to many of the participating stakeholders and the Commission. A report summarizing the stakeholder process and input received is attached to my testimony as Exhibit ___(Podratz), Direct Schedule 9, Minnesota Power 2019 Residential Rate Design Stakeholder Process Summary.

Q. What stakeholders participated in the meetings?

A. Participants included: Citizens Utility Board of MN; City of Duluth; City of Royalton; Ecolibrium3; Energy CENTS Coalition; Fresh Energy; Fond du Lac Band of Lake Superior Chippewa; Minnesota Department of Commerce, Division of Energy Resources; and Minnesota Office of the Attorney General.

Q. What were some of the residential rate design objectives that stakeholders expressed at the first meeting?

A. Participants at the first meeting made clear their interest in having electric service and rates that:

1. Enable customers to meet their needs/desires
2. Maintain or improve the low-income protections offered by inclining block rates ("IBR")
3. Add time-of-day price signals
4. Are understandable/explainable to customers
5. Remove disincentives for beneficial electrification
6. Are easier to administer for the utility internally

Q. What current energy policy pressures were highlighted by stakeholders at the meetings?

A. Priority policy topics mentioned at the meeting included the desire for more renewables, time-varying rates, electrification, low income customer protections, and energy conservation encouragement.

Q. What potential future rate options were discussed at the stakeholder meeting?

A. Following a brainstorming activity where numerous potential alternatives were mentioned, the following prioritized list emerged as being of most interest in the near-term:

1. Reduced blocks IBR with "lifeline" feature (lower rate for small monthly usage amount)
2. Time-of-use rates
3. Flat rates
4. Low-income-specific rates
5. Real-time pricing
6. Demand rates
7. Fixed bill
8. Subscription rates

Q. Which of these alternatives were chosen for additional discussion and analysis?

A. There was deeper discussion of the pros and cons of the current IBR rate structure versus a possible future base time-of-day residential rate. The possibility of a separate low income rate with self-identification of qualified customers was also discussed at length.

Q. What were some of the key take-aways from the meeting discussions?

A. Key take-aways included:

1. Removing tiers helps low income, high use customers but hurts low income, low users.

2. Social policy of multiple tiers has a lot of free riders (example: vacation homes with low usage getting discounted lowest block rate), and is a blunt instrument.
3. Desire for "friction free" qualification for those who need it – no sign-up or difficult qualification process, and as such, is able to give some discount to all low-use, low income customers.
4. Openness to reducing existing tiers, but low income, low-use customers must be protected. There is broad support for protecting low income, low-use customers.
5. Openness to exploring additional, new programs to protect low income, low-use customers.
6. Focus on rates, not just programs – rates are more important.
7. Minnesota Power's Time of Day ("TOD") process will move forward regardless of this process.
8. Minnesota Power's CARE program will continue regardless of this process.

Q. What general options for moving from current IBR to likely eventual TOD were discussed?

A. Two general approaches were considered as possibilities by the stakeholder group:

1. Phase out block rates over time, with a mix of IBR and TOD
2. Eliminate block rates all at once and move to low income and/or low-use rate, plus future TOD and other rate options
    a. Option 1: Low-use program
    b. Option 2: Low income program
    c. Both Option 1 and 2 attempt to hold harmless the existing low-use tier

Q. What feedback did stakeholders provide regarding the transition from existing IBR to a potential flatter rate and ultimately to a future TOD rate?

A. Participants were interested in additional data and analysis of how customers might be affected by TOD – using customer load shapes. This can be addressed in Minnesota Power's separate TOD docket that is open concurrent with this rate case. The rationale for moving to flat rates as an interim step before TOD was also discussed by the group. Based on his experience in other states, Mr. Huber stated that too many changes at once make it hard to determine what caused a change in a customer's bill. For example, removing blocks from an IBR structure at the same time as adding time-varying rates can result in customer misunderstanding and backlash to the rate design change. As a result, Mr. Huber strongly suggested moving to a flat rate first before pursuing a change to TOD rates.

Q. What are the upcoming compliance requirements in Minnesota Power's Residential TOD docket?

A. In its August 16, 2019 Order Accepting Compliance Report as Complete and Modifying Requirements for 2020 Annual Compliance (the "2019 Residential TOD Order"), the Commission required Minnesota Power to include in its August 2020 annual report:

a. A proposal for one or more preferred TOD rate options;
b. A discussion of other options proposed by stakeholders, including consideration of higher on-peak to super-off-peak ratios and potential future implementation of dynamic pricing and dynamic time periods; and
c. A proposed implementation timeline, including discussion of a proposal to phase in TOD rates as soon as Minnesota Power's new Meter Data Management system is implemented.

C. <u>Class Revenue Apportionment and Rate Design Process</u>

Q. Please explain Minnesota Power's overall approach to rate design in this proceeding.

A. Company witness Mr. Shimmin describes the Company's development of its fully-allocated CCOSS, and the results of that study. Minnesota Power used the results of its CCOSS as a starting point in the development of its proposed rate design. However, we also recognize the need to balance cost-based ratemaking and the benefits of sending appropriate price signals with the principle of gradualism in making changes to customer rates. We also considered state energy policy goals such as beneficial electrification and encouraging efficient use of energy. Finally, we considered how Minnesota Power's rates compare to other electric utility rates for various customer classes and the impact of proposed rate design changes on customer competitiveness.

Q. Please describe the basis for Minnesota Power's proposed changes in rate design by customer class.

A. Minnesota Power used the 2020 Test Year class cost-of service study ("CCOSS") as the starting point for rate design. As summarized on Exhibit ___ (Podratz), Direct Schedule 10, Class Revenue Apportionment, the CCOSS indicated that the Residential class should have a 35.6 percent increase to collect the full cost of service. The CCOSS also indicated a 16.9 percent increase for the Lighting class. CCOSS results for the other retail customer classes indicated increases ranging from -0.1 percent to 7.3 percent. To avoid extreme rate impacts and instead take a more gradual approach, Minnesota Power is recommending an overall increase of 15 percent for both Residential and Lighting. With the CCOSS indicating the need for an average retail increase of 10.59 percent, the recommended increases for the Residential and Lighting classes that have much larger indicated increases are appropriately more than the overall retail increase.

Additionally, Minnesota Power is recommending changes to Dual Fuel in order to make the rates more competitive with other heating fuel sources that customers could choose as an alternative to Dual Fuel service. This recommendation is described further in Section IX.C below.

With the recommended increases for the Residential and Lighting classes being below the CCOSS, and the proposed decrease for Dual Fuel, the increases for the remaining rate classes need to be higher than indicated by the CCOSS. Minnesota Power proposes an equal percentage increase for all three remaining customer classes – General Service, Large Light and Power, and Large Power.

It is also worth noting that due to the implementation of Interim Rates at the beginning of the test year in January 2020, and then incremental changes for General Rates at the end of the rate proceeding in mid-2021, the proposed final rate increases would phased in over the course of more than a year.

IX. RATE DESIGN AND PROPOSED RATES

A. <u>Overview</u>

Q. Please summarize Minnesota Power's proposed rate increases by class.

A. Exhibit ___ (Podratz), Direct Schedule 11 sets forth the Company's proposed rate increase allocation to rate classes for interim and final rates. This information is summarized in Table 1 below.

Table 1. Proposed Rate Increase Allocation to Rate Classes

Rate Class	General Rate Class Cost-of-Service Study	Proposed Interim Rate Increase (2020)		Additional Proposed Final Rate Change (mid-2021)		TOTAL Proposed General Rate Increase
	[1]	[2]		[3]		[4]
Residential	35.6%	7.7%	+	7.3%	=	15.0%
General Service	-0.1%	7.7%	+	2.7%	=	10.4%
Large Light & Power	4.5%	7.7%	+	2.7%	=	10.4%
Large Power	7.3%	7.7%	+	2.7%	=	10.4%
Lighting	16.9%	7.7%	+	7.3%	=	15.0%
Total Retail	**10.6%**	**7.7%**	+	**2.9%**	=	**10.6%**

Q. Why does the Company believe these rate increases by class are just and reasonable?

A. First, these rates serve the public interest by reflecting reasonable costs of serving Minnesota Power's customers, as well as its existing revenues, and are necessary to enable the Company to earn a reasonable return. Additionally, the Company's proposed rates move closer to reflecting overall cost causation by class. Finally, Minnesota Power's residential rates and overall customer bills are substantially below the cost of providing service and significantly lower than the Minnesota and national averages.

Q. Please provide more information about how Minnesota Power's current rates for the residential and industrial classes compare to those of other investor-owned utilities in Minnesota and the nation.

A. Figures 1 and 2 below show that Minnesota Power's average industrial rate for a high-load-factor customer is near the middle of the national range and below those of Otter Tail Power and Xcel Energy. However, Minnesota Power's average residential rate of 10.2¢ per kWh is extremely low compared to Otter Tail's average of 11.7¢ per kWh and Xcel's average of 14.2¢ per kWh. Minnesota Power's residential rate ranks 30th lowest of 178 EEI utility rates for January 2019.

Figure 1.

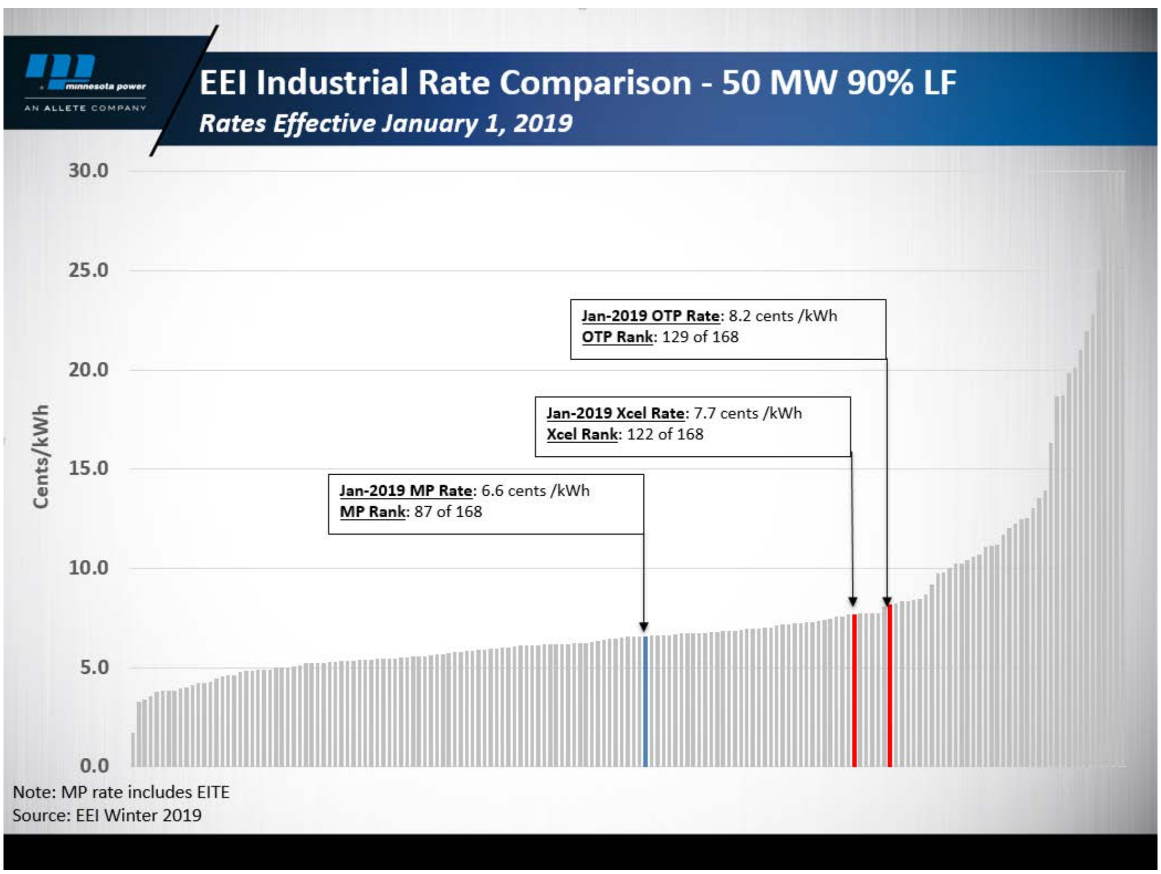
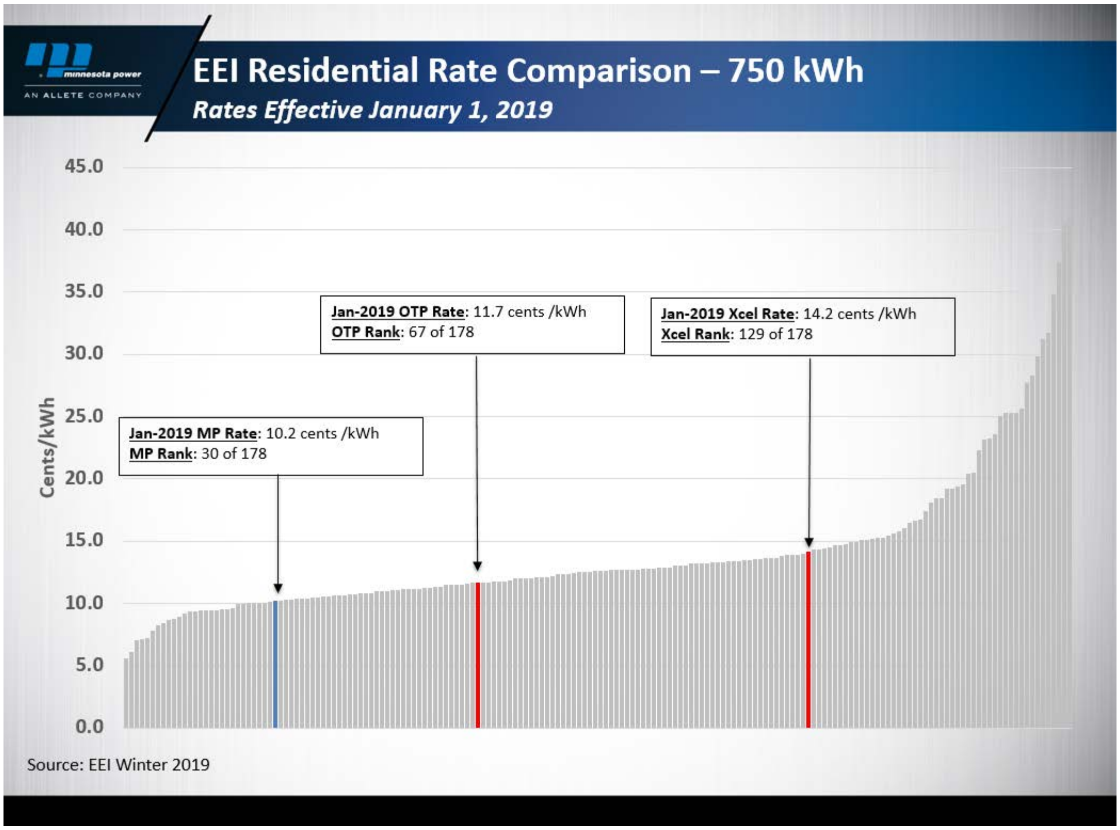


Figure 2.



B. <u>Residential</u>

1. <u>Proposed Residential Rate Increase</u>

Q. What are the proposed test year revenue requirements and recommended rate increase for the Residential class?

A. As a matter of ratemaking policy, the Company determined that an increase of 36 percent, although justified on a cost basis according to the CCOSS, would have an excessive impact on the Residential class customers. Therefore, as described above, less than half this amount, or 15 percent is instead proposed for the Residential class. The proposed Residential class increase is somewhat higher than the proposed retail average increase, in an attempt to move Residential customer rates closer to the full cost of providing service. If the Residential increase were set at an even lower level, other classes that also face financial stressors in the current economy would have to make up the additional difference, which would pose further challenges for them. Put differently, Minnesota Power is requesting an approximate 8 percent Residential rate increase during the interim period (expected to continue at least through the entire 2020 test year), and an additional 7 percent incremental increase for Residential customers beginning with final rate implementation sometime in 2021.

Q. Why is this increase appropriate for the Residential class?

A. While rate increases are rarely welcome to customers, Minnesota Power believes the proposed increase here is reasonable based on the rising costs of providing reliable and environmentally acceptable electricity. Historically, Minnesota Power's residential customers have paid less than the full cost of the generation, transmission, and distribution system facilities used to provide service to them.

In addition, the entire increase would not take effect at once. The proposed interim rate increase of 7.7 percent would affect customer bills starting in January 2020, and the additional 7.3 percent incremental increase proposed for final rates would likely be implemented in mid-2021. This would move Minnesota Power's Residential rates significantly closer to the cost of providing service, even allowing for a margin of error with different assumptions for class COS study and allocation methodologies, and also make Minnesota Power's Residential rates more comparable to those of the other investor owned utilities in Minnesota.

2. <u>Existing Residential Rate Structure</u>

Q. How are Minnesota Power's existing Residential rates structured, and what changes were made in Company's the 2016 rate case?

A. Minnesota Power's five-block Residential energy rates that were put in place as a pilot in the 2009 retail rate case were modified to include only four energy blocks in the 2016 rate case. The energy usage blocks that previously ranged from 200 to 300 kWh in size were combined into three uniformly sized 400 kWh blocks plus an end block for usage above 1,200 kWh per month.

By way of background, prior to the 2009 rate case Minnesota Power's Residential rates included three energy blocks. In the 2009 rate case the Commission required Minnesota Power to adopt a five-block rate design, with "inverted block" rates that increase for higher quantities of energy usage.[13] This system was designed to reduce electric bills for those with the lowest energy consumption while also providing an incentive for conservation by those with high rates of consumption. The Commission noted, however, that this is an uncommon rate design for Minnesota, and stated, "prudence prompts the Commission to regard this new rate design as a pilot program, warranting ongoing oversight."[14]

Minnesota Power began billing customers under the five-block rate structure on June 1, 2011. The Commission directed the Company to evaluate the effectiveness of this pilot program on an annual basis, which the Company did in annual compliance filings in 2013, 2014, 2015, and 2016.[15] In Order Point 26 of the Commission's November 2, 2010 Order in the 2009 rate case, the Commission required the Company in its next rate case filing to recommend whether to continue the pilot Residential General service rate design.

Q. What were the conclusions regarding the effectiveness of Minnesota Power's five-block energy rates in previously analyses?

A. Minnesota Power's prior analysis following implementation of five-block IBR did not provide clear evidence that the five-block rates incentivized residential conservation or led to lower energy consumption. Data analyzed for 2013 through 2015 indicated some

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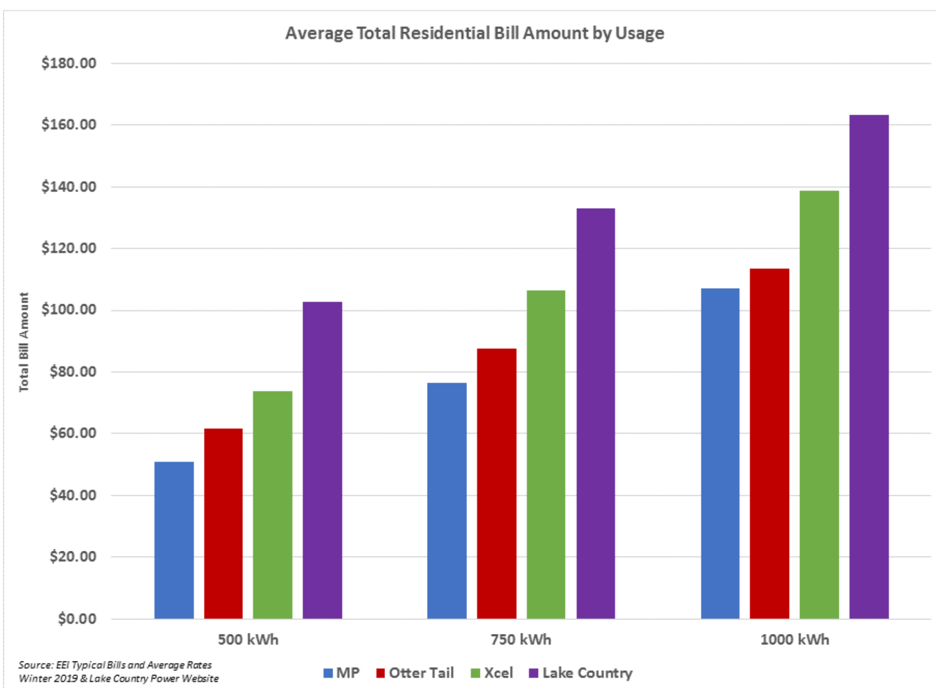
[13] Findings of Fact, Conclusions, and Order, Docket No. E015/GR-09-1151, pages 65-66.
[14] *Id.*
[15] Minnesota Power's compliance filings dated January 11, 2013; April 28, 2014; May 5, 2015; and July 26, 2016 in Docket No. E015/GR-09-1151.

reduction in consumption, but the reasons for the reduction were unclear. The reduction may also be attributed to other factors, such as fuel switching for some end uses due to the low price of natural gas relative to electricity, customer participation in conservation programs, and economic reasons. In addition, customers were previously receiving a similar signal to conserve energy under the Company's previous three-block rates that were in place until May 31, 2011.

Q. How do Minnesota Power's current monthly bills for Residential customers compare to those of Xcel Energy, Otter Tail Power, and Lake Country Power?

A. Minnesota Power has lower bills than those of other investor-owned utilities in Minnesota (Otter Tail Power and Xcel Energy) and the closest neighboring cooperative electric utility (Lake Country Power). As shown in the chart below Minnesota Power's rates at an average 500 kWh usage level are much lower than our peers compared to the 1,000 kWh usage level. Figure 3 below is based on EEI Typical Bills and Average Rates Winter 2019.

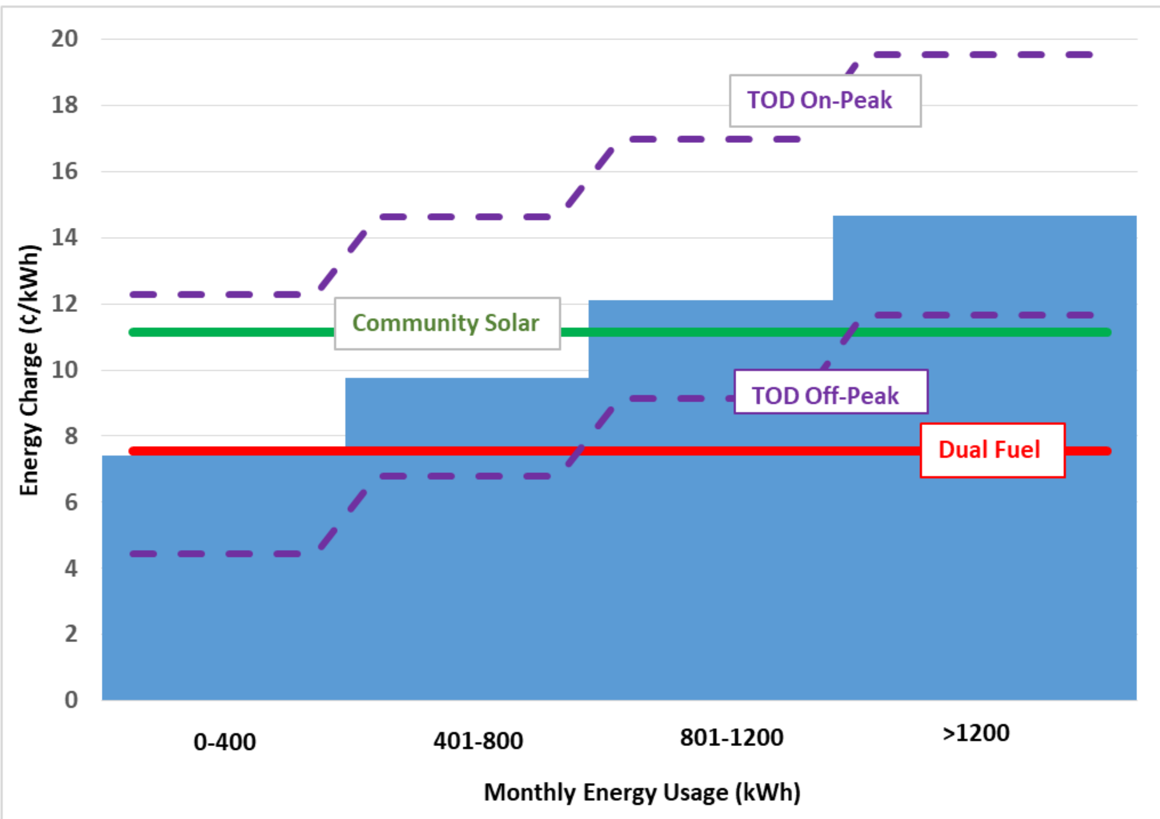
Figure 3.



Q. How manageable are the current four-block rates for customers?

A. The increased complexity of the four-block energy rate structure versus a flat rate or even an energy rate with fewer blocks presents added complications when offering rates that are layered on top of the existing base rate structure, such as the optional Pilot Rider for Residential Time-of-Day ("TOD") Service, Dual Fuel Interruptible Electric Service, and Pilot Rider for Community Solar Garden Subscription ("Community Solar Pilot"). See Figure 4 below for an illustration of the different energy charges applicable to standard Residential customers of different sizes and those taking optional energy products.

Figure 4. Energy Charges by Customer Usage Levels



Note that small Residential energy consumers with under 400 kWh of monthly energy usage pay less than 8 cents per kWh on the standard energy rate. These customers would pay about 3 cents per kWh more for Community Solar energy, which is priced at a flat rate of 11.15 cents per kWh). In contrast, large Residential energy customers with more than 1200 kWh of monthly energy usage pay more than 14 cents per kWh for their incremental energy usage. These customers would pay about 3 cents per kWh less for Community Solar energy. A similar situation arises for Dual Fuel Interruptible Service customers, who pay a flat rate of 7.563 cents per kWh.

Residential TOD Service energy prices were intentionally structured as positive or negative cents-per-kWh adjustments, respectively, to the standard Residential on-peak and off-peak energy charges, because a flat TOD rate as an alternative to inclining block standard Residential rates would encourage only large residential energy users to choose TOD service.

Customer education regarding the inclining block rate structure and complex interactions with other rate alternatives has generally been needed as part of describing these other offerings to customers. This would much more be straightforward if Minnesota Power's standard Residential Service rates instead included a flat energy charge.

3. Residential Rate Proposal

Q. Are you proposing any changes in the overall structure of Residential rates?

A. Yes. I propose a phased transition from the existing IBR structure of the Residential energy charges to a flat Residential energy charge that includes a usage qualified discount for eligible customers intended to protect low income customers, as described in detail below. Along with this, I propose a modest $1.00 increase to the monthly service charge.

Q. Please summarize why Minnesota Power recommends transitioning to a Residential flat energy rate.

A. The proposed energy rate structure would alleviate the complexity and the potential unintended consequences discussed above. Minnesota Power recognizes the complexity of the IBR structure versus a flat energy rate when offering rates that are layered on top of the existing base rate structure, such as the Residential TOD Service, Community Solar Garden, Electric Vehicle rates, and opportunities for Minnesota Power to encourage beneficial electrification.

Q. Do you have any concerns regarding customer impacts during a transition from the current four-block energy rate structure to a flat energy rate structure?

A. Yes. Moving from the current four-block structure directly to a single flat energy rate could cause a rate impact for electric customers that currently receive a natural benefit from inclining block rates. Therefore, I propose changing to a flat energy rate structure via a phased approach with low income protections.

Q. What do you recommend going forward for the residential energy rate structure and how would the transition from the existing IBR structure to a flat rate structure occur?

A. I recommend moving to a simpler, flat energy rate that would initially be effective with final rates in this rate case and would be completed in two phases. As part of my recommendation there would be a discount for customers whose average monthly energy usage currently benefits from the inclining block rate structure for a limited period of time, which would transition to a more permanent discount only available to qualifying low income customers impacted by the structure change. The proposal consists of changing to a flat rate structure when final rates are implemented.. During the first phase any residential customer who meets a specified average usage threshold would receive a discount on a portion of their usage. In phase 2 only low income customers who meet the usage threshold would qualify to continue receiving a discount. Customers who are eligible for either the Low Income Home Energy

Assistance Program ("LIHEAP") in Minnesota Power's billing system or complete a simple self-certification process will qualify. The phased approach is described in detail below.

Q. Please explain Minnesota Power's proposed modification to the standard Residential Service Charge.

A. Along with Minnesota Power's proposed reduction in the number of energy charge blocks, we are also requesting an increase to the monthly service charge. Minnesota Power proposes to increase the Residential monthly service charge by $1.00 per month. The current Residential service charge of $8.00 has been in place since the effective date of final rates in Minnesota Power's 2008 rate case, November 1, 2009. This proposed increase from $8.00 per month to $9.00 per month is a 12.5 percent increase, which is less than the rate of inflation over the past ten years since Minnesota Power's Residential service charge was last increased in 2009. As illustrated below, it still results in a much smaller monthly service charge than neighboring distribution cooperatives, some of which serve customers across the street from Minnesota Power customers.

The proposed $9.00 monthly Service Charge does not come close to recovering residential customer-related service connection costs. The Company's test year cost-of-service study indicates residential customer costs of $25.57 per customer per month. However, recognizing that customers in the existing smallest usage blocks would be impacted most by the request to move to a flat energy charge in addition to an increase in the monthly Service Charge, Minnesota Power has chosen to moderate the proposed increase at this time.

Q. How does Minnesota Power's proposed Residential Service Charge of $9.00 per month compare to other investor-owned electric utilities in Minnesota?

A. It would still be lower than Otter Tail Power's monthly service charge of $9.75 per month, and it would be equal to the average of Xcel Energy's charges of $8.00 per month for overhead service and $10.00 per month for underground service.

Q. How does Minnesota Power's proposed Residential Service Charge of $9.00 per month compare to neighboring electric utilities in northeastern Minnesota?

A. It is extremely low in comparison. Minnesota Power researched the monthly service charges of several distribution cooperatives and municipal utilities that provide electric service to customers adjacent to Minnesota Power's service territory. Minnesota Power considers these service charges to be a good proxy for the level of service charge Minnesota Power customers could reasonably afford because the customers/members of municipals and cooperatives live in the same region as Minnesota Power customers and are subject to similar economic conditions and financial challenges. In addition, the distribution cooperatives' and municipal utilities' service charges are essentially approved by its members through their member-elected Boards of Directors or municipal public utilities commissions. Monthly service charge information was gathered for the following cooperatives:

Table 2. Cooperative Monthly Service Charge Data

Cooperative (headquarters and service center locations shown in parentheses)	**2009 Monthly Service Charge**	**2016 Monthly Service Charge**	**2019 Monthly Service Charge**
Cooperative Light & Power (Two Harbors)	$16.00	$27.00	$30.00
Crow Wing Power (Brainerd)	$12.00	$18.00	$24.00
East Central Energy (Braham)	$16.00	$28.75	$30.25
East Itasca-Mantrap (Park Rapids)	$16.50	$33.00	$38.00
Lake Country Power (Grand Rapids, Virginia, and Kettle River)	$20.00	$42.00	$42.00
Mille Lacs Energy Cooperative (Aitkin)	$24.00	$25.00	$33.00
North Itasca Electric Cooperative (Bigfork)	$31.50	$43.00	$46.00

Among these seven distribution cooperatives, the lowest current residential customer charge is $24.00 per month (Crow Wing Power), and the highest is $46.00 per month (North Itasca), with an average of $34.75 per month. Minnesota Power's proposed monthly Service Charge of $9.00 is less than one-third of the average level and $15 lower than the lowest of the group of neighboring cooperative utilities.

Q. What are the proposed Residential energy rates compared to the present Residential energy rates in phase 1 and phase 2?

A. The present and proposed Residential energy rates include the energy charge, fuel adjustment, and the excess ADIT credit. The detail for each usage block are shown in the table below:

Table 3: Residential Energy Rates*

	Total Present (¢/kWh)	Proposed Phase 1 (¢/kWh)	Proposed Discount Phase 1 (¢/kWh)	Proposed Phase 2 (¢/kWh)	Proposed Discount Phase 2 (¢/kWh)
0-400 kWh	7.641	12.181	-2.436	11.436	-2.287
401-800 kWh	9.949		NA		NA
801-1200 kWh	12.259		NA		NA
Over 1200 kWh	14.760		NA		NA

**Includes cost of fuel and purchased energy*

Q. How will Minnesota Power phase the transition to flat rates?

A. Phase 1 is proposed to begin when final rates are implemented and will include a discount for customers who meet the average monthly energy usage eligibility threshold, which is described in detail below. Phase 2 is proposed to begin twelve months after final rates are implemented.

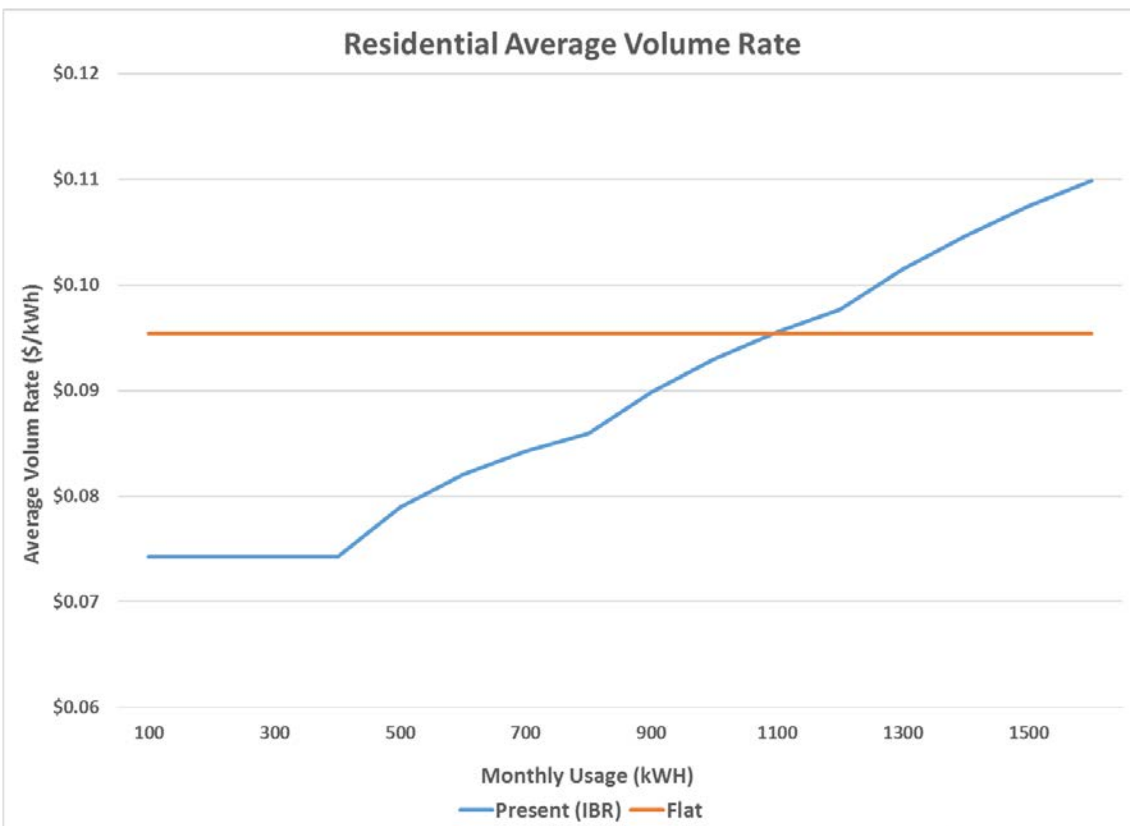
Q. What is the proposed eligibility criteria to qualify for a discount?

A. During phase 1 the eligibility threshold would be based on a customer having annual average monthly energy usage of 1,200 kWh or less. The annual time period will be determined based on when final rates are implemented. Eligible customers will qualify to receive the discount for the entirety of phase 1. Eligibility in phase 2 will continue to have eligibility usage threshold of 1,200 kWh or less but will also include a low income requirement to qualify.

Q. Why was a 1,200 kWh eligibility threshold used to qualify customers for the discount?

A. An annual average monthly energy usage threshold of 1,200 kWh was used to qualify customers for the discount to maximize the number of negatively impacted customers eligible to receive the benefit of the phased discount approach and most importantly, to maximize the number of low income customers who continue to benefit from a discounted rate on their first 400 kWh. The 1,200 kWh threshold helps to ensure that nearly all customers who see an annual net increase in their electricity costs solely as a result of moving from IBR to flat rates are eased into the increase, and that impacted low income customers are receiving the benefits of the low income protections built into the rate design. As demonstrated in Figure 5 below, on the current IBR structure, customers naturally benefit from the IBR rate structure up to approximately 1,100 kWh. Once a bill reaches 1,100 kWh, the portion of the bill charged at the higher tier rate(s) begins to offset the benefit of the first 800 kWh being billed at the lower rates. A lower qualifying threshold may therefore result in excluding customers who would have bill increases every month under the proposed flat rate structure.

Figure 5.



Q. If a customer qualifies based on the usage threshold for the discount, how much energy usage will receive the discount?

A. Up to the first 400 kWh of monthly energy usage would receive the discount for qualifying customers.

Q. What is the proposed flat energy rate during phase 1?

A. The proposed flat energy rate during phase 1 is 12.181 cents/kWh, including FPE costs.

Q. What is the proposed discount rate for energy usage up to 400 kWh per month during phase 1?

A. The proposed discount for phase 1 is 2.436 cents per kWh, which is a 20 percent discount from the proposed flat rate, including FPE costs.

Q. What is the proposed flat energy rate during phase 2?

A. The proposed flat energy rate during phase 2 is 11.436 cents per kWh, including FPE costs.

Q. What is the proposed discount rate for energy usage up to 400 kWh per month during phase 2?

A. The proposed discount for phase 2 is 2.287cents per kWh, which is a 20 percent discount from the proposed flat rate, including FPE costs.

Q. Why do low income customers that are qualified based on the usage threshold for the discount continue to receive a discount in phase 2?

A. Minnesota Power conducted a series of stakeholder meetings that resulted in a rate design objective of maintaining or improving the low income protections offered by IBR. Future rate options discussed were reducing IBR blocks, and including a “lifeline” feature or a discounted rate for lower monthly usage customers that are naturally protected by the IBR rate structure.

Q. Please explain why Minnesota Power is proposing a flat rate structure with a discount instead of offering two separate rates.

A. A flat rate structure simplifies customer billing and allows for additional rate offerings to be layered on top of a flat rate including TOD, Community Solar Garden, Electric Vehicle Rates, etc..

Q. How did Minnesota Power use the stakeholder input in the development of its residential rate design proposal for this rate case?

A. Minnesota Power used stakeholder input to design a flat rate structure that includes a phased approach to protect low income and customers that qualify based on the usage threshold who currently benefit from the IBR structure. The phased approach creates a period during which low income customers who are impacted by the structure change are automatically receiving a discount. This period allows for a year of active outreach to encourage as many of these low income customers as possible to self-identify under an expanded definition in order to continue to receive the discount in Phase 2. This approach helps to address the stakeholder objective of having a "friction free" qualification process with minimal effort or obstacles for low income customers to receive the benefit of proposed low income protections. It also addresses the objective related to reducing "free riders" that exist in the current IBR where higher income customers receive the same benefit on the low usage tiers, and the objective related to focusing on rates rather than programs to address low income customers.

4. <u>Impact of Proposed Change from IBR to Flat Rates</u>

Q. What is the impact of moving from IBR to the proposed flat rate structure on Residential customers with various usage levels?

A. Exhibit **___** (Podratz), Direct Schedule 12, Residential Present Rates Impact of IBR to Flat Rates Structure Change, shows standard Residential monthly bills (reflecting customer and energy charges only) for various monthly usage levels using present rates under the existing IBR rate structure compared to the proposed flat rate structure, as well as the dollar and percentage change at each level. Impacts for phase 1 and phase

2 are shown separately. Additionally, Exhibit ___ (Podratz), Direct Schedule 13, Residential Annual Profile Impacts with Present Revenue Requirement, shows seven examples of the annualized impact on residential customers with various usage levels and patterns over the course of a year. Impacts in this exhibit reflect implementation of phase 2.

Q. Please explain the three different tables in Exhibit ___ (Podratz), Direct Schedule 12.

A. The three different tables represent the three potential eligibility scenarios in the proposed rate structure. The first table, "Eligible Low Income Customer – Eligible in phase 1 and 2," represents a customer whose average monthly usage meets (is equal to or below) the 1,200 kWh eligibility threshold *and* is a low income customer (either LIHEAP eligible or self-certified) making them eligible for the discount in both phase 1 and phase 2. The bill amounts in this table reflects the discounted energy rate in both phases.

The second table, "Eligible Non-Low Income Customer – Eligible in phase 1 only," represents a customer whose average monthly usage meets the 1,200 kWh threshold but is not low income making them eligible only during phase 1. The bill amounts in this table reflect the discounted energy rate only in phase 1, while in phase 2 the standard flat rate is applied to all energy usage.

The third table, "Ineligible Customer – Not eligible in phase 1 or phase 2," represents a customer whose average monthly usage exceeds the 1,200 kWh usage threshold meaning they are not eligible for the discount regardless of income in phase 1 or in phase 2. Customers with usage that exceeds 1,200 kWh do not receive the discount because they naturally see a benefit from a flat rate structure. The bill amounts in this table are all calculated applying the standard proposed flat rate to all energy.

Q. **Please explain the overall higher percent impacts in phase 1 for eligible customers.**

A. In phase 1, all customers who meet the average monthly threshold of 1,200 kWh or less automatically receive the discount. In phase 2, there is an added requirement of also being low income. As a result, in phase 1, many more customers are eligible for the discount compared to phase 2 meaning the discount cannot be as significant. In phase 2, fewer customers are eligible so the overall discount is spread among fewer customers and is able to achieve a larger impact. This expansion in phase 1 is necessary in order to cast a wider net initially providing time for outreach, education, and allowing low income customers time to self-certify without experiencing a period with higher impacts.

Q. **Please explain the higher percent changes for ineligible customers that have monthly usage in the 100 kWh to 1,000 kWh tiers.**

A. Eligibility for the discount is based on average monthly energy usage using a 12-month period. Customers that are ineligible have average monthly usage greater than 1,200 kWh. Therefore, customers whose average usage exceeds 1,200 kWh are likely not to have bills in the lower usage levels or will not be impacted by the higher percent increases that are shown in Exhibit ___ (Podratz), Direct Schedule 12, Page 3 of 3.

Q. **Why do the tables representing eligible customers in Exhibit ___ (Podratz), Direct Schedule 12 show impacts for usage levels beyond 1,200 kWh?**

A. Eligibility for the discount is based on a monthly average using a 12-month period. It is possible for customers to have usage above 1,200 kWh in some months and still average under 1,200 kWh if they have several months with very low usage. For example, a customer who is a low user in the summer but partially heats with electric in the winter.

Q. Why do the tables representing ineligible customers show impacts for usage levels below 1,200 kWh?

A. Because eligibility for the discount is based on a monthly average using a 12 month period, it is possible for customers to have usage below 1,200 kWh in some months and still average above 1,200 kWh if they have months that are well above 1,200 kWh.

Q. Please explain what additional information is included in the annualized examples shown in Exhibit ___ (Podratz), Direct Schedule 13.

A. Because a customer's monthly usage level can vary significantly over the course of a year, it is important to look at annual impact scenarios to get a better understanding of how the proposed rate will impact customers with different annual profile patterns. For example a customer who has low usage during the summer and higher usage during the winter may see bill increases during the summer but will experience significant decreases during the winter that will either partially offset or more than offset increases in other months. The tables in this exhibit reflect bills associated with phase 2.

Q. Please explain the reason for including seven different examples in Exhibit ___ (Podratz), Direct Schedule 13.

A. Each of the seven examples represent customers with different usage patterns (or profiles) throughout the year. Because the change in structure from IBR to a flat rate will result in bill increases during months where usage is below a certain level and bill decreases when usage is above a certain level, customers with different profiles will experience different annual impacts. A customer with high winter usage and low summer usage will see a different overall impact than a customer with less variance in usage throughout the year. By providing examples of seven different annual customer profiles, it is easier to understand how different customers may be impacted by the proposed rate structure.

Q. Please explain the color scheme used in Exhibit ___ (Podratz), Direct Schedule 13.

A. In phase 2, a customer must be low income to qualify for the discount. As a result a low income customer with the same usage and usage pattern throughout the year will have different bill amounts than their non-low income counterparts. In these examples, the blue columns reflect bills and bill impacts for non-low income customers for each profile and the green columns reflect bills and bill impacts for low income customers with each profile.

Q. Why are the "Eligible" columns shown as not applicable ("NA") for profile examples 1 and 2?

A. In profile examples 1 and 2, the customer's average monthly usage over the course of the 12 months exceeds the 1,200 kWh eligibility threshold. As a result, these customers are not eligible for the discount regardless of income status.

Q. Why aren't low income customers whose average monthly usage exceeds 1,200 kWh eligible for the discount in phase 1 or phase 2?

A. Customers whose average usage exceeds 1,200 kWh are highly likely to receive the natural benefit that occurs on higher usage bills when moving from IBR to flat rates. This is demonstrated in example 1 and 2 of Exhibit ___ (Podratz), Direct Schedule 13. In both examples, even though the customer is not eligible for the discount, they still see a net decrease in bill amounts over the course of the year.

Q. What solutions does Minnesota Power have for a customer who would not qualify for a discount during phase 2, yet does not experience the natural benefit of moving to a flat rate?

A. During the twelve months of phase 1, Minnesota Power would be proactive with robust education and outreach materials and tools (including an online calculator) to create customer awareness and understanding around potential impacts in phase 2. As part of these outreach efforts, the Company will actively promote existing programs and tools such as energy efficiency offerings, budget billing, and the MyAccount portal as ways to help customers manage usage and bills under the new structure. Strategic marketing and special promotional offers for energy efficiency programs that would effectively lower customers overall energy consumption would be implemented to encourage customers to take action before phase 2 rates take effect. Actions such as completing a home energy audit, replacing inefficient lighting with light emitting diodes ("LED"), or replacing inefficient appliances can help offset potential bill impacts.

5. Combined Impact of Proposed Residential Rate Increase and Change in Energy Rate Structure

Q. What is the impact of moving from IBR to the proposed flat rate structure on Residential customers with various usage levels?

A. Exhibit ___ (Podratz), Direct Schedule 14, Residential Phased Flat Rates with Proposed Rates Bill Impacts shows standard Residential monthly bills (reflecting minimum charge, energy charge, fuel adjustment, and excess ADIT credit) for various monthly usage levels using present rates under the existing IBR rate structure compared to the proposed rates and proposed flat rate structure, as well as the dollar and percentage change at each level. Impacts for phase 1 and phase 2 are shown separately. Additionally, Exhibit ___ (Podratz), Direct Schedule 15, Residential Annual Bill Comparison with Proposed Phase 2 Rates shows seven examples of the annualized impact of the proposed rate and rate structure change on residential customers with various usage levels and patterns over the course of a year. Impacts in this exhibit reflect implementation of phase 2.

Q. Explain the three different tables in Exhibit ___ (Podratz), Direct Schedule 14.

A. The three different tables represent the three potential eligibility scenarios in the proposed rate structure. The first table "Eligible Low Income Customer (eligible in phase 1 and 2)," represents a customer whose average monthly usage meets (i.e., is equal to or below) the 1,200 kWh eligibility threshold *and* is a low income customer (either LIHEAP eligible or self-certified) making them eligible for the discount in both phase 1 and phase 2. The bill amounts in this table reflect the discounted energy rate in both phases.

The second table "Eligible Non-Low Income Customer (eligible in phase 1 only)," represents a customer whose average monthly usage meets the 1,200 kWh threshold but is not low income making them eligible only during phase 1. The bill amounts in this table reflect discounted energy only in phase 1, while in phase 2 the standard proposed flat rate is applied to all energy.

The third table, "Ineligible Customer (not eligible in phase 1 or phase 2)," represents a customer whose average monthly usage exceeds the 1,200 kWh usage threshold meaning they are not eligible for the discount regardless of income in phase 1 or in phase 2. Customers with usage that exceeds 1,200 kWh do not receive the discount because they naturally see a benefit from a flat rate structure. The bill amounts in this table are calculated by applying the standard proposed flat rate to all energy.

Q. For Exhibit ___ (Podratz), Direct Schedule 14, please explain the overall higher percent impacts in phase 1 for eligible customers.

A. In phase 1, all customers who meet the average monthly threshold of 1,200 kWh or less automatically receive the discount. In phase 2, there is an added requirement of also being low income. As a result, in phase 1, many more customers are eligible for the discount compared to phase 2 meaning the discount cannot be as significant. In phase 2, fewer customers are eligible, so the overall discount is spread among fewer customers and is able to achieve a larger impact. This expansion in phase 1 is necessary in order to cast a wider net initially providing time to do outreach, education, and allowing low income customers time to self-certify without experiencing a period with higher impacts.

Q. **Please explain the higher percent changes for ineligible customers that have monthly usage in the 100 kWh – 1,000 kWh tiers.**

A. Eligibility for the discount is based on average monthly usage using a 12-month period. Customers that are ineligible have average monthly usage greater than 1,200 kWh. Therefore, customers whose average usage exceeds 1,200 kWh are likely not to have bills in the lower usage levels or will not be impacted by the higher percent increases that are shown in Exhibit ___ (Podratz), Direct Schedule 14, Page 3 of 3.

Q. **Why do the tables representing eligible customers show impacts for usage levels beyond 1,200 kWh?**

A. Because eligibility for the discount is based on a monthly average using a 12 month period, it is possible for customers to have usage above 1,200 kWh in some months and still average under 1,200 kWh if they have several months with very low usage. For example, a customer who is a low user in the summer but partially heats with electric in the winter.

Q. **Why do the tables representing ineligible customers show impacts for usage levels below 1,200 kWh?**

A. Because eligibility for the discount is based on a monthly average using a 12 month period, it is possible for customers to have usage below 1,200 kWh in some months and still average above 1,200 kWh if they have months that are well above 1,200 kWh.

Q. **Please explain what additional information is included in the annualized examples shown in Exhibit ___ (Podratz), Direct Schedule 15.**

A. Because a customer's monthly usage level can vary significantly over the course of a year, it is important to look at annual impact scenarios to get a better understanding of how the proposed rate will impact customers with different annual profile patterns. For example, a customer who has low usage during the summer and higher usage during the winter may see bill increases during the summer but will experience significant decreases during the winter that will either partially offset or more than offset increases in other months. The tables in this exhibit reflect bills associated with phase 2.

Q. Please explain the reason for including seven different examples in Exhibit ___ (Podratz), Direct Schedule 15.

A. Each of the seven examples represent customers with different usage patterns (or profiles) throughout the year. Because the change in structure from IBR to a flat rate will result in bill increases during months where usage is below a certain level and bill decreases when usage is above a certain level, customers with different profiles will experience different annual impacts. A customer with high winter usage and low summer usage will see a different overall impact than a customer with less variance in usage throughout the year. By providing examples of 7 different annual customer profiles, it is easier to understand how different customers may be impacted by the proposed rate structure.

Q. Will you also please explain the color scheme used in Exhibit ___ (Podratz), Direct Schedule 15.

A. In phase 2, a customer must be low income to qualify for the discount. As a result, a low income customer with the same usage and usage pattern throughout the year will have different bill amounts than their non-low income counterparts. In these examples, the blue columns reflect bills and bill impacts for non-low income customers for each profile. The green columns reflect bills and bill impacts for low income customers with each profile.

Q. Why are the eligible columns not applicable ("NA") for profile examples 1 and 2?

A. In profile examples 1 and 2, the customer's average monthly usage over the course of the 12 months exceeds the 1,200 kWh eligibility threshold. As a result, these customers are not eligible for the discount regardless of income status.

Q. Why aren't low income customers whose average monthly usage exceeds 1,200 kWh eligible for the discount in phase 1 or phase 2?

A. Customers whose average usage exceeds 1,200 kWh are highly likely to receive the natural benefit that occurs on higher usage bills when moving from IBR to flat rates. This is demonstrated in example 1 and 2 on Exhibit ___ (Podratz), Direct Schedule 15.

Q. How much of the total impact for various different usage levels is related to the structure change from IBR to a flat rate with a low income discount compared to the proposed change in revenue requirement for the standard residential class?

A. Exhibit ___ (Podratz), Direct Schedule 16, Residential Phase 2 Structure Change and Revenue Change Impact Summary, shows the bill amounts (reflecting minimum charge, energy charge, fuel adjustment, and excess ADIT credit) for various usage levels under the current rate structure and present revenue requirements, the proposed structure and present revenue requirements, and the proposed structure and proposed revenue requirements. The "Bill Impact Specific to IBR to Flat Structure Change" section shows the impact related to the change in rate structure without a change in revenue requirement. The "Bill Impact Specific to Change in Revenue Requirement" section indicates the impact related to the proposed change in revenue requirements and is calculated by taking the difference between the total impact from the proposed rate and the impact specific to the structure change.

Q. What are the proposed residential rates in phase 2?

A. As discussed above, Minnesota Power is proposing a phased approach for moving from IBR to a flat rate structure. The proposed phase 1 would be effective with final rates in this rate case. Twelve months after final rates are implemented, Minnesota Power proposes to implement the phase 2 rates. A billing comparison of present and proposed phase 2 rates and revenues is shown in Exhibit ___ (Podratz), Direct Schedule 17.

6. Seasonal Residential Service

Q. What changes are proposed for Seasonal Residential Service?

A. Minnesota Power proposes to increase the rates for Seasonal Residential customers slightly more than for standard Residential customers so these customers with additional dwellings will pay somewhat closer to the actual cost of providing service. The existing Service Charge for Seasonal Residential is $10.00 per month, which is 25 percent higher than the existing standard Residential Service Charge. Minnesota Power proposes a Service Charge of $12.00 per month for Seasonal Residential customers, which is a slightly higher percentage increase compared to the proposed 12.5 percent increase for the standard Residential Service Charge (from $8.00 to $9.00). The proposed Energy Charge for Seasonal Residential is 9.947¢ per kWh, which is slightly higher than the proposed flat rate for standard Residential Service. These rates for Seasonal Residential customers come closer to recovering Minnesota Power's full cost of service than do the rates for standard Residential service.

Q. What other changes are being proposed for the Seasonal Residential Service?

A. Minnesota Power proposes to update the definition language of a seasonal residence. The current language, "Any additional residence shall be provided service at Residential – Seasonal rate," which was adopted with the implementation of the 2016 Rate Case, is causing confusion. For example, a landlord with multiple services could have only one service at the standard residential rate and all remaining services would have to be at the seasonal residential rate. The proposed language, "A customer will be billed on the seasonal rate if the dwelling is occupied for 182 days or less each year," simplifies how to determine the difference of a seasonal and principle residence by adopting a variation of the Minnesota Department of Revenue's 183-Day Rule.[16] This simplification of determining a seasonal property as being occupied for 182 or less will

[16] Minnesota Department of Revenue uses the 183-day rule for tax purposes to be considered a Minnesota resident; which states that you must spend at least 183 days in Minnesota during the year (any part of the day counts as a full day) and you or your spouse rent, own, maintain or occupy a residence suitable for year-round use or equipped with its own cooking and bathing facilities (https://www.revenue.state.mn.us/183-day-rule)

reduce implementation confusion and create better customer service by placing customers on the correct rate.

C. <u>Dual Fuel and Controlled Access</u>

Q. Are you proposing any changes to the rates for Residential Dual Fuel Interruptible Service and Controlled Access Service and Commercial/Industrial?

A. Yes. The Company proposes to modify the Residential and Commercial/Industrial Service Schedules for Dual Fuel and Controlled Access by separating service under each of the schedules into Small Service and Large Service. The metering and load control technology for both services have changed since these rates were first developed. The meters required a separate hardware from the meter and an entirely different communication network which added costs. Today, this additional communication system has become obsolete as well as the extra hardware. Customers, depending of their load size require different equipment. The technology for the control system for customers with small service is no longer external equipment, but is now an internal part of the meters. This component is no longer included.

Q Are you proposing to keep the current four Residential and Commercial/Industrial Dual Fuel and Controlled Access service schedules in the future?

A. No. The proposal is to eliminate the Residential Dual Fuel Interruptible Electric Service and the Commercial/Industrial Dual Fuel Interruptible Electric Service and replace them with a single Dual Fuel Service schedule with Small and Large service options. Similarly, the existing Residential Controlled Access Electric Service and Commercial/Industrial Controlled Access Electric Service would be replaced with a single Controlled Access Service schedule with Small and Large service options. This consolidation would likely be requested in Minnesota Power's next rate case.

Q. Please explain more about the proposed Small Service.

A. Small Service will be for customers who are served by a single-phase self-contained meter and with load that can be controlled remotely, through the current radio Advanced Metering Infrastructure network, by a service switch integrated into the meter. This service will be for customers with load rated at 75 kW or less with single-phase because of the amperage limitation of the meter integrated disconnect.

Q. Please explain more about the proposed Large Service.

A. Large Service will be for customers with service who generally have connected load above 75 kW or take service at three-phase. The service will require a more complex meter, instrument transformers, and an additional load control module. Costs associated with these larger installations (see Volume 4, Workpaper RD-3) are thus usually much higher for providing and metering the service. There is also one circumstance where a connected load at or below 75 kW would be considered a Large Service, which is when the load is served at three-phase and thus also requires more equipment to serve. So the justification to classify these customer in the Large Service is based on meter configuration required to provide this level of service.

Q. How did you split the customers between Small and Large Service?

A. Minnesota Power analyzed data from its Customer Information Systems ("CIS") for all current customers taking Dual Fuel and Controlled Access services. The data included the type of meter form,[17] the equipment and associated customers' energy usage. The different types of meters and other installed equipment were used to distinguish between the sizes of customers. There is a clear dividing line between meter equipment installations, which were used to define the Small Service and Large Service. All Dual Fuel customers (Residential and Commercial/Industrial) identified as small service were then combined to make the Small Service group, and those identified as large

[17] A meter form is the physical design and configuration of the meter. Each meter is matched to a service configuration such as 120/240 volt single phase, 120/208 three phase, etc.

service were also combined to make the Large Service group. Associated energy usage for each group was totaled, and ratios were calculated and applied to budgeted sales to determine the total usage in each group. The same process was followed to calculate the usage for each group for Controlled Access customers.

Q. What is the advantage of the proposed restructuring of the Dual Fuel and Controlled Access Service Schedule?

A. Dual Fuel is an interruptible electric service available to customers who have non-electric sources of energy available to satisfy energy requirements during periods of interruption. Controlled Access is a controlled energy storage or controlled loads which are only energized for a specific daily period. Minnesota Power's proposed rates for Dual Fuel and Controlled Access services are based on customer service size and a consideration of the market competitiveness of the services. The advantage of the Small and Large customer segmentation is to bill customers with minimal equipment requirements at a more advantageous rate which partially reflects the cost of the equipment required and increases the competitiveness and attractiveness of the Dual Fuel or Controlled Access rates for them.

Q. How do Minnesota Power's Dual Fuel rates with the proposed changes compare to other fuel alternatives?

A. Minnesota Power had seen a steady growth in the number of Dual Fuel customers at the inception of Dual Fuel service for both Residential and Commercial/Industrial. However, starting in about 2010 the growth became almost stagnant as shown in Figure 6 below, and started decreasing with the implementation of the Company's 2016 Rate Case final rates.

Current rates levels are not competitive compared to alternative fuel sources. See Figure 7 – Fuel Alternative Price Comparison for the cost comparison with alternative heating sources:

- Fuel oil variable charge is approximately $2.50 per gallon or $1,500 per year,

- Propane cost is approximately $1.59[18] per gallon or $1,221 per year (heating season average of 3 years)
- Dual Fuel current rate results in about $1,738 per year, and
- The Company's proposed Dual Fuel energy rate at $0.060 per kWh or $1,231 per year.

Figure 6. Dual Fuel Customer Growth From 1990 to 2018

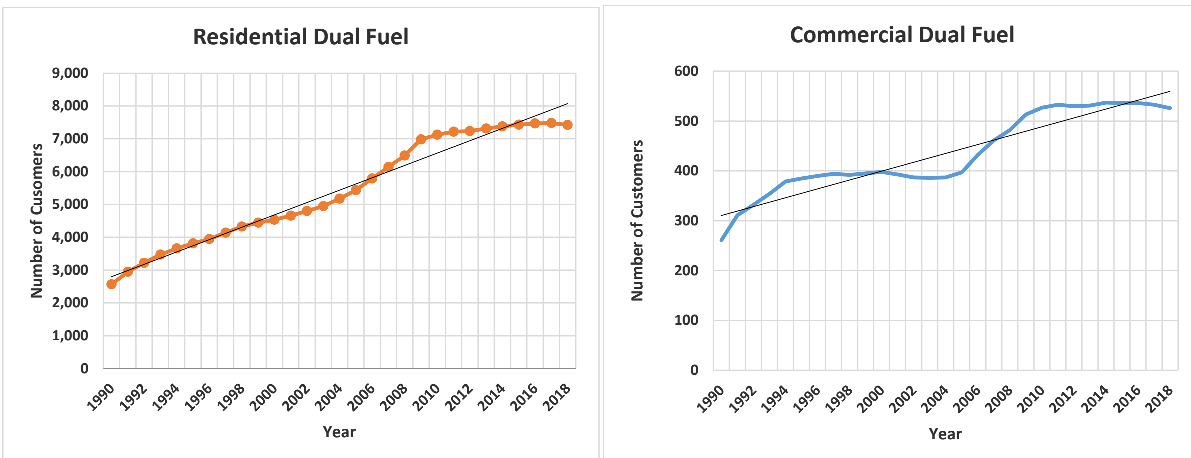
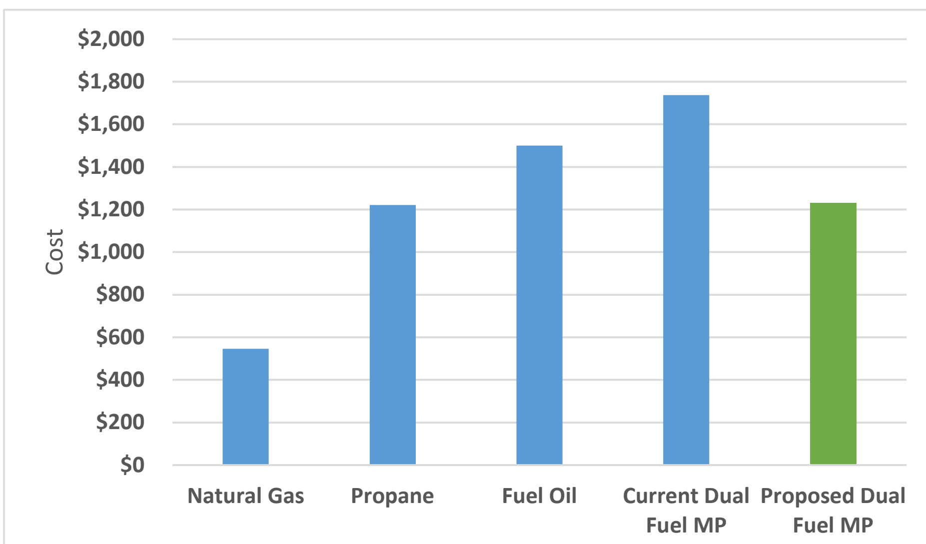


Figure 7. Fuel Alternative Price Comparison



[18] United States Energy Information Administration, Petroleum & Other Liquids: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPLLPA_PRS_SMN_DPG&f=W

Q. What cost analysis did Minnesota Power perform for Dual Fuel rates?

A. Minnesota Power's cost analysis used to develop the proposed Dual Fuel rates is provided in Volume 4, Workpaper RD-3. Page 1 of Workpaper RD-3 summarizes the analysis the shows the overall cost components that were included for energy, generation capacity, and transmission and distribution. These costs were considered along with the desire to be more competitive with alternative fuel sources as described above. The incremental cost analysis results for Dual Fuel show a total cost of 6.78¢ per kWh for Primary voltage service and 7.56¢ per kWh for Secondary voltage service. However, these costs include firm capacity, and Dual Fuel is interruptible service. Therefore, it is appropriate to set the rates at a slightly lower level that doesn't include the entire capacity cost. Also, because of the proposed change to exclude FPE costs from base rates, the test year average FPE cost is subtracted from the energy costs in the calculations.

Page 2 of 5 of Workpaper RD-3 shows the calculation of metering costs for Small and Large Dual Fuel customers, and indicates that the annual cost for Small customers is approximately $370, while the cost for Large customers is greater than $3,300. In the interest of gradualism for rate changes, Minnesota Power does not propose to adjust rates to cover the full cost, but does proposes service charges differentiated by customer size.

Q. Based on these analyses, what rates does the Company propose for Dual Fuel?

A. Based on these analyses, the Company proposes that the energy charge for Dual Fuel be set at 3.635¢ per kWh. The Service Charge is proposed to be $5.00 for Small Service and $15.00 for Large Service.

Q. What rates does the Company propose for Controlled Access?

A. Similarly to Dual Fuel, Minnesota Power proposes that the energy charge for Residential and Commercial/Industrial Controlled Access service be set at 3.635¢ per kWh. The Controlled Access monthly Service Charges are proposed to be $5.00 for Small Service and $15.00 for Large Service.

Q. What additional changes are being proposed for Residential Controlled Access and Commercial/Industrial Controlled Access Services?

A. Minnesota Power proposes to modify the current off-peak energizing period by one hour on each end, from 11 p.m. to 7 a.m. currently, to 10 p.m. and 6 a.m. The Company reviewed historical MISO Day Ahead and Real Time Locational Marginal Price ("LMP") data going back to the beginning of 2010 to determine the eight hours of the day that LMPs and cost to serve loads were at the lowest. Four different scenarios across the four different seasons were analyzed for each year. On an annualized basis, it was determined that the period 10 p.m. and 6 a.m., which also corresponds with off-peak hours in the MISO energy market, saw the lowest Day Ahead and Real Time LMPs along with the lowest cost to serve loads. The Company proposes to change the energizing period, which normally would require that customer meters be reprogrammed. However, the reprogramming will not be necessary in this instance because it will coincide with the deployment of new meters in the service territory.

D. General Service

Q. What revisions does Minnesota Power propose for the General Service rate?

A. Minnesota Power proposes to make the following changes to the General Service rate levels: increase the monthly Service Charge from $12.00 to $14.00; change the Energy Charge from 10.204¢ per kWh (including 2.196¢ per kWh of FPE cost) to 8.638¢ per kWh (including zero FPE cost) for customers without demand meters and from 7.619¢ per kWh (including 2.196¢ per kWh of FPE cost) to 6.054¢/kWh (including zero FPE cost) for customers with demand meters; and increase the demand charge from $6.50 to $7.25 per kW per month.

Q. What changes were made to the Determination of Billing Demand for the General Service Schedule in the 2016 Rate Case?

A. In the DETERMINATION OF THE BILLING DEMAND section of the General Service schedule, Minnesota Power received approval in the 2016 Rate Case to change the power factor adjustment threshold from 85 percent to 90 percent. This change will go into effect on December 1, 2019. The delay was necessary to allow customers who currently do not maintain a 90 percent power factor, the time to install the equipment necessary to correct their power factor and avoid additional billing. For final rates in this case, the service schedule language is therefore modified to reflect that the transition has been completed. It will read as follows: Demand will be adjusted by multiplying by ~~85% (~~90% ~~effective December 1, 2019~~ and dividing by the average monthly power factor in percent when the average monthly power factor is less than ~~85% (~~90% ~~effective December 1, 2019)~~ lagging.

E. Municipal Pumping

Q. What revisions does Minnesota Power propose for the Municipal Pumping rate?

A. Minnesota Power proposes to eliminate the Municipal Pumping schedule from its rate book. The transition of existing customers to a favorable rate schedule began with the implementation of the 2016 Rate Case final rates and is scheduled to complete by the end of the projected year 2019.

F. Large Light and Power

Q. What revisions does Minnesota Power propose for Large Light and Power ("LLP") Service?

A. The Demand Charge for the first 100 kW of billing demand, is proposed to increase from $1,200 per month to $1,325 per month. The Demand Charge for all additional demand is proposed to increase from $10.50 per kW-month to $12.00 per kW-month. The same Demand Charge changes are also incorporated for the LLP Rider for Schools, which has a lower minimum billing demand. The Energy Charge is proposed to change from 5.811¢ per kWh (including FPE cost of 2.142¢ per kWh) to 4.050¢ per kWh (including zero FPE cost).

Q. What changes were made to the Determination of Billing Demand for the Large Light and Power Service Schedule in the 2016 Rate Case?

A. Under DETERMINATION OF THE BILLING DEMAND section of this service schedule, Minnesota Power received approval in the 2016 Rate Case to change the power factor adjustment threshold from 85 percent to 90 percent, with a delay in the effective date to allow for customer notification and ability to make changes to their operations if warranted. This change will go into effect on December 1, 2019. The delay was necessary to allow customers who currently do not maintain a 90 percent power factor, the time to install the equipment necessary to correct their power factor and avoid additional billing. For final rates in this case, the service schedule language is therefore modified to reflect that the transition has been completed. It will read as follows: Demand will be adjusted by multiplying by ~~85% (~~90% ~~effective December 1, 2019~~ and dividing by the average monthly power factor in percent when the average monthly power factor is less than ~~85% (~~90% ~~effective December 1, 2019)~~ lagging.

Q. In its 2009 rate case, Minnesota Power was required to develop and file a voluntary time-of-use ("TOU") rate for LLP customers. Please provide an update regarding that rate option.

A. The Commission's November 2, 2010, Order in Minnesota Power's 2009 Rate Case, Order Point 24, directed Minnesota Power to develop and propose a TOU tariff for the LLP customer class. This requirement arose from Enbridge Energy, Limited Partnership's ("Enbridge") February 17, 2010 public comments in the 2009 Rate Case, which requested that the Commission require Minnesota Power to offer a Time-of-Use rate for the LLP rate class, so that Enbridge can operate its pipelines in a more cost-effective manner. On April 5, 2011, Minnesota Power filed its Petition for Approval of a Pilot Rider for Large Light and Power Time-of-Use Service in Docket No.

E015/M-11-311. The Commission approved the Pilot Rider for Large Light and Power Time-of-Use Service ("LLP TOU Rider") in an Order dated August 8, 2011.

Q. How many customers are taking service under the LLP TOU Rider?

A. Enbridge began taking service under the LLP TOU Rider on July 1, 2019.

Q. Were there any compliance requirements related to the LLP TOU Rider?

A. On July 31, 2019, Minnesota Power filed a compliance filing in Docket No. E015/M-11-311 notifying the Commission that Enbridge had started taking LLP TOU Rider service. The Commission's August 8, 2011 Order also required Minnesota Power to submit a LLP TOU rate pilot evaluation report within 60 days after the first customer taking service under the Rider completed one year of service on the Rider. This compliance report will be submitted by August 31, 2020.

Q. What changes does Minnesota Power proposed for the LLP TOU Rider rates?

A. Minnesota Power proposes to change the on-peak energy rate from 6.337¢ per kWh to 5.053¢ per kWh and the off-peak energy charge from 5.275¢/kWh to 3.369¢/kWh. This will result in a ratio of the on-peak to off-peak rates of about 1.5, which is equal to the lowest of the three options included in Minnesota Power's February 20, 2019, Residential Time-of-Day Rate Compliance Report[19] and slightly higher than the existing LLP TOU Rider energy charge ratio of 1.2. Similar to standard LLP service, the monthly demand charge for the first 100 kW or less in the LLP TOU Rider is increased from $1,200 to $1,325.

G. Lighting

Q. What changes does Minnesota Power propose for its Lighting rates?

A. Minnesota Power proposes changes intended to simplify the application of its Lighting tariffs and the addition of more light-emitting diode ("LED") rate options for Option 1

[19] Docket No. E015/M-12-233

Lighting Customers. These changes are shown in the redlined tariff pages for proposed General Rates in Volume 3.

The Outdoor and Area Lighting Service (Minnesota Power Electric Rate Book, Section V, Page No. 37) and Street and Highway Lighting Service (Minnesota Power Electric Rate Book, Section V, Page No. 46) schedules currently include four Rate Options. Under Option 1, Minnesota Power owns, installs, and maintains all equipment necessary for providing lighting service. Under Option 4, the Customer owns, installs, and maintains all equipment and buys only the energy required to power the lights from Minnesota Power. Options 2 and 3 involve a combination of Company and Customer ownership and maintenance.

Q. What specific changes do you propose for Options 2 and 3, and why?

A. Options 2 and 3 have become difficult to administer because of the complexity of tracking equipment ownership and identifying who is responsible for maintaining various portions of the equipment. Options 2 and 3 are currently closed to new customers. Minnesota Power has been phasing customers off of Options 2 and 3 and transitioning them to either Option 1 or Option 4, which the Company anticipates will be completed by the end of 2020. With the completion of the phase-out of Options 2 and 3, the Company proposes the elimination of these two options from its Rate Book with final rates.

Q. What change does Minnesota Power propose for Mercury Vapor lighting?

A. As Minnesota Power replaces lamps or convert fixtures, all Mercury Vapor fixtures are being replaced with other lamp types because of the growing environmental concern related to mercury in recent years. Furthermore, the Company no longer purchases Mercury Vapor bulbs. Therefore, Minnesota Power requests closing all Mercury Vapor rates to new customers.

Q. How were the proposed changes to individual Lighting rates developed?

A. The Lighting rate changes were developed using a separate analysis that incorporates the cost of purchasing, installing, and maintaining equipment along with the cost of providing electricity. This analysis is included in Volume 4, Rate Design Workpaper RD-1. For the Lighting class, Minnesota Power proposes an overall rate increase of 15 percent in an effort to move toward cost, but avoid an extreme rate change all at once. This is somewhat lower than the CCOSS results, which indicate an increase of 16.9 percent for the Lighting class.

Q. What are the specific proposed changes for Outdoor and Area Lighting Service and Street and Highway Lighting Service?

A. Under both of these service schedules, the energy charge for Option 4, where the customer owns and maintains the equipment, is proposed to change from 7.142¢ per kWh (including 1.751¢ per kWh of FPE cost) to 6.020¢ per kWh (including zero FPE cost). It is reasonable for this energy rate to be lower than the General Service class energy rate for customers without demand meters because outdoor lighting service is provided when it is dark outside, which is primarily during the lower-cost off-peak hours. In addition to the energy rate changes, Minnesota Power proposes to increase the fixed monthly service charge from $2.09 to $3.34 for Option 4. The monthly service charge covers the cost of the meter and customer service.

Q. What are the proposed changes for LED Lighting rates?

A. To continue expanding LED options for customers, we have added new LED lamps types and sizes. For Outdoor and Area Lighting the Company proposes the following:

- a 10,000 Lumens (71 watts or less) LED option with a proposed monthly rate of $13.06,
- a 24,000 Lumens (184 watts or less) LED option with a proposed monthly rate of $19.73,

- a 43,500 Lumens (316 watts or less) LED option with a proposed monthly rate of $28.36, and
- 30,000 Lumens (278 watts or less) LED option with a proposed monthly rate of $24.43.

The rates for these four new LED options were calculated based on costs as well as current per lamp rates for the existing LED options, as shown in Volume 4, Rate Design Workpaper RD-1.

H. <u>Large Power</u>

Q. What is Minnesota Power's philosophy regarding Large Power rates?

A. As with all of its customer classes, Minnesota Power's goal is to have reasonable rates that recover the cost of providing service. Historically Minnesota Power's Large Power rates have been set somewhat higher than the level indicated by CCOSS results based largely on the desire to keep Residential rates at affordable levels. However, Figures 1 and 2 earlier in my testimony indicate that Minnesota Power's Residential rates will be materially below national averages both under current and proposed rates. Further, it is just as important to have affordable, competitive rates for Large Power customers so they continue operating facilities that are critical to the economic health of the region, to the jobs of many of Minnesota Power's residential customers, and to maintaining an overall affordable cost of service. Therefore, a key goal in this rate case is to keep Large Power rates as competitive as possible.

Q. What Large Power service schedules and riders does Minnesota Power propose to change in this rate case?

A. Minnesota Power proposes cancellation of the Large Power Rider for Energy-Intensive Trade-Exposed (EITE) Customers ("EITE Rider") at the end of this rate case, increases to the standard Large Power demand and energy charges as indicated by the CCOSS, and corresponding changes to the Non-Contract Large Power Service. Each of these is discussed in more detail below.

Q. What changes is Minnesota Power proposing for the EITE Rider?

A. Minnesota Power is not requesting any changes to the current EITE Rider in this rate case. However, per the Company's October 7, 2019 letter in Docket No. E015/M-16-564 (the "EITE docket"), Minnesota Power is requesting the Commission grant a procedural extension to continue the EITE Rider for several months beyond its anticipated expiration date of February 1, 2021, so it will expire concurrent with the effective date of new final rates in this rate case.

Q. Is the EITE rate discount included in present rate revenues in this rate case?

A. Yes, the EITE rate discount currently in effect is included in present rate revenues for the Large Power class, as shown on Volume 3, Direct Schedule E-1.

Q. What impact has offering the EITE rate discount to eligible Large Power customers had on Minnesota Power's other customer classes?

A. Minnesota Power's other customers have not had to pay any surcharge associated with the EITE rate discount. Subsequent to Minnesota Power's offering of the EITE Rider, Large Power customer U.S. Steel restarted its Keetac facility, which increased Minnesota Power's sales and revenues above the baseline before offering the EITE Rider. These increased revenues made it unnecessary to collect additional revenue to offset the EITE rate discount from other customer classes.

Q. Does Minnesota Power include the EITE rate discount in its proposed final rates?

A. No, subject to Commission approval, Minnesota Power proposes to cancel the EITE Rider and rate discount effective with final rates. Instead of offering a separate discount, Minnesota Power aims to design its Large Power base rates to be reasonably close to the Large Power class cost of service.

Q. What changes does Minnesota Power propose for the standard Large Power Service Schedule Demand Charge and Energy Charge?

A. Minnesota Power proposes to increase the Demand Charge for the first 10,000 kW or less of Billing Demand from $250,087 to $273,180 and increase the Demand Charge for all additional Firm Demand from $24.96 to $26.90 per kW-month. The LP Firm Energy rate is proposed to decrease from 2.778¢ per kWh to 0.618¢ per kWh. This appears to be a significant reduction, but when the total LP base energy rate plus FPE costs that are moving out of base rates are considered, the overall proposed energy rate change is minimal. The total of the proposed Firm Energy charge of 0.618¢ per kWh plus 2.100¢ per kWh for 2020 test year average Large Power FPE cost to be included in a separate adjustment is 2.718¢ per kWh.

Q. What revisions does Minnesota Power propose for Non-Contract Large Power Service?

A. The Non-Contract Large Power demand charges have historically been set 20 percent higher than standard LP demand charges, as a strong incentive for these large customers to continue making long-term contractual commitments under the standard LP Service Schedule. We propose to continue this precedent and again set the Non-Contract LP demand charges 20 percent higher than the standard demand charges, which is $327,820 for the first 10,000 kW and $32.28 per kW for all additional billing demand.

Q. Does Minnesota Power propose any changes to other existing LP products or services?

A. Yes, the Company proposes a change related to the recently approved Large Power Demand Response ("LP DR") "Product A," which the Commission recently approved in Docket E015/M-18-735. LP DR Product A is a short-term demand response option that will take the place of existing Large Power Replacement Interruptible Service ("RIS"). As a short-term demand resource that Minnesota Power accredits with MISO under the requirements of MISO's Resource Adequacy and that is available for a limited number of hours each year, this LP DR product is similar to peaking capacity.

Therefore, the Company requests that effective with final rates and for future rate proceedings, the credits paid to participating Large Power customers be treated like purchased power demand and allocated accordingly.

Q. What adjustments to test year revenues would be required to effectuate this change?

A. To accomplish this, the existing $1.5 million of revenue credits for RIS that are included in the Large Power rate class must first be removed from Large Power revenues. Then an equal amount of expense would be added to purchased power demand cost. Because this would change the present rate revenue from the Large Power RIS credits to a purchased power expense, it was not able to be reflected cleanly through adjustments in this rate case without distorting the present rate revenue numbers. However, if approved, Minnesota Power will reflect the change in its compliance filing at the end of the case.

Q. Why is this proposed change in ratemaking treatment reasonable?

A. This change would make Minnesota Power's ratemaking treatment for LP DR consistent with Xcel Energy's longstanding methodology for interruptible discounts in rate cases. Most recently, in Xcel's 2015 electric rate case, their cost-of-service witness stated:

> "The Company's CCOSS process treats interruptible discounts as a cost of peaking capacity and allocates that cost to classes based on firm loads. As explained in previous cases, the Company views interruptible service as firm service with an attached, after-the-fact, purchased-power contract provision. Through this provision, the Company has the option to buy back all or part of a customer's regulatory entitlement to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity; this helps the Company obtain a reliable power supply

portfolio at the lowest cost. This means interruptible rate discounts are really power supply costs and they need to be recognized as such in the CCOSS."[20]

I. Service Voltage Adjustment

Q. What revisions does Minnesota Power propose for the service voltage adjustments for General Service and Large Light and Power rates?

A. Minnesota Power proposes to maintain the primary voltage discount at $2.00 per kW and increase the transmission voltage discount to $2.00 per kW plus an additional 0.450¢ per kWh (versus the existing 0.340¢ per kWh). Calculations supporting these proposed changes are included in Volume 4, Rate Design Workpaper RD-2.

J. Rider for Non-Metered Service

Q. Is Minnesota Power proposing any changes to its Rider for Non-Metered Service?

A. Yes. Minnesota Power proposes to split the Holiday Lighting component of the Rider for Non-Metered Service into two separate types: LED and incandescent components. The purpose of this is to provide more accurate billing and clarify the language under the DISCUSSION section in the tariff in order to simplify the billing calculation. Minnesota Power proposes to change the description (Holiday Lighting), units (Est. connected load in (kW)), and 422 kW (estimated monthly energy/unit) for Holiday Lighting to, respectively, Holiday Lighting – LED, kWh, 270 kWh for LED, and to Holiday Lighting – Incandescent, kWh, 3,780 kWh for Incandescent. The changes are shown in redlined and clean format in Volume 3, Tariff Pages for Change in Rates, Minnesota Power Electric Rate Book, Section V, Page No. 67, Rider for Non-Metered Service.

Q. Why are these changes warranted?

A. Minnesota Power noticed through its annual communication with customers that roughly 75 percent of customers are using LED holiday lights and believes this

[20] Docket No. E002/GR-15-826, November 2, 2015, Direct Testimony of Michael A. Peppin, pages 8-9.

modification will be an incentive for the remaining 25 percent of customers to switch to LED. Furthermore, keeping the Estimated Monthly Energy Usage/Unit at 422 kW in the Rate Book was inaccurately stated on the tariff sheet and required manual intervention in the Company's CIS.

K. Extension Rules

Q. Is Minnesota Power proposing any changes to the Extension Rules?

A. Yes. Minnesota Power is proposing some clarifications in the following sections: General, Contributions, Basis for Making Extensions for Permanent Service Where Extension Costs are $30,000 or Less, and Reapportionment and Refunds, as described below. These sections of the tariff have not been modified since the Company's Extension Rules were revamped in Docket No. E015/M-12-1359. The revised language reflecting the proposed changes is shown in redlined and clean format in Volume 3, Tariff Pages for Change in Rates, Minnesota Power Electric Rate Book, Section VI, Page No. 4, Extension Rules.

Q. Why is the Company proposing changes to these sections of the Extension Rules?

A. The Extension Rules current language is complicated and has led customers and Company employees to interpret its intent incorrectly at times. The purpose of the changes in the language is to clarify the intent for all. It does not modify an existing rate. The Company believes that clarifications of the language would result in more consistent and straightforward interpretation.

Q. What change do you propose for the General section of the Extension Rules?

A. This section is clarified to reflect the changed in the name of the Company's reference manual from Company's Engineering Standards to Company's Distribution Construction Standards. This section also makes clear that if a customer requests a second feed for a second service point, it is the customer's responsibility to fund the second one.

Q. What change do you propose for the Contributions section?

A. In this section, the Company proposes adding language describing the cost associated with customer requesting a second extension or an alternate source feed for reliability. Currently, there is no language governing the provision of a second service point in this section. The new proposed language lists the type of additional facilities the customer is authorized to add, such as transformers, cable, switches, and any associated equipment. When additional capacity is needed, the Company will add the facility at its expense; otherwise, a contribution will be required from the customer to support all additional facilities requested.

Q. What change do you propose for the Basis for Making Extensions for Permanent Service Where Extension Costs are $30,000 or Less section?

A. In this section, under the paragraph for Developers of Residential Housing Sites, the Company requests to delete the allowance dollar amount given to a Residential customer for single-phase, and replace the dollar amount, in that section only, with a more general term. The Company requests to delete $668 and replace it with "the current residential allowance amount". By making this change, Minnesota Power would avoid the risk of inadvertently not using the correct amount each time the allowance changes[21] as well as avoid confusion with changes in overlapping dockets related to extension costs.

Q. What change do you propose for the Reapportionment and Refunds section?

A. In this section, the Company modifies the language to clarify that the Guaranteed Annual Revenues ("GAR") is not revisited after it is finalized with the customer. The current language states that: the current Electric Service Agreement ("ESA") for a

[21] *In the Matter of a Request By Minnesota Power for a Modification to its Service Extension Tariff,* Docket No. E015-M-12-1359, the Company is required to file on February 1 of every year, a report when its average embedded service-extension cost for any customer class change by five percent and if the costs have not changed over the course of the year, submit a letter-filing stating that they have not changed. With this modification, the Company will update the new residential allowance only at the beginning of the section rather than have the allowance repeated at multiple places throughout the tariff sheet.

customer with a service extension is revisited at the end of the first two years, and if it differs from the minimum annual revenue the Customer has elected to guarantee, the Company will, at the election of the Customer, either refund to the Customer the GAR or collect an additional contribution from the Customer. This language implies that Minnesota Power revisits the ESA and the GAR at the end of the first two years and adjusts the amount before either refunding or collecting money from the customer. This has been very difficult for the Company to implement successfully.

The proposed modified language does not change any existing rate, but it clarifies that the ESA and GAR are not revisited after they have initially been finalized with the customer. Rather, each year the Company will compare the extension cost GAR to the minimum revenue and will either pay the difference to the customer or collect the difference from the customer.

L. Summary of Present and Proposed General Rates

Q. Please provide a summary of Minnesota Power's present rates and proposed general rates by rate class.

A. A one-page summary of proposed rate revisions for all classes except Large Power and Lighting is attached as Exhibit ___ (Podratz), Direct Schedule 18. The details of proposed Lighting and Large Power rate revisions are provided in Volume 3, Schedule E-1.

X. OTHER COMPLIANCE REQUIREMENTS

A. Renewable Energy Credit ("REC") Purchases

Q. What was the compliance requirement related to REC purchases?

A. In its December 18, 2007 Order Establishing Initial Protocols for Trading Renewable Energy Credits (Dockets E999/CI-03-869 and E999/CI-04-1616), the Commission required utilities seeking recovery of prudent costs related to registration, annual fees and transaction costs related to renewable energy credit purchases to file specific proposals for cost recovery.

Q. Is Minnesota Power proposing recovery of costs related to registration, annual fees, or transaction costs related to renewable energy credit purchases?

A. No. Minnesota Power has not included any REC purchases or related costs in the proposed 2020 test year.

B. Thomson Hydro Investment Tax Credits ("ITCs")

Q. What was the compliance requirement related to Thomson Hydro ITCs?

A. In its November 8, 2017 Order on Minnesota Power's 2017 RRR Rate Factor Filing, the Commission required that the Company "return any amortized federal investment tax credits associated with Thomson Hydro to ratepayers through future RRR filings until they can be included in base rates in a subsequent rate case."

Q. What is the status of Minnesota Power's ITCs related to Thomson Hydro?

A. The Company is not utilizing any new Thomson Hydro investment tax credits at this time and doesn't expect to do so until approximately 2023, as it has been in a federal NOL position or using a federal NOL carryforward in each year since 2010.

Although no new ITCs have been utilized, and consistent with the discussion in our 2016 Rate Case, ITCs earned prior to 2010 continue to be amortized and are reflected in the Company's cost of service. Minnesota Power also earned a federal ITC for Thomson Hydro Dam in 2015 and claimed the ITC on its federal income tax return. However, due to NOL carryforwards, Minnesota Power was not able to utilize the ITC on its return, and the ITC became an ITC carryforward. To reflect that the ITC has not been utilized but has become a carryforward, the ITC is recorded as a carryforward tax asset, in this case a deferred tax asset. Minnesota Power is following the normalization requirements as we understand them, both by beginning the amortization period once the credit is used to reduce federal tax liability, and by amortizing the credit over the remaining book life of the underlying asset.

C. Department of Commerce Recommended Filing Requirements

Q. What were the Department's recommended filing requirements for Minnesota Power's next rate case?

A. In her Surrebuttal Testimony in the 2016 Rate Case,[22] DOC witness Nancy Campbell recommended that the Commission require Minnesota Power to provide the following in Minnesota Power's next rate case before the Commission determines that the Company's rate case petition is complete:

- All MP financial witnesses will need to tie out their numbers to the overall revenue requirements witness;
- MP may use their reliability center[23] information and numbers, but MP must also include all additional information and numbers (such as overheads, allocations, third-party costs and revenues) that ties out to the FERC accounts;
- All numbers should be provided on a Total Company basis, and Minnesota Jurisdictional basis, with reference and support for allocators used;
- Financial schedules should fully support the test year revenue requirement, for example while transmission expenditures by year can be helpful information, the Company needs also to provide the actual plant in-service and retirement amounts that support the Company's test year;
- All schedules should be clearly labeled to reflect, for example, whether the schedule shows capital expenditures, capital additions and retirements, expenses, and the basis (Total Company or Minnesota Jurisdictional); and
- All schedules in a rate case should breakout the rider recovery and rate case recovery.

[22] Docket No. E015/GR-16-664, Surrebuttal Testimony of Nancy Campbell, July 21, 2017, pages 70-71 and 81.
[23] At the evidentiary hearing, Minnesota Power clarified that this was intended to reference "Responsibility Center" rather than reliability center.

Q. How did Minnesota Power address the Department's recommendations?

A. Although the Commission did not specifically order Minnesota Power to follow these recommendations, at the 2016 Rate Case evidentiary hearing I agreed that the Company would follow them. In the planning and preparation of this rate case, Minnesota Power made all witnesses and other staff working on the rate case aware of these expectations, and we have made a good faith effort to follow them. We put in place a detailed review process with documentation to assure that the numbers in all financial witnesses' testimony and schedules tie to the overall revenue requirements witness. We provided more detailed test year information by FERC accounts in the filing to enable comparisons with historical information. For capital projects, we provided plant in-service and retirement amounts and took extra care to be precise and accurate with terminology and labeling. We also provided more detailed information for the test year and historical years for transmission revenues and expenses to make it easier to analyze and reconcile.

As an example of the Company's diligence, in early October as we were working on Total Company and Minnesota Jurisdictional numbers for this case, there was some uncertainty about the meaning of "all numbers." so we contacted Ms. Campbell for clarification. In a telephone conversation she said that her main concern is that she will be able to do test year comparisons to historical amounts for both Total Company and Minnesota Jurisdictional numbers, especially if there have been significant changes to the jurisdictional allocators.

Based on this feedback, we have attempted to provide consistent numbers for all years and to include Minnesota Jurisdictional numbers throughout the case wherever reasonable and practicable – and particularly in the financial witnesses' testimony. Where we included numbers in non-financial witness testimony to show historical trends for certain items, we provided Minnesota Jurisdictional amounts wherever possible. When it wasn't practical to provide both Total Company and Minnesota Jurisdictional numbers, we clearly designated what we did provide.

XI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Minnesota Power Electric Rate Case -- Docket No. E-015/GR-19-442
Calculation of Proposed General Rate Increase Percentage
and Total Proposed Retail Revenues

		COS and Income Statement [1]		Schedule E-1 [2]		Difference [3]
1	Sales of Electricity by Rate Class	$611,687,811		$611,687,806	[2]	-$5
2	Dual Fuel	$10,415,332		$10,415,360	[2]	$28
3	Present Rate Revenue [line 1 + line 2]	$622,103,143	[1]	$622,103,166		$23
4	Gross Revenue Deficiency/Rate Increase	$65,900,138	[1]	$65,899,923	[2]	-$215
5	Proposed Rate Increase Percentage [line 4 / line 3]	10.59%		10.59%	[2]	
6	Total Proposed Revenues [line 3 + line 4] (Excludes Cost Recovery Riders Remaining on Customer Bills)	$688,003,281		$688,003,089		-$192

[1] Volume 3, Direct Schedule E-3, page 2.
[2] Volume 3, Direct Schedule E-1, page 2
[3] Minor differences between column [1] and column [2] are due to rounding in calculations.

Minnesota Power Electric Rate Case -- Docket No. E-015/GR-19-442
Calculation of Proposed Interim Rate Increase Percentage
and Total Proposed Retail Revenues

		COS and Income Statement		Schedule E-1		Difference	
		[1]		[2]		[3]	
1	Sales of Electricity by Rate Class	$611,687,812		$611,687,806	[2]	-$6	
2	Dual Fuel	$10,415,332		$10,415,360	[2]	$28	
3	Present Rate Revenue [line 1 + line 2]	$622,103,144	[1]	$622,103,166		$22	
4	Gross Revenue Deficiency/Rate Increase	$47,905,848	[1]	$47,901,936	[2]	-$3,911	1/
5	Proposed Rate Increase Percentage [line 4 / line 3]	7.70%		7.70%	[2]		
6	Total Proposed Revenues [line 3 + line 4] (Excludes Cost Recovery Riders Remaining on Customer Bills)	$670,008,992		$670,005,102		-$3,889	

[1] Volume 4, Workpaper COS-1, page 2
[2] Volume 4, Workpaper IR-1, page 2
[3] Minor differences between column [1] and column [2] are due to rounding in calculations.

1/ Total E-Schedule Revenue differs from CCOSS by $3,911 due to rounding. The actual percentage result in the CCOSS model is 7.700628%, the E-schedule uses 7.70%.

2020 Test Year Adjustment
Long-term Power Sale to Basin Electric Pro Forma

					Revenue Adjustment					
					Resale - Non-Firm		Resale - Firm			
		Total	Fuel Adjustment Clause	Inter-System	Demand	Energy	Demand	Energy	Clean Coal	Fly Ash Sales
	MWh Sales	(258,167)				(258,167)				
	Operating Revenue									
44000-0000	Residential	$(154,404)	$(154,404)							
44200-0000	Commercial	(155,253)	(155,253)							
44300-0000	Industrial	(745,572)	(699,282)	$(46,290)						
44400-0000	Lighting	(1,736)	(1,736)							
44500-0000	Public Authorities	(5,636)	(5,636)							
44700-0000	Resale	(17,751,644)			$(4,328,311)	$(14,587,061)	$145,841	$1,017,887		
45690-0000	Miscellaneous Revenue	(20,265)							$(17,984)	$(2,281)
	Total Operating Revenue	$(18,834,510)	$(1,016,311)	$(46,290)	$(4,328,311)	$(14,587,061)	$145,841	$1,017,887	$(17,984)	$(2,281)
					$(18,915,372)		$1,163,728		$(20,265)	
					$(17,751,644)					
	Operating Expenses									
50100-0000	Fuel	(616,767)								
	Square Butte	-								
55500-0000	Other Purchased Power	(6,131,703)								
	Total Fuel and Purchased Power	(6,748,470)								
	Transmission Services	-								
	Operation and Maintenance	-								
	Depreciation / Amortization	-								
	Property Taxes and Other	-								
	Total Operating Expenses	(6,748,470)								
	Operating Income	(12,086,040)								
	Other Income (Expense)	-								
	Income Before Taxes	(12,086,040)								
	Income Tax Expense (Benefit)									
41010-1000	Deferred Income Taxes - Utility Operations - Federal	(1,882,245)								
41010-2000	Deferred Income Taxes - Utility Operations - State	(1,049,156)								
41110-1000	Deferred Income Taxes - Credit - Utility Operations - Fec	220,323								
41110-2000	Deferred Income Taxes - Credit - Utility Operations - Sta	-								
41140-1000	Investment Tax Credit Adjustment - Utility Operations	-								
40910-1000	Income Taxes - Utility Operations - Federal	(627,416)								
40910-2000	Income Taxes - Utility Operations - State	(135,276)								
	Total Income Tax Benefit	(3,473,770)								
	Total Net Loss	$(8,612,270)								

MINNESOTA POWER
DOCKET NO. E015/GR-19-442
PROJECTED RETAIL RATE CASE EXPENSES
TEST YEAR ENDING DECEMBER 31, 2020
AND COMPARISON TO 2017 BUDGETED AND ACTUAL RATE CASE EXPENSES

LINE	DESCRIPTION	2017 TEST YEAR BUDGET E015/GR-16-664	2017 ACTUAL E015/GR-16-664		2020 PROJECTED E015/GR-19-442	NOTES
1	Contract and Professional Services	$1,700,000	$2,900,162		$2,200,000	expert witnesses, consultants, outside legal
2	MPUC/Regulatory Assessments	750,000	1,344,190		$1,400,000	MPUC, ALJ, DOC rate case assessments
3	Intervenor Compensation	20,000	0		$20,000	Energy CENTS Coalition or similar
4	Public Hearings, Notices, Communications	75,000	63,145		$65,000	newspaper advertising, hearing venues, etc.
5	Office Supplies, Postage, and Printing	10,000	1,439		$16,500	postage, paper, etc. for customer notices
6	Travel, Lodging, and Meals	15,000	15,601		$16,000	travel to rate case hearings; stakeholder meeti
7	Dues and Subscriptions and Other Expenses	35,000	32,747	∑	$1,000	Includes parking and misc. employee expense
8	**Total Rate Case Expense**	$2,605,000	$4,357,283		**$3,718,500**	
9	Non-Regulated Allocation %	5.57%		x	4.04%	$3,732,953/($88,557,105+$3,732,953)
10	Allocation to Non-Regulated	$145,099		-	$150,406	Non-regulated support services costs divided by total non-reg and MP amount
11	**Net Rate Case Expense to be Amortized**	$2,459,902			**$3,568,094**	
12	Net Rate Case Expense **Monthly Amortization**		Months: 24		$148,671	
13	Net Rate Case Expense **Annual Amortization**		Years: 2		**$1,784,052**	

Minnesota Power - 2017 Rate Case Expenses - Work Order 2349684 (no internal labor)

Cost Type Description	**2017 Rate Case $**	**2017 Rate Case Expense Notes & Assumptions**
Contract/Professional Services	**1,700,000**	Outside legal counsel ($1,500,000), expert witnesses/consultants ($200,000)
Licenses, Insurance, Permits	**750,000**	Regulatory Commission Expenses (MPUC, DOC, ALJ)
Advertising/Communications Expenses	**60,000**	Rate case notices in newspapers, etc.
Dues & Subscriptions - Subscriptions	**32,000**	SNL Financial Subscription
Intervenor Compensation	**20,000**	Intervenor compensation ordered by MPUC
Office Supplies	**15,000**	paper, supplies, customer notices
Postage	**10,000**	postage for mailing of filing documents, customer notices, UPS, etc.
Lodging - Business	**8,000**	Lodging while attending rate case hearings/meetings
Vehicle Commercial (Rental Car, Taxi) - Business	**3,000**	trips to St. Paul, etc. for rate case hearings and meetings
Personal Vehicle Use - Business	**3,000**	trips to St. Paul, etc. for rate case hearings and meetings
Meals - Business Meals	**3,000**	Meals for rate case trips to St. Paul; evidentiary and public hearings
Parking and Misc. Employee Expenses	**1,000**	Parking and misc. employee expenses
TOTAL	**2,605,000**	

Minnesota Power
Docket No. E015/GR-19-442

Minnesota Power
2017 Rate Case Expenses -- Detail by Account -- 2017 Actual

Line No.	Description	Cost	
1	Outside Legal Counsel	$2,665,666	
2	Expert Witnesses/Consultants	$234,497	
3	Forecasting		
4	Cost of Capital		
5	Licenses, Insurance, Permits	$1,344,190	
6	Public Hearings		
7	Advertising/Communications Expenses	$63,145	
8	Dues & Subscriptions - Subscriptions	$32,000	
9	Intervenor Compensation		
10	Office Supplies	$906	
11	Postage	$533	
12	Court Reporter/transcription		
13	Lodging - Business	$6,171	
14	Vehicle Commercial (Rental Car, Taxi) - Business	$1,240	
15	Personal Vehicle Use - Business	$3,413	
16	Meals - Business Meals	$4,776	
17	Parking and Misc. Employee Expenses	$747	
18	Total	**$4,357,283**	
	Summary Description	**Cost**	
19	Expert Witnesses, Consultants, Legal Counsel	$2,900,162	Lines 1,2,3,4
20	MPUC/Regulatory Assessments	$1,344,190	Line 5
21	Public Hearings, Advertising, Communications	$63,145	Lines 6,7
22	Office Supplies and Postage	$1,439	Lines 10,11
23	Travel, Lodging, and Meals	$15,601	Line 13,14,15,16
24	Intervenor Compensation	$0	Line 9
25	Dues and Subscriptions, Misc. Expenses	$32,747	Lines 8,12,17
26	Total	**$4,357,283**	

MINNESOTA POWER
DIRECT COSTS

Support Service Costs -- 2018 Actual

	Business Function	**Minnesota Power Regulated**	**Minnesota Power Non-Reg**	**TOTAL Regulated and Non-Reg**
		[1]	[2]	[3]
1	Strategic Planning	4,641,226	623,234	
2	Strategy & Planning Dept. (RC 0550)	6,465,702.00	234,556.00	
3	Human Resources	18,548,329	116,532	
4	Accounting/Finance	6,427,927	77,717	
5	Corporate Relations/Communications	5,958,921	144,153	
6	Legal and Regulatory Support	776,029	6,076	
7	Environmental Services	1,952,740	470,335	
8	Facilities Management	5,556,349	510,899	
9	Information Technology Services	24,933,920	610,077	
10	Purchasing	841,565	61,022	
11	Engineering	1,586,878	51,034	
12	Risk Management	6,046,087	3,112	
13	Manage Customer Relations	7,507,295.00	13,008.00	
14	Corp Costs - General	10,943,147	1,058,762	
15	Employee Benefits			
16	Distribute Electricity	23,055,770.00	2,489,894.00	
17	Supply Electricity	71,462,723.00	4,244,129.00	
18	Develop and Manage New Businesses	343,987	-	
19	Utility Services	2,609,400.00	4,698.00	
20	Transmit Electricity	7,979,074.00	2,254.00	
21	TOTAL DIRECT COSTS	207,637,069.00	10,721,492.00	
22	Excluding shaded cells (lines 2,13,16,17,19,20)	88,557,105.00	3,732,953.00	92,290,058.00
23				
24				
25	**TOTALS**			
26	**Percent of Support Service Costs**	95.96%	**4.04%**	

Credit Card Processing Fees
Implementation Date: October 2018
Tracking and True-Up Calculation

Line		**Oct.-Dec. 2018**	**Jan.-Dec. 2019**	**2018-2019 TOTAL**
1	Credit Card Processing Expense Allowed in Rates ($350,000/year, per MP Docket E-015/GR-16-664)	$87,500	$350,000	$437,500
2	MP Actual/Projected Credit Card Processing Expense (No-fee credit card payments for customers; FERC a/c 90300)	$35,467	$253,841	$289,308
3	True-Up Amount for 2020 Rate Case (Line 1 - Line 2)			$148,192 Over-Recovery
4	Amortization Period (Years)			2
5	Annual Amortization (Line 3 / Line 4)			$74,096
6	Monthly Amortization (Line 5 / 12)			$6,175

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2020 Test Year Operating Revenue Adjustments to Budget

	Unadjusted Test Year 2020 (1)	CIP Incentive (2)	CIP Carrying Charge (3)	CPA Incentive (4)	Total CPA (5)	CCRC (6)	CARE Rider (7)	Cost Recovery Riders (CSG & SEA) (8)	Basin Sale Pro Forma (9)	Revenue Budget Corrections (10)	**Present Rates / Schedule E** (11)
Sales by Rate Class											
Residential	101,818,240	-	-	823,801	(36,828)	-	497,418	54,022	(130,132)	(851)	103,025,670
General Service	72,353,600	-	-	592,957	(20,336)	5,938	(387,556)	58,384	(86,472)	-	72,516,515
Large Light & Power	104,971,736	-	-	823,641	(30,293)	1,256,449	(103,832)	200,974	(159,239)	138,455	107,097,891
Large Power	326,153,632	-	-	-	-	-	(6,030)	-	(609,177)	-	325,538,425
Lighting	3,538,300	-	-	17,374	(1,193)	-	-	3,074	(2,333)	(45,912)	3,509,310
Resale (Firm - FERC Juris.)	92,818,224	-	-	-	-	-	-	-	1,163,728	-	93,981,952
Total Sales by Rate Class	**701,653,733**	**-**	**-**	**2,257,772**	**(88,650)**	**1,262,387**	**0**	**316,455**	**176,375**	**91,691**	**705,669,763**
Dual Fuel											
Residential	8,122,084	-	-	90,081	2,315	-	-	10,852	(28,958)	-	8,196,373
General Service (Commercial/Industrial)	2,190,798	-	-	24,671	(350)	-	-	3,841	-	-	2,218,959
Total Dual Fuel	**10,312,881**	**-**	**-**	**114,752**	**1,964**	**-**	**-**	**14,693**	**(28,958)**	**-**	**10,415,332**
Intersystem Sales (LP Econ/Non-firm/RFPS)	**35,603,834**	**-**	**-**	**-**	**-**	**-**	**-**	-	**(46,290)**	**-**	**35,557,545**
Sales for Resale (Off-System)	**102,215,752**	**-**	**-**	**-**	**-**	**-**	**-**	-	**(18,915,372)**	**-**	**83,300,380**
Total Revenue from Sales	**849,786,201**	**-**	**-**	**2,372,524**	**(86,686)**	**1,262,387**	**0**	**331,147**	**(18,814,245)**	**91,691**	**834,943,020**
Production	11,899,057	-	-	-	-	-	-	-	(20,265)	-	11,878,792
Transmission	77,949,043	-	-	-	-	-	-	-	-	-	77,949,043
Distribution	1,148,000	-	-	-	-	-	-	-	-	-	1,148,000
General Plant	1,024,133	-	-	-	-	-	-	-	-	-	1,024,133
CIP	1,518,638	(1,591,832)	73,194	-	-	-	-	-	-	-	-
Gains from Disposition of Allowances and Utility Plant	57,972	-	-	-	-	-	-	-	-	-	57,972
Renewable Resources Rider	(15,470)	-	-	-	-	-	-	-	-	-	(15,470)
Solar Renewable Resources Rider	2,531,729	-	-	-	-	-	-	-	-	-	2,531,729
Boswell 4 Rider	(1,307,569)	-	-	-	-	-	-	-	-	-	(1,307,569)
Transmission Cost Recovery Rider	33,786,224	-	-	-	-	-	-	-	-	-	33,786,224
Total Other Operating Revenue	**128,591,758**	**(1,591,832)**	**73,194**	**-**	**-**	**-**	**-**	**-**	**(20,265)**	**-**	**127,052,854**
Total Operating Revenue	**978,377,959**	**(1,591,832)**	**73,194**	**2,372,524**	**(86,686)**	**1,262,387**	**0**	**331,147**	**(18,834,510)**	**91,691**	**961,995,875**

Minnesota Power

Revenue Credits - Test Year 2020 Unadjusted

Line		TOTAL REVENUE CREDITS	
	Dual Fuel:		
1	Residential	8,122,084	
2	General Service (Commercial/Industrial)	2,190,798	
3	**Total Dual Fuel**	**10,312,881**	
4	**Intersystem Sales (LP Econ/Non-firm/RFPS)**	**35,603,834**	
5	**Sales for Resale (Off-system)**	**102,215,752**	See Podratz Direct Schedule 6, page 2
	Other Operating Revenue:		
6	Production	$11,899,057	
7	Transmission	$77,949,043	
8	Distribution	$1,148,000	
9	General Plant	$1,024,133	
10	Gains from Disposition of Allowances and Utility Plant	$57,972	
11	**Total Other Operating Revenue**	**92,078,205**	See Podratz Direct Schedule 6, page 3
12	**Total Revenue Credits**	**240,210,673**	

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Minnesota Power
2020 Unadjusted Test Year Revenue Credits -- Detail for Off-System Sales for Resale

	Total 2020	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
	[TRADE SECRET DATA BEGINS												
* Basin Capacity	[redacted]												
Basin Emissions Recovery													
* Unidentified/Excess Capacity													
Minnkota Power - Capacity													
* MISO (RAA/PRA) - Capacity													
* NextEra - Capacity													
* Oconto - Capacity													
Subtotal - Capacity	**$34,988,679**												**TRADE SECRET DATA ENDS]**
* AEP Energy Partners	[redacted]												
* Basin Energy													
Liquidation - Minnkota Power													
* Market Sales													
* NextEra - Energy													
Non-MP Station Service													
* Oconto - Energy													
Oconto Transmission													
Subtotal - Energy	**$67,227,073**												**TRADE SECRET DATA ENDS]**
TOTAL Off-System Sales for Resale	**$102,215,752**												

***Reconciliation - Items Included in Pierce Direct Schedule 3 - 2020 Unadjusted Budget Asset-Based Wholesale Sales Revenue (Total Company):**

	[TRADE SECRET DATA BEGINS		[TRADE SECRET DATA BEGINS
Basin Capacity	[redacted]	AEP Energy Partners	[redacted]
Unidentified/Excess Capacity		Basin Energy	
MISO (RAA/PRA) - Capacity		Market Sales	
NextEra - Capacity		NextEra - Energy	
Oconto - Capacity		Oconto - Energy	
	TRADE SECRET DATA ENDS]		TRADE SECRET DATA ENDS]
Subtotal - Asset-Based Capacity	**$6,352,188**	**Subtotal - Asset-Based Capacity**	**$44,927,347**

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2020 Unadjusted Test Year Revenue Credits -- Detail for Other Operating Revenue

FERC A/C	Rider			Total 2020
45400		CenturyLink (Rents Hydro Land for Building)	Production-Demand	$650
45610		Recreation Leases	Production-Demand	$732,502
45640		Timber Sales	Production-Demand	$40,000
45690		Steam Sales - Capacity	Production-Demand	$3,465,000
			PRODUCTION - DEMAND	**$4,238,152**
45690		Steam Sales - Variable	Production-Energy	$3,527,050
45690		Steam Sales - Scale Fee Credit	Production-Energy	($6,000)
45690		Clean Coal Solutions Revenue	Production-Energy	$3,267,912
45690		Clean Coal Solutions Revenue - WPPI	Production-Energy	($370,049)
45690		Fly Ash Sales	Production-Energy	$627,405
45690		Blandin Coal Shed Revenue	Production-Energy	$137,784
45690		Blandin Coal Sales & Shed Revenue - WPPI Credit	Production-Energy	($14,412)
45690		Oconto - Meter Data Management Service Charge	Production-Energy	$20,808
45690		ND ITC - Used	Production-Energy	$452,057
45690	RRR	Oconto - Renewable Resource Energy Credits - Offset in RRR	Production-Energy	$18,350
			PRODUCTION - ENERGY	**$7,660,905**
45400		GRE Communication	Transmission	$393,517
45400		Hibbtac Transformer Rental	Transmission	$468
45400		USS Fiber Rental	Transmission	$14,880
45620		MISO	Transmission	$15,515,010
45620		MISO Sch 2 Transfer to Acc 55600 RC 0548	Transmission	($2,835,429)
45620		MISO Sch2/3 Transfer to Acc 45660	Transmission	($1,180,788)
45620		WPPI	Transmission	$416,538
45620		MP/Square Butte - DC Line	Transmission	$14,559,600
45620		GRE (MISO Revenue Sharing)	Transmission	($406,853)
45620		NERC Alert Projects - Schedule 45	Transmission	$7,059,150
45620		NERC Alert Projects - Schedule 45 (DC)	Transmission	$1,132,599
45620		MISO Attachment O, GG, ZZ True Up - Accrual	Transmission	$1,002,000
45660		MISO Reactive Supp -transferred from 45620	Transmission	$1,180,788
Subtotal - Non-Rider Transmission				**$36,851,481**
45620	TCR	RECB Sch 26 (regional Expansion Cost & Benefit)	Transmission	$18,729,130
45620	TCR	RECB Schedule 37	Transmission	$210,000
45620	TCR	RECB Schedule 38	Transmission	$249,600
45620	TCR	Manitoba Must Take Fee	Transmission	$14,370,073
45690	TCR	MH Joint Operating Expense Payments	Transmission	$7,538,760
Subtotal - Rider Transmission				**$41,097,563**
			TRANSMISSION	**$77,949,043**
45000		Late Fees-CSA	Distribution	$689,000
45100		Misc Serv Rev	Distribution	$87,000
45400		Joint Use/Pole Att	Distribution	$360,000
45690		Nashwauk/Essar Billing & Maint Fee	Distribution	$12,000
			DISTRIBUTION	**$1,148,000**
45400		Enventis Rents	General Plant	$433,673
45400		Stora/Berwind Dock Lease	General Plant	$39,000
45400		Xcel	General Plant	$9,313
45690		LSP Parking Ramp	General Plant	$128,400
45690		Misc Bldg Mtc Revenue	General Plant	$175,300
45690		Tower Leasing	General Plant	$238,447
			GENERAL PLANT	**$1,024,133**
		Gains from Disposition of Allowances and Utility Plant		**$57,972**
			TOTAL Revenue Credits	**$92,078,205**

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Average Fuel and Purchased Energy Cost

Unadjusted Test Year 2020	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 2020
Generation Costs													
Company Generating Stations	10,541,777	9,511,897	9,611,930	4,216,342	4,391,279	8,337,678	11,300,950	10,660,347	8,803,223	7,019,168	8,510,797	9,920,361	102,825,751
Purchased Steam-TG5	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Generation	**10,541,777**	**9,511,897**	**9,611,930**	**4,216,342**	**4,391,279**	**8,337,678**	**11,300,950**	**10,660,347**	**8,803,223**	**7,019,168**	**8,510,797**	**9,920,361**	**102,825,751**
Square Butte Energy	**3,184,005**	**2,589,455**	**3,179,905**	**3,089,455**	**3,184,005**	**2,683,535**	**3,184,005**	**3,184,005**	**2,683,505**	**3,184,005**	**3,093,555**	**3,183,085**	**36,422,520**
Purchases													
Purchases excl MISO charges	12,351,902	10,674,474	11,532,757	13,962,237	12,423,850	12,783,261	13,256,804	13,505,659	13,020,379	15,429,828	14,534,144	15,539,394	159,014,691
MISO Charges	1,265,117	599,331	1,052,666	704,493	433,690	787,771	1,134,263	1,258,692	971,906	870,223	1,137,862	1,478,152	11,694,165
Admin in MISO Charge not allocated to Retail FAC	(25,936)	(25,475)	(26,300)	(24,789)	(34,011)	(29,389)	(27,309)	(29,079)	(29,754)	(24,780)	(27,314)	(28,318)	(332,455)
Subtotal Purchases	**13,591,083**	**11,248,330**	**12,559,123**	**14,641,942**	**12,823,529**	**13,541,643**	**14,363,757**	**14,735,272**	**13,962,530**	**16,275,272**	**15,644,692**	**16,989,228**	**170,376,401**
Inter-System Sales													
IPS and RFPS	259,827	236,510	169,566	148,109	125,669	120,931	125,320	131,055	157,921	142,684	252,718	213,160	2,083,469
Economy	1,733,419	1,642,716	1,613,321	1,585,262	1,735,886	1,581,226	1,810,636	1,781,432	1,658,331	1,358,855	1,643,507	1,734,051	19,878,643
Mesabi Nugget	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Firm	2,396,017	2,293,005	2,511,804	2,498,314	911,113	966,716	1,014,488	950,036	945,718	991,598	914,179	991,306	17,384,293
Unidentified Market Sales	2,048,833	1,581,048	1,924,207	1,791,702	2,001,264	2,390,213	3,119,595	2,793,660	2,331,573	3,699,393	3,139,585	3,187,145	30,008,218
Generation Correction	0	0	0	0	0	0	0	0	0	0	0	0	0
WPPI, OC1, OC 2 Station Service	4,337	4,337	4,337	56,747	58,604	4,337	4,337	4,337	4,337	14,991	4,337	4,337	169,376
MISO recovered thru IPS, INT, ECON, NONFIRM FI	21,301	11,358	17,265	12,253	8,113	12,860	21,384	19,918	17,531	15,902	22,483	23,849	204,218
MISO recovered thru Polymet, Mesabi Nugget	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO recovered thru Power Mktg Sales	14,701	3,347	5,923	964	4,743	37,804	69,737	63,339	41,617	84,462	77,157	92,883	496,675
MISO recovered thru LTFS	149,589	78,947	132,816	99,376	24,971	43,927	58,397	60,955	50,522	45,324	51,784	67,273	863,880
Released Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Released Energy Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Liquidation	0	0	0	0	0	0	0	0	0	0	0	0	0
Total IS-S	**6,628,025**	**5,851,268**	**6,379,238**	**6,192,726**	**4,870,364**	**5,158,014**	**6,223,894**	**5,804,731**	**5,207,550**	**6,353,209**	**6,105,749**	**6,314,004**	**71,088,772**
Monthly Cost of Fuel Before TOGA	**20,688,840**	**17,498,414**	**18,971,720**	**15,755,013**	**15,528,450**	**19,404,842**	**22,624,818**	**22,774,892**	**20,241,709**	**20,125,236**	**21,143,296**	**23,778,671**	**238,535,900**
Two Month Costs													
Total Sales of Electricity	**1,179,387**	**1,053,769**	**1,124,603**	**1,031,824**	**990,675**	**983,998**	**1,080,408**	**1,063,216**	**995,764**	**1,058,519**	**1,085,443**	**1,152,401**	**12,800,007**

Unadjusted Test Year 2020	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 2020
Inter-System Sales													
IPS	8,546	8,706	6,116	5,713	5,066	5,213	4,767	5,267	6,663	6,266	10,813	8,516	81,652
LT Firm	119,962	111,293	119,962	117,227	42,362	45,227	47,162	43,962	43,627	45,562	42,027	45,562	823,933
Unidentified Market Sales	96,269	72,456	88,678	81,930	91,259	108,696	139,763	128,817	105,902	167,579	143,260	146,311	1,370,921
WPPI Station Service	167	167	167	2,026	2,092	167	167	167	167	545	167	167	6,172
Economy	64,977	63,074	61,345	60,895	67,126	61,667	69,829	68,961	64,535	53,421	63,985	67,004	766,819
EMSS (Polymet, Mesabi Nugget)	0	0	0	0	0	0	0	0	0	0	0	0	0
Released Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Released Energy Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Total IS-S	**289,921**	**255,697**	**276,268**	**267,792**	**207,906**	**220,971**	**261,688**	**247,174**	**220,895**	**273,373**	**260,252**	**267,560**	**3,049,497**
Sales for FAC Calc Before TOGA	**889,466**	**798,072**	**848,335**	**764,032**	**782,769**	**763,027**	**818,720**	**816,042**	**774,869**	**785,146**	**825,191**	**884,841**	**9,750,510**
Two Month Sales													
BEFORE TOGA and SOLAR													
One-Month Cost of Fuel	23.26	21.93	22.36	20.62	19.84	25.43	27.63	27.91	26.12	25.63	25.62	26.87	
Base Cost of Fuel	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	Average
Fuel Adjustment	**2.05**	**0.72**	**1.15**	**(0.59)**	**(1.37)**	**4.22**	**6.42**	**6.70**	**4.91**	**4.42**	**4.41**	**5.66**	**3.23**
Billing Month	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	
	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 2020
Monthly Cost of Fuel Before TOGA	20,688,840	17,498,414	18,971,720	15,755,013	15,528,450	19,404,842	22,624,818	22,774,892	20,241,709	20,125,236	21,143,296	23,778,671	**238,535,900**
Less Cost Of Solar:	0	0	0	0	0	0	0	0	0	48,838	32,025	20,829	**101,692**
Plus: Time of Generation and SEA	25,930	35,211	39,977	42,926	48,032	44,194	65,662	60,556	43,959	54,963	31,645	26,281	**519,336**
Monthly Cost of Fuel After TOGA	**20,714,770**	**17,533,626**	**19,011,697**	**15,797,939**	**15,576,482**	**19,449,036**	**22,690,480**	**22,835,448**	**20,285,668**	**20,131,360**	**21,142,915**	**23,784,122**	**238,953,543**
Two Month Costs After TOGA													
Sales for FAC Calc Before TOGA	889,466	798,072	848,335	764,032	782,769	763,027	818,720	816,042	774,869	785,146	825,191	884,841	**9,750,510**
Less: Solar Generation and Purchase Kwh to cover SES	868	1,117	1,340	1,585	1,777	1,821	1,952	1,790	1,415	2,318	1,382	1,100	**18,466**
Monthly KWH Sales After TOGA	**888,598**	**796,955**	**846,995**	**762,447**	**780,992**	**761,206**	**816,768**	**814,252**	**773,454**	**782,828**	**823,809**	**883,741**	**9,732,044**
Two Month KWH Sales After TOGA													
AFTER TOGA and SOLAR													
One-Month Cost of Fuel	23.31	22.00	22.45	20.72	19.94	25.55	27.78	28.04	26.23	25.72	25.66	26.91	**24.53**
Base Cost of Fuel	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	**Average**
Fuel Adjustment	**2.10**	**0.79**	**1.24**	**(0.49)**	**(1.27)**	**4.34**	**6.57**	**6.83**	**5.02**	**4.51**	**4.45**	**5.70**	**3.32**
Billing Month	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	

Average Fuel and Purchased Energy Cost

Summary Calculation Average Cost of Fuel and Purchasd Energy

Adjusted Test Year 2020	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 2020
Generation Costs													
Company Generating Stations	10,416,331	9,346,093	9,392,087	4,110,693	4,391,255	8,337,678	11,300,950	10,660,347	8,803,223	7,019,168	8,510,797	9,920,361	102,208,984
Purchased Steam-TG5	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Generation	**10,416,331**	**9,346,093**	**9,392,087**	**4,110,693**	**4,391,255**	**8,337,678**	**11,300,950**	**10,660,347**	**8,803,223**	**7,019,168**	**8,510,797**	**9,920,361**	**102,208,984**
Square Butte Energy	**3,184,005**	**2,589,455**	**3,179,905**	**3,089,455**	**3,184,005**	**2,683,535**	**3,184,005**	**3,184,005**	**2,683,505**	**3,184,005**	**3,093,555**	**3,183,085**	**36,422,520**
Purchases													
Purchases excl MISO charges	10,585,117	9,165,986	9,925,117	12,377,989	12,423,495	12,783,261	13,256,804	13,505,659	13,020,379	15,429,828	14,534,144	15,539,394	152,547,174
MISO Charges	1,376,640	674,550	1,138,693	767,617	433,610	787,771	1,134,263	1,258,692	971,906	870,223	1,137,862	1,478,152	12,029,979
Admin in MISO Charge not allocated to Retail FAC	(33,178)	(34,154)	(34,752)	(34,659)	(34,010)	(29,389)	(27,309)	(29,079)	(29,754)	(24,780)	(27,314)	(28,318)	(366,698)
Subtotal Purchases	**11,928,579**	**9,806,382**	**11,029,058**	**13,110,946**	**12,823,096**	**13,541,643**	**14,363,757**	**14,735,272**	**13,962,530**	**16,275,272**	**15,644,692**	**16,989,228**	**164,210,455**
Inter-System Sales													
IPS and RFPS	251,121	230,596	164,126	143,873	125,669	120,930	125,320	131,055	157,919	142,684	252,718	213,160	2,059,171
Economy	1,722,658	1,637,768	1,603,920	1,578,686	1,735,887	1,581,226	1,810,636	1,781,432	1,658,331	1,358,855	1,643,507	1,734,051	19,846,957
Mesabi Nugget	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Firm	910,042	859,070	954,078	963,885	911,113	966,716	1,014,488	950,036	945,718	991,598	914,179	991,306	11,372,228
Unidentified Market Sales	2,353,788	1,703,697	2,117,230	1,846,511	2,001,478	2,390,213	3,119,595	2,793,660	2,331,573	3,699,393	3,139,585	3,187,145	30,683,868
Generation Correction	0	0	0	0	0	0	0	0	0	0	0	0	0
WPPI, OC1, OC 2 Station Service	4,337	4,337	4,337	56,747	58,604	4,337	4,337	4,337	4,337	14,991	4,337	4,337	169,376
MISO recovered thru IPS, INT, ECON, NONFIRM FIXED PRICE	24,366	13,450	19,795	14,260	8,112	12,860	21,384	19,918	17,531	15,902	22,483	23,849	213,910
MISO recovered thru Polymet, Mesabi Nugget	0	0	0	0	0	0	0	0	0	0	0	0	0
MISO recovered thru Power Mktg Sales	38,028	8,852	18,344	3,526	4,745	37,804	69,737	63,339	41,617	84,462	77,157	92,883	540,492
MISO recovered thru LTFS	64,990	35,022	57,836	44,619	24,967	43,927	58,397	60,955	50,522	45,324	51,784	67,273	605,615
Released Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Released Energy Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Liquidation	0	0	0	0	0	0	0	0	0	0	0	0	0
Total IS-S	**5,369,329**	**4,492,791**	**4,939,666**	**4,652,108**	**4,870,574**	**5,158,014**	**6,223,894**	**5,804,731**	**5,207,548**	**6,353,209**	**6,105,749**	**6,314,004**	**65,491,618**
Monthly Cost of Fuel Before TOGA	**20,159,585**	**17,249,139**	**18,661,384**	**15,658,987**	**15,527,782**	**19,404,843**	**22,624,818**	**22,774,892**	**20,241,710**	**20,125,236**	**21,143,296**	**23,778,671**	**237,350,341**
Two Month Costs													
Total Sales of Electricity	**1,119,858**	**989,988**	**1,059,304**	**962,261**	**990,679**	**983,998**	**1,080,408**	**1,063,216**	**995,764**	**1,058,519**	**1,085,443**	**1,152,401**	**12,541,840**

Minnesota Power
Docket No. E015/GR-19-442

MP Exhibit ___ (Podratz)
Podratz Direct Schedule 7

Adjusted Test Year 2020	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 2020
Inter-System Sales													
IPS	8,546	8,706	6,116	5,713	5,066	5,213	4,767	5,267	6,663	6,266	10,813	8,516	81,652
LT Firm	45,562	41,693	45,562	45,227	42,362	45,227	47,162	43,962	43,627	45,562	42,027	45,562	533,533
Unidentified Market Sales	111,140	78,275	97,779	84,367	91,264	108,696	139,763	128,817	105,902	167,579	143,260	146,311	1,403,154
WPPI Station Service	167	167	167	2,026	2,092	167	167	167	167	545	167	167	6,172
Economy	64,977	63,074	61,345	60,895	67,126	61,667	69,829	68,961	64,535	53,421	63,985	67,004	766,819
EMSS (Polymet, Mesabi Nugget)	0	0	0	0	0	0	0	0	0	0	0	0	0
Released Firm Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Released Energy Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Total IS-S	**230,392**	**191,916**	**210,969**	**198,229**	**207,910**	**220,971**	**261,688**	**247,174**	**220,895**	**273,373**	**260,252**	**267,560**	**2,791,330**
Sales for FAC Calc Before TOGA	**889,466**	**798,072**	**848,335**	**764,032**	**782,769**	**763,027**	**818,720**	**816,042**	**774,869**	**785,146**	**825,191**	**884,841**	**9,750,510**
Two Month Sales													
BEFORE TOGA and SOLAR													
One-Month Cost of Fuel	22.66	21.61	22.00	20.50	19.84	25.43	27.63	27.91	26.12	25.63	25.62	26.87	
Base Cost of Fuel	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	21.21	Average
Fuel Adjustment	**1.45**	**0.40**	**0.79**	**(0.71)**	**(1.37)**	**4.22**	**6.42**	**6.70**	**4.91**	**4.42**	**4.41**	**5.66**	**3.11**
Billing Month	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	
	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total 2020
Monthly Cost of Fuel Before TOGA	20,159,585	17,249,139	18,661,384	15,658,987	15,527,782	19,404,843	22,624,818	22,774,892	20,241,710	20,125,236	21,143,296	23,778,671	**237,350,341**
Less Cost Of Solar:	0	0	0	0	0	0	0	0	0	48,838	32,025	20,829	**101,692**
Plus: Time of Generation and SEA	25,930	35,211	39,977	42,926	48,032	44,194	65,662	60,556	43,959	54,963	31,645	26,281	**519,336**
Monthly Cost of Fuel After TOGA	**20,185,515**	**17,284,350**	**18,701,361**	**15,701,913**	**15,575,814**	**19,449,036**	**22,690,480**	**22,835,448**	**20,285,669**	**20,131,360**	**21,142,915**	**23,784,122**	**237,767,985**
Two Month Costs After TOGA													
Sales for FAC Calc Before TOGA	889,466	798,072	848,335	764,032	782,769	763,027	818,720	816,042	774,869	785,146	825,191	884,841	**9,750,510**
Less: Solar Generation and Purchase Kwh to cover SES	868	1,117	1,340	1,585	1,777	1,821	1,952	1,790	1,415	2,318	1,382	1,100	**18,466**
Monthly KWH Sales After TOGA	**888,598**	**796,955**	**846,995**	**762,447**	**780,992**	**761,206**	**816,768**	**814,252**	**773,454**	**782,828**	**823,809**	**883,741**	**9,732,044**
Two Month KWH Sales After TOGA													
AFTER TOGA and SOLAR													
One-Month Cost of Fuel	22.72	21.69	22.08	20.59	19.94	25.55	27.78	28.04	26.23	25.72	25.66	26.91	**24.41**
Billing Month	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Average**

Fuel and Purchased Energy Cost
Base Cost of Fuel and Purchased Energy
Removed from 2020 Test Year Interim Base Energy Rates

Line No.	Designation	Class Cost Factor [l]	Base Cost of Energy $/kWh	Base Cost of Energy ¢/kWh	Class Billing Units MWh [o]	Base Cost of Fuel Revenues Removed from Energy Rates
1		E8760	0.02121 [n]	2.12100		
2	Residential	1.01406	0.02151	2.15082 [a]	948,850	$20,408,060 [g]
3	General Service	1.03518	0.02196	2.19562 [b]	679,531	$14,919,906 [h]
4	Large Light and Power	1.00982	0.02142	2.14183 [c]	1,324,161	$28,361,254 [i]
5	Large Power	0.99024	0.02100	2.10030 [d]	5,288,437	$111,072,992 [j]
6	Municipal Pumping	1.01571	0.02154	2.15432 [e]	-	$0
7	Residential Dual Fuel	1.01406	0.02151	2.15082 [a]	97,889	$2,105,417 [k]
8	Commercial Dual Fuel	1.03518	0.02196	2.19562 [b]	27,733	$608,910 [l]
9	Lighting	0.82572	0.01751	1.75135 [f]	20,418	$357,591 [m]
	Total Amount Zero Out from Energy Costs				8,387,019	$177,834,131

See Volume 1, Redline Interim Tariff Sheets. For each service, the base cost of energy is subtracted from the energy rate

[a] Sec V Pg 01 Rev 41-42 (IR) Resid. Serv Redline
[a] Sec V Pg 05 Rev 19-20 (IR) Resid. DF Interruptible Redline
[a] Sec V Pg 07 Rev 15-16 (IR) Resid. Controlled Access Redeline
[a] Sec V Pg 08 Rev 05-06 (IR) Electric Vehicle Redline

[b] Sec V Pg 10 Rev 37-38 (IR) General Service Redline
[b] Sec V Pg 16 Rev 22-23 (IR) Commerl-Indust. DF Interrupt Redline
[b] Sec V Pg 17 Rev 15-16 (IR) Commerl-Indust. Controlled Access Redline

[c] Sec V Pg 22 Rev 37-38 (IR) Large Light and Pwr Redline
[c] Sec V Pg 90 Rev 02-03 (IR) Pilot Rider-Large Light Power ToU Serv Redline

[d] Sec V Pg 24 Rev 41-42 (IR) Large Power Serv Redline
[d] Sec V Pg 25 Rev 18-19 (IR) Non Contract LP Serv Redline

[e] Sec V Pg 40 Rev 37-38 (IR) Municipal Pumping Redline

[f] Sec V Pg 37 Rev 14-15 (IR) Outdoor Area Lighting Serv Redline
[f] Sec V Pg 46 Rev 17-18 (IR) Street-Highway Lighting Serv Redline

[g] See Volume 4 Workpapers IR-1, (page 5, line 6) + (page 6, line 3) + (page 7, line 3) + (page 8, line 4)
[h] See Volume 4 Workpapers IR-1, (page 11, line 9) + (page 12, line 3)
[i] See Volume 4 Workpapers IR-1, (page 15, line 9) + (page 16, line 8)
[j] See Volume 4 Workpapers IR-1, Sum of Base Cost of Fuel totals from pages 31, 34, 36, 38, 40, 42, 44, 46
[k] See Volume 4 Workpapers IR-1, (page 17, line 3)
[l] See Volume 4 Workpapers IR-1, (page 18, line 4)
[m] See Volume 4 Workpapers IR-1, (page 21, line 13) + (page 22, line 28) + (page 23, line 17) + (page 24, line 23)
[n] See Docket No.E015/GR-16-664, Supplemental Direct, Supplemental Direct Schedule 6, page 1 of 1
[o] See Volume 4 Workpapers IR-1, Page 2. Note General Service total MWh differs by 776 MWh due to Solar Gardens.

Fuel and Purchased Energy Cost
Base Cost of Fuel and Purchased Energy
Removed from 2020 Test Year General Base Energy Rates

Line No.	Designation	Base Cost of Fuel Revenue Removed from Interim Energy Rates		Remaining Base Rate Revenue that Interim Increase Applies to		IR-1 Operating Revenue Prior to Interim Increase		Proposed Increase Direct Schedule E-1		General Rates Direct Schedule E-1		Less Schedule E-1 Total Fuel Adjustment		Schedule E-1 Base Rate Revenue excluding all Fuel costs
1		[a]		[b]		[c]		[d]		[e]		[f]		[g]
2	Residential	$20,408,060	+	$82,617,570	=	$103,025,631	+	$15,453,878	=	$118,479,508	-	$23,755,629	=	$94,723,879
3	General Service	$14,919,906	+	$57,596,647	=	$72,516,553	+	$7,504,423	=	$80,020,976	-	$17,108,576	=	$62,912,400
4	Large Light and Power	$28,361,254	+	$78,736,637	=	$107,097,891	+	$11,083,286	=	$118,181,177	-	$32,651,406	=	$85,529,770
5	Large Power	$111,072,992	+	$214,465,427	=	$325,538,419	+	$33,689,008	=	$359,227,426	-	$127,890,335	=	$231,337,092
6	Municipal Pumping	$0	+	$0	=	$0	+	$0	=	$0	-	$0	=	$0
7	Residential Dual Fuel	$2,105,417	+	$6,095,843	=	$8,201,260	+	($1,875,748)	=	$6,325,512	-	$2,305,622	=	$4,019,891
8	Commercial Dual Fuel	$608,910	+	$1,605,190	=	$2,214,100	+	($481,315)	=	$1,732,786	-	$685,084	=	$1,047,702
9	Lighting	$357,591	+	$3,151,721	=	$3,509,312	+	$526,392	=	$4,035,704	-	$445,793	=	$3,589,911
		$177,834,131		$444,269,035		$622,103,166		$65,899,923		$688,003,089		$204,842,445		$483,160,644

[a] Base Cost of Fuel total revenue from Podratz Direct Schedule 8 Page 1 of 2.

[b] Base rate revenue excluding Base Cost of fuel. Ties to Volume 4, Workpaper IR-1 Operating Revenues - Interim Column references below

Residential	See Volume 4 Workpapers IR-1, (page 5, lines 1, 2, 3, 4, 5, 8, 14) + (page 6, lines 1, 2, 5, 10) + (page 7, lines 1,2, 5, 10) + (page 8, lines 1, 2, 3, 6, 11)
General Service	See Volume 4 Workpapers IR-1, (page 11, lines 1 through 8, 11, 16) + (page 12, lines 1, 2, 5, 10)
Large Light and Power	See Volume 4 Workpapers IR-1, (page 15, lines 1 through 8, 11, 12, 13, 18) + (page 16, lines 1 through 7, 10, 15) + total Base Cost of Fuel on pages 110, 111, 112
Large Power	See Volume 4 Workpapers IR-1, Page 26, (sum of Firm Service, Interruptible Service, and Riders/CPA in Base, less Base Cost of Fuel pages 31, 34, 36, 38, 40, 42, 44, 46
Residential Dual Fuel	See Volume 4 Workpapers IR-1, (page 17, lines 1, 2, 5, 11)
Commercial Dual Fuel	See Volume 4 Workpapers IR-1, (page 18, lines 1, 2, 3, 6, 11)
Lighting	See Volume 4 Workpapers IR-1, (page 21, lines 1 through 12, 16, 20) + (page 22, lines 1 through 27, 30, 35) + (page 23, lines 1 through 16, 20, 26) + (page 24, lines 1 through 22, 26, 31)

[c] Note: Operating Revenue total is equal to Present Operating Revenue, starting point on Direct Schedule E-1, page 2. The proposed increase is added to equal General Revenue. This is also equal to Direct Schedule E-1 Present Operating Revenue
Present rate revenue prior to 7.44% interim increase.

Residential	See Volume 4 Workpapers IR-1, page 2, line 1.
General Service	See Volume 4 Workpapers IR-1, page 2, line 2.
Large Light and Power	See Volume 4 Workpapers IR-1, page 2, line 3.
Large Power	See Volume 4 Workpapers IR-1, page 2, line 4.
Residential Dual Fuel	See Volume 4 Workpapers IR-1, page 2, line 12.
Commercial Dual Fuel	See Volume 4 Workpapers IR-1, page 2, line 9.
Lighting	See Volume 4 Workpapers IR-1, page 2, line 6.

[d] Proposed Increase. Ties to Direct Schedule E-1, ($) Increase column.

Residential	See Volume 3 Direct Schedule E-1, page 2, line 1.
General Service	See Volume 3 Direct Schedule E-1, page 2, line 2.
Large Light and Power	See Volume 3 Direct Schedule E-1, page 2, line 3.
Large Power	See Volume 3 Direct Schedule E-1, page 2, line 4.
Residential Dual Fuel	See Volume 3 Direct Schedule E-1, page 2, line 8.
Commercial Dual Fuel	See Volume 3 Direct Schedule E-1, page 2, line 9.
Lighting	See Volume 3 Direct Schedule E-1, page 2, line 6.

[e] General rate revenue Ties to E-1, General column.

Residential	See Volume 3 Direct Schedule E-1, page 2, line 1.
General Service	See Volume 3 Direct Schedule E-1, page 2, line 2.
Large Light and Power	See Volume 3 Direct Schedule E-1, page 2, line 3.
Large Power	See Volume 3 Direct Schedule E-1, page 2, line 4.
Residential Dual Fuel	See Volume 3 Direct Schedule E-1, page 2, line 8.
Commercial Dual Fuel	See Volume 3 Direct Schedule E-1, page 2, line 9.
Lighting	See Volume 3 Direct Schedule E-1, page 2, line 6.

[f] Total fuel adjustment including Base Cost of Fuel.

Residential	See Volume 3 Direct Schedule E-1, (page 5, line 9) + (page 6, line 5) + (page 7, line 7) + (page 8, line 6)
General Service	See Volume 3 Direct Schedule E-1, (page 11, line 11) + (page 12, line 7)
Large Light and Power	See Volume 3 Direct Schedule E-1, (page 15, line 13) + (page 16, line 10 ~~9~~)
Large Power	See Volume 3 Direct Schedule E-1, Sum of General Rate Firm FAC totals from pages 31, 34, 36, 38, 40, 42, 44, 46
Residential Dual Fuel	See Volume 3 Direct Schedule E-1, (page 17, line 9~~5~~)
Commercial Dual Fuel	See Volume 3 Direct Schedule E-1, (page 18, line 8)
Lighting	See Volume 3 Direct Schedule E-1, (page 21, line 16) + (page 22, line 30) + (page 23, line 20) + (page 24, line 26)

[g] All fuel costs including Base Cost of Fuel have been removed from this column. Ties to Total Base Revenue for General Rates.

Residential	See Volume 3 Direct Schedule E-1, (page 5, line 8) + (page 6, line 4) + (page 7, line 6) + (page 8, line 5)
General Service	See Volume 3 Direct Schedule E-1, (page 11, line 10) + (page 12, line 6)
Large Light and Power	See Volume 3 Direct Schedule E-1, (page 15, lines 10, 11, 12) + (page 16, line 9)
Large Power	See Volume 3 Direct Schedule E-1, Sum of General Rate Firm Energy totals less Sum of Firm FAC totals from pages 31, 34, 36, 38, 40, 42, 44, 46
Residential Dual Fuel	See Volume 3 Direct Schedule E-1, (page 17, line 8)
Commercial Dual Fuel	See Volume 3 Direct Schedule E-1, (page 18, line 7)
Lighting	See Volume 3 Direct Schedule E-1, (page 21, line 14) + (page 22, line 29) + (page 23, line 18) + (page 24, line 24)

Minnesota Power 2019 Residential Rate Design Stakeholder Process Summary

October 22, 2019

I. Why was this process needed?

In late 2018 and early 2019, the Great Plains Institute and Center for Energy and Environment worked with Minnesota Power to plan and facilitate a stakeholder engagement process to explore time-varying rate designs for residential customers.[1] That process successfully resulted in stakeholders coalescing around a set of possible time-varying rate design options. However, multiple stakeholders were interested to know how a time-varying rate would impact the existing inverted block rate (IBR) design, including whether the IBR would discontinue in favor of a new time-varying rate, if one is developed and deployed.

It became clear in that process that some stakeholders thought a time-varying rate was more favorable because it could integrate additional renewables, support beneficial electrification, and be paired with more effective ways of incentivizing energy conservation (one of the primary goals of an IBR). Others thought that switching from the IBR to a time-varying rate could potentially be more costly for the same general benefits, or have adverse impacts on low-usage customers who are currently benefitting from the IBR. It was suggested that Minnesota Power should evaluate the impacts of the IBR, including customer benefits, in the process of weighing the costs and benefits for a potential time-varying rate.

For this new stakeholder process, Minnesota Power hired GPI and CEE to follow up on the previous time-varying rate design process to engage stakeholders in more broadly evaluating residential rate design options in advance of the company’s anticipated November 2019 rate case filing, and to explicitly address the question of what should happen with the current IBR rate design. In particular, Minnesota Power was seeking to explore stakeholder perspectives on rate design options that could support an increasingly diverse and decarbonized resource mix, while balancing energy affordability as a priority as well as a variety of customer products and services, including electric vehicle offerings, solar offerings, and green pricing programs.

[1] Full details about the process are available in Minnesota Power’s February 20, 2019 filing in Docket No. E015/M-12-233.

II. Who participated?

For this process, Minnesota Power was seeking to engage two groups of key stakeholders: organizations that typically get involved in proceedings at the Minnesota Public Utilities Commission (PUC) in matters concerning Minnesota Power's rates, and local organizations that may represent the interests of Minnesota Power's customers, but that do not typically submit comments to the PUC. The following organizations from those two groups chose to participate in this process. Facilitators allowed participation in-person and by phone, given the dispersion of stakeholders' geographic locations across Minnesota.

PARTICIPANTS:

- Citizens Utility Board of MN
- City of Duluth
- City of Royalton
- Ecolibrium3
- Energy CENTS Coalition
- Fresh Energy
- Fond du Lac Band of Lake Superior Chippewa
- MN Dept. of Commerce, Division of Energy Resources
- MN Office of the Attorney General

III. What did the process look like?

GPI and CEE convened stakeholders for three meetings from July to September 2019. Each meeting was a half-day long and included participation from the stakeholders listed above (in person and by phone), Minnesota Power staff, a third-party technical expert from Navigant Consulting who was hired by Minnesota Power to assist with this process, and facilitators from GPI and CEE. A brief list of the topics covered at each meeting is provided below. Notes and presentation slides from the meetings are also included as an attachment to this summary.

MEETING 1 (JULY 31, 2019 – DULUTH, MN):

- Facilitated discussion to explore stakeholders' perspective on what the utility of the future should look like (as context for discussing rate design options)
- Presentation on rate design policy trends nationally and in Minnesota, as well as on the characteristics of Minnesota Power's system and service territory.
- Facilitated discussion to assess Minnesota Power's current rate design options and identify opportunities for improvement.

MEETING 2 (AUGUST 19, 2019 – MINNEAPOLIS, MN):

- Presentation on rate design examples from other states and information (requested in the first meeting) on low income customers in Minnesota Power's service territory.

- Facilitated discussion to explore stakeholder perspectives around alternative rate design options.

MEETING 3 (SEPTEMBER 17, 2019 – MINNEAPOLIS, MN):

- Presentation from Minnesota Power on a set of specific rate design options
- Facilitated discussion to explore stakeholder perspectives on the options presented and identify areas of agreement and disagreement.

IV. What were the key outcomes?

DEFINING THE UTILITY OF THE FUTURE

In the first meeting, facilitators asked stakeholders to describe what the "utility of the future" looks like from their perspective in order to identify how rate design might fit into a larger vision of a successful utility. In particular, stakeholders were asked to define indicators of failure and success for how they envision the utility of the future. Their responses are summarized in the following table, and complete responses are in the Meeting 1 notes attached to this summary.

THEME	INDICATORS OF FAILURE	INDICATORS OF SUCCESS
Customer Satisfaction	• Needs/expectations not being met • Dissatisfied • Not loyal • Don't understand their choices	• Happy and loyal • Understand their rate structure • Enabled to make choices to meet their needs/desires • Have clear, simple, easy choices • Expectations are being met across different segments • Needs being met and increasing satisfaction through a more granular set of products and services

Utility Business Model	• Not innovating/adapting • Not competitive on costs • Not delivering safe, reliable, affordable service • Not financially healthy • Not doing "efficiency first" • Ignoring community • Utility's financial self-interest is in real conflict with the community's interests	• Delivering safe, reliable, affordable service • Embracing new technology as it develops and using it to benefit all customers • Using data to positively impact customer experience • Financially healthy • Successfully managing fuel switching from electrification • Partnering with homeowners to advance efficient housing • Community partner • Regulatory changes are decoupling sales from profits, with strong DSM incentives
Equity/Fairness	• Cost impacts from new products/services are adversely affecting low income customers (or being subsidized by them without access to the benefits) • Cost shifting across classes causing customer burdens	• Affordable access for low-income customers is being maintained • Utility is successfully resolving tensions around cost shifting between industrial and residential customers • Utility is acknowledging that many new products/services will not benefit low income customers, and is managing that to maintain affordability • Savings from new rate designs are being passed on to make rates more affordable for all
Climate	• Transition to lower emissions caused increased costs and adverse impacts on customers • Climate and other external pressures are not addressed, to the point that they're increasing energy poverty	• Emissions being reduced (both GHG and public health related) • Energy is increasingly renewable • Energy is decarbonized and service may be paid for on a subscription basis

DESIRES FOR ANY NEW RATE DESIGN

Following this conversation, facilitators asked stakeholders (including Minnesota Power staff) what they wanted out of any potential new residential rate design. These are the desires that emerged:

A. Enable customers to meet their needs/desires
B. Maintain or improve the low-income protections offered by the current inverted block rate (IBR)
C. Add time-of-day price signals
D. Have rates that are understandable/explainable to customers
E. Remove disincentives for beneficial electrification
F. Develop rates that are easier to administer for the utility internally

MAINTAINING LOW-INCOME BENEFITS FROM THE INVERTED BLOCK RATE

In the second meeting, it became clear that while the current inverted block rate design is desirable for its low-income customer benefits (desire B above), it poses challenges for meeting the other desires. In particular, stakeholders noted that the IBR is difficult for customers to understand, doesn't facilitate load shaping through time-of-day price signals, and disincentivizes beneficial electrification.

To explore this further, stakeholders discussed the low-income customer benefits of the current IBR rate design at length, seeking to identify what would need to be true to meet desire B. Those benefits were summarized as follows:

- 70% of customers pay less (per kWh) than they would on a flat rate, based on current revenue requirements as a baseline with no assumption about possible rate changes
- No application for low income, low use customers to receive a lower rate (e.g., no upfront qualification process that would pose a barrier to access)
- Offsets upwards pressure on costs from new programs/services that low-income customers may not be participating in.

With these in mind, the group explored what a new rate design could look like that would maintain or improve upon these benefits while also enabling the other desires to be met. Together, group members developed a rough proposal for a low-income, low-usage specific rate design that was more targeted to low-income customers without adding an upfront application process to qualify (which would pose barriers to low-income customers taking advantage of the rate). This low-income, low-usage rate would be paired with a different rate design for other residential customers, such as a time-of-day rate. Stakeholders thought this new low-income, low-use rate could potentially be implemented as follows:

1. Define an income level and usage level (in monthly kWh) under which customers would qualify
2. Temporarily default all customers that meet those criteria onto the rate, drawing from low income program participation data and income data from a survey that Minnesota Power had run in the past two years as a proxy

3. After a time period to be specified, ask customers to self-declare (e.g., through a survey or phone call) their low-income status to continue participation in the rate offering
4. Periodically audit the rate offering to ensure that self-declarations are accurate
5. Provide continual outreach and customer engagement across steps 1-4

The idea behind this rate offering was that it would continue to offer a discount for low-income, low-usage customers similar to what the IBR currently offers, but the discount would be more targeted specifically to low-income customers, as one of the criticisms of the current IBR rate design was that it offers a discount to all low-usage customers regardless of income (e.g., some low-usage, high-income customers receive the same discount as low-usage, low-income customers).

While participants were willing to think through these implementation steps, they also had several questions about this rate design, including whether step 2 was feasible given that Minnesota Power has limited income information about its customers. Some low-income customer advocates stated that while they were interested in this new potential offering, they still ultimately preferred the existing IBR rate design.

REFINING A NEW RATE OPTION

In the third meeting, Minnesota Power stated that it would be open to moving towards a residential time-of-day rate design eventually, with an additional rate option for low-income customers. On that additional option, the company presented the following illustrative rate design options for the group to respond to:

- Option 1A: Any household using less than 800 kWh per month is automatically put on a discounted low-income, low-usage rate. Non-low-income households are encouraged to opt out.
- Option 1B: Same as 1A, but usage threshold is set at 600 kWh.
- Option 2A: New low-use, low-income program for verified low-income customers using less than 800 kWh per month. LIHEAP participants are automatically enrolled; other low-income customers must be verified.
- Option 2B: Same as option 2A, but usage threshold is set at 600 kWh.

Stakeholders ultimately found general agreement around Option 2B, with a preference for an enrollment strategy that would opt-in LIHEAP participants and provide heavy targeted outreach to enroll additional low-income customers. Some participants raised a concern about low-income customers on electric heat, but it was noted that pending changes to Minnesota Power's CARE programs will help to alleviate that concern, with the general understanding that more targeted outreach would be helpful.

The group also discussed the transition process from the current IBR rate design towards time-of-day rates paired with a low-income option as described above. On this topic, there was discussion about whether IBR rates and TOD rates are compatible with one another due to increased complexity for customers to understand their bills, and due to increased complexity for customer billing systems.

There was general agreement that in order to gain stakeholder support for moving away from the current IBR, Minnesota Power needs to make a commitment to moving towards time-of-day, following the recommendations of the previous time-of-day rate design process. However, the group could not reach agreement on how that transition should be implemented, with some participants advocating for a flat rate in the interim, between the current IBR and future TOD rate, and other participants arguing against an interim flat rate.

V. What still needs to be resolved?

At the conclusion of the third meeting, Minnesota Power clarified that it intends to have a broader time-of-day offering for residential customers, but implementation and phasing details would need to be considered as part of the TOD proceeding. The Company also expressed receptivity to an additional rate offering specifically to protect low-income, low-usage customers with the potential for a self-declare option. However, as noted above, stakeholders did not find agreement on how that transition should take place. The two key dates at play are Minnesota Power's next rate case filing, which is expected November 1, 2019, and an updated proposal for a time-of-day rate offering, which the Commission has requested that the company provide by August 2020.

Therefore, one key remaining question is what should happen to rate offerings for Minnesota Power's residential customers between approval of the rate case and deployment of the new time-of-day rate. Some participants felt that the transition from IBR to TOD would be too abrupt, and should be softened by providing a flat rate for an interim period. Others preferred to keep the IBR rate in the interim, possibly with a reduction in the number of blocks (from 4 blocks in the current structure to 3 blocks).

Additionally, more information is needed for Minnesota Power and stakeholders to make a final assessment of the options being presented, including the following:

- How will a gradual shift to a TOD rate affect customer bills before that rate is fully deployed? Will there be significant winners and losers from the transition, and if so, how will those impacts be handled?
- What will be required of Minnesota Power to successfully administer both a TOD rate and low-income, low-usage rate? Will the costs be worthwhile?
- What would the new low-income, low-usage rate look like at a different usage threshold, such as 400 kWh per month?
- Are there other eligibility criteria to consider for a low-income, low-usage rate?
- How would a TOD rate affect the low-income customers that would be enrolled in the low-income, low-usage rate? Would those customers potentially be better off on the TOD rate, depending on their usage patterns? (It was noted that the company's implementation of a meter data management system, which is underway, will provide data that can help to answer this).

Minnesota Power - 2020 Test Year General Rates
Proposed Class Revenue Apportionment and Percent Increase

Line	Customer Class [A]	Present Rate Revenue [B]	CCOSS Percent Increase [C]	CCOSS Dollar Increase [D]	Proposed Percent Increase [E]	Proposed Dollar Increase [F]	Proposed Final Rate Revenue [G]	Final Rate Revenue (E-Schedule) [H]	Final E-Schedule Increase [I]
1	Residential	$103,025,631	35.64%	$36,723,375	15.00%	$15,453,845	$118,479,476	$118,479,508	15.00%
2	General Service	$72,516,553	-0.10%	-$69,964	10.35%	$7,504,550	$80,021,103	$80,020,976	10.35%
3	Large Light & Power	$107,097,891	4.51%	$4,834,140	10.35%	$11,083,282	$118,181,173	$118,181,177	10.35%
4	Large Power	$325,538,419	7.32%	$23,820,990	10.35%	$33,689,125	$359,227,544	$359,227,426	10.35%
5	Lighting	$3,509,312	16.86%	$591,596	15.00%	$526,397	$4,035,709	$4,035,704	15.00%
6	Subtotal by Rate Class	$611,687,806				$68,257,199	$679,945,005	$679,944,791	11.16%
7	Dual Fuel -- Residential	$8,201,260			-22.87%	-$1,875,748	$6,325,512	$6,325,512	-22.87%
8	Dual Fuel -- Comm/Ind	$2,214,100			-21.74%	-$481,314	$1,732,786	$1,732,786	-21.74%
9	Subtotal Dual Fuel	$10,415,360			-22.63%	-$2,357,062	$8,058,298	$8,058,298	-22.63%
10	**TOTAL (Sales of Electricity including Dual Fuel)**	**$622,103,166**	**10.59%**	**$65,900,138**	**10.59%**	**$65,900,137**	**$688,003,303**	**$688,003,089**	**10.59%**
11	Large Power - Other Energy	$35,557,558				$0	$35,557,558	$35,557,558	
12	TOTAL (Sales of Electricity including LP - Other Energy)	$657,660,724			10.02%	$65,900,137	$723,560,861	$723,560,647	10.02%

<u>Sources/Notes:</u>
[B] Direct Schedule E-1, page 2. Excludes ongoing rider adjustments.
[C] Column [D] divided by column [B] expressed as a percentage.
[D] Direct Schedule E-3, page 2.
[E] The Residential and Lighting classes were capped at 15% to avoid rate shock. Then the dual fuel rates were lowered in order to compete with alternative energy sources. As a result, the remaining classes needed increases above the indicated CCOSS results. Minnesota Power proposes to give the remaining three classes an equal percentage increase.
[F] Column [B] multiplied by column [E].
[G] Column [B] plus column [F].
[H] Direct Schedule E-1, page 2.
[I] Final proposed increase built into Direct Schedule E-1.

Minnesota Power
MPUC Docket No. E015/GR-19-442
Proposed Rate Increase Allocation to Rate Classes
Incremental Interim and Final Rate Increases

Rate Class	General Rate Class Cost-of-Service Study [1]	Proposed Interim Rate Increase (2020) [2]		Additional Proposed Final Rate Change (mid-2021) [3]		TOTAL Proposed General Rate Increase [4]
Residential	35.6%	7.7%	+	7.3%	=	15.0%
General Service	-0.1%	7.7%	+	2.7%	=	10.4%
Large Light & Power	4.5%	7.7%	+	2.7%	=	10.4%
Large Power	7.3%	7.7%	+	2.7%	=	10.4%
Lighting	16.9%	7.7%	+	7.3%	=	15.0%
Total Retail	**10.6%**	**7.7%**	+	**2.9%**	=	**10.6%**

Sources:
Podratz Direct Schedule 10 and Volume 1, Direct Schedule A-1(IR)

Minnesota Power
Docket No. E015/GR-19-442

Present Rates - Impact of IBR to Flat Rates Structure Change
Eligible Low Income Customer (eligible in phase 1 and 2)

Eligible for Discount
Ineligible for Discount

Monthly Usage	IBR Mo. Bill	Phase 1 monthly bill (IBR to flat) Flat w/Discount Mo. Bill	$ change to current	% change to current	Phase 2 monthly bill (IBR to flat) Flat w/Discount Mo. Bill	$ change to phase 1	% change to phase 1	$ change to current	% change to current
100	$ 15.52	$ 16.44	$ 0.93	6.0%	$ 15.93	$ (0.52)	-3.1%	$ 0.41	2.6%
200	$ 23.16	$ 24.89	$ 1.73	7.5%	$ 23.86	$ (1.03)	-4.2%	$ 0.70	3.0%
300	$ 30.80	$ 33.33	$ 2.53	8.2%	$ 31.78	$ (1.55)	-4.6%	$ 0.98	3.2%
400	$ 38.44	$ 41.78	$ 3.34	8.7%	$ 39.71	$ (2.07)	-4.9%	$ 1.27	3.3%
500	$ 48.39	$ 52.33	$ 3.94	8.1%	$ 49.62	$ (2.71)	-5.2%	$ 1.23	2.5%
600	$ 58.34	$ 62.89	$ 4.55	7.8%	$ 59.53	$ (3.36)	-5.3%	$ 1.19	2.0%
700	$ 68.29	$ 73.45	$ 5.16	7.6%	$ 69.44	$ (4.00)	-5.5%	$ 1.15	1.7%
800	$ 78.24	$ 84.00	$ 5.76	7.4%	$ 79.35	$ (4.65)	-5.5%	$ 1.11	1.4%
900	$ 90.50	$ 94.56	$ 4.06	4.5%	$ 89.26	$ (5.29)	-5.6%	$ (1.24)	-1.4%
1,000	$ 102.76	$ 105.11	$ 2.36	2.3%	$ 99.17	$ (5.94)	-5.7%	$ (3.58)	-3.5%
1,100	$ 115.02	$ 115.67	$ 0.65	0.6%	$ 109.08	$ (6.59)	-5.7%	$ (5.93)	-5.2%
1,200	$ 127.28	$ 126.23	$ (1.05)	-0.8%	$ 118.99	$ (7.23)	-5.7%	$ (8.28)	-6.5%
1,300	$ 142.04	$ 136.78	$ (5.26)	-3.7%	$ 128.90	$ (7.88)	-5.8%	$ (13.13)	-9.2%
1,400	$ 156.80	$ 147.34	$ (9.46)	-6.0%	$ 138.81	$ (8.52)	-5.8%	$ (17.98)	-11.5%
1,500	$ 171.56	$ 157.89	$ (13.67)	-8.0%	$ 148.72	$ (9.17)	-5.8%	$ (22.84)	-13.3%
1,600	$ 186.32	$ 168.45	$ (17.87)	-9.6%	$ 158.63	$ (9.81)	-5.8%	$ (27.69)	-14.9%
1,700	$ 201.08	$ 179.00	$ (22.08)	-11.0%	$ 168.54	$ (10.46)	-5.8%	$ (32.54)	-16.18%
1,800	$ 215.84	$ 189.56	$ (26.28)	-12.2%	$ 178.45	$ (11.11)	-5.9%	$ (37.39)	-17.3%
1,900	$ 230.60	$ 200.12	$ (30.49)	-13.2%	$ 188.36	$ (11.75)	-5.9%	$ (42.24)	-18.3%
2,000	$ 245.36	$ 210.67	$ (34.69)	-14.1%	$ 198.27	$ (12.40)	-5.9%	$ (47.09)	-19.2%
2,100	$ 260.12	$ 221.23	$ (38.90)	-15.0%	$ 208.19	$ (13.04)	-5.9%	$ (51.94)	-20.0%
2,200	$ 274.88	$ 231.78	$ (43.10)	-15.7%	$ 218.10	$ (13.69)	-5.9%	$ (56.79)	-20.7%
2,300	$ 289.65	$ 242.34	$ (47.31)	-16.3%	$ 228.01	$ (14.33)	-5.9%	$ (61.64)	-21.3%
2,400	$ 304.41	$ 252.90	$ (51.51)	-16.9%	$ 237.92	$ (14.98)	-5.9%	$ (66.49)	-21.8%
2,500	$ 319.17	$ 263.45	$ (55.72)	-17.5%	$ 247.83	$ (15.63)	-5.9%	$ (71.34)	-22.4%
2,600	$ 333.93	$ 274.01	$ (59.92)	-17.9%	$ 257.74	$ (16.27)	-5.9%	$ (76.19)	-22.8%
2,700	$ 348.69	$ 284.56	$ (64.13)	-18.4%	$ 267.65	$ (16.92)	-5.9%	$ (81.04)	-23.2%
2,800	$ 363.45	$ 295.12	$ (68.33)	-18.8%	$ 277.56	$ (17.56)	-6.0%	$ (85.89)	-23.6%
2,900	$ 378.21	$ 305.67	$ (72.54)	-19.2%	$ 287.47	$ (18.21)	-6.0%	$ (90.74)	-24.0%
3,000	$ 392.97	$ 316.23	$ (76.74)	-19.5%	$ 297.38	$ (18.85)	-6.0%	$ (95.59)	-24.3%

Present Rates - Impact of IBR to Flat Rates Structure Change
Eligible Non-Low Income Customer (eligible in phase 1 only)

Eligible for Discount
Ineligible for Discount

Monthly Usage	IBR Mo. Bill	Phase 1 monthly bill (IBR to flat) Flat w/Discount Mo. Bill	Phase 1 $ change to current	Phase 1 % change to current	Phase 2 monthly bill (IBR to flat) Flat w/o discount Mo. Bill	Phase 2 $ change to phase 1	Phase 2 % change to phase 1	Phase 2 $ change to current	Phase 2 % change to current
100	$ 15.52	$ 16.44	$ 0.93	6.0%	$ 17.91	$ 1.47	8.9%	$ 2.39	15.4%
200	$ 23.16	$ 24.89	$ 1.73	7.5%	$ 27.82	$ 2.93	11.8%	$ 4.66	20.1%
300	$ 30.80	$ 33.33	$ 2.53	8.2%	$ 37.73	$ 4.40	13.2%	$ 6.93	22.5%
400	$ 38.44	$ 41.78	$ 3.34	8.7%	$ 47.64	$ 5.86	14.0%	$ 9.20	23.9%
500	$ 48.39	$ 52.33	$ 3.94	8.1%	$ 57.55	$ 5.22	10.0%	$ 9.16	18.9%
600	$ 58.34	$ 62.89	$ 4.55	7.8%	$ 67.46	$ 4.57	7.3%	$ 9.12	15.6%
700	$ 68.29	$ 73.45	$ 5.16	7.6%	$ 77.37	$ 3.92	5.3%	$ 9.08	13.3%
800	$ 78.24	$ 84.00	$ 5.76	7.4%	$ 87.28	$ 3.28	3.9%	$ 9.04	11.6%
900	$ 90.50	$ 94.56	$ 4.06	4.5%	$ 97.19	$ 2.63	2.8%	$ 6.69	7.4%
1,000	$ 102.76	$ 105.11	$ 2.36	2.3%	$ 107.10	$ 1.99	1.9%	$ 4.34	4.2%
1,100	$ 115.02	$ 115.67	$ 0.65	0.6%	$ 117.01	$ 1.34	1.2%	$ 1.99	1.7%
1,200	$ 127.28	$ 126.23	$ (1.05)	-0.8%	$ 126.92	$ 0.70	0.6%	$ (0.36)	-0.3%
1,300	$ 142.04	$ 136.78	$ (5.26)	-3.7%	$ 136.83	$ 0.05	0.0%	$ (5.21)	-3.7%
1,400	$ 156.80	$ 147.34	$ (9.46)	-6.0%	$ 146.74	$ (0.59)	-0.4%	$ (10.06)	-6.4%
1,500	$ 171.56	$ 157.89	$ (13.67)	-8.0%	$ 156.65	$ (1.24)	-0.8%	$ (14.91)	-8.7%
1,600	$ 186.32	$ 168.45	$ (17.87)	-9.6%	$ 166.56	$ (1.89)	-1.1%	$ (19.76)	-10.6%
1,700	$ 201.08	$ 179.00	$ (22.08)	-11.0%	$ 176.47	$ (2.53)	-1.4%	$ (24.61)	-12.2%
1,800	$ 215.84	$ 189.56	$ (26.28)	-12.2%	$ 186.38	$ (3.18)	-1.7%	$ (29.46)	-13.6%
1,900	$ 230.60	$ 200.12	$ (30.49)	-13.2%	$ 196.29	$ (3.82)	-1.9%	$ (34.31)	-14.9%
2,000	$ 245.36	$ 210.67	$ (34.69)	-14.1%	$ 206.20	$ (4.47)	-2.1%	$ (39.16)	-16.0%
2,100	$ 260.12	$ 221.23	$ (38.90)	-15.0%	$ 216.11	$ (5.11)	-2.3%	$ (44.01)	-16.9%
2,200	$ 274.88	$ 231.78	$ (43.10)	-15.7%	$ 226.02	$ (5.76)	-2.5%	$ (48.86)	-17.8%
2,300	$ 289.65	$ 242.34	$ (47.31)	-16.3%	$ 235.93	$ (6.41)	-2.6%	$ (53.71)	-18.5%
2,400	$ 304.41	$ 252.90	$ (51.51)	-16.9%	$ 245.84	$ (7.05)	-2.8%	$ (58.56)	-19.2%
2,500	$ 319.17	$ 263.45	$ (55.72)	-17.5%	$ 255.75	$ (7.70)	-2.9%	$ (63.41)	-19.9%
2,600	$ 333.93	$ 274.01	$ (59.92)	-17.9%	$ 265.66	$ (8.34)	-3.0%	$ (68.26)	-20.4%
2,700	$ 348.69	$ 284.56	$ (64.13)	-18.4%	$ 275.57	$ (8.99)	-3.2%	$ (73.11)	-21.0%
2,800	$ 363.45	$ 295.12	$ (68.33)	-18.8%	$ 285.48	$ (9.63)	-3.3%	$ (77.97)	-21.5%
2,900	$ 378.21	$ 305.67	$ (72.54)	-19.2%	$ 295.39	$ (10.28)	-3.4%	$ (82.82)	-21.9%
3,000	$ 392.97	$ 316.23	$ (76.74)	-19.5%	$ 305.30	$ (10.93)	-3.5%	$ (87.67)	-22.3%

Minnesota Power
Docket No. E015/GR-19-442

Present Rates - Impact of IBR to Flat Rates Structure Change
Ineligible Customer (exceeds 1200 kWh avg monthly threshold)

Eligible for Discount
Ineligible for Discount

Monthly Usage	IBR Mo. Bill	Phase 1 monthly bill (IBR to flat): Flat w/o discount Mo. Bill	Phase 1: $ change to current	Phase 1: % change to current	Phase 2 monthly bill (IBR to flat): Flat w/o discount Mo. Bill	Phase 2: $ change to phase 1	Phase 2: % change to phase 1	Phase 2: $ change to current	Phase 2: % change to current
100	$ 15.52	$ 18.56	$ 3.04	19.6%	$ 17.91	$ (0.65)	-3.5%	$ 2.39	15.4%
200	$ 23.16	$ 29.11	$ 5.95	25.7%	$ 27.82	$ (1.29)	-4.4%	$ 4.66	20.1%
300	$ 30.80	$ 39.67	$ 8.87	28.8%	$ 37.73	$ (1.94)	-4.9%	$ 6.93	22.5%
400	$ 38.44	$ 50.22	$ 11.78	30.6%	$ 47.64	$ (2.58)	-5.1%	$ 9.20	23.9%
500	$ 48.39	$ 60.78	$ 12.39	25.6%	$ 57.55	$ (3.23)	-5.3%	$ 9.16	18.9%
600	$ 58.34	$ 71.34	$ 12.99	22.3%	$ 67.46	$ (3.87)	-5.4%	$ 9.12	15.6%
700	$ 68.29	$ 81.89	$ 13.60	19.9%	$ 77.37	$ (4.52)	-5.5%	$ 9.08	13.3%
800	$ 78.24	$ 92.45	$ 14.21	18.2%	$ 87.28	$ (5.17)	-5.6%	$ 9.04	11.6%
900	$ 90.50	$ 103.00	$ 12.50	13.8%	$ 97.19	$ (5.81)	-5.6%	$ 6.69	7.4%
1,000	$ 102.76	$ 113.56	$ 10.80	10.5%	$ 107.10	$ (6.46)	-5.7%	$ 4.34	4.2%
1,100	$ 115.02	$ 124.11	$ 9.10	7.9%	$ 117.01	$ (7.10)	-5.7%	$ 1.99	1.7%
1,200	$ 127.28	$ 134.67	$ 7.39	5.8%	$ 126.92	$ (7.75)	-5.8%	$ (0.36)	-0.3%
1,300	$ 142.04	$ 145.23	$ 3.19	2.2%	$ 136.83	$ (8.39)	-5.8%	$ (5.21)	-3.7%
1,400	$ 156.80	$ 155.78	$ (1.02)	-0.6%	$ 146.74	$ (9.04)	-5.8%	$ (10.06)	-6.4%
1,500	$ 171.56	$ 166.34	$ (5.22)	-3.0%	$ 156.65	$ (9.69)	-5.8%	$ (14.91)	-8.7%
1,600	$ 186.32	$ 176.89	$ (9.43)	-5.1%	$ 166.56	$ (10.33)	-5.8%	$ (19.76)	-10.6%
1,700	$ 201.08	$ 187.45	$ (13.63)	-6.8%	$ 176.47	$ (10.98)	-5.9%	$ (24.61)	-12.2%
1,800	$ 215.84	$ 198.01	$ (17.84)	-8.3%	$ 186.38	$ (11.62)	-5.9%	$ (29.46)	-13.6%
1,900	$ 230.60	$ 208.56	$ (22.04)	-9.6%	$ 196.29	$ (12.27)	-5.9%	$ (34.31)	-14.9%
2,000	$ 245.36	$ 219.12	$ (26.25)	-10.7%	$ 206.20	$ (12.91)	-5.9%	$ (39.16)	-16.0%
2,100	$ 260.12	$ 229.67	$ (30.45)	-11.7%	$ 216.11	$ (13.56)	-5.9%	$ (44.01)	-16.9%
2,200	$ 274.88	$ 240.23	$ (34.66)	-12.6%	$ 226.02	$ (14.21)	-5.9%	$ (48.86)	-17.8%
2,300	$ 289.65	$ 250.78	$ (38.86)	-13.4%	$ 235.93	$ (14.85)	-5.9%	$ (53.71)	-18.5%
2,400	$ 304.41	$ 261.34	$ (43.07)	-14.1%	$ 245.84	$ (15.50)	-5.9%	$ (58.56)	-19.2%
2,500	$ 319.17	$ 271.90	$ (47.27)	-14.8%	$ 255.75	$ (16.14)	-5.9%	$ (63.41)	-19.9%
2,600	$ 333.93	$ 282.45	$ (51.48)	-15.4%	$ 265.66	$ (16.79)	-5.9%	$ (68.26)	-20.4%
2,700	$ 348.69	$ 293.01	$ (55.68)	-16.0%	$ 275.57	$ (17.43)	-5.9%	$ (73.11)	-21.0%
2,800	$ 363.45	$ 303.56	$ (59.89)	-16.5%	$ 285.48	$ (18.08)	-6.0%	$ (77.97)	-21.5%
2,900	$ 378.21	$ 314.12	$ (64.09)	-16.9%	$ 295.39	$ (18.72)	-6.0%	$ (82.82)	-21.9%
3,000	$ 392.97	$ 324.68	$ (68.30)	-17.4%	$ 305.30	$ (19.37)	-6.0%	$ (87.67)	-22.3%

Minnesota Power
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Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

Phase 2 Billing Example 1 Customer w/ High Usage All Year	Usage	Monthly Bill (IBR)	Monthly Bill (Flat)	Low Income Discount	Monthly Bill (Flat w/Low Income Discount)	Non-Eligible		Eligible	
						$ Change	% Change	$ Change	% Change
Jan	3,200	$ 422.49	$ 325.12	NA	NA	$ (97.37)	-23.0%	NA	NA
Feb	3,000	$ 392.97	$ 305.30	NA	NA	$ (87.67)	-22.3%	NA	NA
Mar	2,500	$ 319.17	$ 255.75	NA	NA	$ (63.41)	-19.9%	NA	NA
Apr	1,900	$ 230.60	$ 196.29	NA	NA	$ (34.31)	-14.9%	NA	NA
May	1,300	$ 142.04	$ 136.83	NA	NA	$ (5.21)	-3.7%	NA	NA
June	700	$ 68.29	$ 77.37	NA	NA	$ 9.08	13.3%	NA	NA
Jul	800	$ 78.24	$ 87.28	NA	NA	$ 9.04	11.6%	NA	NA
Aug	900	$ 90.50	$ 97.19	NA	NA	$ 6.69	7.4%	NA	NA
Sep	700	$ 68.29	$ 77.37	NA	NA	$ 9.08	13.3%	NA	NA
Oct	1,000	$ 102.76	$ 107.10	NA	NA	$ 4.34	4.2%	NA	NA
Nov	1,700	$ 201.08	$ 176.47	NA	NA	$ (24.61)	-12.2%	NA	NA
Dec	2,200	$ 274.88	$ 226.02	NA	NA	$ (48.86)	-17.8%	NA	NA
Total	19,900	$ 2,391.31	$ 2,068.12			$ (323.19)	-13.5%		
Average	1,658	$ 199.28	$ 172.34			$ (26.93)	-13.5%		

Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

Phase 2 Billing Example 2 Customer w/ High Winter, Low Summer Usage	Usage	Monthly Bill (IBR)	Monthly Bill (Flat)	Low Income Discount	Monthly Bill (Flat w/Low Income Discount)	Non-Eligible $ Change	Non-Eligible % Change	Eligible $ Change	Eligible % Change
Jan	2,800	$ 363.45	$ 285.48	NA	NA	$ (77.97)	-21.5%	NA	NA
Feb	2,500	$ 319.17	$ 255.75	NA	NA	$ (63.41)	-19.9%	NA	NA
Mar	1,800	$ 215.84	$ 186.38	NA	NA	$ (29.46)	-13.6%	NA	NA
Apr	1,200	$ 127.28	$ 126.92	NA	NA	$ (0.36)	-0.3%	NA	NA
May	600	$ 58.34	$ 67.46	NA	NA	$ 9.12	15.6%	NA	NA
June	400	$ 38.44	$ 47.64	NA	NA	$ 9.20	23.9%	NA	NA
Jul	500	$ 48.39	$ 57.55	NA	NA	$ 9.16	18.9%	NA	NA
Aug	500	$ 48.39	$ 57.55	NA	NA	$ 9.16	18.9%	NA	NA
Sep	600	$ 58.34	$ 67.46	NA	NA	$ 9.12	15.6%	NA	NA
Oct	900	$ 90.50	$ 97.19	NA	NA	$ 6.69	7.4%	NA	NA
Nov	1,300	$ 142.04	$ 136.83	NA	NA	$ (5.21)	-3.7%	NA	NA
Dec	1,700	$ 201.08	$ 176.47	NA	NA	$ (24.61)	-12.2%	NA	NA
Total	14,800	$ 1,711.26	$ 1,562.70			$ (148.56)	-8.7%		
Average	1,233	$ 142.61	$ 130.23			$ (12.38)	-8.7%		

Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 3 Customer w/ Med-High Usage All Year	**Usage**	**Monthly Bill (IBR)**	**Monthly Bill (Flat)**	**Low Income Discount**	**Monthly Bill (Flat w/Low Income Discount)**	**Non-Eligible** **$ Change**	**% Change**	**Eligible** **$ Change**	**% Change**
Jan	1,100	$ 115.02	$ 117.01	$ (7.93)	$ 109.08	$ 1.99	1.7%	$ (5.93)	-5.2%
Feb	1,000	$ 102.76	$ 107.10	$ (7.93)	$ 99.17	$ 4.34	4.2%	$ (3.58)	-3.5%
Mar	900	$ 90.50	$ 97.19	$ (7.93)	$ 89.26	$ 6.69	7.4%	$ (1.24)	-1.4%
Apr	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
May	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
June	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Jul	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Aug	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Sep	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Oct	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Nov	900	$ 90.50	$ 97.19	$ (7.93)	$ 89.26	$ 6.69	7.4%	$ (1.24)	-1.4%
Dec	1,000	$ 102.76	$ 107.10	$ (7.93)	$ 99.17	$ 4.34	4.2%	$ (3.58)	-3.5%
Total	10,000	$ 999.46	$ 1,087.02	$ (95.14)	$ 991.88	$ 87.55	8.8%	$ (7.58)	-0.8%
Average	833	$ 83.29	$ 90.58	$ (7.93)	$ 82.66	$ 7.30	8.8%	$ (0.63)	-0.8%

Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

Phase 2 Billing Example 4 Customer w/ High Summer, Low Winter Usage	Usage	Monthly Bill (IBR)	Non-Low Income: Monthly Bill (Flat)	Low Income: Low Income Discount	Low Income: Monthly Bill (Flat w/Low Income Discount)	Non-Low Income Non-Eligible: $ Change	Non-Low Income Non-Eligible: % Change	Low Income Eligible: $ Change	Low Income Eligible: % Change
Jan	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Feb	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Mar	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Apr	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
May	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
June	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Jul	900	$ 90.50	$ 97.19	$ (7.93)	$ 89.26	$ 6.69	7.4%	$ (1.24)	-1.4%
Aug	900	$ 90.50	$ 97.19	$ (7.93)	$ 89.26	$ 6.69	7.4%	$ (1.24)	-1.4%
Sep	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Oct	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Nov	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Dec	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Total	7,900	$ 774.36	$ 878.90	$ (95.14)	$ 783.76	$ 104.55	13.5%	$ 9.41	1.2%
Average	658	$ 64.53	$ 73.24	$ (7.93)	$ 65.31	$ 8.71	13.5%	$ 0.78	1.2%

Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

			Non-Low Income	Low Income		Non-Low Income Non-Eligible		Low Income Eligible	
Phase 2 Billing Example 5 Customer w/ Avg Year Round Usage	**Usage**	**Monthly Bill (IBR)**	**Monthly Bill (Flat)**	**Low Income Discount**	**Monthly Bill (Flat w/Low Income Discount)**	**$ Change**	**% Change**	**$ Change**	**% Change**
Jan	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Feb	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Mar	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Apr	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
May	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
June	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Jul	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Aug	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Sep	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Oct	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Nov	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Dec	800	$ 78.24	$ 87.28	$ (7.93)	$ 79.35	$ 9.04	11.6%	$ 1.11	1.4%
Total	8,600	$ 839.38	$ 948.27	$ (95.14)	$ 853.14	$ 108.89	13.0%	$ 13.76	1.6%
Average	717	$ 69.95	$ 79.02	$ (7.93)	$ 71.09	$ 9.07	13.0%	$ 1.15	1.6%

Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 6 Customer w/ Avg-Low Usage						**Non-Eligible**		**Eligible**	
	Usage	**Monthly Bill (IBR)**	**Monthly Bill (Flat)**	**Low Income Discount**	**Monthly Bill (Flat w/Low Income Discount)**	**$ Change**	**% Change**	**$ Change**	**% Change**
Jan	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Feb	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Mar	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Apr	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
May	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
June	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Jul	700	$ 68.29	$ 77.37	$ (7.93)	$ 69.44	$ 9.08	13.3%	$ 1.15	1.7%
Aug	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Sep	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Oct	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Nov	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Dec	600	$ 58.34	$ 67.46	$ (7.93)	$ 59.53	$ 9.12	15.6%	$ 1.19	2.0%
Total	6,700	$ 650.34	$ 759.98	$ (95.14)	$ 664.84	$ 109.64	16.9%	$ 14.50	2.2%
Average	558	$ 54.20	$ 63.33	$ (7.93)	$ 55.40	$ 9.14	16.9%	$ 1.21	2.2%

Annual Bill Comparison: IBR to Phase 2 Flat using Present Revenue Requirements

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 7 Customer w/ Low year Round Usage	**Usage**	**Monthly Bill (IBR)**	**Monthly Bill (Flat)**	**Low Income Discount**	**Monthly Bill (Flat w/Low Income Discount)**	**Non-Eligible** **$ Change**	**% Change**	**Eligible** **$ Change**	**% Change**
Jan	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Feb	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
Mar	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
Apr	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
May	300	$ 30.80	$ 37.73	$ (5.95)	$ 31.78	$ 6.93	22.5%	$ 0.98	3.2%
June	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
Jul	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
Aug	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
Sep	300	$ 30.80	$ 37.73	$ (5.95)	$ 31.78	$ 6.93	22.5%	$ 0.98	3.2%
Oct	400	$ 38.44	$ 47.64	$ (7.93)	$ 39.71	$ 9.20	23.9%	$ 1.27	3.3%
Nov	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Dec	500	$ 48.39	$ 57.55	$ (7.93)	$ 49.62	$ 9.16	18.9%	$ 1.23	2.5%
Total	4,900	$ 475.87	$ 581.60	$ (91.17)	$ 490.42	$ 105.73	22.2%	$ 14.55	3.1%
Average	408	$ 39.66	$ 48.47	$ (7.60)	$ 40.87	$ 8.81	22.2%	$ 1.21	3.1%

Proposed Rates Bill Impacts

Eligible Low Income Customer (eligible in phase 1 and 2)

Eligible for Discount

Ineligible for Discount

Monthly Usage	Present Mo. Bill	Proposed Interim Mo. Bill	Proposed Final Rates - Phase 1: Proposed Mo. Bill	Phase 1: $ change to interim	Phase 1: % change to interim	Proposed Final Rates - Phase 2: Proposed Mo. Bill	Phase 2: $ change to phase 1	Phase 2: % change to phase 1	Phase 2: $ change to current	Phase 2: % change to current
100	$ 15.52	$ 16.71	$ 18.75	$ 2.03	12.2%	$ 18.15	$ (0.60)	-3.2%	$ 2.63	16.9%
200	$ 23.16	$ 24.94	$ 28.49	$ 3.55	14.2%	$ 27.30	$ (1.19)	-4.2%	$ 4.14	17.9%
300	$ 30.80	$ 33.17	$ 38.24	$ 5.06	15.3%	$ 36.45	$ (1.79)	-4.7%	$ 5.65	18.3%
400	$ 38.44	$ 41.40	$ 47.98	$ 6.58	15.9%	$ 45.60	$ (2.38)	-5.0%	$ 7.15	18.6%
500	$ 48.39	$ 52.12	$ 60.16	$ 8.04	15.4%	$ 57.03	$ (3.13)	-5.2%	$ 8.64	17.9%
600	$ 58.34	$ 62.83	$ 72.34	$ 9.51	15.1%	$ 68.47	$ (3.87)	-5.4%	$ 10.13	17.4%
700	$ 68.29	$ 73.55	$ 84.52	$ 10.98	14.9%	$ 79.90	$ (4.62)	-5.5%	$ 11.61	17.0%
800	$ 78.24	$ 84.26	$ 96.71	$ 12.44	14.8%	$ 91.34	$ (5.36)	-5.5%	$ 13.10	16.7%
900	$ 90.50	$ 97.47	$ 108.89	$ 11.42	11.7%	$ 102.78	$ (6.11)	-5.6%	$ 12.28	13.6%
1,000	$ 102.76	$ 110.67	$ 121.07	$ 10.40	9.4%	$ 114.21	$ (6.86)	-5.7%	$ 11.45	11.1%
1,100	$ 115.02	$ 123.87	$ 133.25	$ 9.37	7.6%	$ 125.65	$ (7.60)	-5.7%	$ 10.63	9.2%
1,200	$ 127.28	$ 137.08	$ 145.43	$ 8.35	6.1%	$ 137.09	$ (8.35)	-5.7%	$ 9.81	7.7%
1,300	$ 142.04	$ 152.98	$ 157.61	$ 4.64	3.0%	$ 148.52	$ (9.09)	-5.8%	$ 6.48	4.6%
1,400	$ 156.80	$ 168.87	$ 169.79	$ 0.92	0.5%	$ 159.96	$ (9.84)	-5.8%	$ 3.16	2.0%
1,500	$ 171.56	$ 184.77	$ 181.97	$ (2.80)	-1.5%	$ 171.39	$ (10.58)	-5.8%	$ (0.17)	-0.1%
1,600	$ 186.32	$ 200.67	$ 194.16	$ (6.51)	-3.2%	$ 182.83	$ (11.33)	-5.8%	$ (3.49)	-1.9%
1,700	$ 201.08	$ 216.56	$ 206.34	$ (10.23)	-4.7%	$ 194.27	$ (12.07)	-5.9%	$ (6.82)	-3.4%
1,800	$ 215.84	$ 232.46	$ 218.52	$ (13.94)	-6.0%	$ 205.70	$ (12.82)	-5.9%	$ (10.14)	-4.7%
1,900	$ 230.60	$ 248.36	$ 230.70	$ (17.66)	-7.1%	$ 217.14	$ (13.56)	-5.9%	$ (13.46)	-5.8%
2,000	$ 245.36	$ 264.26	$ 242.88	$ (21.38)	-8.1%	$ 228.57	$ (14.31)	-5.9%	$ (16.79)	-6.8%
2,100	$ 260.12	$ 280.15	$ 255.06	$ (25.09)	-9.0%	$ 240.01	$ (15.05)	-5.9%	$ (20.11)	-7.7%
2,200	$ 274.88	$ 296.05	$ 267.24	$ (28.81)	-9.7%	$ 251.45	$ (15.80)	-5.9%	$ (23.44)	-8.5%
2,300	$ 289.65	$ 311.95	$ 279.42	$ (32.52)	-10.4%	$ 262.88	$ (16.54)	-5.9%	$ (26.76)	-9.2%
2,400	$ 304.41	$ 327.85	$ 291.61	$ (36.24)	-11.1%	$ 274.32	$ (17.29)	-5.9%	$ (30.09)	-9.9%
2,500	$ 319.17	$ 343.74	$ 303.79	$ (39.96)	-11.6%	$ 285.76	$ (18.03)	-5.9%	$ (33.41)	-10.5%
2,600	$ 333.93	$ 359.64	$ 315.97	$ (43.67)	-12.1%	$ 297.19	$ (18.78)	-5.9%	$ (36.74)	-11.0%
2,700	$ 348.69	$ 375.54	$ 328.15	$ (47.39)	-12.6%	$ 308.63	$ (19.52)	-5.9%	$ (40.06)	-11.5%
2,800	$ 363.45	$ 391.43	$ 340.33	$ (51.10)	-13.1%	$ 320.06	$ (20.27)	-6.0%	$ (43.39)	-11.9%
2,900	$ 378.21	$ 407.33	$ 352.51	$ (54.82)	-13.5%	$ 331.50	$ (21.01)	-6.0%	$ (46.71)	-12.4%
3,000	$ 392.97	$ 423.23	$ 364.69	$ (58.54)	-13.8%	$ 342.94	$ (21.76)	-6.0%	$ (50.03)	-12.7%

Proposed Rates Bill Impacts
Eligible Non-Low Income Customer (eligible in phase 1 only)

Eligible for Discount
Ineligible for Discount

Monthly Usage	Present Mo. Bill	Proposed Interim Mo. Bill	Proposed Final Rates - Phase 1: Proposed Mo. Bill	Phase 1: $ change to interim	Phase 1: % change to interim	Proposed Final Rates - Phase 2: Proposed Mo. Bill	Phase 2: $ change to phase 1	Phase 2: % change to phase 1	Phase 2: $ change to current	Phase 2: % change to current
100	$ 15.52	$ 16.71	$ 18.75	$ 2.03	12.2%	$ 20.44	$ 1.69	9.0%	$ 4.92	31.7%
200	$ 23.16	$ 24.94	$ 28.49	$ 3.55	14.2%	$ 31.87	$ 3.38	11.9%	$ 8.71	37.6%
300	$ 30.80	$ 33.17	$ 38.24	$ 5.06	15.3%	$ 43.31	$ 5.07	13.3%	$ 12.51	40.6%
400	$ 38.44	$ 41.40	$ 47.98	$ 6.58	15.9%	$ 54.74	$ 6.76	14.1%	$ 16.30	42.4%
500	$ 48.39	$ 52.12	$ 60.16	$ 8.04	15.4%	$ 66.18	$ 6.02	10.0%	$ 17.79	36.8%
600	$ 58.34	$ 62.83	$ 72.34	$ 9.51	15.1%	$ 77.62	$ 5.27	7.3%	$ 19.28	33.0%
700	$ 68.29	$ 73.55	$ 84.52	$ 10.98	14.9%	$ 89.05	$ 4.53	5.4%	$ 20.76	30.4%
800	$ 78.24	$ 84.26	$ 96.71	$ 12.44	14.8%	$ 100.49	$ 3.78	3.9%	$ 22.25	28.4%
900	$ 90.50	$ 97.47	$ 108.89	$ 11.42	11.7%	$ 111.93	$ 3.04	2.8%	$ 21.43	23.7%
1,000	$ 102.76	$ 110.67	$ 121.07	$ 10.40	9.4%	$ 123.36	$ 2.29	1.9%	$ 20.60	20.1%
1,100	$ 115.02	$ 123.87	$ 133.25	$ 9.37	7.6%	$ 134.80	$ 1.55	1.2%	$ 19.78	17.2%
1,200	$ 127.28	$ 137.08	$ 145.43	$ 8.35	6.1%	$ 146.23	$ 0.80	0.6%	$ 18.96	14.9%
1,300	$ 142.04	$ 152.98	$ 157.61	$ 4.64	3.0%	$ 157.67	$ 0.06	0.0%	$ 15.63	11.0%
1,400	$ 156.80	$ 168.87	$ 169.79	$ 0.92	0.5%	$ 169.11	$ (0.69)	-0.4%	$ 12.31	7.8%
1,500	$ 171.56	$ 184.77	$ 181.97	$ (2.80)	-1.5%	$ 180.54	$ (1.43)	-0.8%	$ 8.98	5.2%
1,600	$ 186.32	$ 200.67	$ 194.16	$ (6.51)	-3.2%	$ 191.98	$ (2.18)	-1.1%	$ 5.66	3.0%
1,700	$ 201.08	$ 216.56	$ 206.34	$ (10.23)	-4.7%	$ 203.41	$ (2.92)	-1.4%	$ 2.33	1.2%
1,800	$ 215.84	$ 232.46	$ 218.52	$ (13.94)	-6.0%	$ 214.85	$ (3.67)	-1.7%	$ (0.99)	-0.5%
1,900	$ 230.60	$ 248.36	$ 230.70	$ (17.66)	-7.1%	$ 226.29	$ (4.41)	-1.9%	$ (4.32)	-1.9%
2,000	$ 245.36	$ 264.26	$ 242.88	$ (21.38)	-8.1%	$ 237.72	$ (5.16)	-2.1%	$ (7.64)	-3.1%
2,100	$ 260.12	$ 280.15	$ 255.06	$ (25.09)	-9.0%	$ 249.16	$ (5.90)	-2.3%	$ (10.96)	-4.2%
2,200	$ 274.88	$ 296.05	$ 267.24	$ (28.81)	-9.7%	$ 260.60	$ (6.65)	-2.5%	$ (14.29)	-5.2%
2,300	$ 289.65	$ 311.95	$ 279.42	$ (32.52)	-10.4%	$ 272.03	$ (7.39)	-2.6%	$ (17.61)	-6.1%
2,400	$ 304.41	$ 327.85	$ 291.61	$ (36.24)	-11.1%	$ 283.47	$ (8.14)	-2.8%	$ (20.94)	-6.9%
2,500	$ 319.17	$ 343.74	$ 303.79	$ (39.96)	-11.6%	$ 294.90	$ (8.88)	-2.9%	$ (24.26)	-7.6%
2,600	$ 333.93	$ 359.64	$ 315.97	$ (43.67)	-12.1%	$ 306.34	$ (9.63)	-3.0%	$ (27.59)	-8.3%
2,700	$ 348.69	$ 375.54	$ 328.15	$ (47.39)	-12.6%	$ 317.78	$ (10.37)	-3.2%	$ (30.91)	-8.9%
2,800	$ 363.45	$ 391.43	$ 340.33	$ (51.10)	-13.1%	$ 329.21	$ (11.12)	-3.3%	$ (34.24)	-9.4%
2,900	$ 378.21	$ 407.33	$ 352.51	$ (54.82)	-13.5%	$ 340.65	$ (11.86)	-3.4%	$ (37.56)	-9.9%
3,000	$ 392.97	$ 423.23	$ 364.69	$ (58.54)	-13.8%	$ 352.08	$ (12.61)	-3.5%	$ (40.89)	-10.4%

Proposed Rates Bill Impacts
Ineligible Customer (exceeds 1200 kWh avg monthly threshold)

Eligible for Discount
Ineligible for Discount

Monthly Usage	Present Mo. Bill	Proposed Interim Mo. Bill	Proposed Final Rates - Phase 1: Proposed Mo. Bill	Phase 1: $ change to interim	Phase 1: % change to interim	Proposed Final Rates - Phase 2: Proposed Mo. Bill	Phase 2: $ change to phase 1	Phase 2: % change to phase 1	Phase 2: $ change to current	Phase 2: % change to current
100	$ 15.52	$ 16.71	$ 21.18	$ 4.47	26.7%	$ 20.44	$ (0.75)	-3.5%	$ 4.92	31.7%
200	$ 23.16	$ 24.94	$ 33.36	$ 8.42	33.8%	$ 31.87	$ (1.49)	-4.5%	$ 8.71	37.6%
300	$ 30.80	$ 33.17	$ 45.54	$ 12.37	37.3%	$ 43.31	$ (2.24)	-4.9%	$ 12.51	40.6%
400	$ 38.44	$ 41.40	$ 57.73	$ 16.32	39.4%	$ 54.74	$ (2.98)	-5.2%	$ 16.30	42.4%
500	$ 48.39	$ 52.12	$ 69.91	$ 17.79	34.1%	$ 66.18	$ (3.73)	-5.3%	$ 17.79	36.8%
600	$ 58.34	$ 62.83	$ 82.09	$ 19.25	30.6%	$ 77.62	$ (4.47)	-5.4%	$ 19.28	33.0%
700	$ 68.29	$ 73.55	$ 94.27	$ 20.72	28.2%	$ 89.05	$ (5.22)	-5.5%	$ 20.76	30.4%
800	$ 78.24	$ 84.26	$ 106.45	$ 22.19	26.3%	$ 100.49	$ (5.96)	-5.6%	$ 22.25	28.4%
900	$ 90.50	$ 97.47	$ 118.63	$ 21.16	21.7%	$ 111.93	$ (6.71)	-5.7%	$ 21.43	23.7%
1,000	$ 102.76	$ 110.67	$ 130.81	$ 20.14	18.2%	$ 123.36	$ (7.45)	-5.7%	$ 20.60	20.1%
1,100	$ 115.02	$ 123.87	$ 142.99	$ 19.12	15.4%	$ 134.80	$ (8.20)	-5.7%	$ 19.78	17.2%
1,200	$ 127.28	$ 137.08	$ 155.18	$ 18.10	13.2%	$ 146.23	$ (8.94)	-5.8%	$ 18.96	14.9%
1,300	$ 142.04	$ 152.98	$ 167.36	$ 14.38	9.4%	$ 157.67	$ (9.69)	-5.8%	$ 15.63	11.0%
1,400	$ 156.80	$ 168.87	$ 179.54	$ 10.67	6.3%	$ 169.11	$ (10.43)	-5.8%	$ 12.31	7.8%
1,500	$ 171.56	$ 184.77	$ 191.72	$ 6.95	3.8%	$ 180.54	$ (11.18)	-5.8%	$ 8.98	5.2%
1,600	$ 186.32	$ 200.67	$ 203.90	$ 3.23	1.6%	$ 191.98	$ (11.92)	-5.8%	$ 5.66	3.0%
1,700	$ 201.08	$ 216.56	$ 216.08	$ (0.48)	-0.2%	$ 203.41	$ (12.67)	-5.9%	$ 2.33	1.2%
1,800	$ 215.84	$ 232.46	$ 228.26	$ (4.20)	-1.8%	$ 214.85	$ (13.41)	-5.9%	$ (0.99)	-0.5%
1,900	$ 230.60	$ 248.36	$ 240.44	$ (7.91)	-3.2%	$ 226.29	$ (14.16)	-5.9%	$ (4.32)	-1.9%
2,000	$ 245.36	$ 264.26	$ 252.63	$ (11.63)	-4.4%	$ 237.72	$ (14.90)	-5.9%	$ (7.64)	-3.1%
2,100	$ 260.12	$ 280.15	$ 264.81	$ (15.35)	-5.5%	$ 249.16	$ (15.65)	-5.9%	$ (10.96)	-4.2%
2,200	$ 274.88	$ 296.05	$ 276.99	$ (19.06)	-6.4%	$ 260.60	$ (16.39)	-5.9%	$ (14.29)	-5.2%
2,300	$ 289.65	$ 311.95	$ 289.17	$ (22.78)	-7.3%	$ 272.03	$ (17.14)	-5.9%	$ (17.61)	-6.1%
2,400	$ 304.41	$ 327.85	$ 301.35	$ (26.50)	-8.1%	$ 283.47	$ (17.88)	-5.9%	$ (20.94)	-6.9%
2,500	$ 319.17	$ 343.74	$ 313.53	$ (30.21)	-8.8%	$ 294.90	$ (18.63)	-5.9%	$ (24.26)	-7.6%
2,600	$ 333.93	$ 359.64	$ 325.71	$ (33.93)	-9.4%	$ 306.34	$ (19.37)	-5.9%	$ (27.59)	-8.3%
2,700	$ 348.69	$ 375.54	$ 337.89	$ (37.64)	-10.0%	$ 317.78	$ (20.12)	-6.0%	$ (30.91)	-8.9%
2,800	$ 363.45	$ 391.43	$ 350.08	$ (41.36)	-10.6%	$ 329.21	$ (20.86)	-6.0%	$ (34.24)	-9.4%
2,900	$ 378.21	$ 407.33	$ 362.26	$ (45.08)	-11.1%	$ 340.65	$ (21.61)	-6.0%	$ (37.56)	-9.9%
3,000	$ 392.97	$ 423.23	$ 374.44	$ (48.79)	-11.5%	$ 352.08	$ (22.35)	-6.0%	$ (40.89)	-10.4%

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

Phase 2 Billing Example 1 Customer w/ High Usage All Year	**Usage**	**Present Monthly Bill (IBR)**	**Proposed Monthly Bill (Flat)**	**Proposed Low Income Discount**	**Proposed Monthly Bill (Flat w/Low Income Discount)**	**Non-Eligible**		**Eligible**	
						$ Change	**% Change**	**$ Change**	**% Change**
Jan	3,200	$ 422.49	$ 374.96	NA	NA	$ (47.54)	-11.3%	NA	NA
Feb	3,000	$ 392.97	$ 352.08	NA	NA	$ (40.89)	-10.4%	NA	NA
Mar	2,500	$ 319.17	$ 294.90	NA	NA	$ (24.26)	-7.6%	NA	NA
Apr	1,900	$ 230.60	$ 226.29	NA	NA	$ (4.32)	-1.9%	NA	NA
May	1,300	$ 142.04	$ 157.67	NA	NA	$ 15.63	11.0%	NA	NA
June	700	$ 68.29	$ 89.05	NA	NA	$ 20.76	30.4%	NA	NA
Jul	800	$ 78.24	$ 100.49	NA	NA	$ 22.25	28.4%	NA	NA
Aug	900	$ 90.50	$ 111.93	NA	NA	$ 21.43	23.7%	NA	NA
Sep	700	$ 68.29	$ 89.05	NA	NA	$ 20.76	30.4%	NA	NA
Oct	1,000	$ 102.76	$ 123.36	NA	NA	$ 20.60	20.1%	NA	NA
Nov	1,700	$ 201.08	$ 203.41	NA	NA	$ 2.33	1.2%	NA	NA
Dec	2,200	$ 274.88	$ 260.60	NA	NA	$ (14.29)	-5.2%	NA	NA
Total	19,900	$ 2,391.31	$ 2,383.80			$ (7.52)	-0.3%		
Average	1,658	$ 199.28	$ 198.65			$ (0.63)	-0.3%		

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

Phase 2 Billing Example 2 Customer w/ High Winter, Low Summer Usage	Usage	Present Monthly Bill (IBR)	Proposed Monthly Bill (Flat)	Proposed Low Income Discount	Proposed Monthly Bill (Flat w/Low Income Discount)	Non-Eligible		Eligible	
						$ Change	% Change	$ Change	% Change
Jan	2,800	$ 363.45	$ 329.21	NA	NA	$ (34.24)	-9.4%	NA	NA
Feb	2,500	$ 319.17	$ 294.90	NA	NA	$ (24.26)	-7.6%	NA	NA
Mar	1,800	$ 215.84	$ 214.85	NA	NA	$ (0.99)	-0.5%	NA	NA
Apr	1,200	$ 127.28	$ 146.23	NA	NA	$ 18.96	14.9%	NA	NA
May	600	$ 58.34	$ 77.62	NA	NA	$ 19.28	33.0%	NA	NA
June	400	$ 38.44	$ 54.74	NA	NA	$ 16.30	42.4%	NA	NA
Jul	500	$ 48.39	$ 66.18	NA	NA	$ 17.79	36.8%	NA	NA
Aug	500	$ 48.39	$ 66.18	NA	NA	$ 17.79	36.8%	NA	NA
Sep	600	$ 58.34	$ 77.62	NA	NA	$ 19.28	33.0%	NA	NA
Oct	900	$ 90.50	$ 111.93	NA	NA	$ 21.43	23.7%	NA	NA
Nov	1,300	$ 142.04	$ 157.67	NA	NA	$ 15.63	11.0%	NA	NA
Dec	1,700	$ 201.08	$ 203.41	NA	NA	$ 2.33	1.2%	NA	NA
Total	14,800	$ 1,711.26	$ 1,800.55			$ 89.29	5.2%		
Average	1,233	$ 142.61	$ 150.05			$ 7.44	5.2%		

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

			Non-Low Income	Low Income		Non-Low Income		Low Income	
						Non-Eligible		Eligible	
Phase 2 Billing Example 3 Customer w/ Med-High Usage All Year	**Usage**	**Present Monthly Bill (IBR)**	**Proposed Monthly Bill (Flat)**	**Proposed Low Income Discount**	**Proposed Monthly Bill (Flat w/Low Income Discount)**	**$ Change**	**% Change**	**$ Change**	**% Change**
Jan	1,100	$ 115.02	$ 134.80	$ (9.15)	$ 125.65	$ 19.78	17.2%	$ 10.63	9.2%
Feb	1,000	$ 102.76	$ 123.36	$ (9.15)	$ 114.21	$ 20.60	20.1%	$ 11.45	11.1%
Mar	900	$ 90.50	$ 111.93	$ (9.15)	$ 102.78	$ 21.43	23.7%	$ 12.28	13.6%
Apr	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
May	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
June	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Jul	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Aug	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Sep	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Oct	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Nov	900	$ 90.50	$ 111.93	$ (9.15)	$ 102.78	$ 21.43	23.7%	$ 12.28	13.6%
Dec	1,000	$ 102.76	$ 123.36	$ (9.15)	$ 114.21	$ 20.60	20.1%	$ 11.45	11.1%
Total	10,000	$ 999.46	$ 1,251.62	$ (109.79)	$ 1,141.83	$ 252.15	25.2%	$ 142.37	14.2%
Average	833	$ 83.29	$ 104.30	$ (9.15)	$ 95.15	$ 21.01	25.2%	$ 11.86	14.2%

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 4 Customer w/ High Summer, Low Winter Usage	**Usage**	**Present Monthly Bill (IBR)**	**Proposed Monthly Bill (Flat)**	**Proposed Low Income Discount**	**Proposed Monthly Bill (Flat w/Low Income Discount)**	**Non-Eligible** **$ Change**	**% Change**	**Eligible** **$ Change**	**% Change**
Jan	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Feb	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Mar	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Apr	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
May	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
June	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Jul	900	$ 90.50	$ 111.93	$ (9.15)	$ 102.78	$ 21.43	23.7%	$ 12.28	13.6%
Aug	900	$ 90.50	$ 111.93	$ (9.15)	$ 102.78	$ 21.43	23.7%	$ 12.28	13.6%
Sep	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Oct	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Nov	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Dec	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Total	7,900	$ 774.36	$ 1,011.46	$ (109.79)	$ 901.67	$ 237.10	30.6%	$ 127.31	16.4%
Average	658	$ 64.53	$ 84.29	$ (9.15)	$ 75.14	$ 19.76	30.6%	$ 10.61	16.4%

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 5 Customer w/ Avg Year Round Usage						**Non-Eligible**		**Eligible**	
	Usage	**Present Monthly Bill (IBR)**	**Proposed Monthly Bill (Flat)**	**Proposed Low Income Discount**	**Proposed Monthly Bill (Flat w/Low Income Discount)**	**$ Change**	**% Change**	**$ Change**	**% Change**
Jan	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Feb	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Mar	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Apr	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
May	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
June	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Jul	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Aug	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Sep	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Oct	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Nov	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Dec	800	$ 78.24	$ 100.49	$ (9.15)	$ 91.34	$ 22.25	28.4%	$ 13.10	16.7%
Total	8,600	$ 839.38	$ 1,091.51	$ (109.79)	$ 981.72	$ 252.13	30.0%	$ 142.34	17.0%
Average	717	$ 69.95	$ 90.96	$ (9.15)	$ 81.81	$ 21.01	30.0%	$ 11.86	17.0%

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 6 Customer w/ Avg-Low Usage	**Usage**	**Present Monthly Bill (IBR)**	**Proposed Monthly Bill (Flat)**	**Proposed Low Income Discount**	**Proposed Monthly Bill (Flat w/Low Income Discount)**	**Non-Eligible** **$ Change**	**% Change**	**Eligible** **$ Change**	**% Change**
Jan	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Feb	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Mar	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Apr	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
May	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
June	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Jul	700	$ 68.29	$ 89.05	$ (9.15)	$ 79.90	$ 20.76	30.4%	$ 11.61	17.0%
Aug	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Sep	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Oct	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Nov	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Dec	600	$ 58.34	$ 77.62	$ (9.15)	$ 68.47	$ 19.28	33.0%	$ 10.13	17.4%
Total	6,700	$ 650.34	$ 874.22	$ (109.79)	$ 764.44	$ 223.88	34.4%	$ 114.09	17.5%
Average	558	$ 54.20	$ 72.85	$ (9.15)	$ 63.70	$ 18.66	34.4%	$ 9.51	17.5%

Annual Bill Comparison: Present Rates to Phase 2 Proposed Rates

			Non-Low Income	Low Income		Non-Low Income		Low Income	
Phase 2 Billing Example 7 Customer w/ Low year Round Usage	**Usage**	**Present Monthly Bill (IBR)**	**Proposed Monthly Bill (Flat)**	**Proposed Low Income Discount**	**Proposed Monthly Bill (Flat w/Low Income Discount)**	**Non-Eligible** **$ Change**	**% Change**	**Eligible** **$ Change**	**% Change**
Jan	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Feb	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
Mar	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
Apr	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
May	300	$ 30.80	$ 43.31	$ (6.86)	$ 36.45	$ 12.51	40.6%	$ 5.65	18.3%
June	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
Jul	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
Aug	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
Sep	300	$ 30.80	$ 43.31	$ (6.86)	$ 36.45	$ 12.51	40.6%	$ 5.65	18.3%
Oct	400	$ 38.44	$ 54.74	$ (9.15)	$ 45.60	$ 16.30	42.4%	$ 7.15	18.6%
Nov	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Dec	500	$ 48.39	$ 66.18	$ (9.15)	$ 57.03	$ 17.79	36.8%	$ 8.64	17.9%
Total	4,900	$ 475.87	$ 668.37	$ (105.21)	$ 563.16	$ 192.50	40.5%	$ 87.29	18.3%
Average	408	$ 39.66	$ 55.70	$ (8.77)	$ 46.93	$ 16.04	40.5%	$ 7.27	18.3%

Phase 2 Structure Change and Revenue Change Impact Summary (Eligible for Discount)

		Present Revenue Requirements			Proposed Revenue Requirements				
Eligible for Discount		Flat Rate w/ Discount: Phase 2	Bill Impact specific to IBR to Flat Structure Change		Proposed Final Rates: Phase 2	Bill Impact Specific to Change in Revenue Requirement		**Total Bill Impact from IBR to Flat & Proposed Revenue Requirement**	
Monthly Usage	Present Mo. Bill	Mo. Bill	$ change	% change	Mo. Bill	$ change	% change	**$ change**	**% change**
100	$ 15.52	$ 15.93	$ 0.41	2.6%	$ 18.15	$ 2.22	14.3%	**$ 2.63**	**16.9%**
200	$ 23.16	$ 23.86	$ 0.70	3.0%	$ 27.30	$ 3.44	14.9%	**$ 4.14**	**17.9%**
300	$ 30.80	$ 31.78	$ 0.98	3.2%	$ 36.45	$ 4.66	15.1%	**$ 5.65**	**18.3%**
400	$ 38.44	$ 39.71	$ 1.27	3.3%	$ 45.60	$ 5.88	15.3%	**$ 7.15**	**18.6%**
500	$ 48.39	$ 49.62	$ 1.23	2.5%	$ 57.03	$ 7.41	15.3%	**$ 8.64**	**17.9%**
600	$ 58.34	$ 59.53	$ 1.19	2.0%	$ 68.47	$ 8.94	15.3%	**$ 10.13**	**17.4%**
700	$ 68.29	$ 69.44	$ 1.15	1.7%	$ 79.90	$ 10.46	15.3%	**$ 11.61**	**17.0%**
800	$ 78.24	$ 79.35	$ 1.11	1.4%	$ 91.34	$ 11.99	15.3%	**$ 13.10**	**16.7%**
900	$ 90.50	$ 89.26	$ (1.24)	-1.4%	$ 102.78	$ 13.51	14.9%	**$ 12.28**	**13.6%**
1,000	$ 102.76	$ 99.17	$ (3.58)	-3.5%	$ 114.21	$ 15.04	14.6%	**$ 11.45**	**11.1%**
1,100	$ 115.02	$ 109.08	$ (5.93)	-5.2%	$ 125.65	$ 16.57	14.4%	**$ 10.63**	**9.2%**
1,200	$ 127.28	$ 118.99	$ (8.28)	-6.5%	$ 137.09	$ 18.09	14.2%	**$ 9.81**	**7.7%**
1,300	$ 142.04	$ 128.90	$ (13.13)	-9.2%	$ 148.52	$ 19.62	13.8%	**$ 6.48**	**4.6%**
1,400	$ 156.80	$ 138.81	$ (17.98)	-11.5%	$ 159.96	$ 21.14	13.5%	**$ 3.16**	**2.0%**
1,500	$ 171.56	$ 148.72	$ (22.84)	-13.3%	$ 171.39	$ 22.67	13.2%	**$ (0.17)**	**-0.1%**
1,600	$ 186.32	$ 158.63	$ (27.69)	-14.9%	$ 182.83	$ 24.20	13.0%	**$ (3.49)**	**-1.9%**
1,700	$ 201.08	$ 168.54	$ (32.54)	-16.2%	$ 194.27	$ 25.72	12.8%	**$ (6.82)**	**-3.4%**
1,800	$ 215.84	$ 178.45	$ (37.39)	-17.3%	$ 205.70	$ 27.25	12.6%	**$ (10.14)**	**-4.7%**
1,900	$ 230.60	$ 188.36	$ (42.24)	-18.3%	$ 217.14	$ 28.77	12.5%	**$ (13.46)**	**-5.8%**
2,000	$ 245.36	$ 198.27	$ (47.09)	-19.2%	$ 228.57	$ 30.30	12.3%	**$ (16.79)**	**-6.8%**
2,100	$ 260.12	$ 208.19	$ (51.94)	-20.0%	$ 240.01	$ 31.83	12.2%	**$ (20.11)**	**-7.7%**
2,200	$ 274.88	$ 218.10	$ (56.79)	-20.7%	$ 251.45	$ 33.35	12.1%	**$ (23.44)**	**-8.5%**
2,300	$ 289.65	$ 228.01	$ (61.64)	-21.3%	$ 262.88	$ 34.88	12.0%	**$ (26.76)**	**-9.2%**
2,400	$ 304.41	$ 237.92	$ (66.49)	-21.8%	$ 274.32	$ 36.40	12.0%	**$ (30.09)**	**-9.9%**
2,500	$ 319.17	$ 247.83	$ (71.34)	-22.4%	$ 285.76	$ 37.93	11.9%	**$ (33.41)**	**-10.5%**
2,600	$ 333.93	$ 257.74	$ (76.19)	-22.8%	$ 297.19	$ 39.46	11.8%	**$ (36.74)**	**-11.0%**
2,700	$ 348.69	$ 267.65	$ (81.04)	-23.2%	$ 308.63	$ 40.98	11.8%	**$ (40.06)**	**-11.5%**
2,800	$ 363.45	$ 277.56	$ (85.89)	-23.6%	$ 320.06	$ 42.51	11.7%	**$ (43.39)**	**-11.9%**
2,900	$ 378.21	$ 287.47	$ (90.74)	-24.0%	$ 331.50	$ 44.03	11.6%	**$ (46.71)**	**-12.4%**
3,000	$ 392.97	$ 297.38	$ (95.59)	-24.3%	$ 342.94	$ 45.56	11.6%	**$ (50.03)**	**-12.7%**

Phase 2 Structure Change and Revenue Change Impact Summary (Ineligible for Discount)

Not Eligible for Discount		Present Revenue Requirements			Proposed Revenue Requirements				
		Flat Rate: Phase 2	Bill Impact specific to IBR to Flat Structure Change		Proposed Final Rates: Phase 2	Bill Impact Specific to Change in Revenue Requirement		**Total Bill Impact from IBR to Flat & Proposed Revenue Requirement**	
Monthly Usage	Current Mo. Bill	Mo. Bill	$ change	% change	Mo. Bill	$ change	% change	**$ change**	**% change**
100	$ 15.52	$ 17.91	$ 2.39	15.4%	$ 20.44	$ 2.53	16.3%	**$ 4.92**	**31.7%**
200	$ 23.16	$ 27.82	$ 4.66	20.1%	$ 31.87	$ 4.05	17.5%	**$ 8.71**	**37.6%**
300	$ 30.80	$ 37.73	$ 6.93	22.5%	$ 43.31	$ 5.58	18.1%	**$ 12.51**	**40.6%**
400	$ 38.44	$ 47.64	$ 9.20	23.9%	$ 54.74	$ 7.10	18.5%	**$ 16.30**	**42.4%**
500	$ 48.39	$ 57.55	$ 9.16	18.9%	$ 66.18	$ 8.63	17.8%	**$ 17.79**	**36.8%**
600	$ 58.34	$ 67.46	$ 9.12	15.6%	$ 77.62	$ 10.16	17.4%	**$ 19.28**	**33.0%**
700	$ 68.29	$ 77.37	$ 9.08	13.3%	$ 89.05	$ 11.68	17.1%	**$ 20.76**	**30.4%**
800	$ 78.24	$ 87.28	$ 9.04	11.6%	$ 100.49	$ 13.21	16.9%	**$ 22.25**	**28.4%**
900	$ 90.50	$ 97.19	$ 6.69	7.4%	$ 111.93	$ 14.73	16.3%	**$ 21.43**	**23.7%**
1,000	$ 102.76	$ 107.10	$ 4.34	4.2%	$ 123.36	$ 16.26	15.8%	**$ 20.60**	**20.1%**
1,100	$ 115.02	$ 117.01	$ 1.99	1.7%	$ 134.80	$ 17.79	15.5%	**$ 19.78**	**17.2%**
1,200	$ 127.28	$ 126.92	$ (0.36)	-0.3%	$ 146.23	$ 19.31	15.2%	**$ 18.96**	**14.9%**
1,300	$ 142.04	$ 136.83	$ (5.21)	-3.7%	$ 157.67	$ 20.84	14.7%	**$ 15.63**	**11.0%**
1,400	$ 156.80	$ 146.74	$ (10.06)	-6.4%	$ 169.11	$ 22.36	14.3%	**$ 12.31**	**7.8%**
1,500	$ 171.56	$ 156.65	$ (14.91)	-8.7%	$ 180.54	$ 23.89	13.9%	**$ 8.98**	**5.2%**
1,600	$ 186.32	$ 166.56	$ (19.76)	-10.6%	$ 191.98	$ 25.42	13.6%	**$ 5.66**	**3.0%**
1,700	$ 201.08	$ 176.47	$ (24.61)	-12.2%	$ 203.41	$ 26.94	13.4%	**$ 2.33**	**1.2%**
1,800	$ 215.84	$ 186.38	$ (29.46)	-13.6%	$ 214.85	$ 28.47	13.2%	**$ (0.99)**	**-0.5%**
1,900	$ 230.60	$ 196.29	$ (34.31)	-14.9%	$ 226.29	$ 29.99	13.0%	**$ (4.32)**	**-1.9%**
2,000	$ 245.36	$ 206.20	$ (39.16)	-16.0%	$ 237.72	$ 31.52	12.8%	**$ (7.64)**	**-3.1%**
2,100	$ 260.12	$ 216.11	$ (44.01)	-16.9%	$ 249.16	$ 33.05	12.7%	**$ (10.96)**	**-4.2%**
2,200	$ 274.88	$ 226.02	$ (48.86)	-17.8%	$ 260.60	$ 34.57	12.6%	**$ (14.29)**	**-5.2%**
2,300	$ 289.65	$ 235.93	$ (53.71)	-18.5%	$ 272.03	$ 36.10	12.5%	**$ (17.61)**	**-6.1%**
2,400	$ 304.41	$ 245.84	$ (58.56)	-19.2%	$ 283.47	$ 37.62	12.4%	**$ (20.94)**	**-6.9%**
2,500	$ 319.17	$ 255.75	$ (63.41)	-19.9%	$ 294.90	$ 39.15	12.3%	**$ (24.26)**	**-7.6%**
2,600	$ 333.93	$ 265.66	$ (68.26)	-20.4%	$ 306.34	$ 40.68	12.2%	**$ (27.59)**	**-8.3%**
2,700	$ 348.69	$ 275.57	$ (73.11)	-21.0%	$ 317.78	$ 42.20	12.1%	**$ (30.91)**	**-8.9%**
2,800	$ 363.45	$ 285.48	$ (77.97)	-21.5%	$ 329.21	$ 43.73	12.0%	**$ (34.24)**	**-9.4%**
2,900	$ 378.21	$ 295.39	$ (82.82)	-21.9%	$ 340.65	$ 45.25	12.0%	**$ (37.56)**	**-9.9%**
3,000	$ 392.97	$ 305.30	$ (87.67)	-22.3%	$ 352.08	$ 46.78	11.9%	**$ (40.89)**	**-10.4%**

MINNESOTA POWER
COMPARISON OF OPERATING REVENUES
PRESENT VS. GENERAL
TEST YEAR 2020
RESIDENTIAL RATE SCHEDULE 20 & 22 - PHASE 2

	Type of Charge	Basis or Unit Upon Which Rates Are Applied	Total Billing Units		Unit Charge		Operating Revenues		Increase	
			Present	General	Present	General	Present	General	($)	(%)
1	Minimum charge	# of Bills	1,310,363	1,310,363	$8.00	$9.00	$10,482,904	$11,793,267	$1,310,363	12.50%
	Energy Blocks									
2	0 kWh to 400 kWh	kWh	449,905,000	355,519,697	$0.07423	$0.08933	$33,396,448	$31,757,123		
	0 kWh to 400 kWh - Discount	kWh		94,385,303		$0.06645		$6,272,242		
3	401 kWh to 800 kWh	kWh	255,062,665	255,062,665	$0.09767	$0.08933	$24,911,970	$22,783,706		
4	801 kWh to 1200 kWh	kWh	110,607,000	110,607,000	$0.12113	$0.08933	$13,397,826	$9,880,072		
5	Over 1200 kWh	kWh	118,575,000	118,575,000	$0.14653	$0.08933	$17,374,795	$10,591,821		
6	Base Cost of Fuel	kWh	934,149,665	934,149,665	$0.00000	$0.00000	$0	$0		
7	Total Base Revenue						$99,563,943	$93,078,231	-$6,485,713	-6.51%
8	Fuel Adjustment		934,149,665	934,149,665	$0.00336	$0.02504	$3,143,117	$23,387,120	$20,244,003	
	Adjustments for Riders Included in Base Rates									
9	Boswell 4 Environmental Adjustment	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
10	Renewable Resource Adjustment	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
11	Transmission Adjustment ($)	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
12	Fuel Adjustment Clause	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
13	Conservation Program Adjustment	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
14	Excess ADIT Credit	%			-0.015259	0.000000	($1,519,246)	$0	$1,519,246	
15	Subtotal Revenue						$101,187,814	$116,465,351	$15,277,537	15.10%
16	Boswell 4 Environmental Adjustment	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
17	Renewable Resource Adjustment	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
18	Transmission Adjustment ($)	kWh	934,149,665	934,149,665	$0.00000000	$0.00000000	$0	$0	$0	
20	Solar Energy Adjustment	kWh	934,149,665	934,149,665	-$0.00015	-$0.00015	-$140,050	-$140,050	$0	
21	Community Solar Garden - Customer Charge	Blocks	5,313	5,313	$15.44	$15.44	$82,058	$82,058	$0	
22	Community Solar Garden - Energy	kWh	55,239	55,239	$0.1115	$0.1115	$6,159	$6,159	$0	
23	Conservation Program Adjustment	kWh	934,149,665	934,149,665	$0.00003880	$0.00003880	$36,244	$36,244	$0	
24	CARE Surcharge	# of Bills	1,310,363	1,310,363	$1.03000000	$1.03000000	$1,349,674	$1,349,674	$0	
24	TOTAL REVENUE						$102,521,899	$117,799,435	$15,277,537	14.90%

Minnesota Power
Non-LP General Rates - Rate Design
Test Year 2020

		General Rates				Current Rates			
Rate	Description	Annual Customer Charge	Monthly Customer Charge	Energy Charge/kWh	Demand Charge/kW	Annual Customer Charge	Monthly Customer Charge	Energy Charge/kWh	Demand Charge/kW
20	Residential Standard (Incl. CARE)								
	Customer Charge		$ 9.00				$ 8.00		
	Block 1 Energy (0-400 kWh)			$ 0.09678				$ 0.07423	
	Block 1 Energy (0-400 kWh) - Discount			$ 0.07241					
	Block 2 Energy (401-800 kWh)			$ 0.09678				$ 0.09767	
	Block 3 Energy (801-1200 kWh)			$ 0.09678				$ 0.12113	
	Block 4 Energy (Over 12000 kWh)			$ 0.09678				$ 0.14653	
21	Dual Fuel - Residential								
	Customer Chg - Small		$ 5.00				$ 8.00		
	Customer Chg - Large		$ 15.00						
	Energy - Small/Large			$ 0.03635				$ 0.07563	
23	Seasonal Residential								
	Customer Chg		$ 12.00				$ 10.00		
	Energy - All			$ 0.09947				$ 0.10853	
24	Controlled Access Residential								
	Customer Chg - Small		$ 5.00				$ 8.00		
	Customer Chg - Large		$ 15.00						
	Energy - All			$ 0.03635				$ 0.06769	
25	General Service								
	Customer Chg		$ 14.00				$ 12.00		
	Demand Meter - Energy			$ 0.06054				$ 0.07619	
	No Demand Meter -Energy			0.08638				$ 0.10204	
	Demand Meter - Demand				$ 7.25				$ 6.50
	High Voltage Discount				$ (2.00)				$ (2.00)
	Transmission Service Discount			$ (0.00450)				$ (0.00350)	
26	Dual Fuel - Commercial/Industrial								
	Customer Chg-Small		$ 5.00				$ 12.00		
	Customer Chg-Large		$ 15.00						
	High Voltage Energy			$ 0.03076				$ 0.06982	
	Low Voltage Energy			$ 0.03635				$ 0.07563	
27	Controlled Access Commercial								
	Customer Chg - Small		$ 5.00				$ 12.00		
	Customer Chg - Large		$ 15.00						
	Energy - High Voltage			$ 0.03076				$ 0.06188	
	Energy - Low Voltage			$ 0.03635				$ 0.06769	
28	Residential Electric Vehicle								
	Customer Chg		$ 4.25				$ 4.25		
	Energy - On-Peak			$ 0.13900				$ 0.11763	
	Energy - Off-Peak			$ 0.02050				$ 0.03903	
75	Large Light & Power						$ 1,200.00		
	Customer Chg		$ 1,325.00						
	Energy - All			$ 0.04050				$ 0.05811	
	Demand - 1st 100kW				$ -				$ -
	Demand - All Additional				$ 12.00				$ 10.50
	High Voltage Discount				$ (2.00)				$ (2.00)
	Foundry Discount				$ (2.50)				$ (2.50)
	Transmission Service Discount			$ (0.00450)				$ (0.00350)	
75S	Large Light & Power - Schools								
	Customer Chg		$ 662.50				$ 600.00		
	Energy - All			$ 0.04050				$ 0.05811	
	Demand - 1st 50 kW				$ -				$ -
	Demand - 2nd 50 kW				$ 13.25				$ 12.00
	Demand - All Additional				$ 12.00				$ 10.50
	High Voltage Discount				$ (2.00)				$ (2.00)
	Transmission Service Discount								
75TOU	LLP Time of Use								
	Customer Chg		$ 1,325.00				$ 1,200.00		
	On-Peak Energy			$ 0.05053				$ 0.06337	
	Off-Peak Energy			$ 0.03369				$ 0.05275	
	On-Peak Demand				$ 12.36				$ 10.90
	Off-Peak Demand				$ 5.13				$ 4.25
87	Municipal Pumping								
	Customer Chg		$ -				$ 12.00		
	Demand Meter - Energy			$ -				$ 0.07619	
	No Demand Meter -Energy			$ -				$ 0.10204	
	Demand Meter - Demand				$ -				$ 6.50
	High Voltage Discount				$ -				$ (2.00)
	Transmission Service Discount			$ -				$ (0.00350)	