NORTH DAKOTA
RATE CASE
2023

Otter Tail Power Company

Before the
North Dakota Public Service Commission

Application for Authority to
Increase Electric Rates in North Dakota
Case No. PU-23

November 2, 2023

Volume 2A
Direct Testimony and Supporting Schedules

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

OTTER TAIL
POWER COMPANY

Otter Tail Power Company
North Dakota General Rate Case Documents
Case No. PU-23-

Volume 2A
Direct Testimony and Supporting Schedules

Bruce G. Gerhardson
Policy

Amber M. Stalboerger
Allocators
Class Cost of Service Study
Revenue Allocation
Other Regulatory Issues

Christy L. Petersen
Revenue Requirement
Budget Process

Paula M. Foster
Transition of Capital Projects from Riders to Base Rates

Christopher L. Byrnes
Corporate Cost Allocation
Lead Lag Study
Energy Adjustment Rider
Other Regulatory Issues

Volume 2A

Direct Testimony and Supporting Schedules:

Bruce G. Gerhardson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

POLICY

Direct Testimony and Schedules of

BRUCE G. GERHARDSON

PUBLIC DOCUMENT –
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

My name is Bruce G. Gerhardson. I am employed by Otter Tail Power Company (OTP or the Company) as Vice President, Regulation and Retail Energy Solutions.

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I have worked for OTP since 2000. In 2017, I was appointed to my current role. My current duties include providing direction and supervision for OTP's Regulatory Economics, Regulatory Proceedings, Regulatory Compliance, Retail Energy Solutions, and Strategic Planning areas. A summary of my qualifications and experience is included as Exhibit___(BGG-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In my Direct Testimony, I give an overview of OTP and summarize our request. I explain how it has been six years since we last requested an increase to our base rates, and I explain the reasonableness of our request. I also address three specific issues: pension and postretirement medical and life insurance plan costs; our proposal to address the potential for changes to our sales volumes between rate cases; and our update to our Super Large General Service rate.

Q. WHY IS OTP REQUESTING A RATE INCREASE?

A. OTP's request for an increase is the result of cost increases that have occurred over the six years since our last rate case (Case No. PU-17-398), which was filed in November 2017 based on a test year ending December 31, 2018. In particular, and as discussed in more detail by OTP witness Ms. Ann E. Bulkley, interest rates and inflation both increased dramatically beginning in 2021 and remain at elevated levels. These specific factors, along with the aggregate of cost increases that have occurred since 2018, require OTP to update its base rates for electric service in North Dakota.

Q. PLEASE SUMMARIZE OTP'S REQUEST IN THIS CASE.

A. The net effect of OTP's proposal to change base rates will increase revenue by $17,358,237, an 8.43 percent increase above total present revenues.[1] As described in my Direct Testimony and the testimony of other OTP witnesses, our proposal includes moving certain investments currently recovered in the Renewable Resource Cost Recovery Rider (RRCR Rider), Transmission Cost Recovery Rider (TCR Rider), Metering & Distribution Technology Cost Recovery Rider (MDT Rider)(formerly Advanced Metering, Distribution and Technology Cost Recovery Rider or ADMT Rider), and Generation Cost Recovery Rider (GCR Rider) into base rates. Overall, our request results in an approximately $23.3 million *reduction* to rider revenues and an approximately $40.7 million *increase* to base revenues. The result of netting rider decreases and base rate increases is a net average increase of 8.43 percent to customers.[2] Annualized over the six years since our last rate case, the net effect of our requested increase to base rates is approximately 1.4 percent per year, which cumulatively is less than inflation over the same period.

Q. HAVE YOU MADE ANY OTHER REQUESTS IN THIS CASE?

A. Yes. Later in my Direct Testimony, I describe a proposal to address changes to sales volumes that occur between rate case proceedings. The potential for such changes has grown since our last rate case.

Q. HOW WILL THESE REQUESTS IMPACT CUSTOMERS' RATES?

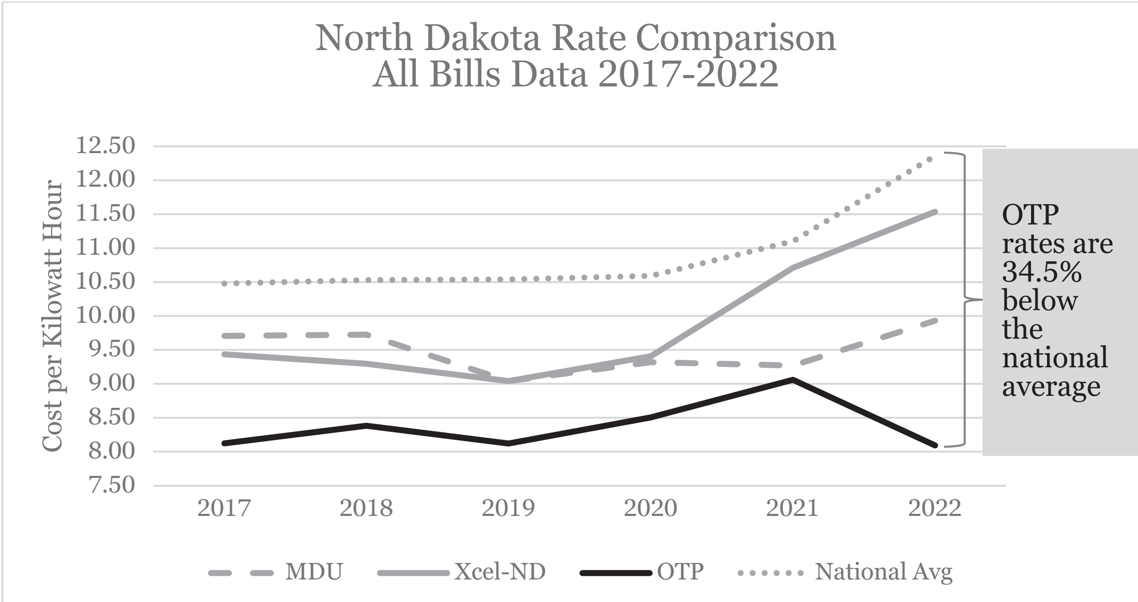
A. As shown in Figure 1, below, OTP has the lowest rates among North Dakota's investor-owned utilities. The same will be true if our requests are granted in this case.

---

[1] As explained in the Direct Testimony of Christy L. Petersen, while finalizing this case for submission, OTP determined that the 2024 Test Year revenue requirement calculation did not include an intended adjustment to normalize plant outage costs. The adjustment has been incorporated into the proposed interim rate revenue increase. The 2024 Test Year revenue requirement and base rate revenue deficiency amounts discussed in my Direct Testimony do not reflect the impact of the plant outage normalization adjustment. OTP intends for this adjustment to be made at an appropriate time as this case develops.

[2] Other than rider decreases noted above, the net increase does not include any annual rider updates, which may occur prior to implementation of proposed rates.

Figure 1[3]



Q. HOW HAS OTP BEEN ABLE TO MAINTAIN ITS LOW RATES?

A. Our low rates reflect our efforts to control costs, execute on major capital projects, and more recently, sales growth. These factors have allowed us to both maintain low rates and avoid an earlier base rate increase. At this point, however, the cost increases we are experiencing can no longer be offset by sales growth or cost reduction efforts. Again, even with the increase requested, OTP's North Dakota rates will be among the lowest in the United States. Ultimately, OTP's proposed base rates and other rate revisions proposed in this case are just and reasonable and should be adopted.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I provide a description of OTP, including OTP's facilities, capital expenditures, service area, small size, and rates. In Section IV, I discuss our pension and postretirement medical and life insurance costs, and our proposed ratemaking treatment for these costs. In Section V, I discuss our proposal for a

---

[3] US Energy Information Administration Electric Sales, Revenue, and Average Price at Table 4, October 2017 – October 2022 Releases accessed October 28, 2023 at https://www.eia.gov/electricity/sales_revenue_price/and EIA Annual Electric Power Industry Report, Form EIA-861 detailed data files , October 2017-October 2023 Releases, accessed October 28, 2023 at https://www.eia.gov/electricity/data/eia861/. The rates reflect an average of classes and include all bill components—i.e., all base rates, all fuel and purchased power rates and all rider rates.

ratemaking mechanism to address the increased potential for material fluctuations in sales volumes between rate cases. In Section VI, I discuss our Super Large General Service rate update. In Section VII, I introduce OTP's other witnesses.

III. DESCRIPTION OF OTP

Q. PLEASE BRIEFLY DESCRIBE OTP.

A. OTP is a very small investor-owned utility that serves customers spread across a very large, sparsely populated area in North Dakota, Minnesota, and South Dakota. We supply retail electric service to approximately 132,500 customers, including approximately 59,000 customers in North Dakota, approximately 62,000 customers in Minnesota, and approximately 11,500 customers in South Dakota.

We serve approximately 420 small communities and rural areas in the eastern two-thirds of North Dakota, western Minnesota, and northeastern South Dakota. We do not, however, serve Fargo or other larger communities in the region, such as Grand Forks, North Dakota, or Moorhead, Minnesota. Our three-state, 70,000 square-mile service territory is roughly the size of Wisconsin. OTP is headquartered in Fergus Falls, Minnesota and is a subsidiary of Otter Tail Corporation, headquartered in Fargo, North Dakota.

Q. HOW DOES OTP COMPARE IN SIZE TO OTHER UTILITIES.

A. OTP is one of the very smallest investor-owned utilities in the country in terms of both number of retail customers and retail revenues generated.

Q. HOW MANY PEOPLE DOES OTP EMPLOY?

In 2024, OTP expects to have an average of 800 full time equivalent (FTE) employees, including approximately 376 union employees and 424 non-union employees (not adjusted for employees of jointly owned power plants).

Q. WHAT IS OTP'S MISSION?

A. OTP's mission is: "To produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business."

Q. PLEASE BRIEFLY DESCRIBE OTP'S GENERATION AND TRANSMISSION FACILITIES.

A. OTP operates two coal-fueled baseload generating plants: Coyote Station (427 megawatts (MW)) and Big Stone Plant (475 MW).[4] We own five major wind farms, all located in eastern North Dakota: the Merricourt Wind Energy Center (Merricourt Wind) (150 MW), the Langdon Wind Energy Center (40.5 MW), the Ashtabula Wind Energy Center (48 MW), Ashtabula III (62.4 MW), and the Luverne Wind Farm (49.5 MW). OTP also owns and operates five peaking plants: Astoria Station simple-cycle natural gas combustion turbine (245 MW), Jamestown 1 and 2 oil combustion turbines (42.5 MW), Lake Preston oil combustion turbine (20 MW), and Solway simple-cycle natural gas combustion turbine (43.7 MW). Finally, we own six hydroelectric stations,[5] the Hoot Lake Solar facility,[6] two smaller solar facilities, and several smaller wind facilities. OTP owns over 6,000 miles of transmission lines. Our electric system is interconnected with the facilities of several neighboring suppliers.

Q. PLEASE FURTHER DESCRIBE THE COMMUNITIES OTP SERVES.

A. As noted above, we serve 420 small communities in total, 245 of which are in North Dakota. The average population of our communities in North Dakota is approximately 240 people. Jamestown is the largest community OTP serves in North Dakota (and system-wide) with a population of approximately 15,800 people. OTP only serves two other communities with populations over 10,000, Fergus Falls (14,000) and Bemidji (14,500), both of which are in Minnesota.

Q. DO YOU HAVE AN ILLUSTRATION SHOWING OTP'S SERVICE AREA AND GENERATING FACILITIES?

A. Yes. Figure 2 is a map illustrating our service area and identifying the locations of our generating facilities.

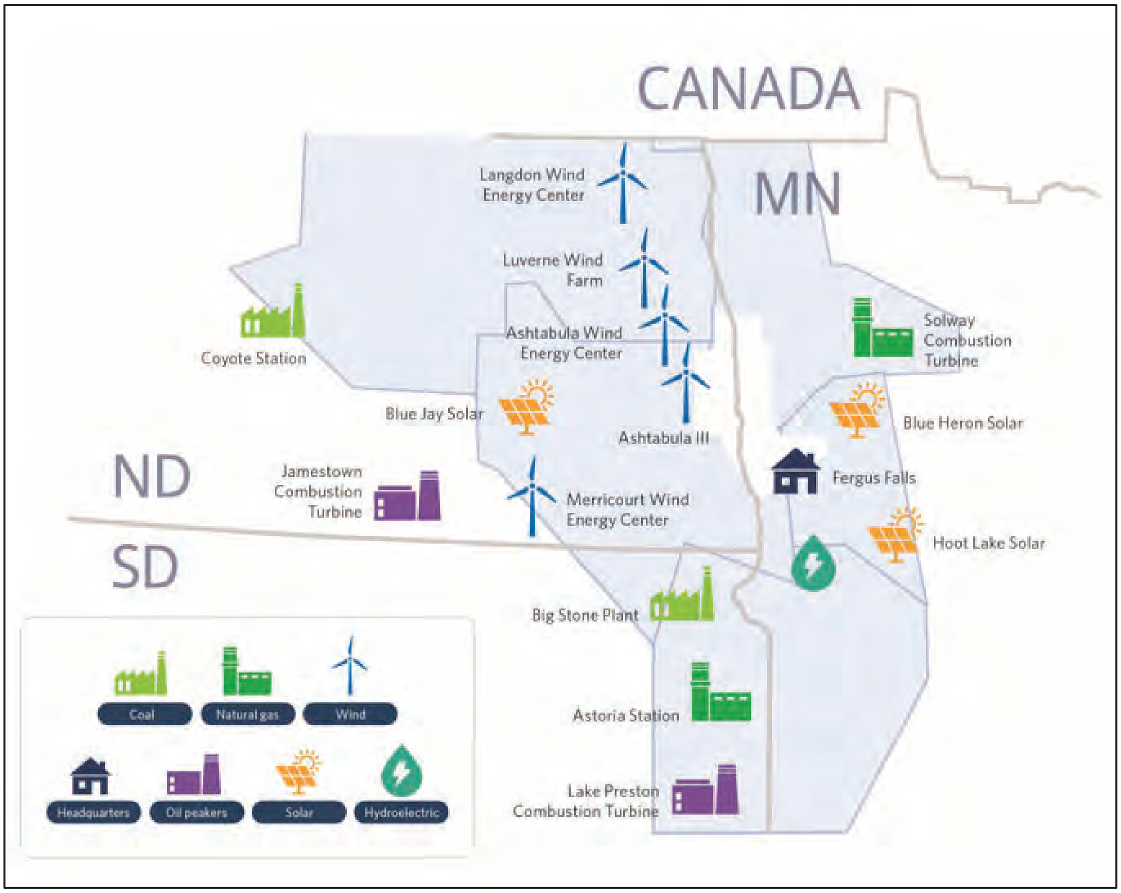
---

[4] OTP is not the sole owner of Coyote or Big Stone: OTP owns 35 percent of Coyote Station and 53.9 percent of Big Stone Plant.

[5] On February 17, 2022, the Federal Energy Regulatory Commission issued an order granting a new 40-year license for our five hydroelectric plants along the Otter Tail River.

[6] The costs for Hoot Lake Solar are entirely allocated to Minnesota, as described in the Direct Testimony of OTP witness Ms. Christy L. Petersen.

Figure 2
Overview of OTP Service Area and Generation Facilities

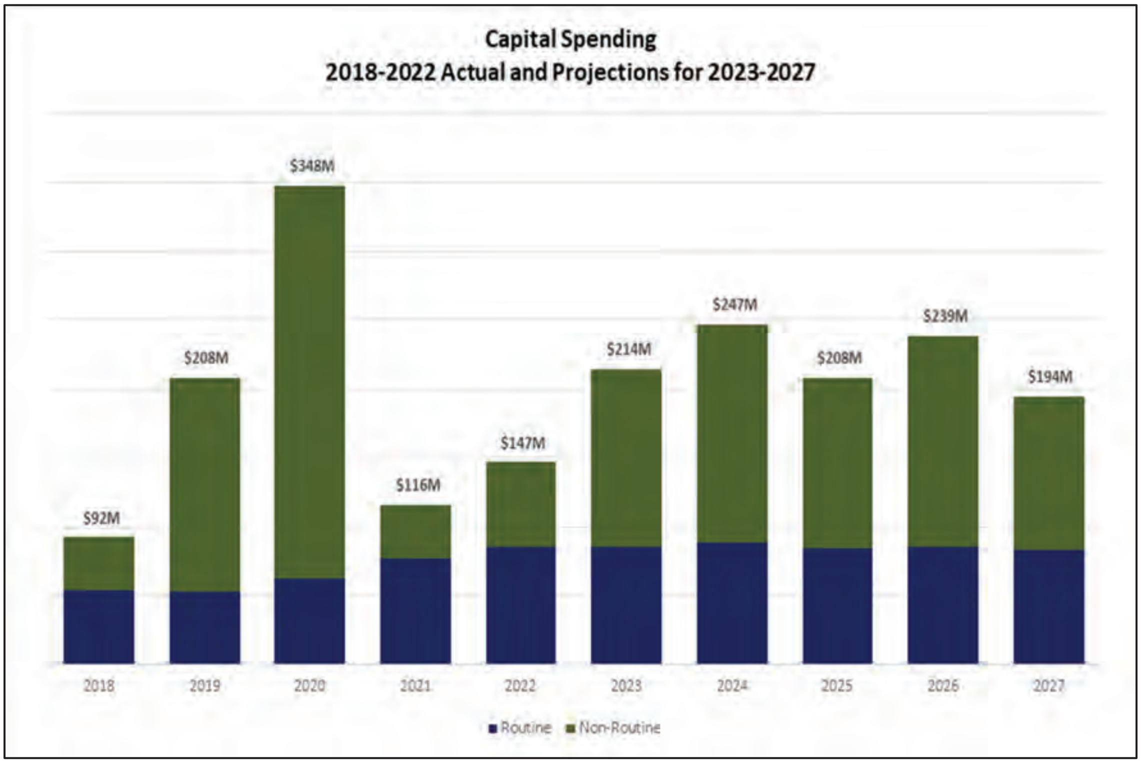


Q. ARE MANY OF OTP'S GENERATING FACILITIES THE RESULT OF CAPITAL EXPENDITURES MADE SINCE OTP'S LAST NORTH DAKOTA RATE CASE?

A. Yes. OTP has made significant investments in generating facilities since its last North Dakota rate case. These include the 150 MW Merricourt Wind Energy Center located in southeast North Dakota (the largest capital investment in OTP's history) and Astoria Station, a 250 MW simple cycle natural gas generator located in Deuel County, South Dakota. As discussed by OTP witness Ms. Paula M. Foster in her Direct Testimony, we were able to complete both projects below the cost estimates the Commission already deemed reasonable and prudent for cost recovery. We also purchased Ashtabula III, which previously served OTP via a power purchase agreement. OTP also completed the Hoot Lake Solar Facility in 2023, though the costs for this facility and its electrical output are allocated entirely to Minnesota.

As shown in the figure below, we have invested approximately $1.125 billion (OTP Total) across our system since 2018, mostly in the form of non-routine projects like the Merricourt Wind Energy Center, Astoria Station and large transmission projects.

Figure 3
Summary of Capital Spending
(OTP Total, $ Millions)[7]



Q. PLEASE DESCRIBE OTP'S PLANNED SYSTEM INVESTMENTS.

A. We expect to invest approximately $888 million (OTP Total) across our system in 2024-2027. The average annual investment is projected to increase from $187.5 million (OTP Total) per year during 2018-2023 to $222 million (OTP Total) per year during 2024–2027. Some of the larger investments over this period include the wind farm Upgrade Project (discussed in more detail by Ms. Foster), continued deployment of Advanced Metering Infrastructure (AMI), Demand Response (DR) and Outage Management System (OMS) projects (all also discussed by Ms. Foster) and new regional transmission projects.

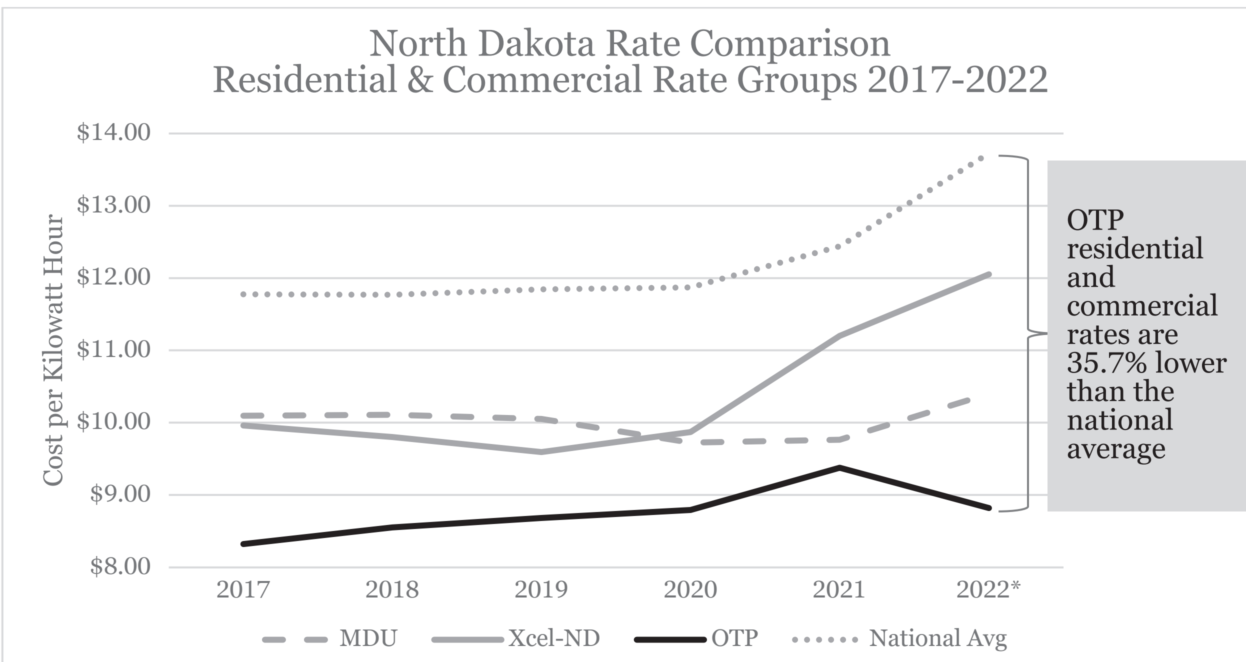
[7] *See* volume 5, Capital Budget Documentation. All values are presented in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts.

Q. HAS OTP BEEN ABLE TO MAINTAIN LOW RATES WHILE CONTINUING TO INVEST IN ITS SYSTEM?

A. Yes. OTP's rates for electric service in North Dakota are among the lowest in the nation and have been so for several years. Even after this case, our rates will remain among the lowest in the nation. We have accomplished this despite the challenges posed by being a very small utility and serving customers in a very large, sparsely populated service territory and with very substantial capital expenditures.

Figure 4 compares OTP's residential and commercial rates to the residential and commercial rates of other North Dakota investor-owned utilities and to the national average of all utilities for residential and commercial rates since 2017.

Figure 4[8]



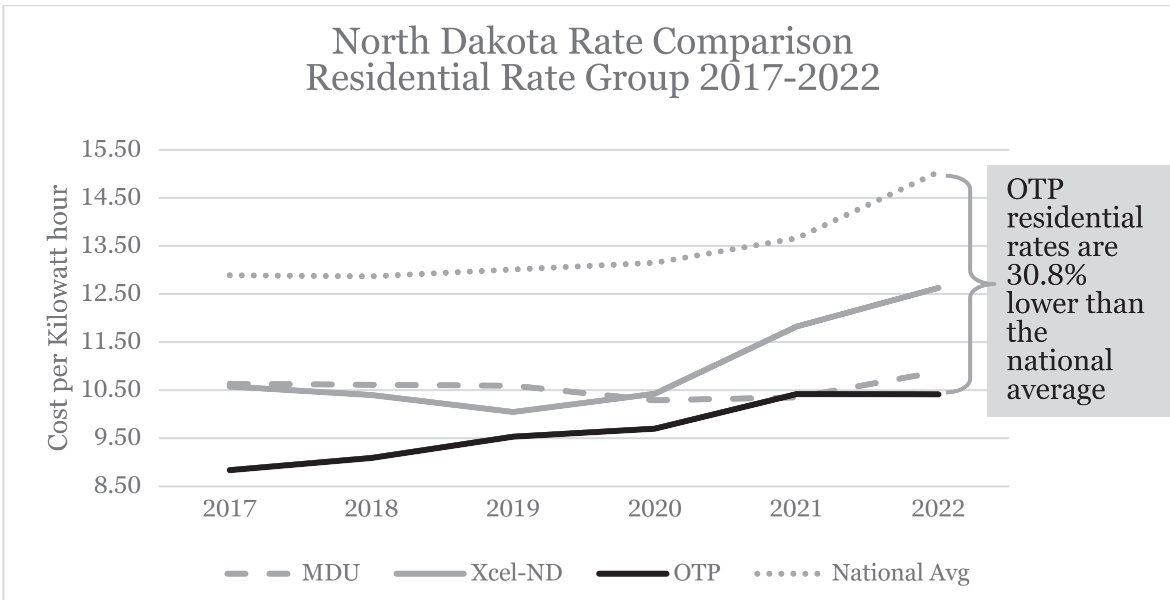
---

[8] US Energy Information Administration Electric Sales, Revenue, and Average Price at Table 4, October 2017 – October 2022 Releases accessed October 28, 2023 at https://www.eia.gov/electricity/sales_revenue_price/and EIA Annual Electric Power Industry Report, Form EIA-861 detailed data files , October 2017-October 2023 Releases, accessed October 28, 2023 at https://www.eia.gov/electricity/data/eia861/.

Q. DOES THE SAME HOLD TRUE FOR OTP'S RESIDENTIAL AND BUSINESS RATES?

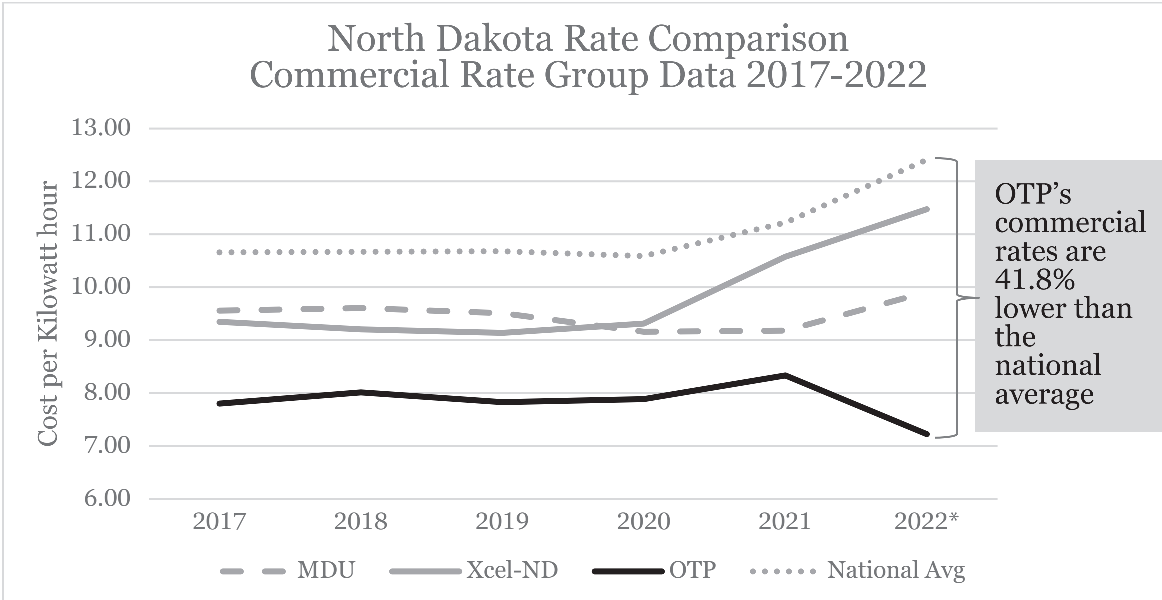
A. Yes. Figures 4, 5 and 6 show that OTP's residential and business rates are the lowest among North Dakota investor-owned utilities and substantially lower than the national average of all utilities.

Figure 5[9]



[9] US Energy Information Administration Electric Sales, Revenue, and Average Price at Table 4, October 2017 – October 2022 Releases accessed October 28, 2023 at https://www.eia.gov/electricity/sales_revenue_price/and EIA Annual Electric Power Industry Report, Form EIA-861 detailed data files , October 2017-October 2023 Releases, accessed October 28, 2023 at https://www.eia.gov/electricity/data/eia861/.

Figure 6[10]



Q. WHAT IS THE SIGNIFICANCE OF THE COMPARISONS ILLUSTRATED BY FIGURES 1, 4, 5, AND 6?

A. Figures 1, 4, 5, and 6 show that OTP has kept rates low despite the challenges that come with its small size and large rural territory. They also illustrate that our customers, overall, benefit from advantageous rates.

Q. HAS OTP COMPLETED ANY CUSTOMER SERVICE INITIATIVES SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. Over the last several years, OTP has witnessed an evolution in customer expectations, especially in the areas of digital account access, digital self-service, and digital commerce. Along with these changes to customer expectations, we have also seen an increase in the number of products and services offered by other utilities and others involved in retail commerce. We have responded by improving our customer experience programming to meet customers' expectations while maintaining our commitments to delivering low-cost reliable service. Some examples of completed customer service initiatives include a comprehensive bill

[10] US Energy Information Administration Electric Sales, Revenue, and Average Price at Table 4, October 2017 – October 2022 Releases accessed October 28, 2023 at https://www.eia.gov/electricity/sales_revenue_price/and EIA Annual Electric Power Industry Report, Form EIA-861 detailed data files , October 2017-October 2023 Releases, accessed October 28, 2023 at https://www.eia.gov/electricity/data/eia861/.

redesign (approved by the Commission in Case No. PU-23-173), launching a new Customer Engagement Portal (CEP) and expanding customer communications through the new Outage Management System (OMS).

IV. PENSION AND POSTRETIREMENT MEDICAL AND LIFE INSURANCE PLAN COSTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. This portion of my Direct Testimony addresses OTP's proposed ratemaking treatment of pension and postretirement medical and life insurance plan (PRM) plan costs in the 2024 Test Year.

Q. HOW ARE OTP'S PENSION AND PRM COSTS DETERMINED?

A. OTP witness Ms. Christy L. Petersen explains in her Direct Testimony that OTP's pension and PRM costs are determined in accordance with ASC 715.[11] The annual costs are calculated by Mercer, who provides actuarial services to OTP and Otter Tail Corporation.

Q. WHAT ARE OTP'S ESTIMATED 2024 PENSION AND PRM COSTS?

A. OTP's estimated 2024 pension and PRM costs are shown in Table 1 below. Both costs are projected to be negative in 2024, meaning they are a credit to income.

Table 1
Estimated 2024 Pension and OPEB Costs[12]
($ Millions)

Category	**Otter Tail Corporation**	**OTP Total**	**OTP ND (est.)**
Pension	($4.7)	($4.58)	($2.0)
PRM	($4.3)	($4.19)	($1.8)

[11] Pension plan costs formerly were accounted for under FAS 87, while PRM costs were subject to FAS 106. A third category of costs, Postemployment (LTD) Medical Benefit Plan costs, are now subject to ASC 712 and formerly were subject to FAS 112.
[12] Amounts shown in Table 1 and throughout my testimony are total costs, including any capitalized portions, unless otherwise noted. Ms. Petersen's testimony discusses the expense portion of pension and PRM costs.

Q. WHEN WILL THE ACTUAL 2024 PENSION AND PRM COSTS BE KNOWN?

A. Mercer will prepare a report based on December 31, 2023, data that will establish the actual pension and PRM costs for 2024. OTP will receive Mercer's final 2024 ASC 715 and ASC 712 accounting report in the first quarter of 2024.

Q. IS OTP RECOMMENDING THAT THE ESTIMATED 2024 PENSION AND PRM COST BE USED TO ESTABLISH THE 2024 TEST YEAR REVENUE REQUIREMENT?

A. No. OTP is recommending that the 2024 Test Year revenue requirement reflect normalized pension and PRM costs based on an average of Mercer's actuarial estimated expense for 2024-2028. These estimates are provided as Schedules 13 and 14 to Ms. Petersen's testimony.

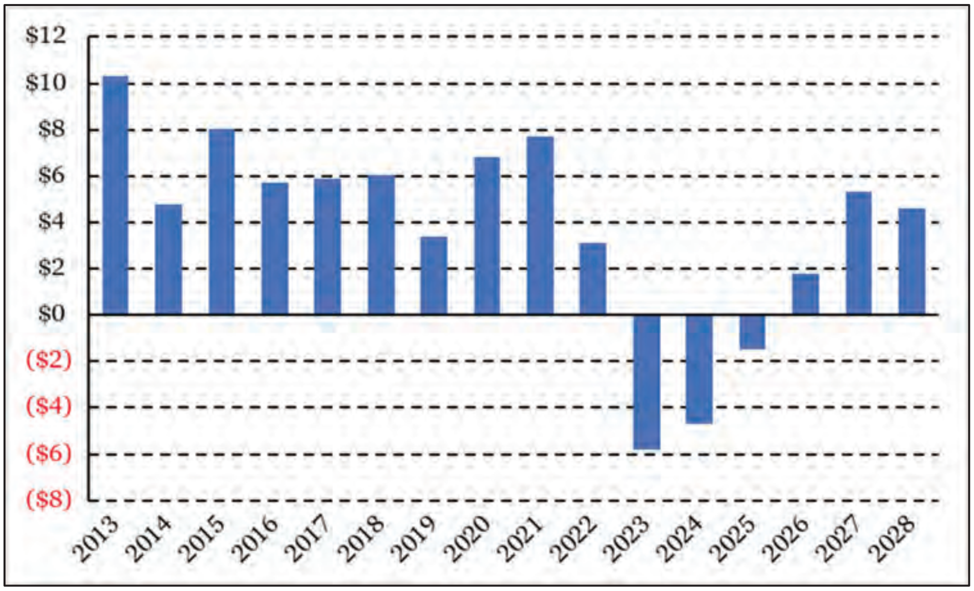
Q. WHY IS OTP RECOMMENDING THAT THE 2024 TEST YEAR REFLECT NORMALIZED PENSION AND PRM COSTS?

A. As discussed in more detail below, 2024 pension and PRM costs are different from both historical experience and our expectations going forward. In this instance, normalization ensures that rates reflect a reasonable and representative amount of costs expected to be incurred during the period rates will be in effect.

Q. HOW DOES THE 2024 EXPECTED PENSION COST COMPARE TO HISTORICAL EXPERIENCE AND EXPECTATIONS GOING FORWARD?

A. As shown in Figure 7 below, the 2024 pension costs are significantly lower than both historical and expected future costs.

Figure 7
Historical and Projected Pension Cost
($ Millions, Otter Tail Corporation)



Q. DO YOU HAVE ANY OBSERVATIONS REGARDING FIGURE 7, ABOVE?

A. Yes. First, the figure shows that until 2023, pension costs always was a positive amount, only turning negative in 2023. Second, pension costs are expected to return to a positive amount in 2026 and return to something approximating historical levels in 2027 and 2028.

Q. WHAT WOULD BE THE EFFECT OF ESTABLISHING THE 2024 TEST YEAR REVENUE REQUIREMENT ON THE ESTIMATED 2024 PENSION COST?

A. Establishing the 2024 Test Year revenue requirement based on the estimated 2024 pension cost would result in a large credit to the cost of service being incorporated into base rates. As pension costs increase in subsequent years, the credit would drive a revenue deficiency and accelerate the need to file a new rate case.

Q. IS THIS DIFFERENT FROM HISTORICAL EXPERIENCE?

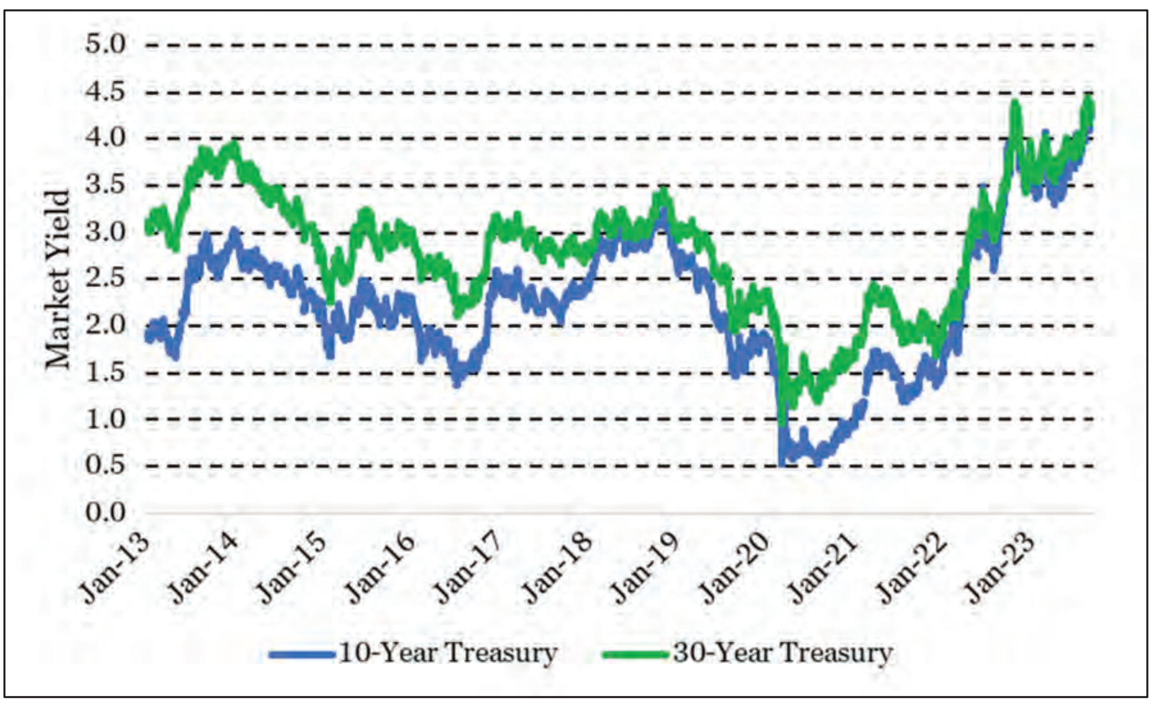
A. Yes. OTP's last rate case was based on a 2018 Test Year and the revenue requirement reflected the actual 2018 pension costs. Pension costs in 2019 were slightly below 2018 levels, while costs in 2020 and 2021 were slightly above the 2018 levels. These ups and downs, however, were not material and did not accelerate the need to file a rate case. Deviations in 2022 and 2023 were larger, but those deviations supported earnings and helped offset cost increases in other areas and delayed the need to seek rate relief.

Setting rates based only on the 2024 costs would have the opposite effect. Base rates would reflect an abnormally low amount (as compared to history and future expectations) and a deficiency would materialize almost immediately as pension costs normalize.

Q. WHAT FACTORS ARE CONTRIBUTING TO THE TEMPORARY DECLINE IN PENSION COSTS?

A. Ms. Petersen explains in her Direct Testimony that pension costs generally are inversely related to interest rates: as interest rates fall, pension costs increase; and as interest rates increase, pension costs fall. As shown in Figure 8 below, interest rates are much higher than historic levels. Interest rates have increased almost continuously since Spring 2020, with increases accelerating rapidly in late 2021 and early 2022. These higher interest rates put downward pressure on pension costs in 2022 and 2023 and are expected to continue placing downward pressure on pension costs in 2024.

Figure 8
Historical Interest Rates



Q. PLEASE EXPLAIN HOW INTEREST RATES IMPACT PENSION COSTS.

A. Ms. Petersen discusses that pension costs are based on five components. Those components are:

(1) The present value of pension benefits that employees will earn during the current year (Annual Service Cost), with the present value being established using the discount rate;

(2) Increases in the present value of the pension obligation that plan participants have earned in previous years (Interest Cost), which is based on the discount rate;

(3) Expected earnings on the pension plan assets during the year (Expected Return on Assets or EROA);

(4) Costs (or income) that differ from assumptions (Amortization of Unrecognized Gains and Losses); and

(5) Cost of changes in benefits (Amortization of Unrecognized Prior Service Cost).

Interest rates impact items (1), (2) and (4) of the calculation, though in different ways. Interest rates influence the discount rate, which is used to determine the present value of Annual Service Cost. All else being equal, a higher discount rate will decrease Annual Service Cost (because you are discounting by a larger number). The higher discount rate will have a similar effect on the present value calculation of the Interest Cost, though that effect is more than offset by the increase in projected benefit obligations, which are assumed to grow at the discount rate.

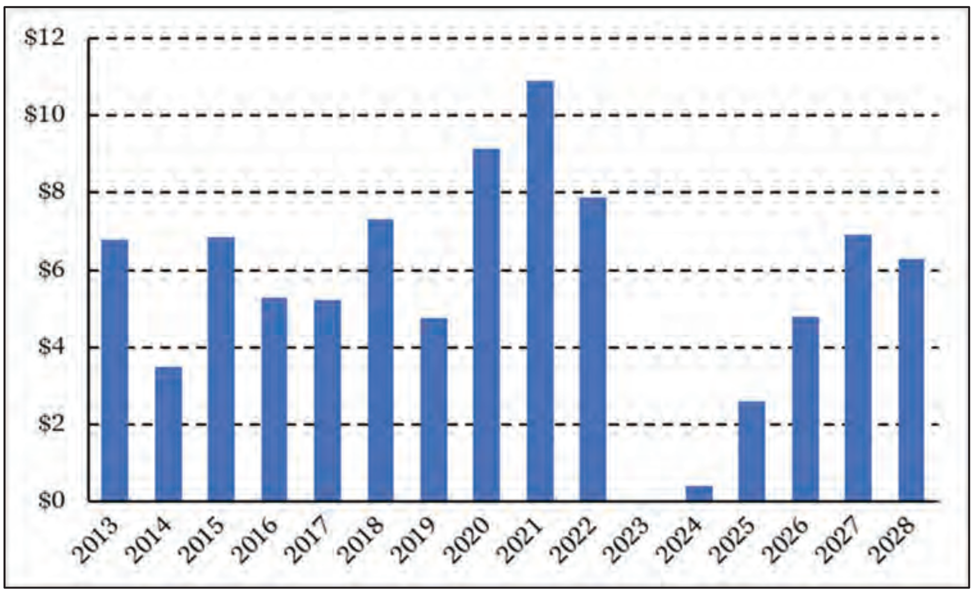
Interest rates impact the Amortization of Unrecognized Gains and Losses through the effect on differences between assumed and actual liabilities. The Amortization of Unrecognized Gains and Losses calculation considers all gains and losses, with gains and losses calculated as the difference between actual results and assumptions. Asset gains and losses are the differences between the actual return on assets during the period and the expected return on assets for that period. Liability gains and losses are the differences between the actual liability at the end of a measurement period and the expected liability at the end of a measurement period.

As interest rates have risen, liabilities have decreased more than initially assumed and the decline in liabilities has been greater than asset losses. These factors have had particularly acute impacts on 2023 and 2024 results.

Q. HAS AMORTIZATION OF UNRECOGNIZED GAINS AND LOSSES HISTORICALLY BEEN A MAJOR CONTRIBUTOR TO THE ANNUAL PENSION COST?

A. Yes. As shown in Figure 9 below, while the Amortization of Unrecognized Gains and Losses has fluctuated over time, 2023 and 2024 are the only years in which this factor does not contribute to pension cost.

Figure 9
Amortization of Unrecognized Gains and Losses – Otter Tail Corporation
($ Millions)



Q. WHY IS THE AMORTIZATION OF UNRECOGNIZED GAINS AND LOSSES EXPECTED TO GROW IN THE FUTURE?

A. Generally, there are two reasons. First, the pension plan experienced a significant market loss in 2022, with year-end plan assets being approximately $101 million lower than expected. Under accounting rules, that loss is "phased-in" over a period of not more than five years. Thus, 2023 was the first year that the market loss was incorporated into the annual cost calculation, but that year only reflected 20 percent of the loss. In subsequent years, an additional 20 percent will be incorporated (so, 40 percent of the 2022 market loss is incorporated into the 2024 pension expense, 60 percent in 2025, 80 percent in 2026 and 100 percent in 2027 and beyond). This phase-in smooths the impact of significant losses and contributes to the increase in the Amortization of Unrecognized Gains and Losses in future years.

The second reason Amortization of Unrecognized Gains and Losses is expected to grow in the future is that it is anticipated that interest rates have stabilized at a new, higher level. As noted above, interest rates increased rapidly throughout 2022, resulting in the decline in pension liabilities being much larger than expected. With an expectation of higher interest rates going forward, the difference between expected liabilities and actual liabilities should stabilize and no longer act as an offset to the Amortization of Unrecognized Gains and Losses.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE REASONABLENESS OF NORMALIZING PENSION EXPENSE?

A. Yes. In Case No. PU-15-090, Advocacy Staff witness Victor Schock noted that actuarial-based pension accounting "takes into account, among other things, future projected earnings/losses in the pension … accounts." Mr. Schock asserted this approach "exposes the ratepayers to stock market fluctuations from year to year." As a result, Mr. Schock recommended pension expense be based on historical figures, which he contended "remove[ed] market risk exposure [and was] more stable and accurate over time."[13] Mr. Schock's recommendation was incorporated into the Case No. PU-15-090 Settlement Agreement,[14] which the Commission approved in its November 4, 2015 Findings of Fact, Conclusions of Law and Order.[15]

Q. WHY IS OTP RECOMMENDING THE 2024 TEST YEAR BE BASED ON FORWARD-LOOKING PENSION DATA RATHER THAN HISTORICAL INFORMATION?

A. We agree with the observations of Mr. Schock, described above, but we believe using a forward-looking average is preferable to an historical average. First, a forward-looking average incorporates the new, higher interest rate environment that is likely to apply during the period rates are in effect rather than the historically low interest rates that drove historical results. Second, the forward-looking approach matches the expense to the period we expect rates to be in effect.

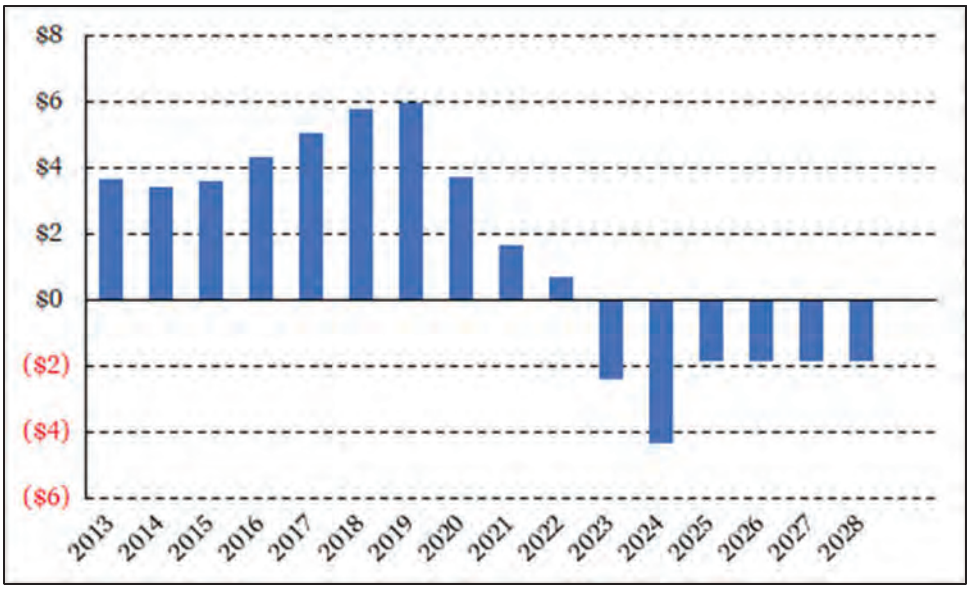
[13] Case No. PU-15-090, Schock Direct at 3 (Schock Direct) (Aug. 7, 2015).
[14] Case No. PU-15-090, Settlement Agreement at ¶2 (Aug. 26, 2015) ("The Company's test year included $426,000 for pension and post-retirement expenses based upon actuarial studies. For ratemaking purposes, the Settling Parties agree this amount shall be reduced to $115,000.").
[15] Case No. PU-15-090, Findings of Fact, Conclusion of Law and Order (Nov. 4, 2015).

Third, the forward-looking estimate considers projected census counts and accounts for what is known today about future obligations.[16] Fourth, in this case, a five-year forward looking average (2024-2028) results in a lower pension expense than a five-year historical average (2019-2023).

Q. WHY IS OTP RECOMMENDING PRM EXPENSE BE NORMALIZED IN THE 2024 TEST YEAR?

A. As with pension expense, the 2024 estimated PRM costs are not reflective of expectations going forward.

Figure 10
Historical and Projected PRM Cost
($ Millions, Otter Tail Corporation)



Q. WHY HAS PRM COST DECLINED FROM 2019 LEVELS?

A. Generally, there are two causes of the decline in PRM costs from 2019 levels. First, as with pension costs, PRM costs generally are inversely related to interest rates. With interest rates increasing during 2020-2023, PRM costs decreased. Second, as discussed by OTP witness Mr. Peter E. Wasberg in his Direct Testimony, OTP made changes to the PRM plan beginning in 2020 that have reduced plan costs.

[16] As discussed below, this will be particularly important for PRM costs.

Q. WHAT CHANGES HAVE IMPACTED THE PRM PLAN?

A. Mr. Wasberg explains that OTP has made two general changes to the PRM plan. First, beginning in 2020, OTP began the process of moving from the Retiree Drug Subsidy (RDS) to the Employer Group Waiver Plan (EGWP) within the PRM plan. This change occurred gradually, with different employees moving to the EGWP plan at different times. Then, in 2023, OTP made the decision to move to a private exchange for Medicare-eligible retirees (post-65), with all Medicare supplemental medical and prescription benefits no longer being provided through our self-insured plan. All age-65 and older retirees will move to the Mercer Marketplace Exchange effective January 1, 2024.

Q. HOW HAVE THESE CHANGES IMPACTED PRM COSTS?

A. The majority of the savings associated with the adoption of the EGWP plan were recognized through Amortization of Unrecognized Prior Service Cost in the years 2020 through 2024. Moving to the Mercer Marketplace Exchange also results in Amortization of Unrecognized Prior Service Cost credits through 2028, but also makes permanent reductions to service costs.

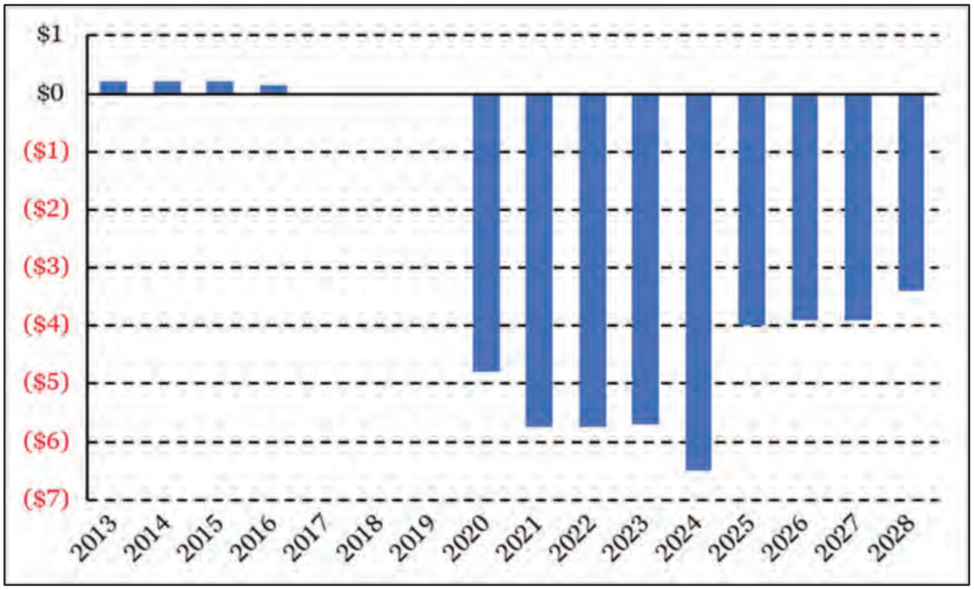
Q. PLEASE EXPLAIN AMORTIZATION OF UNRECOGNIZED PRIOR SERVICE COST CREDITS.

A. Similar to pension, the PRM cost calculation must incorporate Amortization of Unrecognized Prior Service Cost. The Amortization of Unrecognized Prior Service Cost is intended to capture the effect of plan changes on services rendered in prior periods. The effects of those changes are amortized over a period of years.

Q. IS THE AMORTIZATION OF UNRECOGNIZED PRIOR SERVICE COST CREDITS EXPECTED TO CONTINUE BEYOND 2024?

A. Yes, though 2024 reflects the greatest amount of Amortization of Unrecognized Prior Service Cost credits, as shown in the figure below. The relatively stable amounts of Amortization of Unrecognized Prior Service Cost credits in 2025-2028 contributes to the relatively stable amounts of expected PRM costs in those years.

Figure 11
Historical and Projected PRM Amortization of Unrecognized Prior Service Cost Credits
($ Millions, Otter Tail Corporation)



Q. WHY IS OTP RECOMMENDING THE 2024 TEST YEAR BE BASED ON FORWARD-LOOKING PRM DATA RATHER THAN HISTORICAL INFORMATION?

A. As shown in Figure 11, above, our future expected PRM costs are dissimilar to historical experience, primarily due to underlying plan changes. Using a forward looking average to normalize the expense makes sure those savings are reflected in rates. Further, OTP used the same normalization approach for pension and PRM expense. Arguably, using 2025 PRM costs (credit of approximately $1.8 million (Otter Tail Corporation)), or an average of 2025-2028 (credit of approximately $1.65 million (Otter Tail Corporation)) would produce a more representative amount of going-forward PRM expense, after the amount of Amortization of Unrecognized Prior Service Cost credits stabilizes, than the $2.18 million (Otter Tail Corporation) credit used in the 2024 Test Year. We feel that it is reasonable and appropriate to use the same normalization period for both pension and PRM costs.

V. SALES ADJUSTMENT PROPOSAL

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. This portion of my Direct Testimony addresses OTP's proposal to address the effects of changes to sales between rate cases.

Q. PLEASE DESCRIBE OTP'S PROPOSAL.

A. OTP's proposal has two elements: one focusing on base rates and one focusing on riders. Regarding base rates, OTP proposes to create a new mandatory rider, called the Sales Adjustment Rider, which would capture the effect of sales changes on base rate jurisdictional cost allocations and revenues. OTP also requests that the Commission authorize OTP to update jurisdictional allocators used to develop rider revenue requirements between rate cases. The mechanics of both elements of OTP's proposal are discussed further by OTP witness Ms. Amber M. Stalboerger.

Q. WHY IS OTP MAKING THIS PROPOSAL?

A. OTP has experienced several material changes in sales to its largest customers over the last two years or so and conditions are such that we may experience additional abrupt and material changes going forward. Our proposal is intended to develop an efficient regulatory mechanism that provides customers with benefits more quickly and does not allow material sales changes to accelerate otherwise unnecessary rate case filings.

Q. PLEASE DESCRIBE THE RECENT MATERIAL CHANGES IN OTP'S SALES TO ITS LARGEST CUSTOMERS.

A. In 2021, OTP received a Certificate of Public Convenience and Necessity (CPCN) to provide service to APLD Hosting, LLC, a wholly owned affiliate of Applied Digital, Inc. ("Applied") (formerly known as Applied Blockchain).[17] Applied started taking service under OTP's Super Large General Service Tariff, Electric Rate Schedule Section 10.06 (SLGS) in 2022.[18] Applied is OTP's largest North Dakota customer (by sales) and second largest customer (by sales) across all jurisdictions served by OTP. OTP witness Ms. Tammy K. Mortenson also explains that OTP **[PROTECTED DATA BEGINS…**

---

[17] *See* PU-21-365, Order on Electric Service Area Agreement and Certificate of Public Convenience and Necessity (Sept. 21, 2021).
[18] *See* PU-21-366, Order (Sept. 21, 2021).

...PROTECTED DATA ENDS]. Also, another large customer currently is planning to materially *reduce* its sales **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS].

Q. ARE THESE KINDS OF CHANGES CONSIDERED TO BE NORMAL FLUCTUATIONS IN SALES VOLUMES?

A. No. These kinds of changes are beyond what is considered the normal sales growth (or attrition) that occurs between rate cases. Rather, these are large, step-wise changes that deviate materially from baseline expectations. We believe additional, material sales changes may occur in the future and OTP's proposal is designed so that these changes can be incorporated into rates on a timely basis without the need to file a new rate case. Because we are a very small utility, changes like these are more material than they may be for other utilities.

Q. WHY DOES OTP BELIEVE IT MAY EXPERIENCE ADDITIONAL, MATERIAL SALES CHANGES IN THE FUTURE?

A. There are several reasons. First, as discussed above, we have the lowest commercial and industrial rates among investor-owned utilities in the region and among the lowest rates in the country. These low rates, along with other geographic benefits, make us a good partner for certain energy-intensive and agricultural processing businesses looking to locate new operations. Further, the presence of OTP's SLGS offering gives us narrowly tailored tools to attract the kind of high load factor customers that ultimately reduce costs for all customers (we have an approved SLGS rate offering in each of our three states). As discussed above, the addition of just one of these very large customers can result in sales (and revenues) that are materially different than what was used to establish base rates.

The converse is also true: the decision of a single customer has the potential to materially undermine the assumptions used to set base rates. This risk is evidenced by the **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS] discussed above. This risk is particularly acute given the Inflation Reduction Act provisions that incentivize certain self-supply resources. There also is the potential for the abrupt loss or restriction of a customer's operations by new regulatory restrictions or market changes for those working in emerging industries. These regulatory changes and incentives can create both risks and opportunities that may materially change OTP's sales volumes.

Q. HOW DOES THE SALES ADJUSTMENT RIDER ACCELERATE PROVIDING CUSTOMERS THE BENEFITS OF SALES GROWTH?

A. This case will establish OTP's base rate revenue requirement, and rates will be designed so that when they are applied to 2024 Test Year billing determinants, OTP recovers its cost of providing service, no more, no less. If OTP has a material increase in load in subsequent years, that provides additional revenue available to meet the cost of service. Yet, customers do not experience the benefit of that additional revenue until OTP's next rate case. The Sales Adjustment Rider would alter this construct: if actual base rate revenues are greater than proposed 2024 Test Year base rate revenues, the excess would be credited to customers.

Q. IS THIS SIMILAR TO HOW OTP'S OTHER RIDERS WORK TODAY?

A. Yes. Each rider has its own revenue requirement and rates are designed using an assumed sales volume. The deviations between projected and actual sales are captured in the rider true-up process. Thus, if actual sales in a particular year are much higher than what was assumed when the rider rates were established, customers receive credits through the true-up process. Also, each annual rider update incorporates a new projected sales volume, so material changes in sales (like those discussed above) are incorporated more quickly. This precise thing occurred in 2022 when the addition of Applied resulted in material reductions to OTP's mandatory riders.

Q. WHY IS OTP PROPOSING TO CAPTURE THE EFFECTS OF SALES CHANGES ON JURISDICTIONAL ALLOCATIONS AS PART OF ITS PROPOSAL?

A. This is a natural consequence of updating revenues. If OTP adds a material new load in North Dakota, it has additional revenues to meet its cost of service. At the same time, however, North Dakota would constitute a larger part of OTP's system and North Dakota would bear a larger responsibility for the costs of OTP's integrated system. Updating both revenues and costs maintains symmetry and ensures that these material sales changes contribute to neither over- nor under-recovery.

Q. IS OTP'S PROPOSAL SYMMETRICAL IN TERMS OF SALES INCREASES AND DECREASES?

A. Yes. Over the past two years, OTP has gained far more load from new Large Commercial customers than it has experienced in load attrition. Ms. Stalboerger explains that the addition of Applied in particular provides almost $2.0 million of benefits to other customers in the 2024 Test Year. As such, I have focused most of my discussion on large sales increases, but OTP's proposal is symmetrical in that it would address both sales increases and decreases from what was used to design rates in the 2024 Test Year.

Q. ARE JURISDICTIONAL ALLOCATORS PARTICULARLY IMPORTANT WHEN CONSIDERING POTENTIAL NORTH DAKOTA SALES ATTRITION?

A. Yes. If the proposal only focused on revenue, then a material sales loss would result in a positive Sales Rider adjustment charge, as the rider would recover the difference between 2024 Test Year base rate revenue and actual base rate revenue; it would not account for the fact that North Dakota would constitute a relatively smaller portion of OTP's integrated system. By including the effect of sales changes on jurisdictional allocations and on base rate revenue, the proposal keeps costs and revenues aligned: a material decline in revenue also would need to be matched with a decrease in North Dakota cost responsibility.

Q. DOES YOUR PROPOSAL ADDRESS THE NORTH DAKOTA IMPACTS FROM CHANGES TO SALES VOLUMES IN OTP'S OTHER STATES?

A. Yes. Sales volume changes occurring on OTP's system in other states can have an effect on the allocation of OTP's costs to North Dakota. For example, if OTP were to add a large customer in South Dakota, it would likely have the effect of reducing the cost allocations to North Dakota, and our proposal would have the benefit of getting these cost allocation reductions to our North Dakota customers sooner than under the current regime, which would only permit adjustments following a general rate case filing. As noted above, we have received approval for our SLGS rate offering in each of our states and the forces discussed above that are creating opportunities for large load additions are present in all of our states. Our proposal updates allocators whether due to changes to sales volume in North Dakota or due to changes in a neighboring state.

Q. WHY IS OTP REQUESTING AUTHORIZATION TO UPDATE RIDER JURISDICTIONAL ALLOCATORS BETWEEN RATE CASES?

A. As noted above, our riders already capture the revenue impact of all sales changes, both through the annual true-up process and through the annual update process. Updating the jurisdictional allocator maintains symmetry between costs and revenues, as discussed above.

Q. DID OTP SEEK TO UPDATE JURISDICTIONAL ALLOCATORS IN ITS 2022 RRCR RIDER FILING?

A. Yes. In addition to updating project investments and other matters, OTP proposed in Case No. PU-22-429 to update the jurisdictional allocator used to calculate the RRCR Rider revenue requirement. The Commission did not approve that request.

Q. WHY IS OTP RENEWING ITS REQUEST NOW?

A. First, as discussed above, updating the rider jurisdictional allocators ensures symmetry between rider costs and revenues. Second, this proposal is being made a part of a rate case, where all of OTP's costs and revenues are being assessed. This is in contrast to Case No. PU-22-429, a rider proceeding. We believe making this change in a rate case ensures that all rates, including rider rates, are just and reasonable.

VI. SUPER LARGE GENERAL SERVICE UPDATE

Q. PLEASE DESCRIBE OTP'S SUPER LARGE GENERAL SERVICE OFFERING.

A. In our last North Dakota rate case, we requested the Commission authorize a new SLGS rate offering.[19] The offering primarily is targeted at attracting high load factor large commercial customers to OTP's service territory. Qualifying customers have access to individual contract pricing based on OTP's marginal cost of service, though that pricing must ensure net benefits to other customers.

Q. HOW IS THE SLGS INDIVIDUAL CONTRACT PRICING DEVELOPED?

A. Contract pricing offered under the SLGS tariff is customized for the individual customer based on their specific load characteristics and investment needed to

[19] OTP's proposal was approved by the Commission and OTP's SLGS tariff, Section 10.06 went into effect for bills rendered on or after February 1, 2019.

serve the customer. SLGS customers also pay rates based on marginal costs rather than embedded costs.[20]

Q. IS OTP UPDATING ITS MARGINAL COSTS AS PART OF THIS RATE CASE?

A. Yes. OTP regularly uses a marginal cost study for its rate designs and OTP witness Mr. David G. Prazak explains that OTP obtained an updated marginal cost study in connection with this case (the 2024 Marginal Cost Study).

Q. WHAT IS THE IMPACT OF UPDATING MARGINAL COSTS ON THE SLGS RATE OFFERING?

A. Updating marginal costs impacts the SLGS rate offering in two ways. First, the SLGS rate offering features a regulatory pre-approval process, whereby OTP's proprietary marginal cost-to-serve model is provided to Commission Staff for verification of rate offerings. The model houses OTP's expected marginal unit cost to serve and, when combined with the potential customer's expected load requirements, generates a minimum incremental revenue. OTP is then able to quote the potential customer an individualized rate so long as it exceeds the minimum incremental revenue. OTP has updated the proprietary SLGS model for the 2024 Marginal Cost study results and will provide it to Commission Staff, consistent with the SLGS tariff.

The second way updated marginal costs affects the SLGS rate offering is through the individualized pricing for customers taking service under the SLGS tariff. As marginal costs change, so does the individualized pricing for the SLGS customers.

Q. HOW MANY CUSTOMERS CURRENTLY TAKE SERVICE UNDER THE SLGS TARIFF?

A. OTP currently has one customer, Applied, taking service under the SLGS tariff.[21]

Q. HAS OTP PREPARED UPDATED INDIVIDUALIZED PRICING FOR APPLIED?

A. OTP has prepared an updated rate for its service to Applied. Mr. Prazak further explains development of this updated rate in his Direct Testimony. Given the confidential nature of this information, the revised rate is being provided directly

[20] OTP witness Mr. David G. Prazak discusses the distinction between embedded and marginal costs in his Direct Testimony.
[21] *See* Case Nos. PU-21-364, 21-365, 21-366.

to Applied. The revenues associated with the updated rate have been incorporated into OTP's proposed rate design.

Q. WHY IS OTP PROPOSING TO UPDATE INDIVIDUALIZED PRICING FOR CUSTOMERS TAKING SERVICE UNDER THE SLGS RATE?

A. There are several reasons. First, as contemplated in the SLGS tariff, costs may change over time, necessitating both updated marginal cost studies and pricing through OTP's proprietary model. Updating the rates offered under the SLGS tariff to reflect the most recent marginal cost study ensures other customers continue to receive net benefits of the SLGS offering.

Second, one aspect of this case is that certain project costs are moving from riders into base rates, which is a typical occurrence during rate cases. This movement is merely a change in the form of cost recovery and on net, has no impact on customers' bills. Yet, that would not be the case if SLGS customers' base rates were not updated concurrently with the reduction in rider rates associated with movement of such costs to base rates. Avoiding this mismatch and the resulting inappropriate windfall to SLGS customers also is consistent with the ultimate condition that SLGS rates result in net benefits to other customers.

Q. WHAT IS THE TOTAL IMPACT OF OTP'S PROPOSAL TO UPDATE INDIVIDUALIZED PRICING FOR CUSTOMERS TAKING SERVICE UNDER THE SLGS RATE?

A. OTP's proposal results in SLGS customers paying approximately **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** in base rates.[22] Those same customers will experience an approximate **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** in rider costs (due to projects moving from riders and into base rates, resulting in **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**.

VII. INTRODUCTION OF WITNESSES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I introduce OTP's witnesses and briefly discuss the topics each covers in Direct Testimony.

[22] *See* Volume 3, Schedule E-2.

Q. WHO ARE OTP'S OTHER WITNESSES?

A. OTP's other witnesses are:

- Anne E. Bulkley presents evidence and provides a recommendation regarding the appropriate return on equity for OTP and provides an assessment of the capital structure to be used for ratemaking purposes.
- Christopher E. Byrnes discusses and supports how Otter Tail Corporation allocates its corporate costs to OTP. He explains the Lead Lag Study that is used to calculate the cash working capital component of rate base for the 2024 Test Year. He also presents proposed changes to OTP's Energy Adjustment Rider that will make fuel costs more transparent for our customers, and OTP's proposed treatment of rate case advertising and electronic payment processing expenses.
- Paula M. Foster describes OTP's proposal regarding treatment of certain riders and associated costs in the 2024 Test Year and adjustments to those riders as the result of moving cost recovery from riders and into base rates.
- Tammy K. Mortenson discusses OTP's energy forecasting process and present the results of OTP's sales forecast, which forms the basis of the 2024 Test Year sales and revenues in this proceeding.
- Christy L. Peterson is OTP's overall revenue requirements witness, sponsoring the Jurisdictional Cost of Service Study and the calculation of OTP's 2024 Test Year revenue deficiency. As such, she supports and sponsors much of the financial data provided as part of this case. She also describes OTP's capital and operations and maintenance budgets, which provide the basis for the 2024 Test Year. Finally, she discusses the development of the rate base and net operating statement that are being proposed for use in setting rates in this proceeding, including explaining the financial impact of all Test Year adjustments and providing support for some of the Test Year adjustments.
- David G. Prazak describes the rate structure objectives that were used in developing the proposed rates; explains the role of embedded and marginal costs in OTP's rate design; describes the proposed rate design for OTP's rate schedules; and supports the proposed language changes of OTP's rate schedule provisions.
- Amber M. Stalboerger addresses a variety of regulatory and cost allocation issues, including development of jurisdictional and class allocation factors

and the mechanics of the Company's proposal to address changes in sales volumes between rate case. Ms. Stalboerger also addresses treatment of generator interconnection procedures projects (GIPs), and proration of accumulated deferred income tax (ADIT) in the 2024 Test Year. She also sponsors and presents the results of OTP's 2024 Test Year Class Cost of Service Study and OTP's proposed class revenue responsibilities.

- Todd R. Wahlund supports OTP's capital structure and overall rate of return (ROR). He will also discuss several issues that are related to OTP's proposed capital structure and ROR, including OTP's prior and planned capital expenditures, credit ratings and unique financial characteristics.
- Peter E. Wasberg discusses matters related to OTP's employee compensation and benefits. He describes OTP's current compensation plan, including its four annual incentive plans, and benefits provided to OTP employees and retirees. Finally, he summarizes certain 2024 Test Year compensation and benefit costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Qualifications, Duties and Responsibilities of Bruce Gerhardson

EMPLOYMENT

Vice President, Regulation and Retail Energy Solutions– Otter Tail Power Company
October 2017-Present
Executive leadership over regulatory affairs, market planning and strategic planning

Director, Regulatory Affairs and Compliance – Otter Tail Power Company
April 2017-October 2017
Executive Leadership over regulatory economics, administration, proceedings and compliance

Associate General Counsel - Otter Tail Power Company, Fergus Falls, MN
2000-April 2017
Lead Counsel for regulatory affairs and administrative proceedings. Chief Compliance Counsel. Staff of eight advocacy and compliance personnel, including the Manager of Regulatory Economics and the Manager of Regulatory Proceedings and Compliance.

Partner - Svingen, Athens, Russell and Hagstrom Law Firm, Fergus Falls, MN
1995-2000
Comprehensive legal representation of individual clients, with public utility and agribusiness focus. Regulatory proceedings, project development and other transactions.

EDUCATION

University of Minnesota Law School
JD Cum Laude 1995. Judicial Extern for the Mille Lacs Band of Ojibwe Tribal Court; Summer Associate at Pemberton, Sorlie, Rufer & Kershner Law Firm, Fergus Falls, Minnesota

University of Minnesota-Duluth
Graduate Work, English Literature and Writing 1990-1992; Fellowships and Teaching Assistantships in Writing and Literature

St. Olaf College
BA Cum Laude, English 1988; Semester Abroad at University of Aberdeen, Scotland

Fergus Falls Community College
AA Liberal Arts 1985

INDUSTRY CERTIFICATIONS

Law licenses in Minnesota, North Dakota and South Dakota

Volume 2A

Direct Testimony and Supporting Schedules:

Amber M. Stalboerger

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

ALLOCATORS, CLASS COST OF SERVICE,
REVENUE ALLOCATION AND OTHER REGULATORY ITEMS

Direct Testimony and Schedules of

AMBER M. STALBOERGER

November 2, 2023

TABLE OF CONTENTS

ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My name is Amber M. Stalboerger. I am employed by Otter Tail Power Company (OTP or the Company).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Manager of Regulatory Analysis. I am responsible for providing leadership in areas of financial analysis related to setting rates and overall cost recovery, cost allocation methodologies, cost of energy, and cost of service study analysis.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(AMS-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony addresses a variety of regulatory and cost allocation issues, including development of jurisdictional and class allocation factors and the mechanics of the Company's proposal to address changes in sales volumes between rate cases. I also address the treatment of generator interconnection procedures projects (GIPs) and proration of accumulated deferred income tax (ADIT) in the 2024 Test Year. I sponsor and present the results of OTP's 2024 Test Year Class Cost of Service Study (CCOSS) and OTP's proposed class revenue responsibilities. Finally, I address one CCOSS compliance issue from OTP's last North Dakota rate case (Case No. PU-17-398).

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. The allocation factors OTP uses in its Jurisdictional Cost of Service Study (JCOSS) and CCOSS are reasonable and appropriate for determining the 2024 Test Year revenue requirement and calculating class cost responsibilities. OTP's overall approach for addressing changes in sales between rate cases also is just and reasonable, as is the proposed treatment of GIPs and ADIT proration in the 2024 Test Year. The Company's CCOSS is an appropriate, but not exclusive, guide for establishing class revenue responsibilities. Ultimately, considering the CCOSS and other relevant factors, OTP's proposed class revenue responsibilities are reasonable and should be adopted.

III. JURISDICTIONAL AND CLASS ALLOCATORS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I introduce and discuss the allocation factors OTP uses in its jurisdictional and class cost of service studies.

Q. WHAT IS THE ROLE OF JURISDICTIONAL AND CLASS ALLOCATORS IN THE RATEMAKING PROCESS?

A. Jurisdictional allocators are used to allocate system costs among jurisdictions and class allocators are used to allocate jurisdictional costs among customer classes.

Q. WHY ARE JURISDICTIONAL AND CLASS ALLOCATORS NECESSARY?

A. OTP operates an integrated electrical system that serves customers across multiple jurisdictions. This integrated system design takes advantage of economies of scale to provide least-cost energy solutions for all our customers. Because OTP operates as one system, costs of investment in the system and the expenses necessary to operate the system need to be allocated among the jurisdictions. Costs allocated to each jurisdiction need to be further allocated to customer classes in order to design rates.

Q. HOW DO THESE ALLOCATIONS OCCUR?

A. OTP uses the JCOSS to allocate system costs and revenues to various jurisdictions in which it provides service, as described in more detail by OTP witness Ms. Christy L. Petersen. OTP then uses the CCOSS to allocate jurisdictional costs and revenues, which I describe in more detail below.

Q. WHAT ALLOCATORS DID OTP USE IN ITS TEST YEAR JCOSS AND CCOSS?

A. Table 1 below identifies the main allocators used in the 2024 Test Year JCOSS and CCOSS. The OTP Cost Allocation Procedures Manual (CAPM), included as Exhibit___(AMS-1), Schedule 2, provides additional detail regarding the development of each allocator.

Table 1
JCOSS and CCOSS Allocators

Cost Function	Classification	JCOSS Allocator[1]	CCOSS Allocator[2]
Production Plant	Base Demand	E1	E1-E8760
	Peak Demand	D1	D1
	Base Energy (Wind)	E2	E2-E8760
Transmission Plant	Demand-Related	D2	D2
Distribution Plant	Demand-Related (Primary)	D3	D3
	Demand-Related (Secondary)	D4	D4
	Customer-Related (Primary)	C2	C2
	Customer-Related (Secondary)	C3	C3
	Street Lighting	C4	C4
	Area Lighting	C5	C5
	Meters	C6	C6
	Load Management	C9	C9

Q. HAS OTP CHANGED THE CAPM SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. No, not materially. Schedule 2, identifies, in redline, the CAPM content changes from the CAPM presented in OTP's last North Dakota rate case.

Q. DID OTP USE THESE SAME ALLOCATORS IN ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. We used the same energy, demand, and customer allocation factors outlined in the CAPM for cost allocations in this case as we did in our last North Dakota rate case. As discussed below, however, we are proposing certain refinements to how the D1, D2, and E1-8760 allocators are calculated for class allocation purposes.

Q. ARE THE ALLOCATORS USED IN THE CURRENT CASE BASED ON FORECASTED INFORMATION?

A. Yes. OTP is using a forecast 2024 Test Year in this case and developed the allocation factors based on forecast information. The process of developing the forecast-based allocators is described in Exhibit___(AMS-1), Schedule 3, which is a supplement to the CAPM.[3]

[1] *See* Volume 3, Supporting Information, Schedule B-5.
[2] *See* Volume 3, Supporting Information, Schedule E-3.
[3] Similar to Schedule 2, Schedule 3 shows revisions to the CAPM supplement in redline format.

A. Jurisdictional Allocation Factors

Q. DOES OTP USE THE SAME JURISDICTIONAL ALLOCATION METHODOLOGIES ACROSS ALL OF ITS JURISDICTIONS?

A. Yes. Each of our jurisdictions has approved the same jurisdictional cost allocation methodology.

Q. IS IT IMPORTANT TO MAINTAIN CONSISTENCY IN JURISDICTIONAL ALLOCATION METHODOLOGIES ACROSS JURISDICTIONS?

A. Yes. Maintaining consistency in cost allocation across jurisdictions helps minimize the potential for any over- or under-recovery of costs from an overall system perspective.

Q. HOW DO THE JCOSS ALLOCATION FACTORS COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. Table 2 below compares the 2024 Test Year JCOSS allocation factors to those used in the 2018 Test Year from OTP's last North Dakota rate case.

Table 2
Comparison of JCOSS Allocation Factors

Cost Function	Classification	JCOSS Allocator[4]	2018 Test Year	2024 Test Year	Change
Production Plant	Base Demand	E1	35.65831%	43.87388%	8.21558%
	Peak Demand	D1	39.84045%	39.48493%	-0.35553%
	Base Energy (Wind)	E2	37.57734%	44.98105%	7.40371%
Transmission Plant	Demand-Related	D2	39.59894%	39.19520%	-0.40371%
Distribution Plant	Demand-Related (Primary)	D3	45.87051%	46.52141%	0.65090%
	Demand-Related (Secondary)	D4	48.02088%	48.69979%	0.67891%
	Customer-Related (Primary)	C2	44.77088%	43.71010%	-1.06078%
	Customer-Related (Secondary)	C3	44.78375%	43.71399%	-1.06976%
	Street Lighting	C4	43.58121%	41.67331%	-1.90790%
	Area Lighting	C5	51.76290%	54.51687%	2.75398%
	Meters	C6	44.67973%	44.58005%	-0.09968%
	Load Management	C9	43.55054%	43.69288%	0.14234%

[4] *See* Volume 3, Supporting Information, Schedule B-5.

Q. WHAT IS CONTRIBUTING TO THE GENERAL INCREASE IN THE E1 AND E2 JCOSS ALLOCATION FACTORS?

A. The increase in the JCOSS E1 and E2 allocation factors is the result of relative growth in OTP's North Dakota sales (as compared to other jurisdictions served by OTP), primarily due to the addition of APLD Hosting, LLC, a wholly owned affiliate of Applied Digital, Inc. ("Applied") (formerly known as Applied Blockchain) as a full-service customer in 2022.

Q. PLEASE DESCRIBE OTP'S SERVICE TO APPLIED.

A. OTP received a Certificate of Public Convenience and Necessity (CPCN) to provide service to Applied in 2021.[5] Applied started taking service under OTP's Super Large General Service Tariff, Electric Rate Schedule Section 10.06 (SLGS) and began operating at full capacity in late 2022. Applied is OTP's largest North Dakota customer (by sales) and second largest customer (by sales) across all jurisdictions served by OTP.

Q. PLEASE DESCRIBE THE SLGS RATE.

A. The SLGS rate, which was approved in OTP's last North Dakota rate case, is designed to attract high load factor large/commercial customers into OTP's service territory. Customers that meet eligibility criteria have access to individual contract pricing based on OTP's marginal cost of service. The Commission approved Applied's individual contract pricing in Case No. PU-21-366.

Q. HAS OTP ANALYZED APPLIED'S CONTRIBUTION TO MEETING ITS NORTH DAKOTA COST OF SERVICE?

A. Yes. During its approval of OTP providing service to Applied under the SLGS rate, the Commission requested that OTP annually assess Applied's contribution to meeting its North Dakota cost of service.[6] OTP provided its first assessment covering calendar year 2022 as part of its annual report filing in Case No. PU-23-249. That assessment confirmed that Applied made a net contribution to system costs. OTP's second assessment covering calendar year 2023 will be provided as part of its next annual report filing.

---

[5] *See* PU-21-365, Order on Electric Service Area Agreement and Certificate of Public Convenience and Necessity (Sept. 21, 2021). Other cases addressing OTP's service to Applied include Case Nos. PU-21-364 and PU-21-366.

[6] Section 10.06, Terms and Conditions, Paragraph 9 requires OTP to provide the Commission annual compliance updates to the marginal cost model used for SLGS pricing.

Q. HAVE YOU EVALUATED APPLIED'S IMPACT ON THE 2024 TEST YEAR REVENUE DEFICIENCY?

A. Yes. As discussed by Ms. Petersen, the 2024 Test Year revenue requirement is $223.3 million, resulting in a $40.7 million base rate revenue deficiency. Both of these values reflect OTP's service to Applied under the Commission-approved SLGS pricing and jurisdictional allocators reflecting anticipated 2024 sales to Applied. Removing both the costs (including the effect on jurisdictional allocations) and revenues associated with OTP's service to Applied *increases* the 2024 Test Year revenue deficiency by approximately $2.0 million. This confirms that OTP's service to Applied continues to benefit other North Dakota customers.

Q. HOW ARE WIND GENERATING RESOURCES TREATED IN THE JCOSS?

A. As discussed in the CAPM, wind generation is a non-dispatchable resource with operating characteristics that are different from other production facilities. OTP uses the Midcontinent Independent System Operator's (MISO) capacity accreditation to classify wind production plant into base energy and peak demand components.

Q. HAS MISO RECENTLY CHANGED HOW IT ACCREDITS WIND CAPACITY?

A. Yes. On February 16, 2023, the Federal Energy Regulatory Commission (FERC), approved revisions to MISO's Energy and Operating Reserve Market Tariff (MISO Tariff).[7] Those revisions implement a seasonal resource adequacy construct whereby Load Serving Entities (LSEs), including OTP, are required to have enough resources (generation, purchased capacity, load management resources) to cover expected customer demand and contingencies for each season (summer, winter, fall, spring). Previously, MISO only required LSEs to meet planning reserve margins during the summer season. With the adoption of a seasonal resource adequacy construct, MISO has changed how it accredits wind capacity, looking to production during all seasons, not just the summer. As a result, OTP's wind facilities have higher accredited capacity under the new construct.

Q. WHAT IS THE EFFECT OF MISO'S NEW RESOURCE ADEQUACY RULES ON THE CLASSIFICATION OF WIND PRODUCTION PLANT?

A. Table 3, below, shows the capacity accreditation factors for each of OTP's wind facilities for each season. Winter capacity factors are higher than summer capacity

[7] *See Midcontinent Independent System Operator, Inc.*, Docket Nos. ER22-495-002, ER22-495-003, Order Addressing Arguments Raised on Rehearing and on Compliance, 182 FERC ¶ 61,096 (Feb. 16, 2023).

factors. Thus, the change to MISO's resource adequacy rules increases each facility's accredited capacity and thus, the portion of wind production plant classified as peak demand.

Table 3
OTP Wind Facility MISO Capacity Accreditation

Wind Facility	Summer	Fall	Winter	Spring	Average
Ashtabula	2.19%	4.32%	7.16%	2.74%	4.10%
Ashtabula III	3.19%	4.65%	9.81%	3.51%	5.29%
Langdon	1.83%	3.34%	6.45%	2.88%	3.62%
Luverne	2.80%	4.48%	7.94%	2.99%	4.55%
Merricourt	9.25%	10.62%	20.45%	15.37%	13.92%
Total	19.25%	27.40%	51.83%	27.49%	**31.49%**

Q. WHAT IS THE BASE RATE REVENUE REQUIREMENT IMPACT OF APPLYING MISO'S NEW RESOURCE ADEQUACY RULES ON THE CLASSIFICATION OF WIND PRODUCTION PLANT?

A. Applying the MISO resource adequacy rules to the classification of wind production plant decreased the 2024 Test Year revenue requirement by approximately $0.5 million.

B. Class Allocation Factors

Q. HOW DO THE CCOSS ALLOCATION FACTORS COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. Table 4 below shows the differences between the 2024 Test Year CCOSS allocation factors and those used in the 2018 Test Year from OTP's last North Dakota rate case.

Table 4
Change in CCOSS Allocation Factors

Class Allocator	Residential	Farm	General Service	Large General Service	Irrigation
Generation Demand (D1)	0.3242%	-0.5525%	-0.6271%	0.6994%	0.0000%
Transmission Demand (D2)	0.3242%	-0.5525%	-0.6271%	0.6994%	0.0000%
Primary Demand (D3)	-0.3845%	-1.7545%	-0.2645%	-2.9564%	0.0567%
Secondary Demand (D4)	-4.7396%	-1.6865%	-0.8935%	-1.6533%	0.0813%
Energy (E1-8760)	-11.6701%	-0.7336%	-7.2854%	21.2278%	0.0000%
Energy (E2-8760)	-8.2183%	-0.5254%	-6.9565%	20.8154%	0.0076%
Total Retail Customers (C1)	-0.4304%	0.1419%	0.6118%	-0.0023%	-0.0085%
Retail Service Locations (C2)	0.3317%	-0.0998%	-0.3975%	0.1460%	-0.0836%
Secondary Service Locations (C3)	0.3250%	-0.1000%	-0.4015%	0.1569%	-0.0836%
Street Lighting (C4)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Area Lighting (C5)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Meter (C6)	0.9508%	-0.2907%	0.4991%	-0.2271%	-0.0101%
Meter Reading (C7)	-9.2398%	-0.0758%	9.7264%	0.0024%	0.0486%
System Service Locations (C8)	0.3340%	-0.0997%	-0.3969%	0.1429%	-0.0836%
Load Management (C9)	-0.3498%	0.0725%	0.0749%	0.0002%	-0.0129%

Class Allocator	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interuptible	Controlled Service Off-peak
Generation Demand (D1)	-0.5274%	0.1177%	0.7144%	0.1004%	-0.2490%
Transmission Demand (D2)	-0.5274%	0.1177%	0.7144%	0.1004%	-0.2490%
Primary Demand (D3)	-0.2675%	0.1069%	6.9893%	0.6678%	-2.1932%
Secondary Demand (D4)	-0.2049%	0.0268%	10.7942%	0.6740%	-2.3985%
Energy (E1-8760)	-0.6124%	-0.2984%	0.1318%	0.0000%	-0.7598%
Energy (E2-8760)	-0.4898%	-0.2137%	0.3319%	-3.4460%	-1.3052%
Total Retail Customers (C1)	0.0736%	0.0590%	-0.0353%	-0.3460%	-0.0638%
Retail Service Locations (C2)	0.0452%	0.0682%	0.0075%	-0.0082%	-0.0095%
Secondary Service Locations (C3)	0.0452%	0.0681%	0.0075%	-0.0083%	-0.0095%
Street Lighting (C4)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Area Lighting (C5)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Meter (C6)	0.1174%	-0.0393%	-0.3998%	0.1665%	-0.7668%
Meter Reading (C7)	0.3547%	1.0084%	-0.2784%	-0.9856%	-0.5609%
System Service Locations (C8)	0.0452%	0.0682%	0.0075%	-0.0082%	-0.0095%
Load Management (C9)	0.0055%	0.0000%	3.1345%	0.4968%	-3.4217%

Q. DO YOU HAVE ANY PRELIMINARY OBSERVATIONS REGARDING TABLE 4?

A. Yes. As discussed below, OTP has reorganized the rate schedules that comprise the controlled services classes (Controlled Service, Controlled Service Deferred, and Controlled Service Interruptible) since its last North Dakota rate case, so the values for those classes in the table above are not directly comparable to those of the previous case. OTP witness Mr. David G. Prazak discusses this issue in more detail in his Direct Testimony.

Q. WHAT IS CONTRIBUTING TO THE GENERAL INCREASE IN THE E1-E8760 AND E2-8760 CCOSS ALLOCATION FACTORS FOR THE LARGE GENERAL SERVICE CLASS?

A. The primary contributor to the increase in the E1-E8760 and E2-E8760 allocation factors for the Large General Service (LGS) class is the addition of Applied as a full-service customer in 2022. That class is now significantly larger (by sales volume) than it was during our last North Dakota rate case and therefore has a larger share of the E1-8760 and E2-8760 allocators.

Q. HAS THERE BEEN A CORRESPONDING INCREASE TO THE D1 AND D2 ALLOCATION FACTORS FOR THE LGS CLASS?

A. No. One of the unique aspects of Applied's operations is that it can rapidly reduce its load in response to OTP load control signals.[8] This flexibility allowed OTP to add Applied as a customer without needing to acquire an amount of additional capacity comparable to its energy amount. Applied's flexibility also is considered in calculation of the D1 and D2 allocation factors (for both jurisdictional and class purposes), which is why there has not been a corresponding increase to those factors.

Q. PLEASE DISCUSS THE CHANGES TO THE PROCESS OF CALCULATING THE CCOSS D1 AND D2 ALLOCATION FACTORS.

A. OTP has set the D1 and D2 allocation factors for the Controlled Service classes to zero kilowatts (kW). Setting these classes to zero kW reflects OTP's ability to completely turn off these loads during high priced periods, as well as during OTP's peak. These classes are considered a low-cost resource and prevent OTP from needing to obtain additional capacity.

Q. PLEASE DISCUSS THE CHANGE TO THE CALCULATION OF THE E1-8760 ALLOCATION FACTOR.

A. Historically, the E1-E8760 allocator was calculated based on applying a 10/24ths factor to forecasted annual kilowatt hours (kWhs) for water heating and deferred loads. We have refined the calculation to better weigh the avoided capacity costs realized by those levels of service that could be controlled.

---

[8] *See* Case No. PU-21-336, Informal Presentations of OTP and Applied (Sept. 1, 2021).

The refinement excludes kWhs related to up to 14 hours of control for water heating and deferred loads based on the highest priced 14 of 24 hours using forecasted marginal hourly capacity costs. Schedule 3 further describes the process for the development of this forecasted factor.

IV. SALES ADJUSTMENT PROPOSAL

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I discuss the mechanics of OTP's sales adjustment proposal. OTP witness Mr. Bruce G. Gerhardson supports this proposal in his Direct Testimony.

Q. WHAT IS THE SALES ADJUSTMENT PROPOSAL DESIGNED TO ADDRESS?

A. Mr. Gerhardson explains that OTP potentially could see significant changes in sales between rate cases. The sales adjustment proposal is designed to address the impacts of such changes on revenues and jurisdictional cost allocations.

Q. IS OTP'S PROPOSAL LIMITED TO BASE RATES?

A. No. Mr. Gerhardson explains the proposal has two elements: one focusing on base rates and one focusing on riders. Regarding base rates, OTP proposes to create a new mandatory rider, called the Sales Adjustment Rider, which would capture the effect of sales changes on base rate jurisdictional cost allocations and revenues. OTP also requests that the Commission authorize OTP to update jurisdictional allocators used to develop rider revenue requirements between rate cases. These changes would occur as part of annual rider filings, as discussed below.

Q. PLEASE EXPLAIN HOW THE SALES ADJUSTMENT RIDER WOULD WORK.

A. Again, as discussed above, the Sales Adjustment Rider is intended to capture the effect of sales changes on base rate jurisdictional cost allocations and revenues. The starting point will be the 2024 Test Year JCOSS for the authorized revenue requirement from this case. OTP will then remove all 2024 Test Year rider costs and revenues. This will form the baseline for comparison (the Sales Adjustment Rider Baseline JCOSS).

Concurrently with the filing of OTP's 2024 annual report (made in the second quarter of 2025) and continuing at the time of filing each annual report thereafter until OTP's next North Dakota rate case, OTP will prepare a JCOSS that captures the effects of differences between actual sales and the amounts included in the 2024 Test Year. Specifically, the filing will include a JCOSS that begins with the Sales Adjustment Rider Baseline JCOSS, but then incorporates the effects of actual sales for the calendar year on allocation factors, base revenues and working capital. This JCOSS will be the Comparison JCOSS. The only differences between the Sales Adjustment Rider Baseline JCOSS and the Comparison JCOSS would be the impact of sales on allocation factors, base revenues and associated working capital: all other aspects would be identical. The difference between the Sales Adjustment Rider Baseline JCOSS and the Comparison JCOSS would be the amount credited to, or collected from, customers through the Sales Adjustment Rider.

Q. HOW WILL THE SALES ADJUSTMENT RIDER AMOUNTS BE CREDITED TO OR COLLECTED FROM CUSTOMERS?

A. The Sales Adjustment Rider would become a new mandatory rider. Sales Adjustment Rider amounts would be credited to or collected from customers on a per-kWh basis.

Q. HAS OTP PREPARED A PROPOSED SALES ADJUSTMENT RIDER TARIFF SHEET?

A. Yes. A proposed Sales Adjustment Rider tariff sheet is provided as Exhibit___(AMS-1), Schedule 4. The tariff sheet describes other mechanics of the Sales Adjustment Rider, including applicable tracker and true-up adjustment provisions.

Q. HOW WILL OTP'S PROPOSAL IMPACT OTHER RIDERS?

A. As discussed by Mr. Gerhardson, OTP intends its overall proposal to address the effects of between-rate-case sales changes on revenues and cost allocations. OTP's other riders already capture revenue effects of between-rate-case changes in sales volumes through annual updates (which incorporate forecasted sales for the applicable recovery period) and true-up adjustments (which capture differences between forecasted sales and actual sales). This process would be unchanged under OTP's proposal. Those riders, however, currently do not accommodate the effects of sales changes on jurisdictional cost allocations.

OTP proposes to change the operation of its riders by allowing for annual updates to jurisdictional cost allocations. Specifically, at the time OTP makes its annual rider filings it would: (1) calculate proposed rider revenue requirements utilizing jurisdictional allocators based on the same sales volumes used to develop the projected rider rates; and (2) include within the true-up calculation amounts due to differences between the jurisdictional allocators used to calculate the prior year's annual revenue requirement and allocators based on actual sales during that year. This is similar to the current process used for the Energy Adjustment Rider.

V. GENERATOR INTERCONNECTION PROCEDURES PROJECTS

Q. WHAT ARE GENERATOR INTERCONNECTION PROCEDURES PROJECTS?

A. Generator Interconnection Procedures Projects, or GIPs, are upgrades to OTP's transmission facilities that are located beyond a generator's point of interconnection with the MISO transmission grid. New generators typically require upgrades of the existing transmission system beyond the point (downstream) of the point of interconnection.

Q. WHAT TYPES OF UPGRADES ARE INCLUDED IN THE GIPS CATEGORY?

A. GIPs involve things that result in an increase to transmission system capacity or that interconnect new generation, such as: (1) replacing structures to increase line clearances; (2) replacing existing conductors with larger conductors; (3) adding new or replacing existing substation equipment; (4) constructing new substations or switch stations; and (5) building new transmission lines or modifying existing transmission lines to interconnect with new switching stations or substations.

Q. HAS OTP BEEN REQUIRED TO MAKE MANY TRANSMISSION UPGRADES BEYOND THE POINT OF INTERCONNECTION?

A. Yes. With the significant number of wind generation projects coming online in North Dakota, Minnesota, and South Dakota, OTP's transmission facilities have required many upgrades in order to interconnect new generators, even if the point of interconnection of the new generator is not on OTP's transmission system.

Q. HOW MUCH HAS OTP INVESTED IN GIPS TO DATE?

A. By the end of 2024, OTP will have approximately $42.8 million (OTP Total) / $16.8 million (OTP ND) of transmission rate base investment for GIPs made in connection with approximately 20 different generating facilities, including Merricourt Wind and Astoria Station.

Q. PLEASE DISCUSS THE RATEMAKING TREATMENT FOR GIPS UNDER THE MISO TARIFF.

A. Under the MISO Tariff, the entire cost of facilities that are specific to the generator itself and provide the initial point of interconnection to the MISO transmission system are paid for in advance by the generator.

The MISO tariff also provides two alternatives to be elected by a transmission owner (TO) for the types of transmission improvements included in OTP's GIPs: (1) pre-funding by the generator; or (2) TO Provided Funding. The TO may elect pre-funding, which requires full payment by the generator in advance of network upgrades being constructed. TO Provided Funding allows TOs (including OTP) to elect to provide funding for network upgrades to the TO's transmission system that are required to transmit energy from the new generators.[9] If the TO elects TO Provided Funding, the generator is required to pay for 100 percent of transmission network upgrades to facilities of 230 kilovolts (kV) or below, and 90 percent of upgrades to facilities of 345 kV or above. The remaining 10 percent of upgrades to facilities of 345 kV or above are allocated to utilities throughout the MISO region.[10]

Q. HOW DOES THE GENERATOR PAY FOR TRANSMISSION OWNER PROVIDED FUNDING?

A. Under the MISO Tariff, the generator pays the TO the cost of TO Provided Funding over a 20-year period at a formula rate established under the MISO Tariff.[11]

Q. DOES OTP'S TRANSMISSION OWNER PROVIDED FUNDING OF GIPS PROVIDE FINANCIAL BENEFITS TO OTP CUSTOMERS?

A. Yes. The MISO Tariff provisions for Transmission Owner Provided Funding provide for recovery of costs over a 20-year period rather than over the 40 to 60-year useful life of the GIPs as they are depreciated. This increases revenues during the 20-year repayment period.

---

[9] *Order Accepting Tariff Revisions*, 171 FERC ¶ 61,075 (2020) [*hereinafter* FERC Transmission Owner Provided Funding Order].

[10] FERC Transmission Owner Provided Funding Order, ¶ 2.

[11] FERC Transmission Owner Provided Funding Order, ¶¶ 35, 49.

Q. WHAT IS THE CURRENT STATUS OF THE MISO TARIFF PROVISIONS RELATED TO RATEMAKING FOR THE GIPS?

A. On December 2, 2022, the United States Courts of Appeals, District of Columbia Circuit issued its opinion in Case No. 20-1453 remanding the MISO Tariff provisions to FERC for additional support.[12] FERC has not acted on the remand as of yet, meaning there is significant uncertainty regarding the ratemaking treatment of these projects.

Q. GIVEN THIS UNCERTAINTY, HAS OTP INCLUDED THE GIPS INVESTMENTS IN THE 2024 TEST YEAR?

A. Except for investments related to Merricourt Wind and Astoria Station, the 2024 Test Year does not include GIPs investments. There are too many uncertainties regarding the ultimate ratemaking treatment for these projects to include them in the 2024 Test Year. Merricourt Wind and Astoria Station GIPs are included in the 2024 Test Year because there are no intercompany revenue payments associated with those projects due to OTP being owner of both the generator and transmission facilities.

VI. ACCUMULATED DEFERRED INCOME TAX PRORATION

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I will explain the Federal ADIT Proration that is required in order to meet normalization requirements, as explained by the Internal Revenue Service (IRS) in a Private Letter Ruling issued by the IRS to OTP. I also will explain how OTP has applied these requirements to the 2024 Test Year for both final rates and interim rates in this case and provide a discussion of the financial effects of doing so.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE BASIC PRINCIPLES OF INCOME TAX NORMALIZATION.

A. Income tax normalization is an approach to determining the regulated rates for a utility that is required by the Internal Revenue Code (IRC) and IRS Regulations as a precondition of the utility being allowed to use accelerated and bonus depreciation for determining its federal income taxes. Under normalization, the

[12] *American Clean Power Ass'n v. Federal Energy Regulatory Commission*, 54 F.4th 722 (D.C. Cir 2022).

income tax expense reflected in regulated rates is determined using straight-line depreciation and the difference between the straight-line income tax expense and the current income tax payable under accelerated and bonus depreciation is determined as ADIT, which reduces rate base.

Q. IS THE USE OF INCOME TAX NORMALIZATION A COMMON PRACTICE FOR UTILITIES AND REGULATORY AGENCIES?

A. Yes. The Commission and virtually every state regulatory agency, along with virtually every utility, use income tax normalization and have done so consistently for many years.

Q. DOES THE TREATMENT OF ADIT THAT IS PART OF INCOME TAX NORMALIZATION LEAD TO LOWER RATES FOR CUSTOMERS?

A. Yes. ADIT leads to substantial reductions in rate base. In this case, ADIT reduces OTP's 2024 Test Year rate base by approximately $371.7 million (OTP Total) / $175.8 million (OTP ND).[13] This reduction in rate base, in turn, leads to a reduction in the revenue requirement.

Q. IS A UTILITY REQUIRED TO PRORATE FEDERAL ADIT IF IT USES A FORWARD-LOOKING TEST YEAR?

A. Yes. IRS Regulation Section 1.167(l)-1(h)(6) provides that ratemaking procedures and adjustments must be consistent with normalization accounting. This regulation sets procedures a utility must use to normalize the impact on rate making if the utility wants to use accelerated depreciation methods to determine its federal income taxes. The monthly changes to the Federal deferred taxes balance, as calculated by the utility, must be prorated prior to computing the average of beginning and ending balances for ADIT.

When a utility utilizes a forecast test year to determine depreciation, the IRS requires that "the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period."[14] The prorated amount of any increase or decrease during the future portion of the period is determined by multiplying the increase or

[13] Petersen Direct, Schedule 6. Note, because proration is not required for the 2024 Test Year, these amounts are not prorated.
[14] Treas. Reg. § 1.167(l)-1(h)(6)(ii).

decrease by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.[15]

Q. WHAT HAPPENS IF OTP FAILS TO COMPLY WITH THIS REGULATION?

A. If a utility does not comply with this regulation, the utility would be at serious risk of losing the ability to claim accelerated depreciation in its federal income tax filings. Losing accelerated depreciation would significantly increase rate base due to the elimination of the ADIT offset to rate base.

Q. HAS OTP OBTAINED A SPECIFIC PRIVATE LETTER RULING FROM THE IRS REGARDING ITS OBLIGATIONS WITH RESPECT TO ADIT PRORATION?

A. Yes. OTP obtained a private letter ruling dated June 26, 2017, addressing the requirements for ADIT proration (the Otter Tail PLR) and the IRS released a public version of the Otter Tail PLR on September 29, 2017.

Q. DID THE OTTER TAIL PLR PROVIDE DIRECTION AS TO HOW TO PRORATE ADIT IN ORDER TO COMPLY WITH NORMALIZATION REQUIREMENTS?

A. Yes. The Otter Tail PLR directs that, in order to comply with normalization requirements, ADIT proration is to be based on the date rates become effective (relative to the dates of the test year used to compute those rates). The Otter Tail PLR also determined how ADIT proration must be applied for both final rates and for interim rates and interim rate refunds.

Q. PLEASE EXPLAIN HOW THE EFFECTIVE DATES OF RATES AFFECT THE REQUIREMENTS.

A. The principle is that if rates become effective and are in effect during the time when the basis for the rates is forecast, proration must be applied. If rates become effective or are in effect after the forecast period, proration is no longer necessary. For example, if a rate (including an interim or final rate) goes into effect as of January 1 of a forecast January 1 to December 31 test year, ADIT proration is applied to the entire Test Year period (because the entire period is deemed a future period). If the rate goes into effect at some other date in the test year, ADIT proration must be applied in setting rates for the period from the effective date of

[15] *Id.*

the rate to December 31. If the rate goes into effect after the conclusion of the test year, ADIT proration need not be applied to that rate.

Q. HOW DO THESE REQUIREMENTS APPLY TO THE FINAL RATES IN THE CURRENT CASE?

A. As I explained, to comply with normalization requirements, the rate must be computed by applying ADIT proration to only the portion of the test year that follows the date of implementation of the rates. If it is assumed that final rates will be implemented as of August 1, 2024, ADIT Proration would be required only for the period from August 1, 2024 through December 31, 2024. Changes in ADIT balances from January 1, 2024 to July 31, 2024 are not prorated, but the incremental monthly changes to ADIT from August 1, 2024 to December 31, 2024 are prorated.

Q. HAS OTP PRORATED FEDERAL ADIT IN THE 2024 TEST YEAR?

A. No. The 2024 Test Year revenue requirement is calculated as if final rates go into effect January 1, 2025, so no proration has been applied.

Q. WHAT IS THE FINANCIAL IMPACT IF FINAL RATES GO INTO EFFECT BEFORE JANUARY 1, 2025?

A. Assuming final rates are implemented as of August 1, 2024, the impact of applying proration to Federal ADIT decreases ADIT and increases the net rate base amount by approximately $2.3 million (OTP Total) / $0.9 million (OTP ND), resulting in an increase in the revenue requirement of approximately $0.09 million (OTP ND) as shown in Exhibit___(AMS-1), Schedule 5. This is the approach that is required under the Otter Tail PLR if final rates go into effect in 2024, as I explained above.

Q. HOW IS ADIT PRORATION COMPUTED FOR INTERIM RATES?

A. Interim rates are proposed to become effective January 1, 2024. Interim rates are computed based on a January 1, 2024 to December 31, 2024 Test Year. Because interim rates are computed based on an entirely future test period as defined by the IRS, proration is applied to all incremental changes to ADIT balances from January 1, 2024 to December 31, 2024.

Q. WHAT IS THE IMPACT OF PRORATING FEDERAL ADIT IN INTERIM RATES?

A. The impact of applying proration to the additional Federal ADIT attributable to the 2024 Test Year amounts for purposes of computing interim rates increases the net rate base amount by approximately $3.6 million (OTP Total) / $1.4 million (OTP ND), resulting in an increase in the revenue requirement of approximately $0.13 million (OTP ND). These calculations are also shown in Schedule 5. If interim rates are in effect for only a portion of 2024, the actual impact will be less, and the interim effect will be limited to a one-time effect. This is the approach that is required under the Otter Tail PLR, as I have also explained.

VII. CLASS COST OF SERVICE STUDY AND CLASS REVENUE RESPONSIBILITY

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I explain OTP's 2024 Test Year CCOSS and present OTP's proposed class revenue responsibilities. The 2024 Test Year CCOSS is included in Volume 3, Supporting Information. A one-page summary of the CCOSS results is provided as Exhibit___(AMS-1), Schedule 6.

A. CCOSS

Q. WHAT COSTS ARE MEASURED BY THE CCOSS?

A. OTP's CCOSS is an embedded cost study, meaning it measures the 2024 Test Year cost of service for the North Dakota jurisdiction and all costs are fully distributed to classes.

Q. DOES OTP ALSO USE A MARGINAL COST STUDY?

A. Yes. Mr. Prazak discusses the marginal cost study and its use in his Direct Testimony.

Q. ARE THE CCOSS AND THE MARGINAL COST STUDY USED FOR DIFFERENT PURPOSES?

A. Yes. OTP uses the CCOSS to inform the development of inter-class revenue responsibilities. As discussed in more detail by Mr. Prazak, OTP uses the marginal cost study to guide intra-class revenue responsibilities (i.e., by rate schedule) and to develop rate elements (i.e., energy charges, demand charges, etc…).

Q. WAS THE CCOSS PREPARED USING THE SAME GENERAL CCOSS METHODOLOGY AS WAS USED IN OTP'S LAST NORTH DAKOTA RATE CASE?

A. Yes. The proposed CCOSS was prepared using the same basic cost classification and allocation methodology used in OTP's last North Dakota rate case.

Q. HAS OTP REVISED ITS CCOSS CUSTOMER CLASSES SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. OTP revised its controlled services classes to better group like-customers. Mr. Prazak discusses the reasoning for the change in his Direct Testimony.

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2024 CCOSS.

A. Table 5 below compares the present revenue responsibilities [Column B] and cost responsibilities [Column C] of OTP's customer classes, as calculated in the CCOSS. As shown in Table 5, the revenue responsibility of the Residential class currently is below its CCOSS-indicated cost responsibility. Conversely, the revenue responsibility of the Large General Service class is greater than its CCOSS-indicated cost responsibility.

Table 5
Comparison of Present Revenue Responsibility and Cost Responsibility

	A	B	C	D
Line No.	**Class**	**Present Revenue Responsibility**	**CCOSS Cost Responsibility**	**Difference**
1	Residential	27.88%	31.09%	3.22%
2	Farms	1.44%	1.49%	0.05%
3	General Service	21.07%	21.04%	-0.03%
4	Large General Service	39.71%	36.55%	-3.16%
5	Irrigation	0.05%	0.07%	0.02%
6	Lighting	1.73%	1.18%	-0.54%
7	OPA	0.74%	0.94%	0.19%
8	Controlled Service Deferred Load	1.30%	1.96%	0.66%
9	Controlled Service Interruptible	5.69%	5.44%	-0.25%
10	Controlled Service Off-Peak	0.39%	0.23%	-0.16%

B. Class Revenue Responsibilities

Q. PLEASE SUMMARIZE HOW OTP USED THE CCOSS IN THE DEVELOPMENT OF OTP'S RECOMMENDED CLASS REVENUE RESPONSIBILITIES.

A. The CCOSS is the primary guide for setting the class revenue responsibilities. However, determining the appropriate class revenue responsibilities is not as simple as setting them to equal the results of the CCOSS. It is necessary to consider other objectives, particularly the objective of maintaining reasonable rate continuity, and mitigating disproportionate or abrupt rate impacts. A more complete discussion of the rate design considerations applied by OTP is contained in Mr. Prazak's Direct Testimony.

Q. HOW DOES OTP PROPOSE TO ALLOCATE TOTAL REVENUE TO CUSTOMER CLASSES?

A. Absent a rate case, OTP estimates 2024 class revenues (including riders) are approximately $206.0 million, as shown in Column B of Table 6 below. OTP's proposed 2024 Test Year revenues are approximately $223.3 million as shown in Column C of Table 6. The total net dollar increase for OTP's North Dakota customers is $17.4 million (Column D), or 8.43 percent (Column E).

Based on a consideration of all of OTP's rate design objectives, OTP proposes the distribution of revenue responsibilities contained in Table 6. This distribution of revenue responsibilities results in a reasonable movement toward class cost responsibility (as calculated in the proposed CCOSS) without producing unreasonable bill impacts.

Table 6
Proposed Revenue Allocation and Net Bill Impact

	A	B	C	D	E
Line No.	**Class**	**Total Present Revenues**	**Total Proposed Revenues**	**Net Bill Increase**	**Net Bill Impact**
1	Residential	$ 58,596,832	$ 64,807,623	$ 6,210,791	10.60%
2	Farms	$ 3,035,105	$ 3,357,543	$ 322,438	10.62%
3	General Service	$ 44,329,329	$ 49,019,629	$ 4,690,300	10.58%
4	Large General Service	$ 79,991,537	$ 86,326,696	$ 6,335,159	7.92%
5	Irrigation	$ 105,695	$ 117,613	$ 11,918	11.28%
6	Lighting	$ 3,705,988	$ 3,215,029	$ (490,959)	-13.25%
7	OPA	$ 1,551,133	$ 1,738,362	$ 187,230	12.07%
8	Controlled Service Deferred Load	$ 2,666,277	$ 2,682,814	$ 16,537	0.62%
9	Controlled Service Interruptible	$ 11,230,365	$ 11,298,787	$ 68,422	0.61%
10	Controlled Service Off-Peak	$ 776,948	$ 783,351	$ 6,403	0.82%
11	Total	$ 205,989,209	$ 223,347,447	$ 17,358,238	8.43%

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT THE TOTAL NET DOLLAR INCREASE IDENTIFIED IN TABLE 6.

A. OTP currently receives a certain amount of base rate and rider revenue from its North Dakota customers that it would continue to receive without a rate case. The combined total of these amounts is identified in Column B of Table 6. Like Column B, Column C (Total Proposed Revenues), also includes base rate and rider revenue. The detail for the base revenue amounts included in Columns B and C of Table 6 is provided in Exhibit___(AMS-1), Schedule 7. Mr. Prazak's proposed base rate design utilizes the base revenue of $155.0 million as provided in Schedule 7 (Column I, Line No. 11).

OTP witness Ms. Paula A. Foster explains that as part of this case, OTP proposes to move certain projects currently being recovered in riders into base rates. This is a shift in the recovery mechanism and does not result in a change to a customer's overall bill. Therefore, Table 6, Column B, which is the sum of the base and rider revenues, provides the appropriate base from which to measure the rate increase being proposed in this case. Table 6, Column C identifies the 2024 Test Year proposed revenues, which includes the shift in recovery mechanism between riders and base rates. The overall bill impact that customers will experience under OTP's proposal is shown in Table 6, Columns D and E.

Q. DOES OTP'S PROPOSAL GENERALLY MOVE CLASSES CLOSER TO COST RESPONSIBILITY?

A. Yes. OTP attempted to move classes closer to their CCOSS-indicated cost responsibilities, and as shown in Table 7, was able to do so for its two largest classes (by revenue) and several of the smaller customer classes. Table 7 below compares present revenue and cost responsibilities (as measured in the CCOSS) and OTP's proposed revenue responsibilities for all of OTP's customer classes.

Table 7
Comparison of Proposed Revenue Responsibility and Cost Responsibility

Line No.	Class (A)	Present Revenue Responsibility (B)	Cost Responsibility from CCOSS (C)	Proposed Revenue Responsibility (D)
1	Residential	27.88%	31.09%	29.07%
2	Farms	1.44%	1.49%	1.51%
3	General Service	21.07%	21.04%	21.88%
4	Large General Service	39.71%	36.55%	38.52%
5	Irrigation	0.05%	0.07%	0.05%
6	Lighting	1.73%	1.18%	1.58%
7	OPA	0.74%	0.94%	0.78%
8	Controlled Service Deferred Load	1.30%	1.96%	1.20%
9	Controlled Service Interruptible	5.69%	5.44%	5.06%
10	Controlled Service Off-Peak	0.39%	0.23%	0.35%

Q. PLEASE PROVIDE FURTHER CONTEXT FOR OTP'S PROPOSED REVENUE RESPONSIBILITY FOR THE RESIDENTIAL CLASS.

A. As shown in Table 7, the CCOSS indicates Residential class revenues would need to increase from 27.88 percent [Column B] to 31.09 percent [Column C] to bring the revenues for this class up to its cost level. To provide a reasonable balance of the cost of service and rate continuity objectives of rate design, OTP proposes increasing the Residential class revenue responsibility from 27.88 percent [Column B] to 29.07 percent [Column D].

Q. IF OTP'S RECOMMENDED REVENUE DISTRIBUTION IS ACCEPTED, WILL THERE STILL BE DIFFERENCES BETWEEN CLASS REVENUE RESPONSIBILITY AND COST RESPONSIBILITY?

A. Yes. OTP does not propose an unmoderated adherence to the results of the CCOSS. For this reason, differences remain between OTP's proposed class revenue responsibility and cost responsibilities identified by the CCOSS. For example, OTP's recommended revenue increase of approximately $6.2 million for the Residential class (shown above in Table 6, Column D) moves the Residential class closer to its cost responsibility. In order to be at its full cost responsibility, the Residential class revenues would need to increase by approximately $10.8 million, an additional $4.6 million of revenue responsibility compared to OTP's proposal. Table 8 below identifies the net bill impacts if revenue responsibility is based entirely on cost.

Table 8
Unmoderated Revenue Responsibilities

	A	B		C		D	E
Line No.	**Class**		**Total Present Revenues**		**Total Proposed Revenues**	**Net Bill Increase**	**Net Bill Impact**
1	Residential	$	58,596,832	$	69,445,591	$ 10,848,758	18.51%
2	Farms	$	3,035,105	$	3,337,900	$ 302,795	9.98%
3	General Service	$	44,329,329	$	46,990,988	$ 2,661,659	6.00%
4	Large General Service	$	79,991,537	$	81,636,850	$ 1,645,313	2.06%
5	Irrigation	$	105,695	$	166,449	$ 60,754	57.48%
6	Lighting	$	3,705,988	$	2,637,134	$ (1,068,854)	-28.84%
7	OPA	$	1,551,133	$	2,095,672	$ 544,539	35.11%
8	Controlled Service Deferred Load	$	2,666,277	$	4,375,580	$ 1,709,303	64.11%
9	Controlled Service Interruptible	$	11,230,365	$	12,145,104	$ 914,739	8.15%
10	Controlled Service Off-Peak	$	776,948	$	516,179	$ (260,769)	-33.56%
11	Total	$	205,989,209	$	223,347,447	$ 17,358,238	8.43%

Q. HOW MUCH OF THE RECOMMENDED INCREASE IN CLASS REVENUES IS TIED TO MOVING CLASSES CLOSER TO CLASS COST RESPONSIBILITY?

A. Table 9 below identifies the portion of the change in revenue responsibility due to the change in the revenue requirement and the portion due to the movement towards cost. For most classes, the recommended movement toward cost is a minor component of the overall change in revenue responsibility.

Table 9
Components of Change in Class Revenue Responsibility

	A	B		C		D	
Line No.	Class	Due to Change in Revenue Requirement		Due to Movement to Cost		Total Change in Class Revenue Responsibility	
1	Residential	$	3,667,775	$	2,543,015	$	6,210,791
2	Farms	$	190,689	$	131,749	$	322,438
3	General Service	$	2,726,181	$	1,964,120	$	4,690,300
4	Large General Service	$	8,692,032	$	(2,356,873)	$	6,335,159
5	Irrigation	$	6,641	$	5,277	$	11,918
6	Lighting	$	147,521	$	(638,480)	$	(490,959)
7	OPA	$	109,239	$	77,991	$	187,230
8	Controlled Service Deferred Load	$	242,754	$	(226,217)	$	16,537
9	Controlled Service Interruptible	$	1,471,707	$	(1,403,286)	$	68,422
10	Controlled Service Off-Peak	$	103,699	$	(97,296)	$	6,403
11	Total	$	223,347,447	$	(0)	$	17,358,238

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION WITH RESPECT TO CLASS REVENUE RESPONSIBILITY.

A. OTP's recommended class increases move rates closer to cost while moderating impacts, particularly to the Residential class. OTP's proposed class revenue responsibility proposal is appropriately based on the CCOSS results and rate design objectives, and it is therefore reasonable for setting rates in this case.

VIII. 2018 NORTH DAKOTA RATE CASE CCOSS COMPLIANCE ITEM

Q. PLEASE DESCRIBE THE CCOSS COMPLIANCE ITEM FROM OTP'S LAST NORTH DAKOTA RATE CASE.

A. The Settlement Agreement approved by the Commission in OTP's last North Dakota rate case required OTP, in consultation with MLEC, to investigate the feasibility of unbundling the embedded costs to serve LGS customers at the secondary, primary and transmission voltage service levels. The investigation was to primarily look into the feasibility of: (a) unbundling the distribution costs and (b) quantifying the loss differentials between secondary, primary, and transmission service respectively.[16]

[16] *See* Case No. PU-17-398, Settlement Agreement at 11 (July 6, 2018) (the Settlement Agreement). The Settlement Agreement was approved (with three modifications) by the Commission in its September 26,

Q. DID OTP INVESTIGATE THE FEASIBILITY OF UNBUNDLING THE EMBEDDED COSTS TO SERVE LGS CUSTOMERS?

A. Yes. OTP met with MLEC in August to discuss possible approaches to unbundling the embedded costs to serve LGS customers. Based on the discussion with MLEC, OTP was able to develop a way to separate the LGS class into secondary, primary, and transmission sub-classes.

Q. HOW DID OTP SEPARATE THE LGS CLASS INTO THE SECONDARY, PRIMARY, AND TRANSMISSION SUB-CLASSES?

A. We modified the CCOSS demand, energy and customer allocation factors to have separate allocations for LGS secondary, LGS primary and LGS transmission sub-classes. The demand and energy allocation factors account for voltage losses at each service level. These voltage losses were calculated in OTP's 2020 System Loss Study. OTP then applied these allocation factors to the costs allocated to the LGS class in the CCOSS. This is a similar method used to allocate costs from the JCOSS to the CCOSS.

Q. WHAT WERE THE RESULTS OF UNBUNDLING THE EMBEDDED COSTS TO SERVE?

A. The results showed the marginal cost study and the embedded cost study produced a similar allocation of costs between the secondary and primary LGS service levels.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

2018 Order on Settlement. The Settlement Agreement also provided that OTP and MLEC were to work together to attempt to identify a reasonable means of making available wind turbine maintenance data or some proxy thereof. OTP discussed this issue with MLEC. MLEC reviewed the item and concluded this issue is resolved.

Ms. Amber M. Stalboerger
Manager Regulatory Analysis, Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8042

<u>CURRENT RESPONSIBILITIES: (February 2023 to Present)</u>

Provide leadership for financial analysis related to setting rates and overall cost recovery, including managing the financial analysis used to determine revenue requirements associated with various state cost recovery mechanisms. Manage regulatory analysis and review of state jurisdictional and class cost of service studies that determine utility revenue requirements and are used as a basis for rate design. Oversee the development of theories, methodologies, and procedures used to establish embedded cost allocations.

<u>PREVIOUS POSITIONS:</u>

Otter Tail Power Company

2023 - Present	Manager Regulatory Analysis, Regulatory Economics
2022 - 2023	Senior Data Analyst, Advanced Concepts
2021 - 2022	Supervisor, Regulatory Analysis, Regulatory Administration
2019 - 2020	Supervisor, DSM Administration, Market Planning
2014 - 2018	Evaluation Analyst, Market Planning
2013 - 2014	Internal Auditor II, Otter Tail Corporation
2008 - 2013	Rates Analyst, Regulatory Administration

EDUCATION
Minnesota State University Moorhead, Moorhead, MN
Bachelor of Science, Mathematics emphasis Actuarial Science
Bachelor of Arts, Mathematics
Bachelor of Science, Accounting

OTTER TAIL POWER COMPANY

Cost Allocations Procedures Manual

~~Revised October 2017~~Revised October 2023

INTRODUCTION

The general methodology used in this procedure manual is one of functionalization and classification. Functionalization is the process by which costs are arranged according to the major utility function they serve, such as production, transmission, etc. Classification is the arrangement of costs within a function by the service characteristic to which they most closely apply or relate, to facilitate their allocation based on these service characteristics.

The major functional areas used in this procedure manual are production, transmission, distribution, customer accounting and collecting, and customer service and information. The reason for using functions other than the three major ones (production, transmission, and distribution) is to provide a better base for eventual allocation of cost and to provide the flexibility necessary to handle certain cost items.

The principal service characteristics used in the classification process are demand, energy, number of customers, and number of meters. Sub-characteristics within each of these principal characteristics which allow a more precise division of cost, such as type of demand or energy, voltage level, or type of customer or meter were also used. These sub-characteristics provide added detail for a more accurate allocation of cost. The service characteristics or sub-characteristics provide the basis for determining allocation factors when allocation is necessary. Unless otherwise noted, all allocation factors described herein are used for both jurisdictional and class allocations.

The philosophy used to arrive at the service characteristics was to determine what characteristic or characteristics best describe or approximate the decisions made or factors considered when an expense is incurred or a plant investment is made. The amount of dollars to be allocated and the cost of determining or obtaining values for a service characteristic were also factors considered when determining the service characteristics to use.

There are ~~16~~ 17 service characteristics used in this study. They consist of four demand characteristics, ~~three~~ four energy or kilowatt-hour characteristics, and nine meter or customer characteristics. These service characteristics, which are used to develop allocation factors are:

1. GENERATION DEMAND FACTOR (D1) - this factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes excluding controllable load. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.
2. TRANSMISSION DEMAND FACTOR (D2) - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes. The hours used are the same as those for the Generation Demand Factor.
3. DISTRIBUTION PRIMARY DEMAND FACTOR (D3) - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand

minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

4. DISTRIBUTION SECONDARY DEMAND FACTOR (D4) - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are included in this factor.
5. ENERGY FACTOR (E1) - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ ths of water heating and deferred sales. It is only used for jurisdictional allocations.
6. ENERGY FACTOR (E2) - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.

~~6.~~7. ENERGY FACTOR (E1-E8760) – this factor is based on hourly energy usage, to which are applied hourly marginal capacity costs to develop an hourly cost relationship excluding interruptible, irrigation, and water heating, and deferred sales in the highest priced 14 of 24 marginal capacity cost hours. It is only used to allocate jurisdictional amounts to the customer classes.

~~7.~~8. ENERGY FACTOR (E2-E8760) - this factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. It is only used to allocate jurisdictional amounts to the customer classes.

~~8.~~9. TOTAL RETAIL CUSTOMERS FACTOR (C1) - this factor is based on the total active retail customers served in each jurisdiction.

~~9.~~10. TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2) – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.

~~10.~~11. TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3) - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).

~~11.~~12. STREETLIGHT FACTOR (C4) - this factor is based on the weighted installed cost of the streetlights in each jurisdiction.

~~12.~~13. AREA LIGHT FACTOR (C5) - this factor is based on the weighted installed cost of area lights in each jurisdiction.

~~13.~~14. METER FACTOR (C6) - this factor is based on the weighted installed cost of meters in service.

~~14.~~15. METER READING FACTOR (C7) - this factor is based on total weighted meter reading time.

~~15.~~16. TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8) - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.

~~16.~~17. LOAD MANAGEMENT FACTOR (C9) - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

The methodology for applying the various procedures and allocators to system cost values to develop jurisdictional and class or group cost values is explained in detail on the following pages.

RATE BASE COMPONENTS

PRODUCTION PLANT IN SERVICE

The plant in service within this function was classified into preliminary demand and energy categories as follows:

1. DEMAND COST - this category includes all production plant (accounts 310- 346), except that related to the Big Stone Plant unit train.
2. BASE LOAD ENERGY COST - Big Stone unit train only.

The demand category was then reclassified into Base (Energy-Related) and Peak Demand categories based on the following formulas:

$$\text{Total Current Cost} = (\text{Existing Peaking Capacity [kW]})(\text{Current Peaking Unit Cost [\$/kW]})$$
$$+ (\text{Existing Steam \& Hydro Capacity [kW]})(\text{Current Base Load Unit Cost [\$/kW]})$$

$$\text{Peaking Demand Factor} = \frac{(\text{Total Existing Plant Capacity})(\text{Current Peaking Unit Cost})}{\text{Total Current Cost}}$$

$$\text{Base (Energy-Related) Demand Factor} = 1 - \text{Peaking Demand Factor}$$

$$\text{\$ of Peak Demand} = (\text{Demand Cost}) \times (\text{Peaking Demand Factor})$$

$$\text{\$ of Base (Energy-Related) Demand} = (\text{Demand Cost}) \times (\text{Base Demand Factor})$$

This determination of Base and Peak Demand amounts is based on the premise that all plants are or can be used to supply system peak demands. However, base load plants (steam and hydro) are also used to supply the bulk of the energy used on the system. Therefore, the base load plants have a dual function of supplying both energy and demand. The above classification of production plant into base and peak categories recognizes this fact and assigns a portion of the base load plants to each of these functions. The underlying assumption is that the cost to supply a peak kW of demand capacity to the system is the cost of a kW of capacity from a peaking plant.

New unit costs in current year dollars were used to determine the peaking and base factors to provide an allocation method that separates costs based on present circumstances not on past circumstances. The use of current costs also eliminates any potential problems associated with the timing of plant additions, changes in load factors or changes in generation mix criteria which could lead to large short-term allocation factor variations.

The dollars in each category were then allocated based on the following:

BASE DEMAND - Energy Factor (E1)
PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E1)
PEAK ENERGY - Generation Demand Factor (D1)

3. Wind generation is a non-dispatchable production resource with operating characteristics different from other base load or peaking generation. The capacity factor for wind generation is determined by the Midwest Independent System Operator (MISO) as they accredit capacity on a four-season construct based on each generation site's production. While a majority of a wind turbine's output is energy, a portion of the investment is also needed to meet the system's peak demand. The most recent MISO accreditations are used to create a weighted average for each wind farm that results in a base/peak split. Wind generation investment is allocated based on the following factors:
   BASE ENERGY – Energy Factor (E2)
   PEAK DEMAND – Generation Demand Factor (D1)

TRANSMISSION PLANT IN SERVICE

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION PLANT IN SERVICE

The plant in service within this function was classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)
5. Streetlighting
6. Area Lighting
7. Meters
8. Load Management

based on the following account-by-account methodology:

ACCOUNT 360 (LAND) - classified primary demand related (substation land).
ACCOUNT 360.1 (LAND RIGHTS) - classified primary demand related.
ACCOUNT 361 (STRUCTURES AND IMPROVEMENTS) - classified primary demand related.
ACCOUNT 362 (STATION EQUIPMENT) - classified primary demand related.
ACCOUNTS 364-369.1 - classified based on minimum size system (see Appendix A-1).
ACCOUNT 370 (METERS) - direct assignment to meters characteristic.
ACCOUNT 370.05 (SMART METERS) - direct assignment to meter characteristic.
ACCOUNT 370.1 (LOAD MANAGEMENT SWITCHES) - direct assignment to load management characteristic.
ACCOUNT 371 (INSTALLATION ON CUSTOMER'S PREMISES) - classified secondary customer related.
ACCOUNT 371.1 (~~RENTAL EQUIPMENT~~EV CHARGING STATIONS) - classified ~~primary~~

secondary demand and customer related.
ACCOUNT 371.2 (ALL OTHER PRIVATE LIGHTING) - direct assignment to area lighting.
ACCOUNT 373 (STREETLIGHTING AND SIGNAL SYSTEMS) - direct assignment to streetlighting.

The categories were then allocated based on the following:
PRIMARY DEMAND - Distribution Primary Demand Factor (D3)
SECONDARY DEMAND - Distribution Secondary Demand Factor (D4)
PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2)
SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3)
STREETLIGHTING - Streetlight Factor (C4)
AREA LIGHTING - Area Light Factor (C5)
METERS - Metering Factor (C6)
LOAD MANAGEMENT - Load Management Factor (C9)

GENERAL PLANT IN SERVICE

General Plant in Service, except Account 397.3 (Radio Load Control Equipment), was functionalized into the following categories based on the labor ratios developed from data in FERC Form No. 1, Page 354, or similar data for a forecast year.

1. Production
2. Transmission
3. Distribution
4. Customer Accounting
5. Customer Service and Information

The amounts in the production, transmission, and distribution categories were then allocated using the gross plant in service ratios from the related plant in service functions. Customer Accounting and Customer Service and Information were allocated based on the expense ratios from the related expense functions. Account 397.3 directly assigned to Load Management category and allocated on the Load Management Factor (C9).

INTANGIBLE PLANT IN SERVICE

Intangible Plant in Service was allocated using the gross general plant in service ratios.

ACCUMULATED PROVISION FOR DEPRECIATION

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

NET CAPITALIZED ITEMS - BIG STONE PLANT

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

PLANT HELD FOR FUTURE USE

PRODUCTION - allocated using gross plant in service ratios developed from the Production Plant in Service function.

TRANSMISSION - allocated using the Transmission Demand Factor (D2).

DISTRIBUTION - allocated using gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - allocated using gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using gross plant in service ratios developed from the Intangible Plant in Service function.

CONSTRUCTION WORK IN PROGRESS (CWIP)

CWIP was separated into three parts or types: Major Projects, Short-Term, and Long-Term. The Major Projects section includes capital expenditures on which a current return is requested without an offset for Allowance For Funds Used During Construction (AFUDC). The Short-Term section are those projects with less than $10,000 cost or expected to be completed in less than 30 days. AFUDC is not accrued on short-term projects. The Long-Term section includes all other projects and AFUDC is accrued on this portion.

The CWIP of each type was functionalized as production, transmission, distribution, general, or intangible plant. The allocations are then based on the gross plant in service ratios for each individual function.

WORKING CAPITAL

MATERIALS AND SUPPLIES:

Materials and Supplies are separated into production, transmission, and distribution functions. The production portion includes materials and supplies at Big Stone and Coyote Plants as well as production repair parts. The remaining materials and supplies are split between transmission and distribution functions based on data from Page 227 of the latest FERC Form No. 1. The functional amounts are allocated on their respective gross plant in service ratios.

FUEL STOCKS:

COAL STOCKS - allocated using Energy Factor (E1).

FUEL OIL STOCKS - allocated using Generation Demand Factor (D1).

PREPAYMENTS - allocated based on total net plant in service ratios.

CUSTOMER ADVANCES - allocated based on total net plant in service ratios.

CASH WORKING CAPITAL - calculated separately for each jurisdiction. Allocated to customer class on total operating expenses for each jurisdiction (OX).

ACCUMULATED DEFERRED INCOME TAXES

Allocated using the total "net" plant in service ratios.

UNAMORTIZED BALANCE - SPIRITWOOD PLANT

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

UNAMORTIZED RATE CASE EXPENSE

Directly assigned to jurisdiction. Allocated to customer class on each jurisdiction's retail revenues (R10).

OPERATING REVENUES

RETAIL SALES

Directly assigned to each jurisdiction and class as billed.

WHOLESALE SALES

MUNICIPALITIES (SUPPLEMENTAL POWER ACCOUNTS 400.1-81, 400.2-81, and 400.3-81) - directly assigned to FERC jurisdiction and group as billed.

NONASSOCIATED UTILITIES, COOPERATIVES AND OTHER PUBLIC AUTHORITIES

The revenues from asset-based sales are classified as base demand, peak demand, base energy, and peak energy as follows:

1. All revenues from these sales, except those considered Participation or Peaking Power, are classified as Base Energy.
2. Demand charges for Peaking sales are classified as Peak Demand.
3. Demand charges for Participation Power sales are classified as follows:

$$\text{\$ of Peak Demand} = \text{Market price (\$/MW/Mo.)} \times \text{capacity of the sale (MW)}$$

$$\text{\$ of Base Demand} = \text{Total Demand charges} - \text{\$ of Peak Demand.}$$

4. Energy charges for Participation Power sales are classified Base Energy.
5. Energy charges for Peaking Power sales are classified Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)
PEAK DEMAND - Generation Demand Factor (D1)
BASE ENERGY - Energy Factor (E2)
PEAK ENERGY - Generation Demand Factor (D1)

OTHER ELECTRIC REVENUE

ACCOUNT 450 (FORFEITED DISCOUNTS) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 451 (CONNECTION FEES) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 456.5 (WHEELING) - directly assigned to FERC groups as collected.

ACCOUNT 456.7 (RESIDENTIAL CONSERVATION SERVICE) - directly assigned to jurisdictions. Allocated to classes based on E8760 (Energy Factor).

ALL OTHER ACCOUNTS - allocated using total net plant in service ratios.

EXPENSE COMPONENTS

PRODUCTION EXPENSES

The expenses within this function, except those in Account 555, were classified into PRELIMINARY demand and energy categories as follows:

1. STEAM AND HYDRO (SH) DEMAND - this category includes all expenses in Accounts 500, 502-511, 535-543, and 556.
2. INTERNAL COMBUSTION (IC) DEMAND - this category includes all expenses in Accounts 546-554, except Account 547.
3. BASE ENERGY - includes Accounts 501, 512, 513, 514, 544, and 545.
4. PEAK ENERGY - includes Account 547.

The two demand categories (SH and IC) were then reclassified into BASE and PEAK Demand categories using the same methodology and formulas applied to those categories in Production Plant in Service.

The expenses in Account 555 (Purchased Power) are classified into base and peak demand and energy based on the following:

A. All expenses, except those for purchases labeled Participation or Peaking Power, were classified as Base Energy.
B. Demand charges for Peaking Power were classified as Peak Demand.
C. Demand Charges for Participation Power (including co-generators and shared customers) were classified as follows:

$$\begin{aligned}\$\text{ of Peak Demand} = {} & \text{MAPP Schedule H (peaking) rate (\$/MW/Mo.)}\\ & \times \text{capacity of the purchase (MW)}\\ & \times \text{number of months purchased.}\end{aligned}$$

$$\$\text{ of Base Demand} = \text{Total Demand Charges} - \$\text{ of Peak Demand.}$$

D. Energy charges for Participation Power were classified as Base Energy.
E. Energy charges for Peaking Power were classified as Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)
PEAK DEMAND - Generation Demand Factor (D1)
BASE ENERGY - Energy Factor (E2)
PEAK ENERGY - Generation Demand Factor (D1)

TRANSMISSION EXPENSES

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION EXPENSES

The expenses within this function were classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)

5. Streetlights
6. Area Lights
7. Meters
8. Load Management

Based on the following account-by-account methodology:

OPERATION

ACCOUNT 580 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 582-588.

ACCOUNT 581 (LOAD DISPATCHING) - classified based on classification of Accounts 583-589.

ACCOUNT 582 (STATION EXPENSE) - classified based on classification of related plant in service Account 362.

ACCOUNT 583 (OVERHEAD LINE EXPENSE) - classified based on the classification of related plant in service Accounts 364, 365, 368, and 369.

ACCOUNT 584 (UNDERGROUND LINE EXPENSE) - classified based on the classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 585 (STREETLIGHTING EXPENSE) - classified directly as streetlighting.

ACCOUNTS 586~~.1-586.5 & 586.9~~ (METER EXPENSES) - classified directly as meters.

~~ACCOUNTS 586.6-586.7 (METER EXPENSES) - classified directly as load management.~~

ACCOUNT 587 (~~CUSTOMER INSTALLATION~~OTHER EXPENSE) - classified secondary customer.

ACCOUNT 588 (MISCELLANEOUS EXPENSE) - classified based on classification of Accounts 582-587.

ACCOUNT 589 (RENTS) - classified based on classification of related plant in service Account 364.

MAINTENANCE

ACCOUNT 590 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 592-596.

ACCOUNT 592 (STATION EQUIPMENT) - classified based on classification of related plant in service Account 362.

ACCOUNT 593 (OVERHEAD LINES) - classified based on classification of related plant in service Accounts 364, 365, and 369.

ACCOUNT 594 (UNDERGROUND LINES) - classified based on classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 595 (LINE TRANSFORMERS) - classified based on classification of related plant in service Account 368.

ACCOUNT 596 (STREETLIGHTING) - classified directly to streetlighting.

ACCOUNTS 597~~.1-597.2~~ (METERS) - classified directly to meters.

~~ACCOUNT 597.3 (METERS) - classified directly to load management.~~

ACCOUNT 598 (MISCELLANEOUS DISTRIBUTION PLANT) - classified based on classification of Accounts 592-597.

Each category was then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3).
SECONDARY DEMAND - Distribution Secondary Demand Factor (D4).
PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2).
SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3).
STREETLIGHTING - Streetlight Factor (C4).
AREA LIGHTING - Area Light Factor (C5).
METERS - Meter Factor (C6).
LOAD MANAGEMENT - Load Management Factor (C9).

<u>CUSTOMER ACCOUNTING AND COLLECTING EXPENSES</u>

Expenses in this function were classified into two categories:

1. Meter Reading
2. Other Expenses

as specified by the following:

ACCOUNT 901 (SUPERVISION) - classified based on classification of Accounts 902-905.
ACCOUNT 902 (METER READING EXPENSE) - classified meter reading.
ACCOUNT 903 (CUSTOMER RECORDS AND COLLECTIONS) - classified other expense.
ACCOUNT 904 (UNCOLLECTIBLE ACCOUNTS) - classified other expense.
ACCOUNT 905 (MISCELLANEOUS CUSTOMER ACCOUNTING EXPENSES) - classified other expense.

The METER READING category was allocated using the Meter Reading Factor (C7) and the OTHER EXPENSES category using the Total System Service Locations Factor (C8).

<u>CUSTOMER SERVICE AND INFORMATION EXPENSES</u>

Conservation related programs and promotional rebates are directly assigned to jurisdiction and then allocated to class based on E8760 (Energy Factor). All other Customer Service and Information Expenses are allocated based on Total Customer Factor (C1).

<u>SALES EXPENSES</u>

Economic Development is directly assigned to jurisdiction and then allocated to class based on Total Customer Factor (C1). Account 913, Advertising, is assigned below the line. All other Sales Expenses are allocated based on Total Customer Factor (C1).

ADMINISTRATIVE AND GENERAL EXPENSES

ACCOUNTS 920 (SALARIES), 921 (SUPPLIES, ETC.), AND 926 (PENSIONS AND BENEFITS) - these accounts functionalized as: Production, Transmission, Distribution, Customer Accounting, or Customer Service, based on FERC labor ratios (FERC Form No. 1, Page 354, or comparable data for a forecast year). Functional categories were then allocated using the expense ratios from the related expense functions, except that in the Production category the energy-related expenses and buy/sell transactions were not included in the ratios. (Energy-related expenses and buy/sell transactions are excluded because they are mainly purchased fuel which requires a minimum of company labor.)

ACCOUNT 923 (OUTSIDE SERVICES) - allocated based on total net plant in service ratios.

ACCOUNTS 924 (PROPERTY INSURANCE) and 925 (INJURIES & DAMAGES) - ~~were~~ allocated based on the total net plant in service ratios.

ACCOUNTS 928 (REGULATORY COMMISSION EXPENSES) - directly assigned to each jurisdiction. Allocated to classes or groups based on total electric revenues from each class or group.

ACCOUNT 930.1 (GENERAL ADVERTISING) -– The majority of this account is assigned below the line. Any remaining amount is allocated based on Total Customers Factor (C1).

ACCOUNTS 930.2 (MISCELLANEOUS), 931 (RENTS), and ~~935.1-935.5 & 935.9~~935 (MAINTENANCE) - allocated based on the gross general plant in service ratios.

ACCOUNT 935.6 (MAINTENANCE) - directly assigned to load management and allocated on (C9).

DEPRECIATION EXPENSES

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - Allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

BIG STONE PLANT CAPITALIZED ITEMS EXPENSES

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

OTHER EXPENSE - SPIRITWOOD AMORTIZATION

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

GENERAL TAXES

Allocated using total net plant in service ratios.

DEFERRED INCOME TAXES

Allocated using total net plant in service ratios.

INVESTMENT TAX CREDIT

Allocated using total gross plant in service ratios.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

Allocated based on long-term construction work in progress ratios.

INCOME TAXES

Income taxes are calculated for each jurisdiction separately.

APPENDIX A-1

DETERMINATION OF THE DEMAND & CUSTOMER COMPONENTS OF THE DISTRIBUTION SYSTEM

The customer component of the distribution system, that portion which varies with the number of customers, was determined by applying the minimum size system method. This method involves determining the minimum size unit currently being installed and using the average installed book cost of that unit to determine the customer component. However, our accounting system is such that, except for Account 368 (transformers), the only average installed book cost available is for all the units in an account regardless of size. To circumvent this problem, the following procedures were used:

1. The ~~Electric Distribution (ED) Department~~Delivery Planning Department specified what the minimum size unit for each account is and then provided information as to the type and quantity of material included in this unit and the amount of labor necessary to install it.
2. For each account that a customer component is required, the average age of the account was determined by using results of the recently completed depreciation study. This age is then subtracted from the study year to determine in what year the average unit was installed.
3. The average installed cost of the minimum size unit for the year indicated above was then determined. This was done by developing material, labor, transportation, and payroll costs for the year this unit was installed and applying them to the information supplied in No. 1, above.

The following pages describe how the dollars in each account were assigned to the various categories of cost using the data developed above and other figures from the various accounts.

Symbol Legend:

PSL = Poles for Streetlights
DSL = Dollars allocated to Streetlighting
DAL = Dollars allocated to Area Lighting
DPCC = Dollars allocated to Primary Customer Category
DPDC = Dollars allocated to Primary Demand Category
DSCC = Dollars allocated to Secondary Customer Category
DSDC = Dollars allocated to Secondary Demand Category
UPD = Units of Primary Distribution
USD = Units of Secondary Distribution

Account 364 (Poles): (All poles considered primary)

A. Average age of a pole.
B. Minimum size pole.
C. Installed cost of the minimum size pole of the age in "A."
D. Number of streetlights on separate poles. (Based on sample survey by Engineering Services.)
E. Number of area lights on separate poles. (Based on sample survey by Engineering Services.)

F. Number of poles in Account 364.
G. Total dollars in Account 364.

Dollar Allocations for Account 364

To Streetlighting = $D \times C^{*}$ = DSL

To Area Lighting = $E \times C^{*}$ = DAL

Customer Component = $(F - D - E) \times C$ = DPCC

Demand Component = DSL – DAL – DPCC = DPDC

*Cost of a minimum size pole was used because most streetlights are mounted on minimum size poles and those that are on larger poles are mounted on poles that do not have the usual framing (crossarms, etc.).

Account 365 (Overhead Conductor and Devices):

I. Primary

A. Average age of primary conductor.
B. Minimum size primary unit.
C. Average installed cost of a minimum size primary unit of the age in "A."
D. Average number of poles in a minimum size unit of primary conductor. (Estimated by ED Department.)
E. Total dollars in Account 365 considered primary (see note).
F. Total number of poles used for primary distribution. (Number of poles in Account 364 - Number of poles allocated to streetlighting and area lighting.)

$$\text{Number of units of primary distribution} = \text{UPD} = \frac{F}{D1}$$

Dollar Allocations for Account 365 Primary

Customer Component = $C \times$ UPD = DPCC

Demand Component = E – DPCC = DPDC

NOTE: All bare copper, aluminum, ACSR and iron wire are primary. 30% of WP copper, 80% of WP aluminum and 50% of the steel wire are primary. (Estimated by ~~ED Department~~Delivery Planning - exact percentages very difficult to determine.) All miscellaneous conductor and other equipment are primary.

II. Secondary

A. Average age of secondary conductor.
B. Minimum size secondary unit.
C. Average installed cost of a minimum size unit of the age in "A."

D. Number of units of secondary conductor (see note).
E. Total dollars in Account 365 considered secondary. (All conductor not primary - see primary section.)
F. Dollar value of duplex conductor in Account 365. (Duplex assumed to be used entirely for street and area lights.)
G. Percent of total number of lighting units (street and area lights) that are streetlights.

Dollar Allocations for Account 365 Secondary

To Streetlighting $= F \times G = DSL$

To Area Lighting $= F - DSL = DAL$

Customer Component $= C \times D = DSCC$

Demand Component $= E - F - DSCC = DSDC$

NOTE: Estimated by ~~ED Department~~Delivery Planning based on 250' of secondary for each five urban residential cottages, and urban commercial customers, 3,360' of secondary per unit.

Account 366 (Underground Conduit):

The percentages developed from the allocation of Account 367 will be applied to this account.

Account 367 (Underground Conductor and Devices):

I. Primary

A. Average age of primary unit.
B. Minimum size primary unit.
C. Average installed cost of a minimum size primary unit of the age in "A."
D. Number of feet of conductor in the minimum size primary unit.
E. Total dollars in Account 367 considered primary. (All conductor rated 5 kV and above, and all nonconductor items are considered primary.)
F. Total number of feet of primary conductor in Account 367.

$$\text{Number of units of primary distribution} = UPD = \frac{F}{D2}$$

Dollar Allocations for Account 367 Primary

Customer Component $= C \times UPD = DPCC$

Demand Component $= E - DPCC = DPDC$

II. Secondary

A. Average age of secondary unit.
B. Minimum size of secondary unit.
C. Average installed cost of a minimum size secondary unit of the age in "A."

D. Number of feet of conductor in the minimum size secondary unit.
E. Total dollars in Account 367 considered secondary. (All conductor rated 600 volts or less is secondary.)
F. Total number of feet of secondary conductor in Account 367 (see note).
G. Dollar value of duplex conductor in Account 367 (duplex conductor is assumed to be used entirely for street and area lights).
H. Percent of total number of lighting units (street and area lights) that is streetlights.

$$\text{Number of units of secondary distribution} = \text{USD} = \frac{\text{F}}{\text{D3}}$$

<u>Dollar Allocations for Account 367 Secondary</u>

To Streetlighting = G × H = DSL

To Area Lighting = G – DSL = DAL

Customer Component = C × USD = DSCC

Demand Component = E – G – DSCC = DSDC

NOTE: Includes all quadruplex and triplex cable and 1/3 of 600 volt single wire. (Duplex is for lighting only.)

<u>Account 368 (Transformers):</u> (All transformers classified secondary)

A. Average installed cost of minimum size 2400 V. overhead unit.*
B. Average installed cost of minimum size 7200 V. overhead unit.*
C. Average installed cost of minimum size 14400 V. overhead unit.*
D. Average installed cost of minimum size 2400 V. underground unit.*
E. Average installed cost of minimum size 7200 V. underground unit.*
F. Number of 2400 V. overhead units in the account.
G. Number of 7200 V. overhead units in the account.
H. Number of 14400 V. overhead units in the account.

*Overhead unit cost includes cost of appropriate cutout and arrester.

I. Number of 2400 V. underground units in the account.
J. Number of 7200 V. underground units in the account.
K. Total dollar value of Account 368.

<u>Dollar Allocations for Account 368</u>

Customer Component = (A × F) + (B × G) + (C × H) + (D × I) + (E × J) = DSCC

Demand Component = K – DSCC = DSDC

<u>Account 369 (Overhead Services):</u> (All services classified secondary)

A. Average age of a service.
B. Minimum size of a service.
C. Average installed cost of a minimum size service of the age in "A."
D. Total number of 3 and 4 services.
E. Dollar value of two-wire services (two-wire services are considered all customer component).
F. Total dollar value of Account 369.

<u>Dollar Allocations for Account 369</u>

Customer Component = $(C \times D) + E = DSCC$

Demand Component = $F - DSCC = DSDC$

<u>Account 369.1 (Underground Services):</u> (All services classified secondary)

A. Average age of an underground service.
B. Minimum size of an underground service.
C. Average installed cost of a minimum size three-wire service of the age in "A."
D. Total number of services in Account 369.1.
E. Total dollar value of Account 369.1.

<u>Dollar Allocations for Account 369.1</u>

Customer Component = $(C \times D) = DSCC$

Demand Component = $E - DSCC = DSDC$

Forecast Cost Allocation Factors Manual

Supplement to Otter Tail Power Company's Cost Allocation Procedure Manual

Revised October 2023

This Supplement describes the general processes used to develop forecasted demand, energy and customer cost allocation factors outlined in Otter Tail Power Company's Cost Allocation Procedures Manual.

Introduction:

Otter Tail Power Company ("OTP") operates as a single electrical system to serve customers in three states (Regulatory jurisdictions) – Minnesota, North Dakota, and South Dakota. OTP is subject to the statutes, rules and regulations that dictate the operation of a publicly owned electric utility within each state. Rates are state specific and subject to approval by the respective state's regulatory Commission.

OTP generally accounts for its costs (investment and expense) on a system basis. To determine a particular state's share of its cost of service, the company applies allocation factors to its system costs to further assign those costs to each jurisdiction. The current process OTP uses to allocate its costs is documented in OTP's Cost Allocation Procedure Manual ("CAPM").

Historically, OTP's general rate cases were based on cost of service studies that were developed using a historic test year. The associated cost allocation factors were based on historical information using a single annual coincident peak ("1 CP") for OTP's system. The current CAPM has been previously approved by each state, in OTP's most recent rate case within each state. Maintaining a consistent cost allocation process between jurisdictions is important. Using the same cost allocation methodology in all jurisdictions helps minimize the potential for material over or under-recovery of costs across jurisdictions that might occur if different cost allocation methodologies were used in each state.

In future rate cases, OTP will be using a forecast test year in Minnesota and North Dakota. This supplement to Otter Tail's Cost Allocation Procedures Manual, describes in general terms, the methodologies used to compute the forecast cost allocation factors to be used in a forecast test year.

Summary of Cost Allocation Factors:

OTP has ~~16~~ 17 different demand, energy and customer allocation factors that are used to allocate costs within the jurisdictional cost of service study. As noted earlier, these same factors are used across all ~~three~~ four jurisdictions OTP serves. Below is a summary of the 16 allocation factors as outlined in the CAPM:

1. GENERATION DEMAND FACTOR (D1)
2. TRANSMISSION DEMAND FACTOR (D2)
3. DISTRIBUTION PRIMARY DEMAND FACTOR (D3)
4. DISTRIBUTION SECONDARY DEMAND FACTOR (D4)
5. ENERGY FACTOR (E1)
6. ENERGY FACTOR (E2)

~~6.~~7. ENERGY FACTOR (E1-E8760) (Class allocations only)
~~7.~~8. ENERGY FACTOR (E2-E8760) (Class allocations only~~ — MN & ND~~)
~~8.~~9. TOTAL RETAIL CUSTOMERS FACTOR (C1)
~~9.~~10. TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2)
~~10.~~11. TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3)
~~11.~~12. STREETLIGHT FACTOR (C4)
~~12.~~13. AREA LIGHT FACTOR (C5)
~~13.~~14. METER FACTOR (C6)

~~14.~~15. METER READING FACTOR (C7)
~~15.~~16. TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8)
~~16.~~17. LOAD MANAGEMENT FACTOR (C9)

The rest of this document describes each allocation factor, (as described in the current CAPM) and the related methodology used to develop the forecast of that factor. In some explanations contained below related to the computations of D and E factors, references are made to manually forecasted customers. In some jurisdictions, certain customers are manually forecasted, exclusive from forecasts developed for all other customers. In most cases, these customers are forecasted separately due to size or certain operational characteristics. When the explanation specifically refers to manually forecasted customers, the explanation will specifically state "manually forecasted customers". All other references to forecasted data will refer to all other customers exclusive of the manually forecasted ones.

Forecast Allocation Factors Methodology:

1. **GENERATION DEMAND FACTOR (D1)** - This factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.

   Forecast Methodology for D1: The Forecasted D1 factors are computed using a ~~4~~5-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:
   a. Compute customers demand
   ~~a.~~b. Compute controlled service customers demand
   ~~b.~~c. Compute manually forecasted customers demand
   ~~c.~~d. Compute FERC demand
   ~~d.~~e. Compute total forecasted D1 Factors

   a. Compute customers demand: First, the historical allocation factors are re-computed excluding the manually forecasted customers. Next, annual Generation Demand (D1) and the Energy at the generation level (E2) factors are compiled in a spreadsheet, for the last five years. A Demand/Energy ratio is then computed for each customer class and state for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2 excluding the manually forecasted customers) to compute the Forecasted Generation Demand (Forecasted D1).
   b. Compute controlled services customers demand: Controlled services customers demand is set to zero for class allocation purposes only.

~~b.~~c. Compute manually forecasted customers demand: Manually forecasted customers demand is determined. In some cases, a fixed baseline demand agreed on by OTP and the customer is the level of demand used for those customers in the forecast.

~~c.~~d. Compute FERC demand: The FERC D1 factors are calculated by computing the average historical five-year D1 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

~~d.~~e. Compute total forecasted D1 Factors: The manually forecasted demand is added to the corresponding forecasted demand for all other customers. Total demand by class is combined within each jurisdiction to determine each jurisdiction's total demand. Total system demand is the sum of the jurisdictional demands. The jurisdictional Generation Demand (D1) allocator is based on each jurisdiction's share of the total system demand.

2. **TRANSMISSION DEMAND FACTOR (D2)** - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes. The hours used are the same as those for the Generation Demand Factor.

Forecast Methodology for D2: The Forecasted D2 factors are computed using a ~~4~~5-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute forecasted customers demand
~~a.~~b. Compute controlled service customer demand (class only)
~~b.~~c. Compute manually forecasted customer demand
~~c.~~d. Compute FERC demand
~~d.~~e. Compute total forecasted D2 Factors

a. Compute forecasted customers demand: First, the historical allocation factors for the previous five years are re-computed excluding the manually forecasted customers. Next, the annual transmission Demand (D2) and the Energy at the generation level (E2) are compiled in a spreadsheet, for the last five years. A Demand/Energy ratio is then computed for each customer class and jurisdiction for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2 excluding the manually forecasted customers), to compute the non-manually Forecasted Transmission Demand (Forecasted D2).

~~a.~~b. Compute controlled services customers demand: Controlled services customers demand is set to zero for class allocation purposes only.

~~b.~~c. Compute manually forecasted customer Demand: Manually forecasted customers demand is determined. In some cases, a fixed baseline demand agreed on by OTP and the customer is the level of demand used for those customers in the forecast.

~~c.~~d. Compute FERC demand: The FERC D2 factors are calculated by computing the average historical five-year D2 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

~~d.~~e. Compute total forecasted D2 Factors: The manually forecasted demand is added to the corresponding demand from all other customers. Total demand by class is combined within each jurisdiction to determine each jurisdiction's total demand. Total system demand is the sum of the jurisdictional demands. The jurisdictional demand (D2) allocator is based on the jurisdiction's share of the total system demand.

3. **DISTRIBUTION PRIMARY DEMAND FACTOR (D3)** - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

   Forecast Methodology for D3: The Forecasted D3 factors are computed using a 3-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

   a. Compute non-FERC demand
   b. Compute the FERC demand
   c. Compute total forecasted D3 Factors

   a. Compute non-FERC demand: First, historical allocation factors for the previous five years are re-computed. Next, each year's Distribution Primary Demand (D3) and the Energy at the generation level (E2) are compiled in a spreadsheet, for the previous five years, and a Demand/Energy ratio is computed for each class and jurisdiction for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2) to compute the Distribution Primary Demand (Forecasted D3).
   b. Compute the FERC demand: The FERC D3 factors are calculated by computing the average historical five-year D3 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.
   c. Compute total forecasted D3 Factors: The non-FERC forecasted demand is added to the corresponding FERC forecasted demand. The entire system is summed up by class and the jurisdictional total is divided by the total system to get the Forecasted Distribution Primary Demand (D3) allocation factor.

4. **DISTRIBUTION SECONDARY DEMAND FACTOR (D4)** - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are

included in this factor.

Forecast Methodology for D4: The Forecasted D4 factors are computed using a 3-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute non-FERC demand
b. Compute the FERC demand
c. Compute total forecasted D4 Factors

a. Compute non-FERC demand: The historical allocation factors are re-computed for the prior five year's Distribution Secondary Demand (D4) and the Energy at the generation level (E2) factors. These factors are compiled in a spreadsheet and a Demand/Energy ratio is computed for each class and state for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2) to compute the non-manually forecast Distribution Secondary Demand factor. (Forecasted D4).
b. Compute the FERC demand: The FERC D4 factors are calculated by finding the average historical five-year D4 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.
c. Compute total forecasted D4 Factors: The non-FERC forecasted demand is added to the corresponding FERC demand. The entire system is summed up by class and the jurisdictional total is divided by the total system to get the Forecasted Distribution Secondary Demand (D4) allocation factor.

5. **ENERGY FACTOR (E1)** - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak sales. It is only used for jurisdictional allocations.

Forecast Methodology for E1: The Forecasted E1 factors are computed using a 4-step process:

a. Compute Energy at the meter level
b. Compute Energy at the generation level excluding interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak sales
c. Compute FERC Energy
d. Compute total forecasted E1 Factors

a. Compute Energy at the meter level: The annual kWh Sales forecast at the rate group level is the initial dataset for developing this factor. Where applicable, the kWh energy forecast from manually forecasted customers are added to the appropriate rate group to calculate total energy sales at the meter by rate group.
b. Compute Energy at the generation level excluding interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak sales: The meter level kWh energy forecast at

the rate group level above is converted to MWhs. The forecast amounts are then multiplied by the loss factor applicable for each respective rate group level forecast to arrive at the generation level energy forecast for each state. Interruptible and irrigation rates are excluded, and ~~water heating and~~ deferred and off-peak rates energy is multiplied by 10/24ths (excluding 14/24ths).

c. Compute FERC Energy: The FERC E1 Energy is calculated by summing up the 3 states E1 total for each forecasted year and multiplying that by the 5-year average of the historical FERC E1 factors.

d. Compute total forecasted E1 Factors: The generation level energy less interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak energy is then summed by class (manually forecasted customers are summed with their appropriate class) and state for each year to reach the system level energy. Then each jurisdictional total is divided by the system total to get the forecasted Energy Factor (E1).

6. **ENERGY FACTOR (E2)** - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.

Forecast Methodology for E2: The Forecasted E2 factors are computed using a 4-step process:

a. Compute Energy at the meter level
b. Compute Energy at the generation level
c. Compute FERC Energy
d. Compute total forecasted E2 Factors

a. Compute Energy at the meter level: The annual kWh Sales forecast at the rate group level is the initial dataset for developing this factor. Where applicable, the kWh energy forecast from manually forecasted customers are added to the appropriate rate group to calculate total energy sales at the meter by rate group.

b. Compute Energy at the generation level: The meter level kWh energy forecast at the rate group level above is converted to MWhs. The forecast amounts are then multiplied by the loss factor applicable for each respective rate group level forecast to arrive at the generation level energy forecast for each state.

c. Compute FERC Energy: The FERC E2 Energy is calculated by summing up the 3 states E2 total for each forecasted year and multiplying the state energy forecasts by the 5-year average of the historical FERC E2 factors.

d. Compute total forecasted E2 Factors: The generation level energy forecast by rate group is then summed to a class level, state level and system level (manually forecasted customers are added to the appropriate class and state) for each year. Each jurisdictional total is divided by the system total to get the respective jurisdictional Energy Factors (E2).

7. **ENERGY FACTOR (E1-E8760)** - This factor is based on hourly energy usage, to which are applied hourly ~~marginal~~ generation capacity costs to develop an hourly cost relationship. **This factor is only used to allocate jurisdictional amounts to the customer classes in Minnesota and North Dakota.**

   ~~**General Note on E8760 Factors:** The E8760[1] factors are developed in a manner upon which marginal energy prices are applied to energy usage which is comparable to the energy usage levels that included in the determination of the E1 and E2 factors. For example, the E8760 factor which replaces the E1 factor, excludes similar controllable or interruptible loads and irrigation, like the E1 factor does. As a result, there are two E8760 factors that are developed; one that mirrors the energy usage of all customers reflected in the E1 factor and one that mirrors the energy usage and customers reflected in the E2 factor. The two factors are identified as E1-E8760 and E2-E8760.~~

   Forecast Methodology for E1-E8760: Forecasted E1-E8760 allocation factors are developed using a ~~4~~5-step process.

   a. Develop customer load profiles
   b. Apply load profiles to forecast sales and scale to generation levels
   ~~b.~~c. Compute sales for controlled loads and irrigation
   ~~c.~~d. Apply hourly ~~energy~~ generation capacity costs to forecasted hourly sales
   ~~d.~~e. Compute E1-E8760 factor ~~excluding controllable load and irrigation~~

   a. Develop customer load profiles: Annual hourly kWh load survey data[2] is gathered for each customer load research group (which includes manually forecast customer data). Based on the annual hourly load research data, hourly "profiles" are developed by customer group as the basis to shape forecasted kWhs across all 8760 hours of the forecast year. Multiple profiles are developed based on applicable customer types.
   b. Apply load profiles to forecast sales and scale to generation levels: Each month's hourly load shape developed in step a. is applied to the corresponding monthly kWh sales forecast for the respective customer group to distribute those sales across the hours of the month. This process applied to all twelve months of the year yields the distribution of the forecasted sales across all 8760 hours of the year. Within this step of the process, the forecast kWh sales are also calibrated to account for losses, which vary depending on customer type and service voltage level. The end result of this step is forecasted generation level kWh sales by customer class for all 8760 hours of the year.
   ~~b.~~c. Compute E1-E8760 Factors for controlled loads and irrigation: Interruptible and irrigation sales are excluded from the calculation of the E1-E8760 factors. Deferred and off-peak loads exclude the sales from the highest priced 14 hours each day.
   ~~c.~~d. Apply hourly ~~energy~~ generation capacity costs to hourly energy sales: Forecasted hourly

~~[1] In a leap year, calculations would be made using 8784 hours.~~
[2] OTP's load research by customer type is conducted on a system basis.

marginal ~~energy~~ generation capacity costs are multiplied against the forecasted hourly kWh sales developed in ~~the prior step~~steps b. and c. to compute total annual marginal revenues.

~~d.~~e. Compute E1-E8760 Factors: excluding Controllable load and irrigation: To compute the E1-E8760 allocation factors, the marginal ~~energy~~ generation capacity costs computed in step ~~e~~d. are aggregated to the class level. The class's marginal ~~energy~~ generation capacity ~~revenues~~ costs are divided by the total jurisdictional marginal ~~energy~~ generation capacity ~~revenues~~ costs to determine each class's allocation factor (percentage). The resultant set of factors (percentages) are converted back to equivalent kWhs by class and used in place of the ~~E2~~ E1 factor cost allocation in the class cost of service study. ~~Customers who are excluded from the calculation of the E1 factors are excluded from the calculation of the E1-E8760 factors (interruptible, irrigation, and 14/24ths of water heating and deferred sales).~~

8. **ENERGY FACTOR (E2-E8760)** – This factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. **This factor is only used to allocate jurisdictional amounts to the customer classes in Minnesota and North Dakota.**

Forecast Methodology for E2-E8760: Forecasted E2-8760 allocation factors are developed using a ~~4~~5-step process.

a. Develop customer load profiles
b. Apply load profiles to forecast sales and scale to generation levels
c. Apply hourly energy costs to forecasted hourly sales
~~c.~~d. Apply hourly energy costs to controllable loads
~~d.~~e. Compute E2-E8760 Factor

a. Develop customer load profiles: Annual hourly kWh load survey data[3] is gathered for each customer load research group (which includes manually forecast customer data). Based on the annual hourly load research data, hourly "profiles" are developed by customer group upon which to use to shape forecasted kWhs across all 8760 hours of the forecast year. Multiple profiles are developed based on applicable customer types.

b. Apply load profiles to forecast sales and scale to generation levels: Each month's hourly load shape developed in step a. is applied to the corresponding monthly kWh sales forecast for the respective customer group to distribute those sales across the hours of the month. This process applied to all twelve months of the year yields the distribution of the forecasted sales across all 8760 hours of the year. Within this step of the process, the forecast kWh sales are also calibrated to account for losses, which vary depending on customer type and service voltage level. The end result of this step is forecasted

[3] OTP's load research by customer type is conducted on a system basis.

generation level kWh sales by customer class for all 8760 hours of the year.

c. Apply hourly energy costs to hourly energy sales: Forecasted hourly marginal energy costs are multiplied against the forecasted hourly kWh sales developed in the prior step to compute total annual marginal ~~revenues~~costs.

~~c.~~d. Apply hourly energy costs to controllable loads: A strike-price is set on the hourly marginal energy cost for interruptible and deferred loads. If the hourly marginal energy costs exceeds the set strike-price, the hourly marginal energy cost is reduced by 90 percent. Forecasted hourly marginal energy costs are multiplied against the forecasted hourly kWh sales developed in step b. to compute total annual marginal costs.

~~d.~~e. Compute E2-E8760 Factors: To compute the E2-E8760 allocation factors, the marginal energy costs computed in steps c. and d. are aggregated to the class level. The class's marginal energy ~~revenues~~ costs are divided by the total jurisdictional marginal energy ~~revenues~~ costs to determine each class's allocation factor (percentage). The resultant set of factors (percentages) are converted back to equivalent kWhs by class and used in place of the E2 factor cost allocation in the class cost of service study.

~~8.~~9. **TOTAL RETAIL CUSTOMERS FACTOR (C1)** - this factor is based on the total distinct active retail customers served in each jurisdiction.

Forecast Methodology for C1: The Forecasted C1 factors are computed using a 4-step process:

a. Compute historical C1 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C1 factors

a. Compute historical C1 values: The historical C1 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C1 factors: To compute forecasted C1 values for each year, the prior year's C1 values are multiplied by the growth factor. The C1 values are summed by state/FERC and system. Each jurisdictional total is divided by the system total to yield the forecasted C1 Factor.

~~9.~~10. **TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2)** – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.

Forecast Methodology for C2: The Forecasted C2 factors are computed using a 4-step process:

a. Compute historical C2 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C2 factors

a. Compute historical C2 values: The historical C2 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C2 factors: To compute forecasted C2 values for each year, the prior year's C2 values are multiplied by the growth factor. The C2 values are summed by jurisdiction and system. Each jurisdictional total is divided by the system total to yield the jurisdictional forecasted C2 factor.

~~10.~~11. **TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3)** - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).

Forecast Methodology for C3: The Forecasted C3 factors are computed using a 4-step process:

a. Compute historical C3 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C3 factors

a. Compute historical C3 values: The historical C3 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C3 factors: To get the Forecasted C3 values for each year, the prior year's C3 values are multiplied by the growth factor. The C3 values are summed by

jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the forecasted C3 factor.

~~11.~~12. **STREETLIGHT FACTOR (C4)** - this factor is based on the weighted installed cost of the streetlights in each jurisdiction.

Forecast Methodology for C4: The most recent historical C4 factor is used as the forecasted C4 factor with no change.

~~12.~~13. **AREA LIGHT FACTOR (C5)** - this factor is based on the weighted installed cost of area lights in each jurisdiction.

Forecast Methodology for C5: The most recent historical C5 factor is used as the forecasted C5 factor with no change.

~~13.~~14. **METER FACTOR (C6)** - this factor is based on the weighted installed cost of meters in service.

Forecast Methodology for C6: The most recent historical C6 factor is used as the forecasted C6 factor with no change.

~~14.~~15. **METER READING FACTOR (C7)** - this factor is based on total weighted meter reading time.

Forecast Methodology for C7: The Forecasted C7 factors are computed using a 4-step process:

a. Compute historical C7 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Combine historical values and growth factor and computes Forecasted C7 factors

a. Compute historical C7 values: The historical C7 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C7 factors: To compute the Forecasted C7 values for each year, the prior year's C7 values are multiplied by the growth factor. The C7 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to

yield the Forecasted C7 Factor.

~~15.~~16. **TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8)** - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.

Forecast Methodology for C8: The Forecasted C8 factors are computed using a 4-step process:

a. Compute historical C8 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Combine historical values and growth factor and computes Forecasted C8 factors

a. Compute historical C8 values: The historical C8 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C8 factors: To compute the Forecasted C8 values for each year, the prior year's C8 values are multiplied by the growth factor. The C8 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the forecasted C8 factor.

~~16.~~17. **LOAD MANAGEMENT FACTOR (C9)** - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

Forecast Methodology for C9: The Forecasted C9 factors are computed using a 4-step process:

a. Compute historical C9 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C9 factors

a. Compute historical C9 values: The historical C9 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each~~

~~class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~

c. Compute the FERC values: Remain the same as the most recent historical year.

d. Compute Forecasted C9 factors: To compute the forecasted C9 values for each year, the prior year's C9 values are multiplied by the growth factor. The C9 values are summed by jurisdiction and system. Then each jurisdiction is divided by the system total to yield the forecasted C9 factor.

Non-Legislative Version of

Tariff Sheet ND 13.13 - Sales Adjustment Rider

SALES ADJUSTMENT RIDER **N**

DESCRIPTION	RATE CODE
All Services	NSA

N
N
N

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider. **N N**

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's retail rate schedules as described in the Mandatory Riders – Applicability Matrix. **N N**

COST RECOVERY FACTOR: There shall be included on each North Dakota Customer's monthly bill a Sales Adjustment (SA) Rider charge, which shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules. **N N N N N**

Sales Adjustment - $0.000 per kWh

N

DETERMINATION OF SALES ADJUSTMENT RIDER: The Sales Adjustment (SA) Rider Factor shall be determined by dividing the effect of sales changes on base rate jurisdictional cost allocations and revenues from Otter Tail Power Company's most recent general rate case by the forecasted retail sales (kWh) subject to the SA Rider for a designated 12-month recovery period. For each recovery period, a true-up adjustment to the SA Tracker account will be calculated reflecting the difference between actual prior period SA recoveries and actual prior period recoveries. Any resulting over/under recovery will be reflected as a carryover balance and included in calculating the next SA Factor plus carrying charges or credits accrued at the rate of return approved in Otter Tail Power Company's most recent general rate case. **N N N N N N N N N N**

Forecasted retail sales used for calculating the SA Factor shall include the forecast of retail electric revenue collected through all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Section 14.09 (**Tail***Winds*). **N N N**

The SA Factor may be adjusted annually with approval of the Commission. **N**

<u>MANDATORY AND VOLUNTARY RIDERS</u>: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders. **N N N N**

Otter Tail Power Company
Proration of Accumulated Deferred Income Tax for Final Rates Implemented August 1, 2024
Unadjusted Projected Fiscal Year 2024

	(A)	(B)	(C)	(D)
Line No.		**12/31/23**	**12/31/24**	**Simple Average**
1	**Accumulated Deferred Income Taxes**			
2	Non-Prorated:			
3	Federal (above the line including Wind)	(314,143,869)	(328,958,993)	(321,551,431)
4				
5	Prorated:			
6	Federal (above the line including Wind)	(314,143,869)	(324,310,973)	(319,227,421)
7				
8	**Adjustment to ADIT**			**2,324,010**
9				
10			NEPIS	37.8769%
11			North Dakota Share	880,263
12				
13			Rate Base Revenue Requirement Factor	10.38%
14			Test Year ND Revenue Requirement Impact	**91,409**

Otter Tail Power Company
Proration of Accumulated Deferred Income Tax for Interims
Unadjusted Projected Fiscal Year 2024

	(A)	(B)	(C)	(D)
Line No.		**12/31/23**	**12/31/24**	**Simple Average**
1	**Accumulated Deferred Income Taxes**			
2	Non-Prorated:			
3	Federal (above the line including Wind)	(314,143,869)	(328,958,993)	(321,551,431)
4				
5	Prorated:			
6	Federal (above the line including Wind)	(314,143,869)	(321,741,362)	(317,942,615)
7				
8	**Adjustment to ADIT**			**3,608,816**
9				
10			NEPIS	37.8177%
11			North Dakota Share	1,364,771
12				
13			Rate Base Revenue Requirement Factor	9.80%
14			Test Year ND Revenue Requirement Impact	**133,778**

Otter Tail Power Company
North Dakota Cost of Service Study
2024 Projected Test Year

Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Rate Base		661,733,555	205,126,967	10,826,081	147,590,894	226,405,626	578,900	13,293,092	6,108,235	15,571,307	35,235,809	996,643
2													
3	Total Available for Return		21,208,695	2,105,053	321,162	5,158,815	10,895,058	(10,923)	1,432,702	(78,072)	(286,637)	1,438,974	232,561
4													
5	Rate of Return Earned		3.21%	1.03%	2.97%	3.50%	4.81%	-1.89%	10.78%	-1.28%	-1.84%	4.08%	23.33%
6													
7	Rate of Return Requested		7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
8													
9	Operating Income Required		51,946,084	16,102,467	849,847	11,585,885	17,772,842	45,444	1,043,508	479,496	1,222,348	2,766,011	78,236
10													
11	Total Available for Return		21,208,695	2,105,053	321,162	5,158,815	10,895,058	(10,923)	1,432,702	(78,072)	(286,637)	1,438,974	232,561
12													
13	Operating Income Defeciency		30,737,389	13,997,414	528,685	6,427,071	6,877,784	56,366	(389,194)	557,568	1,508,984	1,327,037	(154,324)
14													
15	Incremental Taxes		9,923,169	4,518,884	170,679	2,074,897	2,220,403	18,197	(125,646)	180,004	487,156	428,417	(49,822)
16													
17	Revenue Increase (Decrease) Required		40,660,558	18,516,298	699,364	8,501,967	9,098,187	74,564	(514,841)	737,572	1,996,140	1,755,453	(204,146)
18													
19	Percentage Increase		22.26%	36.36%	26.51%	22.09%	12.54%	81.15%	-16.33%	54.31%	83.89%	16.90%	-28.34%
20													
21													
22													
23													
24													
25	Present Revenues		182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
26	Revenue Increase (Decrease) Required		40,660,558	18,516,298	699,364	8,501,967	9,098,187	74,564	(514,841)	737,572	1,996,140	1,755,453	(204,146)
27	Revenue Responsibility		223,347,446	69,445,591	3,337,900	46,990,988	81,636,850	166,449	2,637,134	2,095,672	4,375,580	12,145,104	516,179
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													
38													
39													
40													
41													
42													
43													
44													
45													
46													
47													
48													
49													
50													
51													
52													
53													
54													
55													
56													
57													
58													
59													
60													
61													
62													
63													
64													
65													
66													
67													
68													
69													
70													

Otter Tail Power Company
Base Revenue Responsibilities
2024 Base Revenues

	A	B	C	D	E	F	G	H	I	I
Line No.	**Class**	**Present Base Revenue**	**POET Sales moving into EAR**	**Change in Rider Revenues due to Changes in Allocation Factors**	**RRCR moving into base****	**TCR moving into base**	**GCR moving into base**	**AMDT moving into base**	**Net deficiency**	**Total Proposed Base Revenues**
1	Residential	36,934,037	(480,371)	592,636	5,020,393	1,278,967	1,161,634	206,546	6,210,791	50,924,632
2	Farm	1,830,773	(17,239)	32,727	251,924	77,410	58,291	8,944	322,438	2,565,269
3	General Service	27,366,763	(297,241)	457,062	3,765,812	1,022,544	871,345	180,607	4,690,300	38,057,192
4	Large General Service	38,106,045	931,990	(959,344)	5,243,594	985,090	1,213,279	10,911	6,335,159	51,866,724
5	Irrigation	54,144	131	(64)	7,451	3,585	1,724	1,050	11,918	79,939
6	Area / Street lighting	2,693,795	(39,218)	46,256	370,680	34,065	85,769	63,498	(490,959)	2,763,887
7	Other Public Authorities	820,854	(1,427)	11,454	112,954	47,854	26,136	6,090	187,230	1,211,143
8	Controlled Service Deferred Load	1,289,964	69,258	(6,944)	177,506	12,310	41,072	55,950	16,537	1,655,653
9	Controlled Service Interruptible	4,005,936	397,729	166,755	551,238	80,450	127,547	81,479	68,422	5,479,556
10	Controlled Service Off Peak	279,169	(32,156)	43,174	38,415	5,553	8,889	3,766	6,403	353,213
11	Total Present Revenues	113,381,480	531,458	383,711	15,539,967	3,547,829	3,595,685	618,840	17,358,238	154,957,208
					-	-	-	-		-

Volume 2A

Direct Testimony and Supporting Schedules:

Christy L. Petersen

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

REVENUE REQUIREMENT AND BUDGET PROCESS

Direct Testimony and Schedules of

CHRISTY L. PETERSEN

PUBLIC DOCUMENT –

NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

TABLE OF CONTENTS

ATTACHED SCHEDULES

Schedule 1 – Petersen Qualifications and Responsibilities

Schedule 2 – OTP Jurisdictional and Class Cost of Service Study and Rate Design Process Overview Manual

Schedule 3 – Summary of 2024 Test Year Revenue Deficiency

Schedule 4 – Jurisdictional Financial Summary

Schedule 5 – Capital and O&M Budget to Actual Comparison – 2020 through 2022

Schedule 6 – Rate Base Summary

Schedule 7 – Traditional Adjustments Rate Base Bridge Schedule

Schedule 8 – Test Year Adjustments Rate Base Bridge Schedule

Schedule 9 – Income Statement Summary

Schedule 10 – Test Year O&M by Function

Schedule 11 – Traditional Adjustments Income Statement Bridge Schedule

Schedule 12 – Test Year Adjustments Income Statement Bridge Schedule

Schedule 13 – Mercer March 2023 Five Year Pension Expense Estimate NOT PUBLIC

Schedule 14 – Mercer September 2023 Five Year PRM Expense Estimate NOT PUBLIC

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My name is Christy L. Petersen. I am employed by Otter Tail Power Company (OTP).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Manager, Regulatory Accounting. I lead the work group that prepares the jurisdictional cost of service study for all three states in which we provide service (North Dakota, Minnesota and South Dakota). I also oversee the budgeting and forecasting process for our companies' operations and maintenance expenses.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(CLP-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I am OTP's overall revenue requirements witness, sponsoring the jurisdictional cost of service study (JCOSS) and the calculation of OTP's 2024 Test Year revenue requirement and base rate revenue deficiency. As such, I support and sponsor much of the financial data provided as part of this case. I also describe OTP's capital and operations and maintenance (O&M) budgets, which provide the basis for the 2024 Test Year. Finally, I discuss the development of the rate base and income statement that are being proposed for use in setting rates in this proceeding, including explaining the financial impact of all Test Year adjustments and providing support for some of the Test Year adjustments. Other Test Year adjustments are supported by other OTP witnesses.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. OTP uses the JCOSS to determine the portion of OTP's total company costs and revenues that should be recognized in the North Dakota jurisdiction for the 2024 Test Year. The overall revenue deficiency for the 2024 Test Year, after incorporating adjustments discussed in Sections VII.C and VIII.B below, is

$40,660,558. OTP uses a thorough budgeting process that results in a reliable and accurate forecast that serves as the basis for the 2024 Test Year revenue requirement.

Q. WILL OTP BE MAKING ADDITIONAL ADJUSTMENTS AS THE CASE DEVELOPS?

A. Yes. While finalizing this case for submission, OTP determined that the 2024 Test Year revenue requirement calculation did not include an intended adjustment to normalize plant outage costs. This adjustment occurs in all rate cases to reflect the fact that plant outages occur on a multi-year cycle, so that base rates are neither over-stated (by reflecting the full cost of an outage if the test year coincides with an outage) nor under-stated (if the test year is not an outage year).[1]

Our Big Stone Plant underwent a major outage in 2022 and Coyote Station is scheduled for an outage in 2025. There are no outages scheduled for 2024. As a result, OTP intends that the 2024 Test Year reflect a normalized expense amount based on an annual outage schedule, rather than every three years. Once incorporated, this adjustment will: (1) increase O&M expenses by $1,091,341; (2) decrease total income taxes by $266,341; and (3) decrease net operating income by $825,000. OTP will incorporate this adjustment to the 2024 Test Year revenue requirement calculation at the appropriate time in the procedural schedule (either as an errata or in Rebuttal Testimony). The adjustment has been incorporated into the proposed interim rate revenue increase. The 2024 Test Year revenue requirement and base rate revenue deficiency amounts discussed in my Direct Testimony do not reflect the impact of the plant outage normalization adjustment.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss the JCOSS, followed in Section IV with a discussion of the 2024 Test Year revenue deficiency, including selection of the 2024 Test Year. Section V describes the financial data provided as part of OTP's requests. Section VI explains OTP's budget process. In Sections VII and VIII, I discuss the 2024 Test Year rate base and income statement.

[1] For example, *see* Case No. PU-17-398, Akerman Direct at 40.

Q. HOW HAVE YOU LABELED DOLLAR VALUES IN YOUR DIRECT TESTIMONY AND SUPPORTING SCHEDULES?

A. Throughout my testimony and schedules, I label dollar values as "(OTP ND)" when the values are jurisdictionalized to North Dakota. I label total company costs as "(OTP Total)." Some costs fall into numerous functions each with its own jurisdictional allocation, and therefore a straightforward calculation of a jurisdictional amount based on a single allocator is not possible (e.g., labor cost categories, which may include costs functionalized as generation, transmission, distribution, administration, and general, with each function having its own unique jurisdictional allocation). For costs like this, I have estimated the North Dakota jurisdictional dollar values by multiplying the total company costs by a single blended allocator. I have labeled these values as "(OTP ND EST.)."

Finally, for power plant and transmission projects where OTP is only a part owner, and for which I included total project costs, I labeled the values as "(Total Plant)" or "(Total Project)."

III. JURISDICTIONAL COST OF SERVICE STUDY

Q WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to explain OTP's JCOSS.

Q. WHAT IS THE PURPOSE OF A JCOSS?

A. Multijurisdictional utilities use a JCOSS to determine the portion of a total company costs and revenues that should be recognized in a specific jurisdiction. In this case, OTP used the JCOSS to determine the portion of OTP's total company costs and revenues that should be recognized in the North Dakota jurisdiction for the 2024 Test Year revenue requirement.

Q. WHY IS A JCOSS NECESSARY FOR OTP?

A. OTP serves retail customers in North Dakota, Minnesota and South Dakota. In addition, OTP provides wholesale service to some municipal utilities, and those services, as well as transmission services, are regulated by the Federal Energy Regulatory Commission (FERC). Costs that OTP incurs to meet the requirements of a particular jurisdiction are directly assigned to that jurisdiction. Costs that cannot be directly assigned to a specific jurisdiction are allocated to jurisdictions based upon allocation factors included in the JCOSS. In this way, OTP uses the

JCOSS to determine what portion of the total costs it incurs should be recovered from our North Dakota customers.

Q. IS IT IMPORTANT THAT ALL OF A UTILITY'S STATE JURISDICTIONS USE THE SAME JURISDICTIONAL ALLOCATION PROCEDURES FOR THE JCOSS?

A. Yes. Having uniform jurisdictional allocation procedures in all its state jurisdictions is what allows OTP to accurately recover its cost of providing retail service across its entire service territory, no more and no less. In this case, OTP used allocation procedures the Commission approved in OTP's last North Dakota rate case (Case No. PU-17-398).

Q. DO ALL OF OTP'S JURISDICTIONS USE THE SAME JURISDICTIONAL ALLOCATION PROCEDURES FOR OTP'S JCOSS?

A. Yes. The Minnesota Public Utilities Commission (MN PUC) and South Dakota Public Utilities Commission (SD PUC) have approved the same jurisdictional allocation procedures for OTP's JCOSS that the Commission has approved for OTP's JCOSS.

Q. HOW WAS OTP'S JCOSS DEVELOPED?

A. OTP developed the JCOSS using procedures contained in the OTP Jurisdictional and Class Cost of Service Study and Rate Design Process Overview Manual, a copy of which is attached as Exhibit___(CLP-1), Schedule 2. This is the same process that was used and approved by the Commission in OTP's last North Dakota rate case.

Q. WHAT ARE THE GENERAL STEPS FOR PREPARING OTP'S JCOSS?

A. Preparing the JCOSS involves the following steps: functionalization, classification, and allocation. *Functionalization* is the process by which costs are arranged according to the utility function they serve, such as production, transmission, distribution, etc. *Classification* is the arrangement of costs within a function by the service characteristic to which they most closely apply or relate, in order to facilitate their allocation based on these service characteristics. *Allocation*, in the JCOSS, is the process of distributing costs to each jurisdiction. I discuss the functionalization and classification steps in more detail below. OTP witness Ms. Amber M. Stalboerger discusses jurisdictional allocations and OTP's Cost Allocation Procedures Manual (CAPM) in her Direct Testimony.

Q. IS FUNCTIONALIZATION OF COSTS REQUIRED?

A. Yes. The assignment of costs to each function (production, transmission, distribution, customer service, administrative and general) generally follows the accounting categories defined in the FERC Uniform System of Accounts (USOA). At times, however, there are exceptions. When there are exceptions, the purpose of functionalization, not the accounting treatment, determines the distribution of the functional costs for the cost of service study. For example, lines and substations can fulfill production, transmission, or distribution functions. Additional details regarding OTP's functionalization procedures are included in the CAPM.

Q. HOW WERE COSTS CLASSIFIED IN THE JCOSS?

A. Classification approaches differ across different functional categories. For example, fixed production plant is classified into energy-related and demand-related subcategories using the equivalent peaker method. OTP has used the equivalent peaker method to classify fixed production plant costs since 1980. Additional details regarding classification procedures are available in the CAPM.

Q. WHAT IS YOUR CONCLUSION RELATED TO OTP'S JCOSS?

A. After review, I have determined that the results of the JCOSS are appropriate for determining the 2024 Test Year revenue requirement.

IV. TEST YEAR REVENUE REQUIREMENT AND REVENUE DEFICIENCY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. This section of my testimony identifies OTP's proposed test year and summarizes the overall revenue requirement and revenue deficiency for that test year.

Q. WHAT TEST YEAR IS OTP PROPOSING IN THIS CASE?

A. OTP is proposing a forecast 2024 Test Year that is a based primarily on OTP's 2024 O&M and capital expenditure budgets, with adjustments. I discuss the development of the 2024 O&M and capital budgets in Section VI, below. The 2024 Test Year is a "future test year" as defined in N.D.C.C. § 49-05-04.1.1C.[2]

[2] N.D.C.C. § 49-05-04.1.1C provides a "future test year" is "any consecutive twelve-month period ending no later than twenty-four months after the date new schedules are filed."

Q. PLEASE PROVIDE THE 2024 TEST YEAR JURISDICTIONAL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. OTP's overall jurisdictional revenue requirement for the 2024 Test Year is $223,347,446 (including $1,594,045 of revenue requirements that will remain in riders), and the 2024 Test Year base rate revenue deficiency is $40,660,558.[3] The 2024 Test Year base rate revenue deficiency represents a an approximately 36.00 percent overall increase in base rate retail revenues compared to projected 2024 retail base rate revenues at current rates.[4] The overall increase in base rate retail revenue reflects $23,302,320 of rider revenue that is moving into base revenues. The overall net increase in base rate revenue (excluding amounts moving from riders to base rates) is 8.43 percent.

Q. HAVE YOU PREPARED A SUMMARY OF THE 2024 REVENUE DEFICIENCY?

A. Yes. Exhibit___(CLP-1), Schedule 3 and Volume 3, Schedule A-1 is a summary of the 2024 Test Year base rate revenue deficiency. Line 1 shows average total rate base of $662 million. Line 2 shows the total amount available for return of $21.2 million, determined at present rate levels. Line 3 shows the 3.21 percent overall rate of return (ROR) earned before any rate increase. Line 4 shows the 7.85 percent required ROR. OTP witness Mr. Todd R. Wahlund supports OTP's requested ROR in this proceeding. Line 5 shows the required operating income of $51.9 million, determined by multiplying the 7.85 percent required ROR by the $662 million rate base. Line 6 shows the $30.7 million income deficiency, which is the difference between the required operating income of $51.9 million (on Line 5) less the $21.2 million of available return (on Line 2). The $40.7 million revenue deficiency on Line 8 is determined by multiplying the $30.7 million income deficiency (on Line 6) by the 1.32284 gross-revenue conversion factor (based on the applicable income tax rates and uncollectible factor that derives the increased expense). The calculation of the gross revenue conversion factor appears in Volume 3, Schedule F-2.

---

[3] This amount excludes the effect of POET Steam Sales moving into the Energy Adjustment Rider and change in rider revenue due to changes in allocation factors.

[4] See Volume 3, Schedule E-1.

Q. HAVE YOU COMPARED OTP'S EARNED OVERALL ROR TO ITS REQUIRED OVERALL ROR SINCE 2022?

A. Yes. OTP's earned ROR was lower than OTP's required ROR in 2022 and will be lower than OTP's required ROR in both 2023 and 2024 at current rates. Exhibit___(CLP-1), Schedule 4 and Volume 3, Schedule A-2 is a Jurisdictional Financial Summary for the 2022 Actual Year, 2023 Current Period (projected), 2024 Regulatory Year (projected), and the 2024 Test Year. Schedule 4 and Volume 3, Schedule A-2 shows: (1) the overall ROR for the 2022 Actual Year was 6.31 percent and the required ROR was 7.26 percent; (2) the projected overall ROR for the 2023 Current Period is 6.60 percent and the projected required ROR is 7.33 percent; (3) the projected overall ROR for the 2024 Regulatory Year is 6.54 percent and the projected required ROR is 7.41 percent; and (4) the projected overall ROR for the 2024 Test Year is 3.21 percent and the required ROR is 7.85 percent.

V. FINANCIAL DATA PROVIDED

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my testimony is to describe the financial data OTP has provided to support its requests in this proceeding.

Q. HAS OTP PROVIDED REQUIRED FINANCIAL DATA AS PART OF THIS APPLICATION?

A. Yes. Additional supporting financial data is included in Volume 3, Supporting Information. The Volume 3, Supporting Information provides the information required under N.D.C.C. §§ 49-05-04 and 49-05-04.1(2).

Q. PLEASE PROVIDE AN OVERVIEW OF THAT FINANCIAL DATA.

A. OTP is providing additional financial data with this filing for the 2022 Actual Year, 2023 Current Period, 2024 Regulatory Year, and 2024 Test Year. Volume 3, Supporting Information contains separate rate base and income statement bridge schedules that identify traditional and rate case adjustments for the 2024 Test Year.[5] Additional rate base and income statement information is found in Volume 3, Supporting Information.

---

[5] The concepts of traditional and rate case adjustments are discussed below.

Q. PLEASE DESCRIBE THE INFORMATION AVAILABLE FOR 2022 AND 2023.

A. 2022 is the most recent year for which 12 months of actual information is available. Information for 2023 reflects a combination of actual information (January through July) and projected information (August through December).

Q. PLEASE IDENTIFY THE FINANCIAL SCHEDULES PROVIDED AS PART OF THE FILING.

A. There are six financial schedules, which have alphabetical headings, A through F. These are in Volume 3, Supporting Information, under the tab: Supporting Financial Information. I am sponsoring the information contained in all sections except Section D, Cost of Capital and Section E, Test Year Revenue. I will briefly describe the sections I am sponsoring.

Q. PLEASE DESCRIBE FINANCIAL SCHEDULE A-2.

A. Schedule A-2 is the Jurisdictional Financial Summary of OTP, as allocated to North Dakota, for the 2022 Actual Year, the 2023 Current Period, the 2024 Regulatory Year, and the 2024 Test Year, as adjusted.

Q. PLEASE EXPLAIN FINANCIAL SCHEDULE B-1.

A. Schedule B-1 is the rate base summary of OTP, as allocated to North Dakota, for the 2022 Actual Year, the 2023 Current Period, the 2024 Regulatory Year, and the 2024 Test Year, as adjusted.

Q. WHAT IS SHOWN ON FINANCIAL SCHEDULE C-1?

A. Schedule C-1 is the operating income summary of OTP, as allocated to North Dakota, for the 2024 Regulatory Year and the 2024 Test Year, as adjusted. The electric revenues are the revenues from sales of electricity to OTP's North Dakota customers under rate schedules presently on file with the Commission. To those electric revenues, I added the North Dakota allocated share of OTP's other operating revenues from other services provided by OTP. Next, I deducted operating expenses to arrive at net operating income before income taxes. Finally, I deducted total income tax expense from net operating income before income taxes to arrive at net operating income after income taxes.

Q. WHAT IS SHOWN ON FINANCIAL SCHEDULE D-1?

A. Schedule D-1 is a cost of capital summary showing the required RORs for 2022, 2023, and 2024. The 2024 Test Year required ROR is 7.85 percent, along with the amounts of common equity and the amounts and costs of long-term debt and short-term debt. OTP witness Ms. Ann E. Bulkley supports the 10.60 percent return on equity (ROE) reflected in the 2024 Test Year cost of capital. Mr. Wahlund supports the 7.85 percent overall ROR.

Q. WHAT IS SHOWN ON FINANCIAL SCHEDULE E-1?

A. Schedule E-1 shows the operating revenue under the present and proposed rates by rate schedule. Schedule E-1 indicates that on an annual basis the proposed rates will produce additional base rate revenues of $40,660,558 for the North Dakota jurisdiction. OTP witness Mr. David G. Prazak sponsors this Schedule in his Direct Testimony.

Q. WHAT DOES FINANCIAL SCHEDULE F-2 SHOW?

A. Schedule F-2 shows the development of the gross revenue conversion factor. This factor is used on Schedule A-1 to convert the 2024 Test Year income deficiency to the 2024 Test Year revenue deficiency.

VI. CAPITAL AND O&M BUDGET

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will provide an overview of the process used to develop OTP's capital and O&M budgets. I begin by discussing the capital budget, including the process used to develop the capital budget. I then discuss the O&M budget, including the process to develop that budget.

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN OTP'S BUDGETS AND THE 2024 TEST YEAR.

A. OTP's 2024 Test Year jurisdictional revenue requirement and revenue deficiency in this case is based on OTP's 2024 capital and O&M budgets, with adjustments.

Q. DO THOSE BUDGETS PRESENT A REASONABLE AND RELIABLE BASIS FOR THE TEST YEAR?

A. Yes. As discussed below, and in more detail in Volume 5, Budget Documentation, OTP uses a thorough budgeting process that results in a reliable and accurate forecast. The 2024 Test Year, which builds upon OTP's budgets and reflects adjustments discussed below, is reasonable, reliable and was made in good faith; and all basic assumptions used in making or supporting the 2024 Test Year are reasonable, evaluated, identified, and justified so the Commission can test the appropriateness of the 2024 Test Year. Further, the accounting treatment applied to anticipated events and transactions in the 2024 Test Year is the same as the accounting treatment to be applied in recording the events once they have occurred.

Q. HAVE YOU PREPARED A SUMMARY SCHEDULE COMPARING HISTORICAL BUDGETED TO ACTUAL AMOUNTS?

A. Yes. Exhibit___(CLP-1), Schedule 5 compares budged capital and O&M to actual costs for the years 2020 through 2022. This Schedule demonstrates that OTP's budgets are reliable, accurate and form an appropriate basis for calculating the 2024 Test Year revenue requirement.

Q. DO THE 2022 VARIANCES IDENTIFIED IN SCHEDULE 5 REFLECT CERTAIN ANOMALOUS OR NON-RECURRING EVENTS?

A. The 2022 actual costs reflect some unexpected challenges. For example, there was an unexpected equipment failure at our Big Stone plant. As a result, OTP needed to rent a piece of equipment for the plant to continue operating running while the original equipment was being fixed. The additional rental expense was not in the original forecast.

Some of the 2022 variance also relates to additional tree trimming following some large storms in our service territory. Some of the expense was capitalized, but not all of it. We used the opportunity to proactively perform additional tree trimming so as mitigate effects of future storms.

A. Capital Budget

Q. WHAT SYSTEMS DOES OTP USE FOR CAPITAL BUDGETING?

A. The capital budget is developed using a software package called Power Plan. OTP has used Power Plan since 2012. OTP also uses a software package called Utilities International (UI). UI is used by many utilities for budgeting, forecasting, financial reporting, and cost of service studies. After the capital budget is developed in Power Plan, the information is loaded into UI to develop cost of service studies.

Q. PLEASE IDENTIFY THE PRIMARY PARTICIPANTS IN THE CAPITAL BUDGETING PROCESS.

A. The OTP capital budget is developed, maintained, and updated by the Fixed Assets Department. Several other groups within OTP also have significant roles in the OTP capital budgeting process, including the business areas within OTP. Sponsors of individual projects and the Vice Presidents of the business areas and the Department Managers within the business areas have significant roles.

OTP also has a Capital Budget Committee that is comprised of managers from various business areas. The Capital Budget Committee plays a significant role in prioritizing capital projects and determines if projects can be deferred, removed, or need to be kept in the year for which they are forecasted.

The OTP Chief Financial Officer (CFO) and OTP President also have significant roles. Annual targets for OTP's routine capital projects (which I discuss further below) are determined by the OTP CFO and President. Approval of a specific project by the OTP Board of Directors or the Otter Tail Corporation Board of Directors also may be required, depending on the level of spending involved in a project. Final approval of the overall capital budget requires approval of the OTP Board of Directors and the Otter Tail Corporation Board of Directors.

Q. WHAT ARE THE CATEGORIES OF PROJECTS IN OTP'S CAPITAL BUDGETS?

A. OTP's capital budgets are made up of routine and non-routine projects.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF ROUTINE PROJECTS.

A. Routine projects typically are lower cost projects with construction timelines that generally do not span more than one year. Routine projects are projects done in the normal course of business that help maintain the functionality of an asset, support typical customer growth, address minor compliance requirements, and/or maintain system reliability. Routine projects also include projects related to serving new customers by building new facilities or upgrading existing facilities.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF NON-ROUTINE PROJECTS.

A. Non-routine capital projects are typically higher cost projects that are not done on a yearly basis and for which the construction duration normally spans more than one year. Non-routine projects are typically done to address major compliance requirements and/or add significant transmission or generation assets. An example of a non-routine project is the Upgrade Project discussed by OTP witness Ms. Paula M. Foster in her Direct Testimony.

Q. WHAT IS THE PLANNING HORIZON FOR OTP CAPITAL BUDGETS?

A. The OTP capital budget normally covers a horizon from the current year to five years into the future. OTP annual capital budgets are developed in the context of a five-year capital budget. Each year, the five-year capital budget is revisited and extended for an additional year.

Q. PLEASE SUMMARIZE THE INITIAL STEPS IN DEVELOPING OTP'S CAPITAL BUDGET.

A. OTP's capital budget process begins the first quarter of the year before the budget year (i.e., 2023 for the OTP 2024 capital budget). The capital budget process begins with identification of new projects for consideration or updating of projects previously submitted through a prior capital budget to be reconsidered for the upcoming five-year capital budget.

Project sponsors (the managers responsible for projects) propose new projects. The project sponsors are required to identify: (1) the need for the project; (2) the work to be completed; (3) the benefits of the project; and (4) any alternatives that were considered. After new projects are proposed by the project sponsors, the proposed projects are reviewed by the Vice Presidents for the business areas responsible for the projects. At this stage, the Vice President determines whether the project is to be considered further or be denied for consideration in the five-year capital budget.

After all projects for further consideration have been identified, the Capital Budget Committee categorizes each project as either routine or non-routine. The Capital Budget Committee representative for each functional area will assess priority of their projects. The objective of the Capital Budget Committee is to develop the best list of projects to include in the preliminary five-year capital budget in accordance with the capital budget targets set for OTP.

Q. PLEASE DESCRIBE FURTHER HOW POTENTIAL PROJECTS ARE PRIORITIZED.

A. After the Capital Budget Committee finalizes the list of projects to include in the preliminary five-year capital budget, the list is presented to the OTP executive team[6] for approval. The presentation and approval by the OTP executive team generally occurs in the first half of March.

Q. WHAT HAPPENS AFTER THE CAPITAL BUDGET COMMITTEE HAS DEVELOPED THE LIST OF CAPITAL PROJECTS?

A. After being returned to the Capital Budget Committee, the list is shared with the respective functional area. Smaller projects (generally less than $500,000) are presented and approved through the business area Vice President. Routine (and non-routine) capital projects over $500,000 generally require project review and approval from the OTP executive team.

The OTP President can approve routine (and non-routine) capital projects up to $5,000,000. If the capital project is greater than $5,000,000, it requires approval by the OTP Board of Directors. The OTP Board of Directors can approve capital projects up to $15,000,000. Any capital project over $15,000,000 requires approval by the Otter Tail Corporation Board of Directors.

Q. HOW IS THE FIVE-YEAR CAPITAL SPENDING FORECAST FINALIZED?

A. During the third quarter of the year before the budget year (i.e. the fourth quarter of 2023 for the 2024 budget year), the Plant & Capital Budget Accountant closely works with each functional area to make updates to non-routine projects and routine projects if known in the five-year capital budget forecast. A further review is then conducted by the OTP executive team in conjunction with overall Company review of the upcoming forecast. Thereafter, the OTP Board of Directors and the Otter Tail Corporation Board of Directors approve the total spending levels within the five-year capital budget.

Q. ARE NON-ROUTINE PROJECTS SUBJECT TO ADDITIONAL SCRUTINY IN THE CAPITAL BUDGET PROCESS?

A. Yes. Non-routine projects (and a few routine projects) are also subject to the Phase Review Process. There are three phases in the Phase Review Process. The first phase in the Phase Review Process is the Development Phase. The Development Phase of the project secures funding to do the necessary research to determine the feasibility of the project. At this stage, there is no commitment to the project.

[6] The OTP executive team consists of the OTP President, CFO, Vice Presidents of Asset Management, Customer Service, Energy Supply, HR/Safety, IT, Communications, and Regulation and Retail Energy Solutions.

After the Development Phase, the project sponsor seeks approval and final commitment to proceed with construction. During the Construction Phase (following the Development Phase), detailed project scopes and objectives are developed, agreements are negotiated, and vendors are selected. Completion of these steps leads to construction of the project.

After the project is completed, there is a Post Project Review Phase. During the Post Project Review Phase, the project is reviewed, including an assessment of: (1) the performance of the project against the scope and objectives that had been developed at the beginning of the project; (2) expenses of the project; and (3) lessons learned.

Q. AFTER PROJECT DEVELOPMENT BEGINS, WHAT STEPS DOES OTP TAKE TO MONITOR AND MANAGE COMPLETION OF THE PROJECT?

A. Capital spending is monitored and reported monthly by comparing actual cash-flows to budgeted cash-flows to ensure accuracy and accountability, and to quickly identify any issues that may arise throughout the construction process. The monitoring and reporting process includes preparation and circulation of reports that outline the actual versus budgeted capital spend for projects on a monthly and year-to-date basis for purposes of receiving answers for any outstanding questions that may arise.

Project updates are provided to business area Vice Presidents by project sponsors. Project updates include milestone schedules, budget summaries, major accomplishments, upcoming milestones/activities, deviations from project scope, and updated risk summaries.

Q. DOES OTP PERFORM REFORECASTING OF PROJECTS UNDER CONSTRUCTION?

A. Yes. Plan sponsors perform monthly reforecasting for all routine and non-routine projects on a monthly basis. the Fixed Asset Department also conducts monthly re-forecasting.

More extensive quarterly reforecasting of routine projects occurs in the second and third quarters. This process allows forecasts to be refreshed as the construction process is occurring and as progress removes levels of uncertainty.

The level of monthly reforecasting of non-routine projects makes additional quarterly reforecasting unnecessary.

Q. DOES THE OTP EXECUTIVE TEAM PROVIDE ADDED SUPERVISION OF SOME NON-ROUTINE PROJECTS?

A. Yes. Certain non-routine projects that span multiple years and have intensified risk or capital spending have also been incorporated into a review process at regularly scheduled staff meetings of the OTP executive team. For example, the Upgrade Project has been reviewed at regular intervals by the OTP executive team.

Q. HAS OTP PROVIDED FURTHER INFORMATION ON THE DEVELOPMENT OF ITS CAPITAL BUDGET IN CONNECTION WITH THIS APPLICATION?

A. Yes, further information about the development of OTP's capital budget is contained in Volume 5, Budget Documentation.

B. O&M Budget

Q. PLEASE IDENTIFY THE PRIMARY PARTICIPANTS IN OTP'S O&M BUDGETING PROCESS.

A. The Business Planning Department (which is part of the Finance Area) has a central role in establishing the O&M budgets. The Business Planning Department's responsibilities include establishing, forecasts, preliminary estimates, and criteria, and providing coordination, evaluation, and oversight of O&M budgets.

The functional areas within OTP, including functional area Vice Presidents and Department Managers also have significant roles in the O&M budgeting process. These functional areas include Regulation and Retail Energy Solutions, Asset Management, Customer Service, Energy Supply, Finance, Human Resources/Safety, Communications, and Information Technology Departments. In addition, OTP's CFO and President have significant roles, which include conferring with functional area Vice Presidents as budgets are being refined and reviewing the O&M budget as it is being developed by Business Planning. Finally, the OTP Board of Directors reviews and approves the OTP O&M budget, and the Otter Tail Corporation Board of Directors provides final review and approval.

Q. PLEASE PROVIDE AN OVERVIEW OF THE TIMELINE FOR DEVELOPMENT OF THE OTP O&M BUDGET.

A. The OTP O&M Budget is developed and refined in the first and second quarters of the year before the budget year (i.e., the first and second quarters of 2023 for the 2024 budget year).

The process begins in the first quarter with the development by the Business Planning Department of past years history, normalizing for plant outages. The functional areas review and propose modifications to the preliminary total of O&Ms in the second quarter.

For 2024, an updated O&M budget was prepared by Business Planning in June 2023. This updated O&M budget was then further reviewed by the functional areas.

The OTP CFO and President confer with the functional area Vice Presidents, and necessary modifications are made in the third quarter. After further review by the functional areas, the 2024 O&M budget is presented in the fourth quarter to the OTP Board of Directors and Otter Tail Corporation Board of Directors.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE O&M BUDGET?

A. The O&M budget includes two primary components: (1) labor and (2) non-labor costs.

Q. HOW WERE LABOR COSTS DEVELOPED FOR THE 2024 O&M BUDGET?

A. Labor costs were developed based on the number of individual employees within each department within each functional area and are then cumulated at the functional area level. The process begins with estimated full-time equivalent (FTE) employee projections provided in total to the functional areas by the Business Planning Department in the first quarter. For the 2024 O&M budget, these projections were based primarily on the recent historical employee levels.

A composite basic labor rate was determined for union and non-union employees within each functional area based on total job description salaries for each department within the functional area. A rate of increase was determined based on existing contracts and estimated cost increases, and was applied to the basic, unloaded labor costs. Overtime projections were also made and included. A labor loading rate was then applied to all basic labor costs. The labor loading rate reflects benefit costs, payroll taxes, and paid time off, which includes holidays, vacations, sick leave, and other compensated time off.

Q. PLEASE FURTHER EXPLAIN HOW THE BASIC UNLOADED LABOR RATES WERE DETERMINED.

A. The Human Resources Area works with the Vice Presidents of the other functional areas, as well as with the OTP President and CFO, to develop the estimate of the overall annual increase to non-union employee rates for the budget year. The labor rate for union employees is based on contracts between OTP and the respective unions, including any increases that will become effective in the budget year. Overall labor costs were finalized by the Human Resources Area.

Q. HOW WERE BUDGETED NON-LABOR COSTS DEVELOPED?

A. The non-labor component of the O&M budget was primarily developed by the Business Planning Department. For the 2024 O&M budget, the Business Planning Department began with averages from recent years and requested adjustments from Department Managers within the functional areas. These adjustments reflected changes that were known for the 2024 O&M budget, either increasing or reducing costs for known changes and expected major events, such as generating plant outages.

Q. IS OTP PROVIDING FURTHER INFORMATION ON THE DEVELOPMENT OF O&M COSTS?

A. Yes. Further information about the O&M budget is contained in Volume 5, Budget Documentation.

VII. RATE BASE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss the components of rate base for the 2024 Regulatory Year and the 2024 Test Year. I will also address the rate base effects of transferring recovery of certain projects from riders into base rates, as further discussed by Ms. Foster in her Direct Testimony. Finally, I identify and explain the traditional and rate case adjustments that are made to the 2024 Unadjusted Year rate base to arrive at the 2024 Test Year rate base.

Q. WHAT RATE BASE FINANCIAL SCHEDULES HAS OTP PROVIDED?

A. OTP has provided Schedules B-1 through B-5 in Volume 3, Supporting Information, under Tab II, B.

Q. WHAT TIME PERIODS ARE SHOWN ON THOSE FINANCIAL SCHEDULES?

A. The rate base schedules show information for: (1) 2022 Actual Year; (2) 2023 Current Period; and (3) 2024, including the 2024 Regulatory Year and 2024 Test Year.

Q. PLEASE BRIEFLY DESCRIBE THE RATE BASE FINANCIAL SCHEDULES INCLUDED IN VOLUME 3.

A. Schedule B-1, Rate Base Summary, summarizes the North Dakota electric utility rate base for each of the four time periods under discussion (2022 Actual Year, 2023 Current Period, the 2024 Regulatory Year, and the 2024 Test Year). Schedule B-2 shows average utility plant in service, average accumulated depreciation, and net average utility plant in service in detail by function and all remaining rate base components in total for the entire system and the North Dakota jurisdiction. Schedule B-2 provides the detail underlying the information in the summary Schedule B-1. Schedule B-3 shows the adjustments made to the 2024 Regulatory Year data to develop the 2024 Test Year. This information is shown for the 2024 Regulatory Year and 2024 Test Year. Schedule B-4 is a summary of approaches used and assumptions made in determining the average rate base for the 2024 Test Year. Schedule B-5 summarizes jurisdictional allocation factors by rate base component.

Q. WHAT IS THE SOURCE OF THE 2022 ACTUAL YEAR RATE BASE INFORMATION?

A. The 2022 Actual Year information is taken from OTP's North Dakota normalized for weather JCOSS, which is the basis for reporting the earned regulated returns included in the 2022 North Dakota Annual Report filed with the Commission.

Q. WHAT IS THE SOURCE OF THE 2023 CURRENT PERIOD RATE BASE INFORMATION?

A. The 2023 Current Period is based on actual results through July 2023 and a forecast for August through December 2023. We can make full 2023 actual results available to stakeholders upon request, once complete (typically April or May).

Q. WHAT IS THE SOURCE OF THE 2024 REGULATORY YEAR RATE BASE INFORMATION CONTAINED IN THE FINANCIAL SCHEDULES?

A. The 2024 Regulatory Year is based on prior years' data along with OTP's 2024 capital budget, and reflects traditional adjustments described in Section VII.C.1, below.

Q. WHAT IS THE AMOUNT OF THE 2024 REGULATORY YEAR RATE BASE AND 2024 TEST YEAR RATE BASE?

A. As shown in Exhibit___(CLP-1), Schedule 6 and Volume 3, Schedule B-1, the 2024 Regulatory Year North Dakota jurisdictional rate base is $651.6 million, and the 2024 Test Year rate base is $661.7 million. I will explain the differences between the 2024 Regulatory Year North Dakota jurisdictional rate base and the 2024 Test Year Rate Base in Section VII.C.2, below.

Q. PLEASE BRIEFLY DESCRIBE THE COMPONENTS OF THE RATE BASE.

A. Rate base consists primarily of the capital expenditures made by a utility to obtain or construct plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation expense and non-investor sources of capital (such as accumulated deferred income tax).

Q. HOW WERE THE 2024 REGULATORY YEAR AND 2024 TEST YEAR RATE BASE AMOUNTS DEVELOPED?

A. OTP developed its 2024 capital budget, the 2024 Regulatory Year, and the 2024 Test Year based on simple averages. OTP adjusted for known and measurable changes along with "traditional" regulatory adjustments described in Section VII.C.1 below to arrive at the 2024 Regulatory Year. These adjustments were made to reflect recognized regulatory requirements and to "normalize" the budgeted financial information for one-time events that will not be recurring on an on-going basis. Other rate case adjustments were made to develop the 2024 Test Year. I will discuss those adjustments in Section VII.C.2 of my Direct Testimony.

A. Rate Base Summary

Q. WHAT ARE THE MAJOR COMPONENTS OF THE 2024 TEST YEAR RATE BASE?

A. The 2024 Test Year rate base is generally comprised of the following major items:

- Net utility plant in service (which reflects accumulated depreciation);
- Construction work in progress (CWIP);
- Cash working capital items; and
- Accumulated deferred income taxes (ADIT).

These different components are all identified in Schedule 6 for the 2024 Regulatory Year and the 2024 Test Year.

1. Net Utility Plant in Service

Q. WHAT DOES SCHEDULE 6 INCLUDE REGARDING UTILITY PLANT IN SERVICE?

A. Schedule 6 shows utility plant in service (by total and component), which is before depreciation, accumulated depreciation (by total and component), and net utility plant in service (by total and component). These are shown for the 2024 Regulatory Year and the 2024 Test Year. Schedule 6 shows OTP's North Dakota jurisdictional net utility plant in service is $788.1 million for the 2024 Regulatory Year and $798.1 million for the 2024 Test Year.

Q. WHAT DOES "UTILITY PLANT IN SERVICE" REPRESENT?

A. Utility plant in service is based upon the original cost of property from the books and records of OTP, adjusted to account for the projected additions and/or retirements identified in the above described capital budgeting process.

Q. WHAT DOES "NET UTILITY PLANT" REPRESENT?

A. Net utility plant represents OTP's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost, reflecting a simple average based on monthly balances from December 2023 through December 2024.

Q. DOES SCHEDULE 6 INCLUDE ALL COMPONENTS OF NET UTILITY PLANT?

A. Yes. Schedule 6 includes all components of utility plant in service (production, transmission, distribution, general, and intangible) and the accumulated depreciation related to each of these components. The net of utility plant in service and accumulated depreciation is the net utility plant in service. Schedule 6 shows these amounts and adjustments, and the amounts and adjustments that are allocated to the North Dakota jurisdiction.

Q. DOES SCHEDULE 6 INCLUDE THE RATE BASE COMPONENTS DISCUSSED BY OTP WITNESSES?

A. Yes. Schedule 6 includes all the rate base components discussed by the other OTP witnesses, including the investments currently recovered in riders that are being rolled into base rates discussed in the Direct Testimony of Ms. Foster. I discuss the process of including the investments currently recovered in riders in Section VII.B., below.

Q. PLEASE BRIEFLY DESCRIBE ACCUMULATED DEPRECIATION SHOWN IN SCHEDULE 6.

A. Schedule 6 includes accumulated depreciation for all the utility plant in service components. The sum of the 2024 Regulatory Year North Dakota jurisdiction accumulated depreciation for these components is negative ($461.1 million) and negative ($461.2 million) for the 2024 Test Year.

2. CWIP

Q. WHAT IS THE AMOUNT OF CWIP INCLUDED IN SCHEDULE 6?

A. Schedule 6 shows that OTP's North Dakota jurisdictional CWIP is $780,990 for the 2024 Regulatory Year and for the 2024 Test Year.

Q. PLEASE EXPLAIN CWIP SHOWN IN SCHEDULE 6.

A. CWIP consists of two parts: (1) short-term and (2) long-term. Short-term CWIP applies to small rebuilds, increasing capacity of lines, upgrading lines, and similar types of activity which benefit existing customers. These are construction projects which cost less than $10,000 and require less than 30 days to complete. The Commission has ruled in our previous rate cases that short-term CWIP could be included in rate base. Long-term CWIP is all CWIP that is not defined as short-term CWIP. Long-term CWIP has not been included in rate base.

Q. HAS OTP REMOVED ANY REIMBURSABLE AMOUNTS FROM ITS CWIP BALANCE?

A. Yes, the CWIP balance (and thus rate base) does not include amounts that are reimbursable by government entities, as occurs in limited cases where lines must be moved because of highway work, or by customers (contribution in aid of construction).

3. Working Capital

Q. PLEASE EXPLAIN THE WORKING CAPITAL INCLUDED IN SCHEDULE 6.

A. Schedule 6 shows the North Dakota 2024 Regulatory Year and 2024 Test Year jurisdictional amounts for all working capital elements, including materials and supplies, fuel stocks, prepayments and customer advances/deposits and cash working capital.

Q. PLEASE EXPLAIN MATERIALS AND SUPPLIES INCLUDED IN SCHEDULE 6.

A. Schedule 6 shows OTP's North Dakota jurisdictional materials and supplies for the 2024 Regulatory Year and 2024 Test Year is $14.7 million. OTP's accounting records provide the materials and supplies inventory at the generating plants, central stores, and at various locations throughout OTP's service territory. The dollar amount used to calculate revenue requirements is based on a simple average.

Q. PLEASE EXPLAIN FUEL STOCKS INCLUDED IN SCHEDULE 6.

A. Schedule 6 shows OTP's North Dakota jurisdictional fuel stocks for the 2024 Regulatory Year and 2024 Test Year is $4.5 million. Fuel stocks is based on the simple average of inventory balances for fuel stocks. Fuel stocks include coal stockpiles and fuel oil for OTP's generating plants.

Q. PLEASE DESCRIBE THE PREPAYMENTS INCLUDED IN SCHEDULE 6.

A. Schedule 6 shows OTP's North Dakota jurisdictional prepayments for the 2024 Regulatory Year and 2024 Test Year are $18.6 million. Four separate items are grouped together under the line item of prepayments. The four items are: (1) pre-paid insurance; (2) pre-paid pension; (3) post-retirement benefits liability; and (4) post-employment benefits liability. The amounts for each item are developed using simple averages.

Q. PLEASE DESCRIBE CASH WORKING CAPITAL INCLUDED IN SCHEDULE 6.

A. Schedule 6 shows OTP's North Dakota jurisdictional cash working capital for the 2024 Regulatory Year is $1.3 million and 2024 Test Year is $1.5 million. Cash working capital represents a determination of cash working capital requirements for operation, maintenance, and other expenses.

Q. HOW WERE CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. The cash working capital requirements included in rate base is based on a Lead Lag Study prepared by OTP using calendar year 2020 financial data. This study analyzes the lapse of time between the average day on which OTP incurs expenses to serve its customers and the average day on which cash is received from customers in payment of that service. OTP witness Mr. Christopher E. Byrnes explains the Lead Lag Study in his Direct Testimony.

4. ADIT

Q. WHAT IS THE AMOUNT OF ADIT INCLUDED IN SCHEDULE 6?

A. Schedule 6 shows OTP's North Dakota jurisdictional ADIT for the 2024 Regulatory Year is ($175.7 million) and ($175.8 million) for the 2024 Test Year. These amounts reflect a simple average of the beginning and end of year balances, without proration, as discussed by Ms. Stalboerger in her Direct Testimony.

B. Rider Roll-In

Q. IS OTP PROPOSING TO MOVE ANY PROJECTS FROM RIDER RECOVERY TO BASE RATE RECOVERY IN THIS FILING?

A. Yes. Ms. Foster explains that OTP proposes to transfer recovery of certain costs presently recovered in the Renewable Resource Adjustment Rider (RRAR), Transmission Cost Recovery Rider (TCRR), Metering & Distribution Technology Cost Recovery Rider (MDT), and Generation Cost Recovery Rider (GCR) to base rates.

Q. WHAT IS THE AMOUNT OF THE 2024 TEST YEAR RATE BASE ATTRIBUTABLE TO THE PROJECTS MOVING FROM THE RRAR INTO BASE RATES?

A. The 2024 Test Year rate base for the projects currently recovered in the RRAR that are moving to base rate recovery (collectively, the RRAR Projects) is $229.7 million (OTP Total), and $86.3 million (OTP ND).

Q. WHAT IS THE 2024 TEST YEAR RATE BASE ATTRIBUTABLE TO PROJECTS MOVING FROM THE TCRR INTO BASE RATES?

A. The 2024 Test Year rate base for the projects currently recovered in the TCRR that are moving to base rate recovery (collectively, the TCRR Projects) is $172.2 million (OTP Total) and $68.2 million (OTP ND).

Q. WHAT IS THE 2024 TEST YEAR RATE BASE ATTRIBUTABLE TO PROJECTS MOVING FROM THE MDT RIDER INTO BASE RATES?

A. The 2024 Test Year rate base for the projects currently recovered in the MDT rider that are moving to base rate recovery (collectively, the MDT Projects) is $3.55 million (OTP Total) and $1.46 million (OTP ND).

Q. WHAT IS THE 2024 TEST YEAR RATE BASE ATTRIBUTABLE TO PROJECTS MOVING FROM THE GCR RIDER INTO BASE RATES?

A. The 2024 Test Year rate base for the projects currently recovered in the GCR rider that are moving to base rate recovery (collectively, the GCR Projects) is $1,132.9 million (OTP Total) and $529.2 million (OTP ND).

C. Rate Base Adjustments

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will identify and explain the traditional and rate case adjustments that are made to the 2024 Unadjusted Year rate base to arrive at the 2024 Test Year rate base.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN REQUIRED ADJUSTMENTS AND RATE CASE ADJUSTMENTS.

A. As discussed above, OTP's capital and O&M budgets provide the basis for the 2024 Test Year. Those budgets, however, do not necessarily reflect certain ratemaking conventions used when establishing retail rates. As a result, OTP prepares "traditional" adjustments that reflect recognized regulatory requirements and to "normalize" the budgeted financial information for one-time events that will not be recurring on an on-going basis in order to arrive at the Regulatory Year data. "Rate case adjustments" reflect specific ratemaking proposals being made in this case.

Q. HAVE YOU PREPARED BRIDGE SCHEDULES SHOWING ALL ADJUSTMENTS YOU MADE TO ARRIVE AT THE 2024 TEST YEAR RATE BASE?

A. Yes. Exhibit___(CLP-1), Schedule 7 is a bridge schedule that identifies the traditional adjustments made to the 2024 Unadjusted Year to arrive at the 2024 Regulatory Year. Exhibit___(CLP-1), Schedule 8 identifies rate case adjustments made to the 2024 Regulatory Year in developing the 2024 Test Year.

Q. HOW IS THE INFORMATION IN SCHEDULEs 7 and 8 AND IN THIS SECTION OF YOUR DIRECT TESTIMONY PRESENTED?

A. All the information in Schedules 7 and 8 and in this section of my Direct Testimony is presented in terms of North Dakota jurisdictional amounts.

Q. WHAT ARE THE ADJUSTMENTS TO RATE BASE MADE FOR THE 2024 TEST YEAR?

A. The following is a list of the traditional adjustments (necessary to arrive at the 2024 Regulatory Year) and rate case adjustments (necessary to arrive at the 2024 Test Year):

Traditional Adjustments to Rate Base

- Generator Interconnection Procedures (GIPs) Projects
- Hoot Lake Solar
- Transmission Recovery
- Electric Vehicles

Test Year Adjustments to Rate Base

- Normalize Langdon Upgrade Project

1. Traditional Rate Base Adjustments

a) GIPs Projects

Q. HAVE YOU MADE AN ADJUSTMENT REGARDING GIPS PROJECTS?

A. Yes. Ms. Stalboerger explains there are too many uncertainties regarding the ultimate ratemaking treatment for these projects before FERC to include the projects in the 2024 Test Year. As a result, OTP has removed the GIPs investments from the 2024 Test Year. This adjustment: (1) decreases total plant in service by $19,287,409; (2) decreases accumulated depreciation by $1,221,465; (3) decreases accumulated deferred income taxes by $1,425,013; and (4) decreases total average rate base by $16,649,931, all as shown on Schedule 7.

b) Hoot Lake Solar

Q. HAVE YOU MADE AN ADJUSTMENT TO REMOVE THE HOOT LAKE SOLAR PROJECT FROM THE 2024 TEST YEAR?

A. Yes. Mr. Byrnes explains the basis for this adjustment in his Direct Testimony. This adjustment: (1) decreases total plant in service by $26,462,276; (2) decreases accumulated depreciation by $568,838; (3) decreases accumulated deferred income taxes by $2,633,993; and (4) decreases total average rate base by $23,259,445, all as shown on Schedule 7.

c) Transmission Recovery

Q. PLEASE SUMMARIZE THE ADJUSTMENT FOR TRANSMISSION RECOVERY.

A. The non-retail portion of OTP's investments in the multi-value project (MVP) transmission are removed from the 2024 Test Year. This adjustment: (1) decreases total plant in service by $88,138,714; (2) decreases accumulated depreciation by $8,657,099; (3) decreases accumulated deferred income taxes by $7,549,696; and (4) decreases total average rate base by $71,931,919, all as shown on Schedule 7.

d) Electric Vehicles

Q. HAVE YOU MADE AN ADJUSTMENT REGARDING ELECTRIC VEHICLE COSTS?

A. Yes. On October 27, 2020, the Minnesota Public Utilities Commission approved OTP's plan to construct 11 electric vehicle (EV) fast-charging stations in its Minnesota service territory.[7] OTP expects to complete construction at six of these charging sites, with full operation, in the fall of 2023. The remaining five sites are scheduled for completion in 2024. OTP has directly assigned the costs of the Minnesota electric vehicle charging infrastructure to the Minnesota retail jurisdiction, therefore excluding those costs from the 2024 Test Year revenue requirement. This adjustment: (1) decreases total plant in service by $846,512; (2) decreases accumulated depreciation by $42,659; and (3) decreases total average rate base by $803,853, all as shown on Schedule 7.

2. Test Year Rate Base Adjustments

a) Normalize Langdon Upgrade Project

Q. DID YOU NORMALIZE 2024 TEST YEAR PLANT IN SERVICE FOR THE LANGDON UPGRADE PROJECT?

A. Yes. Schedule 8 shows the adjustment to plant in service for the Langdon Upgrade Project that will go into service during the 2024 Test Year. The adjustment: (1) removes the project and any 2024 AFUDC from CWIP; (2) annualizes the project in plant in service; and (3) includes any accumulated depreciation and the

---

[7] *Order Approving Pilot Program, Granting Deferred Accounting, and Setting Additional Requirements*, MN PUC Docket No. E017/M-20-181 (Oct. 27, 2020).

associated depreciation expense for this project. Ms. Foster explains the basis for this adjustment in her Direct Testimony.

Q. PLEASE SUMMARIZE THE EFFECT OF THE LANGDON UPGRADE PROJECT NORMALIZATION ADJUSTMENT ON 2024 TEST YEAR RATE BASE.

A. The adjustment: (1) increases plant in service by $10,079,520; (2) increases accumulated depreciation by $155,713; and (3) increases total average rate base by $9,923,807. The corresponding impacts on the 2024 Test Year income statement are explained in Section VIII.B.2, below.

3. Effect of Adjustments on Allocations

Q. DO THE 2024 TRADITIONAL AND TEST YEAR RATE BASE ADJUSTMENTS CAUSE IMPACTS TO ALLOCATIONS?

A. Yes. The impacts are due to changes in the allocators that result from the other financial adjustments made to the 2024 Test Year. They are the result of calculations within the cost of service model itself. For example, any adjustment to net plant in service will have a direct impact on the net electric plant in service (NEPIS) allocation factor calculated as a percentage of total system net plant. The allocation percentage is simultaneously recalculated each time an adjustment to net plant in service occurs, thereby providing the most up-to-date factor possible. As a result, anything that is allocated on NEPIS is simultaneously re-calculated on a jurisdictional basis as well. The overall effect of traditional adjustments on allocators is identified on page 1, of Schedule 7, in Column G, while the overall effect of rate case adjustments on allocators is identified on page 1 of Schedule 8, in Column D.

VIII. INCOME STATEMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss the income statement and explain the income statement schedules for the 2024 Regulatory Year and the 2024 Test Year.

Q. WHAT INCOME STATEMENT FINANCIAL SCHEDULES HAS OTP PROVIDED?

A. OTP has provided Income Statement Schedules C-1 through C-9 in Volume 3, Supporting Information.

Q. WHAT TIME PERIODS ARE SHOWN ON THESE SCHEDULES?

A. Those Income Statement schedules show information for: (1) 2022 Actual Year; (2) 2023 Current Period; and (3) 2024, including the 2024 Regulatory Year and the 2024 Test Year.

Q. WHAT IS THE SOURCE OF THE 2022 ACTUAL YEAR INCOME STATEMENT INFORMATION?

A. The source of the 2022 Actual Year Income Statement information is OTP's North Dakota JCOSS, which is the basis for reporting the earned ROR and ROE included in the 2022 North Dakota Jurisdictional Report filed with the Commission. The sources of the 2022 Actual Year information for the income statement are the same as for the rate base.

Q. WHAT IS THE SOURCE OF THE 2023 CURRENT PERIOD INCOME STATEMENT INFORMATION?

A. The 2023 Current Period is based on actual results through July 2023 and a forecast for August through December 2023. We can make full 2023 actual results available to stakeholders upon request.[8] The sources of the 2023 Current Period information for the income statement is the also the same as for the rate base.

Q. WHAT IS THE SOURCE OF THE 2024 REGULATORY YEAR INCOME STATEMENT INFORMATION?

A. The sources of the 2024 Regulatory Year information for the income statement are the same as for the rate base. The 2024 Regulatory Year is based on OTP's 2024 budget and reflects traditional adjustments described in Section VIII.B.1, below.

A. Income Statement Summary

Q. WHAT ARE THE 2024 REGULATORY YEAR AND 2024 TEST YEAR TOTALS AVAILABLE FOR RETURN?

A. As shown in Exhibit___(CLP-1), Schedule 9, the 2024 Regulatory Year total available for return (which is net income) is $42.6 million and the 2024 Test Year total available for return is $21.2 million.

[8] Actual results are typically available in April or May.

Q. PLEASE BRIEFLY DESCRIBE WHAT IS INCLUDED IN THE INCOME STATEMENT.

A. The income statement is composed primarily of: (1) operating revenues (which includes both retail revenues and other operating revenues); (2) operating expenses (which includes O&M expenses for the various operating segments, administrative and general expenses, depreciation expense, and general taxes, including property taxes); (3) income tax expense; and (4) total available for return (which is net income).

Q. HOW WAS THE 2024 REGULATORY YEAR INCOME STATEMENT DEVELOPED?

A. The 2024 Regulatory Year income statement was developed using the 2024 budget for revenues and operation and maintenance expense, adjusted to remove the revenues and expenses that are part of traditional regulatory adjustments. As discussed above, these adjustments were made to reflect recognized regulatory requirements and to normalize the budgeted financial information for one-time events that will not be recurring on an on-going basis. Other rate case adjustments were made to develop the 2024 Test Year. Both traditional and rate case adjustments to the income statement are discussed in Section VIII.B, below.

Q. WHAT ARE THE MAJOR COMPONENTS OF THE INCOME STATEMENT THAT YOU WILL DISCUSS?

A. The major components of the income statement I will discuss are:

- Revenues;
- O&M Expense;
- Depreciation Expense;
- Taxes; and
- Net Income.

1. Test Year Revenues

Q. WHAT ARE THE COMPONENTS OF TEST YEAR REVENUES?

A. There are two components of test year revenues: (1) retail revenues and (2) other revenues. Below, I describe the determination of both for purposes of calculating the 2024 Test Year base rate revenue deficiency.

a) Retail Revenues

Q. WHAT IS THE AMOUNT OF RETAIL REVENUE INCLUDED IN SCHEDULE 9?

A. Schedule 9 shows that OTP's North Dakota jurisdictional retail revenue is $206.0 million for the 2024 Regulatory Year and $182.7 for the 2024 Test Year.

Q. HOW WAS RETAIL REVENUE DETERMINED?

A. Retail revenue in the 2024 budget and Test Year was determined on a calendar month basis using the projected sales forecast (as described in the Direct Testimony of OTP witness Ms. Tammy K. Mortenson) applied to current tariffs. Ms. Mortenson explains how sales (in kilowatt hours) in this forecast were developed.

b) Other Electric Operating Revenue

Q. WHAT IS THE AMOUNT OF OTHER ELECTRIC OPERATING REVENUE INCLUDED IN SCHEDULE 9?

A. Schedule 9 shows that OTP's North Dakota jurisdictional other electric operating revenue is $13.0 million for the 2024 Regulatory Year and the 2024 Test Year.

Q. WHAT ARE THE COMPONENTS OF OTHER ELECTRIC OPERATING REVENUE?

A. Other electric operating revenue includes items such as: (1) Midcontinent Independent System Operator (MISO) transmission-related revenues not included in the TCRR; (2) revenue from Integrated Transmission Agreements (ITAs); (3) revenues from plant operations and steam sales; and (4) other miscellaneous revenues.

Q. ARE MISO REVENUES INCLUDED IN THE 2024 TEST YEAR?

A. Yes. Pursuant to MISO's Transmission and Energy Market Tariff and the MISO Transmission Owners Agreement, OTP receives revenues from several sources for use of its transmission system and related services that it provides. These sources of revenue include, but are not limited to, the following: Schedule 1 - Scheduling, System Control & Dispatch; Schedule 2 - Reactive Supply & Voltage Control; Schedule 7 - Firm Transmission Service; Schedule 8 - Non-Firm Transmission Service; Schedule 9 - Network Integrated Transmission Service; and Schedule 24 – Market Settlements. Net revenues included in the 2024 Test Year for the MISO schedules noted above are $4.7 million.

Q. DOES OTP RECEIVE REVENUES FOR SCHEDULING AND DISPATCH SERVICES?

A. Yes. OTP has agreements with transmission-owning, load-serving entities in its control area for which OTP provides scheduling and dispatch services. These agreements are distinct from the MISO tariff schedule revenue. These scheduling and dispatch services include: (1) transmission line switching; (2) emergency line operations; (3) scheduling or outages; and (4) various related transmission scheduling and transmission dispatch services. There are $978,910 of revenue for these services in the 2024 Test Year.

Q. WHAT IS AN ITA?

A. An ITA is an agreement to jointly plan and construct a common transmission system with discrete ownership of individual facilities with reciprocal usage rights granted to each party. OTP has one remaining ITA with Minnkota Power Cooperative (Minnkota). The Minnkota ITA has been approved by FERC.

Q. HOW IS OTP COMPENSATED FOR SERVICES PROVIDED UNDER THE MINNKOTA ITA?

A. OTP charges for scheduling and dispatch services based on OTP's costs associated with system control and dispatching, including operating, maintenance, and fixed costs. Minnkota pays its pro rata share of the system control and dispatching, operating, and maintenance expenses based on the respective joint use facilities owned by Minnkota and OTP.

Q. IS REVENUE FROM THE MINNKOTA ITA INCLUDED IN THE 2024 TEST YEAR?

A. Yes. Minnkota ITA revenue of $848,757 is included in the 2024 Test Year.

Q. DOES OTP RECEIVE COMPENSATION AS THE PLANT OPERATOR FOR THE TWO JOINTLY OWNED GENERATING UNITS, BIG STONE AND COYOTE?

A. Yes. OTP operates the Big Stone Plant and Coyote Station on behalf of itself and its ownership partners (Minnkota, Northwestern, and Montana-Dakota Utilities for Big Stone and Minnkota, Northwestern, Montana-Dakota Utilities, and Northwestern Municipal Power Agency for Coyote Station). As the plant operator, OTP provides services for which it is compensated by its partners. The services include: scheduling and operations of the plants for both the day-ahead and real-time market; acting as the meter data management agent for all partners of the plants; settlement reconciliation of unit dispatches and actual generation; providing accounting reports and records to the partners; scheduling generator outages; communicating directly with the MISO generator dispatch desk; and providing and maintaining reliable communications between MISO, the plants, and the OTP control center.

Q. IS PLANT OPERATION REVENUE INCLUDED IN THE 2024 TEST YEAR?

A. Yes. Plant operation revenue in the amount of $134,853 is included in the 2024 Test Year.

Q. DOES OTP RECEIVE REVENUE FROM THE SALE OF STEAM?

A. Yes. OTP supplies steam to the POET ethanol plant that is located near the Big Stone Plant.

Q. IS REVENUE FROM STEAM SALES INCLUDED IN THE 2024 TEST YEAR?

A. Yes. POET steam sales revenue is included in the 2024 Test Year. Mr. Byrnes discusses OTP's proposal for treatment of POET steam sales revenue going forward.

Q. ARE ALL OTHER SOURCES OF OTHER ELECTRIC OPERATING REVENUES ALSO INCLUDED IN THE 2024 TEST YEAR?

A. Yes. While I will not address all the other sources of other electric operating revenues, they are included in the 2024 Test Year.

2. O&M Expenses

a) Schedule of O&M Expenses

Q. HAVE YOU PREPARED A SCHEDULE OF 2024 TEST YEAR O&M EXPENSES?

A. Yes. Exhibit___(CLP-1), Schedule 10, the schedule of O&M expenses, includes all O&M expenses included in the 2024 Test Year, whether they are specifically discussed by me or by other OTP witnesses.

Q. DO THE 2024 TEST YEAR O&M EXPENSES INCLUDE ALLOCATIONS OF COSTS FROM OTTER TAIL CORPORATION?

A. Yes. Like compensation and employee benefits expenses (discussed below), Otter Tail Corporation costs allocated to OTP are reflected in several categories of O&M

expenses. Mr. Byrnes describes how Otter Tail Corporation costs allocated to OTP have been reflected in the 2024 Test Year in his Direct Testimony.

Q. WHAT IS THE AMOUNT OF PRODUCTION EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional production expense is $86.7 million for the 2024 Regulatory Year and $87.1 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN PRODUCTION EXPENSE?

A. The most significant production expenses are fuel and purchased power. Production expense also includes maintenance costs of OTP's generation plants.

Q. WHAT IS THE AMOUNT OF TRANSMISSION EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional transmission expense is $13.8 million for the 2024 Regulatory Year and $14.1 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN TRANSMISSION EXPENSE?

A. Transmission Expense includes such things as load dispatching, substation expense, transmission line and substation maintenance, the transmission of electricity by others, rents for transmission property, engineering, computer hardware and software for the operation of the transmission system, and transmission market costs.

Q. WHAT IS THE AMOUNT OF DISTRIBUTION EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional distribution expense is $8.0 million for the 2024 Regulatory Year and $8.4 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN DISTRIBUTION EXPENSE?

A. Distribution expense includes expenses for operation and maintenance of the distribution system, including substations, wires, transformers, meters, and lighting.

Q. WHAT IS THE AMOUNT OF CUSTOMER ACCOUNTING EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional customer accounting expense is $7.0 million for the 2024 Regulatory Year and $7.3 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN CUSTOMER ACCOUNTING EXPENSE?

A. Customer accounting expense includes meter reading, billing, and maintenance of customer records (customer information systems).

Q. WHAT IS THE AMOUNT OF CUSTOMER SERVICE AND INFORMATION EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional customer service and information expense is $1.3 million for the 2024 Regulatory Year and $1.3 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN CUSTOMER SERVICE AND INFORMATION EXPENSE?

A. Customer service and information expense includes customer assistance expenses.

Q. WHAT IS THE AMOUNT OF SALES EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional sales expense is $0.1 million for the 2024 Regulatory Year and $0.1 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN SALES EXPENSE?

A. Sales expense includes selling and advertising expenses as well as economic development costs.

Q. WHAT IS THE AMOUNT OF ADMINISTRATIVE AND GENERAL EXPENSE INCLUDED IN SCHEDULE 10?

A. Schedule 10 shows that OTP's 2024 North Dakota jurisdictional administrative and general expense is $17.5 million for the 2024 Regulatory Year and $20.8 million for the 2024 Test Year.

Q. WHAT IS INCLUDED IN ADMINISTRATIVE AND GENERAL EXPENSE?

A. Administrative and general expense includes certain salaries and benefits related to administration; office supplies & expenses; various admin & general expenses; outside services employed; property insurance, injuries & damage; employee benefits; regulatory commission expenses; miscellaneous general expenses; informational advertising; rents; and building maintenance expenses.

b) Employee Compensation and Benefits Costs

Q. ARE EMPLOYEE COMPENSATION EXPENSES REFLECTED IN THE VARIOUS CATEGORIES IDENTIFIED IN SCHEDULE 10?

A. Yes. Salaries, wages, annual incentive compensation, and benefits costs (including employee medical/dental benefits, retirement benefits, including a defined benefit pension plan, defined contribution 401(k) plans, and other post-retirement employee benefits expenses) are reflected throughout the O&M expense categories such as production expense, transmission expense, distribution expense, and others, based on the employees providing services in those expense categories.

Q. WHAT IS THE 2024 BUDGETED AMOUNT FOR EMPLOYEE SALARIES, WAGES AND ANNUAL INCENTIVE COMPENSATION?

A. The 2024 budgeted, non-capitalized portion of employee salaries and wages, including annual incentive compensation, is $55.0 million (OTP Total) / $24.0 million (OTP ND EST.). OTP witness Mr. Peter E. Wasberg discusses the purposes, design, and reasonableness of OTP's employee compensation programs in his Direct Testimony.

Q. DOES THE 2024 TEST YEAR INCLUDE THE FULL COST OF EMPLOYEE SALARIES, WAGES AND ANNUAL INCENTIVE COMPENSATION?

A. No. Mr. Wasberg explains in his Direct Testimony that OTP is proposing to limit annual incentive compensation for each individual covered by the Management Incentive Plan and the Executive Plan to 25 percent of that individual's wages. The impact of this adjustment is discussed below in Section VIII.B. The 2024 Test Year, non-capitalized portion of employee salaries and wages, including annual incentive compensation and after all adjustments, is $54.2.0 million (OTP Total) / $23.6 million (OTP ND EST.).

Q. WHAT IS THE 2024 BUDGETED PENSION EXPENSE?

A. The 2024 budgeted, non-capitalized pension expense is ($3.4) million (OTP Total) / ($1.5) million (OTP ND EST).[9]

Q. WHAT IS THE BASIS FOR OTP'S 2024 BUDGETED PENSION EXPENSE?

A. The costs for OTP's pension plan are determined in accordance with ASC 715 (formerly FAS 87). Mercer, which provides actuarial services to OTP and Otter Tail Corporation, has provided an estimate of Otter Tail Corporation's pension plan costs for the 2024-2028 period, a copy of which is provided as Exhibit___(CLP-1), Schedule 13 (Mercer Five Year Pension Estimate). Mercer's estimated 2024 pension expense is the basis for the 2024 budgeted pension expense.[10]

Q. PLEASE PROVIDE AN OVERVIEW OF ASC 715.

A. ASC 715 is an accounting standard that governs employers' accounting for pensions and postretirement medical and life insurance (PRM) plans.[11] Under ASC 715, annual pension cost is made up of several components, including:

(1) The present value of pension benefits that employees will earn during the current year (Annual Service Cost), with the present value being established using the discount rate;

(2) Increases in the present value of the pension obligation that plan participants have earned in previous years (Interest Cost), which is based on the discount rate;

(3) Expected earnings on the pension plan assets during the year (Expected Return on Assets or EROA);

(4) Costs (or income) that differ from assumptions (Amortization of Unrecognized Gains and Losses); and

(5) Cost of changes in benefits (Amortization of Unrecognized Prior Service Cost).[12]

---

[9] All of the references to pension expenses included in this subsection of my Direct Testimony are for O&M expenses only and do not include capitalized pension expense.

[10] Mercer will prepare a report based on December 31, 2023 data that will establish the actual 2024 ASC 715 and ASC 712 expense. OTP will receive Mercer's final 2024 ASC 715 and 712 expense report in the first quarter of 2024. OTP can provide the final 2024 ASC 715 and 712 expense report to stakeholders upon request once available.

[11] Pension plan costs formerly were accounted for under FAS 87, while PRM costs were subject to FAS 106. A third category of costs, Postemployment (LTD) Medical Benefit Plan costs, are now subject to ASC 712 and formerly were subject to FAS 112.

[12] The EROA component is not used for calculation of PRM plan expense.

Q. HOW IS ANNUAL SERVICE COST CALCULATED?

A. The annual service cost is the actuarial present value of the projected retirement benefits earned by plan participants in the current period. Actuarial factors are used to reflect the time value of money (the discount rate) and the probability of payment (mortality, turnover, early retirement). The discount rate reflects interest rates on fixed income debt securities that have a rating of AA published by recognized rating agencies, as well as Mercer's proprietary bond model, which determines a set of high-quality bonds that produce cash flows similar to the expected benefit payments and then solves for the average yield of those bonds.

Q. HOW IS INTEREST COST CALCULATED?

A. The interest cost is determined as the increase in the plan's total pension benefit obligation resulting from the fact that anticipated pension benefit payments are one year closer to being paid from the pension plan.

Q. HOW IS EROA DETERMINED?

A. The EROA is determined based on the expected long-term rate of return on the market value of pension plan assets. The product of the EROA multiplied by the amount of assets in the pension trust provides an offset to the service costs and interest costs, and therefore it reduces the pension expense.

Q. HOW IS AMORTIZATION OF UNRECOGNIZED GAINS AND LOSSES CALCULATED?

A. The Amortization of Unrecognized Gains and Losses calculation considers all gains and losses, with gains and losses calculated as the difference between actual results and assumptions. Asset gains and losses are the differences between the actual return on assets during the period and the expected return on assets for that period. Liability gains and losses are the differences between the actual liability at the end of a measurement period and the expected liability at the end of a measurement period. Gains and losses are not included in the period in which the gain or loss occurs, but rather in subsequent periods. Further, the Amortization of Unrecognized Gains and Losses must be included in the calculation of annual cost in a year if, as of the beginning of the year, the unrecognized net gain or loss exceeds a corridor of 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets.

Q. PLEASE EXPLAIN AMORTIZATION OF UNRECOGNIZED PRIOR SERVICE COST CREDITS.

A. The Amortization of Unrecognized Prior Service Cost captures the effect of plan changes on services rendered in prior periods. The effects of those changes are amortized over a period of years.

Q. HAVE THE PENSION DISCOUNT RATE AND EROA ASSUMPTIONS CHANGED SINCE OTP'S LAST NORTH DAKOTA RATE CASE?

A. Yes. The table below compares the discount rate used in OTP's last North Dakota rate case to those incorporated in the Mercer Five Year Pension Estimate. The discount rate is significantly higher than the amount supporting pension expense in OTP's last North Dakota rate case.

Table 1
OTP Pension Expense Factors Assumptions

Pension Expense Factor	**PU-17-398**	**Mercer 2024 Estimate Values**
Discount Rate	3.90%	5.30%
EROA	7.50%	7.00%

Q. WHAT IS THE EFFECT OF THE HIGHER DISCOUNT RATE?

A. All else equal, an increase in the discount rate reduces pension expense.

Q. WHAT IS THE EFFECT OF THE LOWER EROA?

A. All else equal, a decrease in EROA increases pension expense.

Q. IS OTP RECOMMENDING THAT THE 2024 TEST YEAR REVENUE REQUIREMENT REFLECT THE ACTUARIAL ESTIMATE OF 2024 PENSION EXPENSE?

A. No. OTP witness Mr. Bruce G. Gerhardson explains in his Direct Testimony that OTP is requesting that the 2024 Test Year revenue requirement reflect a normalized pension expense based on an average of Mercer's actuarial estimated expense for 2024-2028. The financial impact of this recommendation is addressed in Section VIII.B.2, below. Ultimately, the 2024 Test Year, non-capitalized pension expense (reflecting the adjustment discussed below) is $873,842 (OTP Total)/ $344,674 (OTP ND EST.).

Q. WHAT IS THE 2024 TEST YEAR EXPENSE FOR EMPLOYEE GROUP INSURANCE BENEFITS?

A. The 2024 Test Year O&M cost for employee group insurance benefits, which includes active medical, dental, life insurance, and long-term disability (LTD), is $8.8 million (OTP Total)/ $3.8 million (OTP ND EST).

Q. HOW WERE 2024 TEST YEAR EMPLOYEE GROUP INSURANCE BENEFITS DETERMINED?

A. Mr. Wasberg's Direct Testimony explains the basis of the 2024 Test Year employee group insurance benefits expense.

Q. WHAT IS THE 2024 BUDGETED PRM AND POSTEMPLOYMENT (LTD) MEDICAL BENEFIT PLAN EXPENSES?

A. The 2024 budgeted non-capitalized cost for PRM benefits is $(3.2) million (OTP Total)/ $(1.3) million (OTP ND EST.). The 2024 non-capitalized budgeted cost for postemployment (LTD) medical benefit plan benefits is $442,219 (OTP Total)/ $193,632 (OTP ND EST.).

Q. WHAT IS THE BASIS FOR OTP'S 2024 BUDGETED PRM AND POSTEMPLOYMENT (LTD) MEDICAL BENEFIT PLAN EXPENSES?

A. Similar to OTP's pension plan, PRM and postemployment (LTD) medical benefit expenses are calculated based on demographics and standard actuarial assumptions. The 2024 budgeted PRM and postemployment (LTD) medical benefit expenses are based on the 2024 expense included in Mercer's Five Year Pension Estimate. Due to plan changes that occurred in 2023, Mercer subsequently revised its PRM estimate. The revised five-year PRM estimate is provided as Exhibit___(CLP-1), Schedule 14 (Mercer Five Year PRM Estimate).

Q. IS OTP RECOMMENDING THAT THE 2024 TEST YEAR REVENUE REQUIREMENT REFLECT THE ACTUARIAL ESTIMATE OF 2024 PRM EXPENSE?

A. No. Similar to pension expense, Mr. Gerhardson explains that OTP requests that the 2024 Test Year revenue requirement reflect a normalized level of PRM expense based on an average of Mercer's actuarial estimated expense for 2024-2028. The financial impact of this recommendation is addressed in Section VIII.B.2, below. Ultimately, the 2024 Test Year, non-capitalized PRM expense (reflecting the adjustment discussed below) is $(1.6) million (OTP Total)/ $(684,699) (OTP ND EST.).

Q. WHAT IS THE 2024 TEST YEAR EXPENSE FOR THE OTP DEFINED CONTRIBUTION AND 401(k) MATCH?

A. The 2024 Test Year non-capitalized cost for the OTP defined contribution plan is $1.3 million (OTP Total)/ $555,767 (OTP ND EST.). The 2024 Test Year non-capitalized cost for the OTP 401(k) match is $2.8 million (OTP Total)/ $1.2 million (OTP ND EST.). Mr. Wasberg discusses the basis for these expenses in his Direct Testimony.

3. Depreciation Expense

Q. WHAT IS THE AMOUNT OF DEPRECIATION EXPENSE INCLUDED IN SCHEDULE 9?

A. Schedule 9 shows OTP's North Dakota jurisdictional depreciation expense is $32.6 million for the 2024 Regulatory Year and $33.1 million for the 2024 Test Year.

Q. HOW WERE TEST YEAR DEPRECIATION EXPENSES DETERMINED?

A. The depreciation expense in the 2024 Test Year reflects the remaining lives and salvage percentage parameters as determined in our 2023 depreciation study. These parameters are applied against the forecasted 2023 ending plant in service and accumulated depreciation balances to determine forecasted depreciation rates for the 2024 Test Year. These forecasted depreciation rates are applied against the 2024 Test Year plant in service balances to yield our 2024 Test Year depreciation expense.

4. Income Taxes

Q. WHAT IS THE AMOUNT OF INCOME TAX EXPENSE INCLUDED IN SCHEDULE 9?

A. Schedule 9 shows OTP's North Dakota jurisdictional income tax expense is $0 million for the 2024 Regulatory Year and $0 million for the 2024 Test Year due to net operating losses in the current year.

Q. HOW WERE OTP'S INCOME TAX EXPENSES CALCULATED?

A. OTP's Federal and North Dakota income tax expenses are based solely on the regulated income and expense items included in the revenue requirement calculation using the "stand-alone" method. The stand-alone method determines the jurisdictional regulated income tax expense based solely on allowable regulated income and expense items. The current income tax expense calculation utilizes straight-line depreciation rates to determine depreciation expense as part of the current income tax expense calculation, while modified accelerated income tax depreciation (MACRS) rates and a special bonus depreciation provision were used to determine deferred income taxes (which are treated as a reduction to Rate Base).

B. Income Statement Adjustments

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I will identify and explain the traditional and rate case adjustments that are made to the 2024 Unadjusted Year income statement to arrive at the 2024 Test Year income statement.

Q. HAVE YOU PREPARED BRIDGE SCHEDULES SHOWING ALL ADJUSTMENTS YOU MADE TO ARRIVE AT THE 2024 TEST YEAR INCOME STATEMENT?

A. Yes. Exhibit___(CLP-1), Schedule 11 (which is also included in Volume 3, as Schedule C-7), is a bridge schedule that identifies the traditional adjustments made to the 2024 Unadjusted Year to arrive at the 2024 Regulatory Year, and Exhibit___(CLP-1), Schedule 12 (which is also included in Volume 3, as Schedule C-7) identifies rate case adjustments made to the 2024 Regulatory Year in developing the 2024 Test Year. Schedules 11 and 12 also identify the impact each adjustment has on the income statement.

Q. HOW IS THE INFORMATION IN SCHEDULES 11 AND 12 AND IN THIS SECTION OF YOUR DIRECT TESTIMONY PRESENTED?

A. All the information in Schedules 11 and 12 and in this section of my Direct Testimony is presented in terms of North Dakota jurisdictional amounts.

Q. WHAT ARE THE ADJUSTMENTS TO THE INCOME STATEMENT MADE FOR THE 2024 TEST YEAR?

A. The following is a list of the traditional adjustments (necessary to arrive at the 2024 Regulatory Year) and rate case adjustments (necessary to arrive at the 2024 Test Year):

<u>Traditional Adjustments to Income Statement</u>

- Advertising Expense

- Fuel Expense – Hoot Lake Solar
- Non-Employee Director Restricted Stock Grants
- Economic Development Costs
- Employee Recognition and Gifts
- ESSRP
- Electric Vehicles
- GIPs
- Hoot Lake Solar
- Incentive Compensation
- Investor Relations
- Long-Term Incentive
- Production Tax Credit GAAP Provision
- Rider CWIP Projects
- Transmission Recovery

Test Year Adjustments to Income Statement

- Rate Case Expense
- Normalize Langdon Upgrade Project
- Normalize Pension and PRM
- Non-Employee Director Restricted Stock
- Rider Roll-In
- ESSRP
- Employee Recognition and Gifts
- Investor Relations
- Long-Term Incentive

1. Traditional Income Statement Adjustments

a) Advertising Expense

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT FOR ADVERTISING EXPENSES?

A. Yes. The purpose of this adjustment is discussed by Mr. Byrnes. The adjustment: (1) decreases O&M expenses by $378,406; (2) increases total income taxes by

$92,350; and (3) increases net operating income by $286,056, all as shown on Schedule 11.

b) Fuel Expense - Hoot Lake Solar

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT FOR ADDITIONAL FUEL EXPENSE ASSOCIATED WITH HOOT LAKE SOLAR?

A. Yes. Ms. Foster explains the purpose of this adjustment in her Direct Testimony. The adjustment: (1) increases retail revenues by $1,313,314; (2) increases O&M expenses by $1,267,955 (3) increases total income taxes by $11,070; and (4) increases net operating income by $34,289, all as shown on Schedule 11.

c) Non-Employee Director Restricted Stock

Q. PLEASE SUMMARIZE THE INCOME STATEMENT ADJUSTMENT FOR NON-EMPLOYEE DIRECTOR RESTRICTED STOCK GRANTS.

A. The revenue requirement approved in OTP's last North Dakota rate case expressly excluded the cost of non-employee director restricted stock grants.[13] OTP therefore made an adjustment to remove these costs from the 2024 Regulatory Year. The adjustment: (1) decreases O&M expenses by $262,850; (2) increases total income taxes by $64,148; and (3) increases net operating income by $198,702, all as shown on Schedule 11. As discussed in Section VIII.B.2.d), below, OTP has made a rate case adjustment to reverse the financial effects of this adjustment. Mr. Byrnes explains the rationale for seeking recovery of non-employee director restricted stock grants in his Direct Testimony.

d) Economic Development Costs

Q. PLEASE SUMMARIZE THE INCOME STATEMENT ADJUSTMENT FOR ECONOMIC DEVELOPMENT EXPENSES.

A. Yes. In OTP's 2008 North Dakota rate case (Case No. PU-08-826), the Commission decided to discontinue funding of OTP's then-existing economic development program. While OTP continues to be actively involved in its communities, OTP does not have the dedicated resources and coordinated activities it once had to help support local North Dakota communities and their efforts to sustain or grow their economies. Consistent with the Commission's decision in the 2008 rate case, we have excluded the costs of the limited, ongoing North Dakota economic development activities from the 2024 Test Year. The adjustment: (1) decreases

[13] *See* Case No. PU-17-398, Settlement Agreement at 3, Table 1 (July 6, 2018).

O&M expenses by $5,943; (2) increases total income taxes by $1,450; and (3) increases net operating income by $4,493, all as shown on Schedule 11.

e) Employee Recognition and Gifts

Q. PLEASE SUMMARIZE THE TRADITIONAL INCOME STATEMENT ADJUSTMENT FOR EMPLOYEE RECOGNITION AND GIFTS.

A. As discussed by Mr. Wasberg, a certain amount of Achievement Award expenses was excluded from the 2018 Test Year revenue requirement established by settlement in OTP's last North Dakota rate case. Mr. Wasberg also explains that OTP is seeking to recover these costs in the 2024 Test Year. The traditional adjustment for employee recognition and gifts: (1) decreases O&M expenses by $96,967 (2) increases total income taxes by $23,665; and (3) increases net operating income by $73,302, all as shown on Schedule 11. OTP has made a rate case adjustment to reverse the financial effects of this adjustment, as discussed below.

f) ESSRP

Q. PLEASE EXPLAIN THE TRADITIONAL INCOME STATEMENT ADJUSTMENT FOR ESSRP.

A. Again, Mr. Wasberg explains that the settlement in the last North Dakota rate case excluded a portion of ESSRP costs from the 2018 Test Year revenue requirement, but that OTP continues to believe that recovery of these costs is a necessary component to its compensation package. This traditional adjustment: (1) decreases O&M expenses by $61,296 (2) increases total income taxes by $14,959; and (3) increases net operating income by $46,337, all as shown on Schedule 11. OTP has made a rate case adjustment to reverse the financial effects of this adjustment, as discussed below.

g) Electric Vehicles

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT THAT CORRESPONDS WITH THE TRADITIONAL RATE BASE ADJUSTMENT FOR ELECTRIC VEHICLES?

A. Yes. The purpose of this adjustment is discussed in in Section VII.C.1 above. The adjustment: (1) decreases depreciation expense by $78,037; (2) increases total income taxes by $19,045; and (3) increases net operating income by $58,992, all as shown on Schedule 11.

h) GIPs

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT THAT CORRESPONDS WITH THE TRADITIONAL RATE BASE ADJUSTMENT FOR GIPS?

A. Yes. The purpose of this adjustment is discussed in in Section VII.C.1 above. The adjustment: (1) decreases other operating revenues by $1,688,273 (2) decreases depreciation expense by $311,858; (3) decreases total income taxes by $335,913; and (4) decreases s net operating income by $1,040,502, all as shown on Schedule 11.

i) Hoot Lake Solar

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT THAT CORRESPONDS WITH THE TRADITIONAL RATE BASE ADJUSTMENT FOR HOOT LAKE SOLAR?

A. Yes. The purpose of this adjustment is discussed in Section VII.C.1 above. The adjustment: (1) decreases depreciation expenses by $685,026; (2) decreases investment tax credits by $279,699; (3) increases total income taxes by $167,181; and (3) increases net operating income by $238,149, all as shown on Schedule 11.

j) Incentive Compensation

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT FOR INCENTIVE COMPENSATION?

A. Yes. The incentive compensation adjustment reflects OTP's request that incentive compensation costs be capped at 25 percent of salary for each employee, as described by Mr. Wasberg in his Direct Testimony. The adjustment: (1) decreases O&M expenses by $365,447; (2) increases total income taxes by $89,187; and (3) increases net operating income by $276,260, all as shown on Schedule 11.

k) Investor Relations

Q. PLEASE EXPLAIN THE TRADITIONAL INCOME STATEMENT ADJUSTMENT FOR INVESTOR RELATIONS EXPENSE?

A. Mr. Byrnes explains that the settlement in the last North Dakota rate case excluded certain investor relations costs from the 2018 Test Year revenue requirement, but that OTP continues to believe that recovery of these costs is reasonable and prudent. This traditional adjustment: (1) decreases O&M expenses by $102,431 (2) increases total income taxes by $24,998; and (3) increases net operating income by $77,433 all as shown on Schedule 11. OTP has made a rate case adjustment to reverse the financial effects of this adjustment, as discussed below.

l) Long-Term Incentive

Q. PLEASE EXPLAIN THE TRADITIONAL INCOME STATEMENT ADJUSTMENT LONG-TERM INCENTIVES.

A. Mr. Wasberg explains that the settlement in the last North Dakota rate case excluded long-term incentive costs from the 2018 Test Year revenue requirement, but that OTP continues to believe that recovery of these costs is a necessary component to its compensation package. This traditional adjustment: (1) decreases O&M expenses by $1,221,363 (2) increases total income taxes by $298,072; and (3) increases net operating income by $923,291 all as shown on Schedule 11. OTP has made a rate case adjustment to reverse the financial effects of this adjustment, as discussed below.

m) Production Tax Credit GAPP Provision

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT FOR PRODUCTION TAX CREDIT GAAP PROVISION?

A. Yes. Ms. Foster explains the purpose of this adjustment in her Direct Testimony. The adjustment: (1) increases retail revenues by $4,186,187; (2) decrease total production tax credits by $5,010,974; (3) increases total income taxes by $1,021,635; and (4) decreases net operating income by $1,846,422, all as shown on Schedule 11.

n) Rider CWIP Projects

Q. PLEASE SUMMARIZE THE INCOME STATEMENT ADJUSTMENT FOR RIDER CWIP PROJECTS?

A. Under long-standing North Dakota ratemaking, OTP excludes long-term CWIP from base rate base, though such projects are included in rider revenue requirement calculations. This adjustment ensures present revenues are consistent with this long-standing treatment. The adjustment: (1) decreases retail revenues by $2,720,332; (2) decreases total income taxes by $663,894; and (3) decreases net operating income by $2,056,438, all as shown on Schedule 11.

o) Transmission Recovery

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT THAT CORRESPONDS WITH THE TRADITIONAL RATE BASE ADJUSTMENT FOR TRANSMISSION RECOVERY?

A. Yes. The purpose of this adjustment is discussed in in Section VII.C.1 above. The adjustment: (1) decreases other electric revenues by $12,044,474 (2) decreases depreciation expense by $1,325,266; (3) decreases general taxes by $916,394 (4) decreases total income taxes by $2,392,367; and (3) decreases net operating income by $7,410,447, all as shown on Schedule 11.

2. Test Year Income Statement Adjustments

a) Rate Case Expense

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT FOR RATE CASE EXPENSES?

A. Yes. Mr. Byrnes explains the purpose of this adjustment in his Direct Testimony. The adjustment: (1) increases O&M expenses by $359,404; (2) decreases total income taxes by $87,712; and (3) decreases net operating income by $271,692, all as shown on Schedule 12.

b) Normalize Langdon Upgrade Project

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT THAT CORRESPONDS WITH THE RATE CASE RATE BASE ADJUSTMENT FOR THE LANGDON UPGRADE PROJECT?

A. Yes. The purpose of this adjustment is discussed in Section VII.C.2 above. The adjustment: (1) increases depreciation expense by $489,384; (2) decreases total income taxes by $136,495; and (3) decreases net operating income by $422,799, all as shown on Schedule 12.

c) Normalize Pension and PRM

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT TO NORMALIZE PENSION AND PRM PLAN COSTS IN THE 2024 TEST YEAR?

A. Yes. Mr. Gerhardson explains the purpose of this adjustment in his Direct Testimony. The adjustment: (1) increases O&M expenses by $2,481,411; (2) decreases total income taxes by $605,586; and (3) decreases net operating income by $1,875,825, all as shown on Schedule 12.

d) Non-Employee Director Restricted Stock

Q. HAVE YOU MADE AN INCOME STATEMENT RATE CASE ADJUSTMENT FOR DIRECTOR RESTRICTED STOCK GRANTS?

A. Yes. This adjustment reverses the effects of the traditional adjustment discussed above. Mr. Byrnes explains the reasonableness of these expenses in his Direct Testimony. The adjustment: (1) increases O&M expenses by $262,850; (2) decreases total income taxes by $64,148; and (3) decreases net operating income by $198,702, all as shown on Schedule 12.

e) Rider Roll-In

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT REGARDING RIDER PROJECTS?

A. Yes. This adjustment pertains to the movement of rider projects into base rates, as discussed by Ms. Foster. The adjustment: (1) decreases retail revenues by $23,302,321; (2) decreases total income taxes by $5,686,908; and (3) decreases net operating income by $17,615,413, all as shown on Schedule 12.

f) ESSRP

Q. HAVE YOU MADE AN INCOME STATEMENT RATE CASE ADJUSTMENT FOR ESSRP?

A. Yes. This adjustment reverses the effects of the traditional adjustment discussed above. Mr. Wasberg explains the reasonableness of these expenses in his Direct Testimony. The adjustment: (1) increases O&M expenses by $61,296; (2) decreases total income taxes by $14,959; and (3) decreases net operating income by $46,337, all as shown on Schedule 12.

g) Employee Recognition and Gifts

Q. HAVE YOU MADE AN INCOME STATEMENT RATE CASE ADJUSTMENT FOR EMPLOYEE RECOGNITION AND GIFTS?

A. Yes. This adjustment reverses the effects of the traditional adjustment discussed above. Mr. Wasberg explains the reasonableness of these expenses in his Direct Testimony. The adjustment: (1) increases O&M expenses by $96,967; (2) decreases total income taxes by $23,665; and (3) decreases net operating income by $73,302, all as shown on Schedule 12.

h) Investor Relations

Q. HAVE YOU MADE AN INCOME STATEMENT RATE CASE ADJUSTMENT FOR INVESTOR RELATIONS?

A. Yes. This adjustment reverses the effects of the traditional adjustment discussed above. Mr. Byrnes explains the reasonableness of these expenses in his Direct Testimony. The adjustment: (1) increases O&M expenses by $102,431; (2) decreases total income taxes by $24,998; and (3) decreases net operating income by $77,433, all as shown on Schedule 12.

i) Long-Term Incentives

Q. HAVE YOU MADE AN INCOME STATEMENT RATE CASE ADJUSTMENT FOR LONG-TERM INCENTIVES?

A. Yes. This adjustment reverses the effects of the traditional adjustment discussed above. Mr. Wasberg explains the reasonableness of these expenses in his Direct Testimony. The adjustment: (1) increases O&M expenses by $1,221,363; (2) decreases total income taxes by $298,072; and (3) decreases net operating income by $923,291, all as shown on Schedule 12.

3. Effect of Adjustments on Allocations

Q. DO THE 2024 TRADITIONAL AND TEST YEAR INCOME STATEMENT ADJUSTMENTS CAUSE IMPACTS TO ALLOCATIONS?

A. Yes. Similar to rate base adjustments, the traditional and rate case income statement adjustments impact costs that are used in certain allocation factors. The overall effect of traditional adjustments on allocators is identified on page 1 of Schedule 11, in Column Q, while the overall effect of rate case adjustments on allocators is identified on page 1 of Schedule 12, Column K.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Mrs. Christy L. Petersen, CPA
Manager, Regulatory Accounting
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8541

CURRENT RESPONSIBILITIES: (Feb 2021 to Present)

Provide leadership in budgeting, cost recovery, and forecasting as required by OTP and Otter Tail Corporation for use in strategic planning and decision making. In addition, this position is responsible for managing the production of official company Operations and Maintenance budgets and monthly forecasts, and leading the work group which prepares the jurisdictional cost of service studies for the three jurisdictions in which OTP provides service (Minnesota, North Dakota, and South Dakota) and providing any other regulatory and financial analysis on an as needed basis.

PREVIOUS POSITIONS:

Otter Tail Power Company

2010 – 2021	Senior Financial/Rates Analyst, Business Planning/Regulatory Accounting

Carlson Highland

2008 – 2010	Governmental Auditor

EDUCATIONAL / CERTIFICATIONS

Moorhead State University-Moorhead, B.S.
Major in Accounting

Certified Public Accountant (CPA)

Otter Tail Power Company

Jurisdictional and Class Cost of Service Study

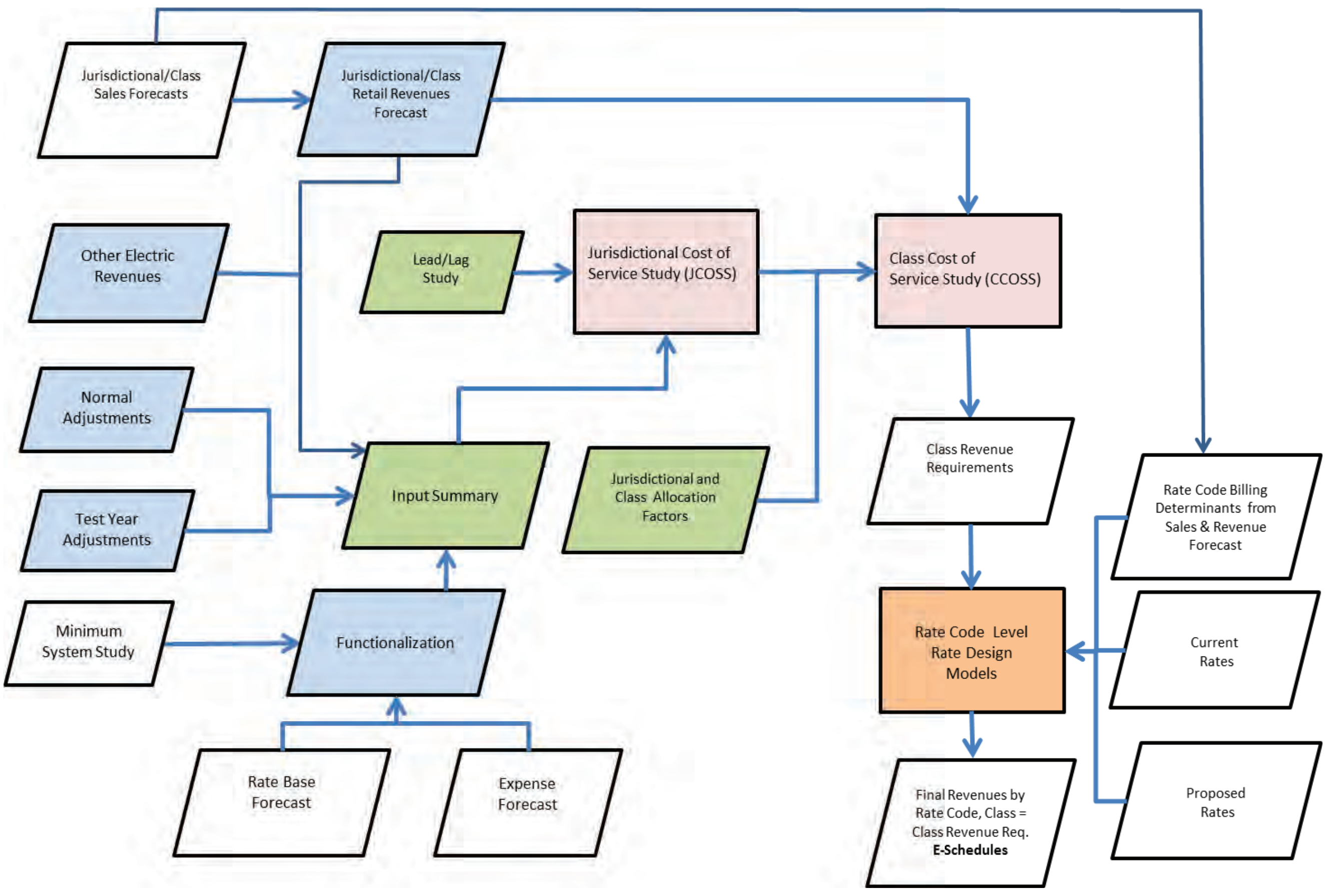
And

Rate Design

Process Overview Manual

1. Introduction:

The purpose of this document is to provide an overview of the various inputs of data which feed into Otter Tail Power's (OTP) Jurisdictional Cost of Service Study (JCOSS) and Class Cost of Service Study (CCOSS) models to determine OTP's revenue requirement upon which subsequent customer class revenue requirements and related rate designs are completed. Flow charts are provided along with descriptive narratives and tables to provide further clarity in how information included in OTP's rate case filing flows from one step in the process to the next. Below is a high-level overview of key components within the overall process that leads to the determination of revenue requirements and corresponding rates necessary to collect the required revenues from the respective customer classes.

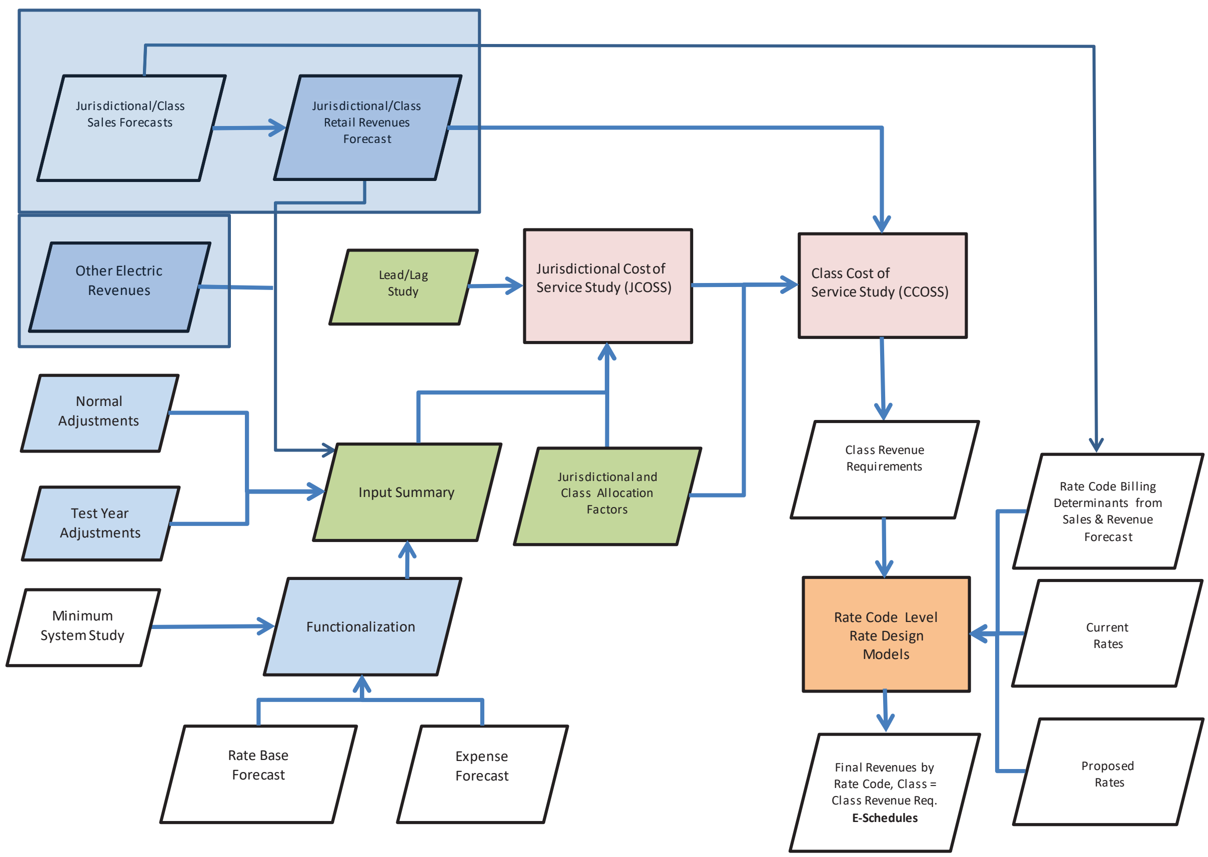


The balance of this document will review in general terms, the various components identified above, describing the flow of data between those components. The descriptions provided are assumed in the context of a forecast test year.

Retail Sales & Revenue Forecast

In summary, the development of the kWh sales forecast at a class and jurisdictional level is the initial step in determining the retail base rate revenue forecast. The kWh sales forecasts and associated billing determinants then serve as inputs into the process which derives forecasted class and jurisdictional revenues based on existing base rate design. Additional revenues from various rate riders make up the balance of revenues associated with kWh sales, as itemized in Work Paper B-1. Total Jurisdictional revenues flow into the Input Summary, which subsequently feeds into the JCOSS. Class Revenues serve as an input in the CCOSS. Billing determinants developed in the process of creating the sales and revenue forecasts, ultimately serve as inputs into the final rate design models used to develop rates to collect the required revenues. These steps will be explained in more detail later in this document.

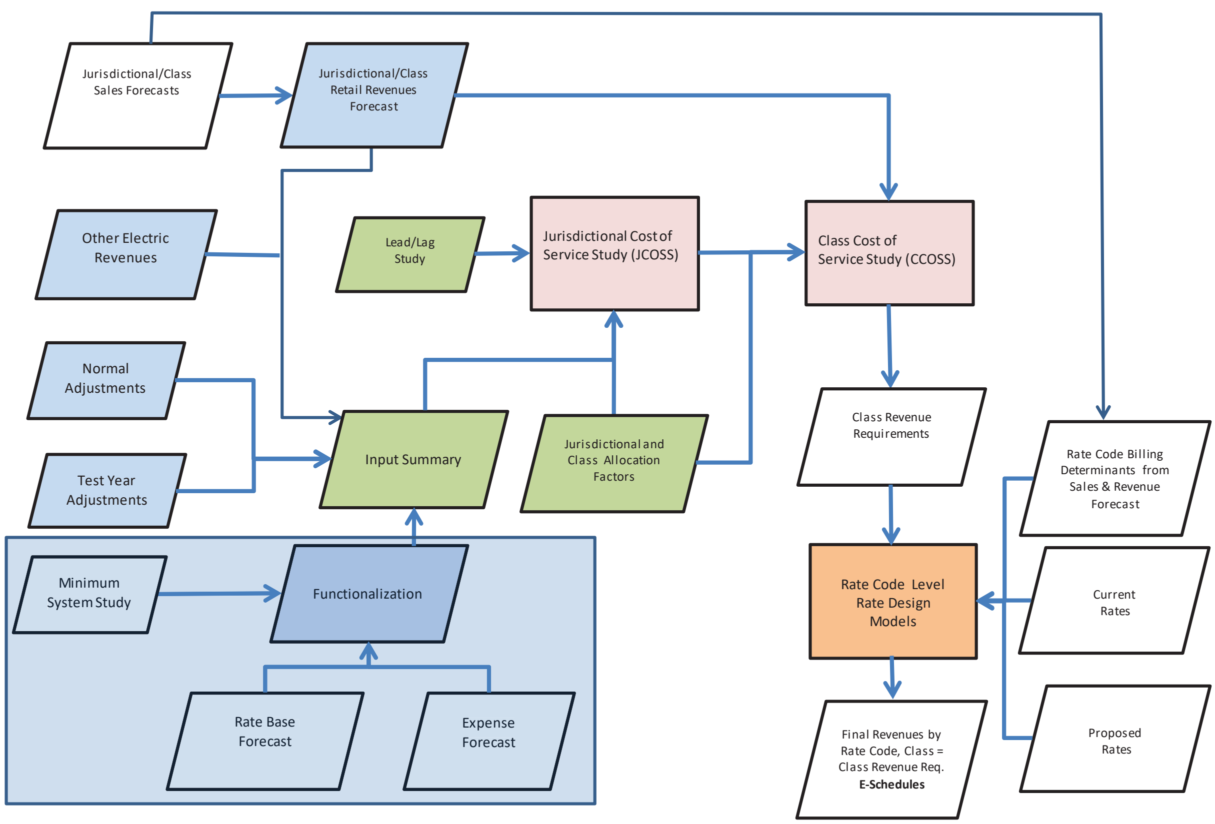
Other Electric Revenues and Sales for Resale are listed in Work Papers B-2 and B-3 and also flow into the Input Summary. These revenues, combined with the forecasted retail revenues, yield total jurisdictional and company revenues.



Functionalization (Volume 4A)

The **Functionalization Schedule, found in Volume 4A** of the rate case filing, is the schedule which takes total company rate base and expense information as accounted for under Federal Energy Regulatory Commission (FERC) accounting rules, and aggregates those amounts into functional cost categories:

production; transmission; distribution; customer accounting and collecting, and customer service and information. In addition, this schedule further "classifies" the information within each function, based on key service characteristics: demand, energy, customers and meters. These classifications have further sub-characteristics such as type of demand or energy, voltage level, or type of customer or meter. These service characteristics or sub-characteristics provide the basis for further cost allocations within the JCOSS and CCOSS. OTP's Cost Allocation Procedures Manual (CAPM) provides further detail on how each class of costs gets allocated jurisdictionally and subsequently to the various classes within each jurisdiction.



Functionalization Pages:

Pages 1-3 is the input section of the Functionalization schedule, where the FERC account balances are entered and amounts are aggregated based on functional area.

Page 4 of the Functionalization schedule takes the distribution rate base and distribution expense balances from pages 1-3 of the Functionalization schedule and allocates those costs to the following classifications for distribution rate base and expenses:

- Primary Demand
- Secondary Demand
- Primary Customer
- Secondary Customer
- Street Lights
- Area Lights
- Meters
- Load Management

The classifications of these costs are based on allocation factors developed from the Minimum System Study. Details of the process to develop the Minimum System Study are found in Appendix A-1 of OTP's CAPM.

Page 4 of the Functionalization schedule also includes an input section on lines 2 and 3 for the Base/Peak split allocation factors which allocate Production Plant rate base and expense amounts between Base Demand and Peak Demand, Base Demand and Base Energy Categories. The calculation of the Base/Peak split factors is found in Cost of Service Workpapers C-1 and C-1a, following the methodology described in pages 3 and 4 of OTP's CAPM.

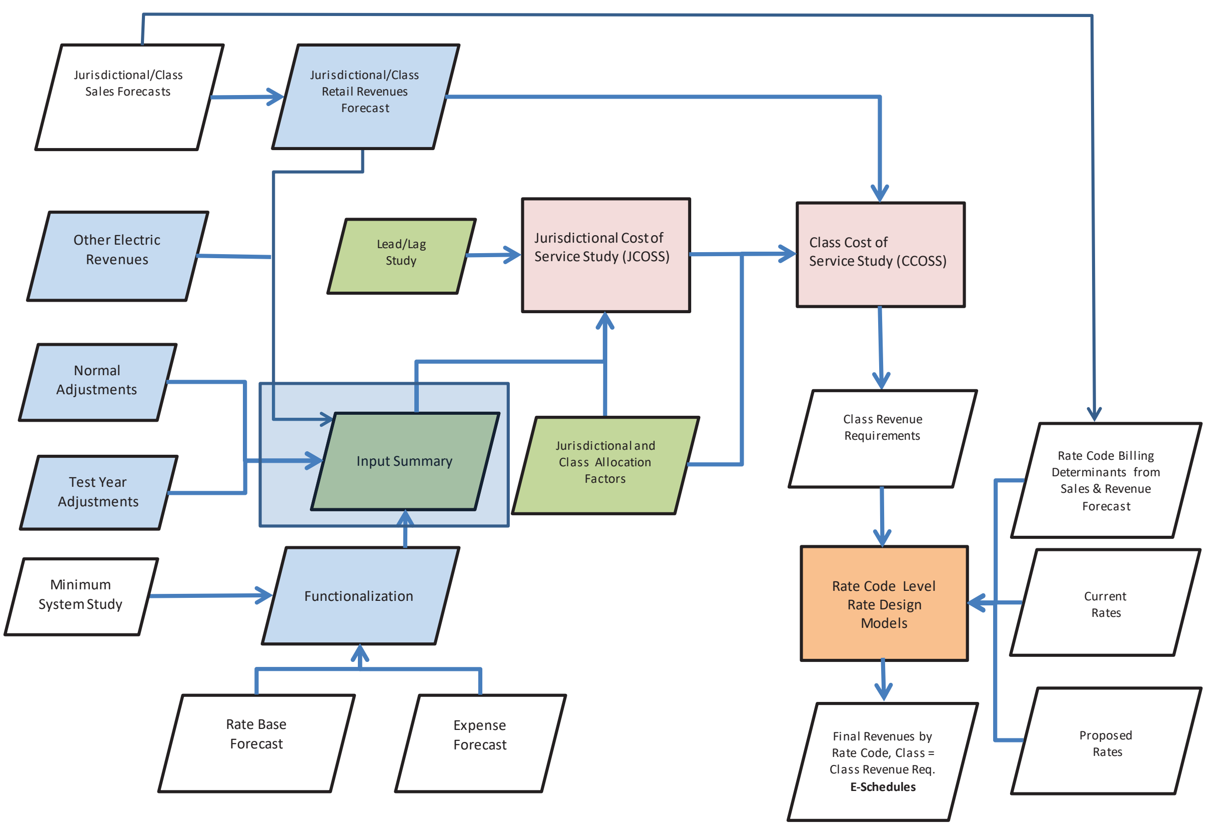
Pages 5 and 6 of the Functionalization schedule summarize the allocations of costs from pages 1-4, into the respective cost categories that align with the categorical breakdowns ultimately included in OTP's JCOSS and CCOSS. The Rate Base and Expense amounts are first entered into the JCOSS Input Summary, which is described in the next section below.

Input Summary (Volume 4A)

The purpose of the Input Summary, found in Volume 4A is to aggregate Total Company cost information (operating statement as well as rate base items) that has been categorized in the Functionalization schedule, as well as incorporate Total Company Revenue amounts and other Company data quantified in other Workpapers, into a single schedule. This schedule serves as the staging schedule from which much of the company financial information is entered into the JCOSS model.

The amounts which have been functionalized and classified by service characteristics are included in Column A of the Input Summary, as well as revenues and certain other rate base items computed in their respective source document workpapers. All data in the Input Summary is footnoted to the source document / work paper of origin. The Input Summary then incorporates into the adjacent columns to the right, adjustments which are necessary for computation of the JCOSS.

A more detailed description of the various sections of the Input Summary is included following the graphic below.



Input Summary Schedules

The **Input Summary** is divided into two primary sections; Rate Base components and Operating Statement components. Further breakdowns of the Input Summary schedules are identified below:

1. **A – Summary** Schedules - These pages include all the **rate base** related accounts and associated adjustments. The A-Summary schedules are broken down further into two sections:
   a. **A-Summary 1 -** This is a bridge schedule which starts with Total Company Simple Average rate base amounts in Column A. These amounts originate from the Functionalization schedule as well as amounts from work paper schedules, as footnoted in the Input summary schedule. Subsequent columns in the schedule incorporate the Normal Adjustments necessary to determine OTP's Total Company Unadjusted amounts in the last column of the schedule. These amounts reflect the values that would be input into the JCOSS Model to compute OTP's Unadjusted JCOSS based on currently approved methodologies and normal adjustments.

   b. **A-Summary 2 -** This is a bridge schedule which starts with Total Company Unadjusted amounts in Column A as computed in the A-Summary 1. Subsequent columns in the A-Summary 2 schedule incorporate the Test Year Adjustments necessary to determine OTP's Total Company Adjusted amounts in the last column of the schedule. These amounts reflect the values that would be input into the JCOSS Model to compute OTP's Test Year JCOSS.

2. **B - Summary** – These pages include all **operating statement** amounts and associated adjustments. The B-Summary schedules are broken down further into two sections:

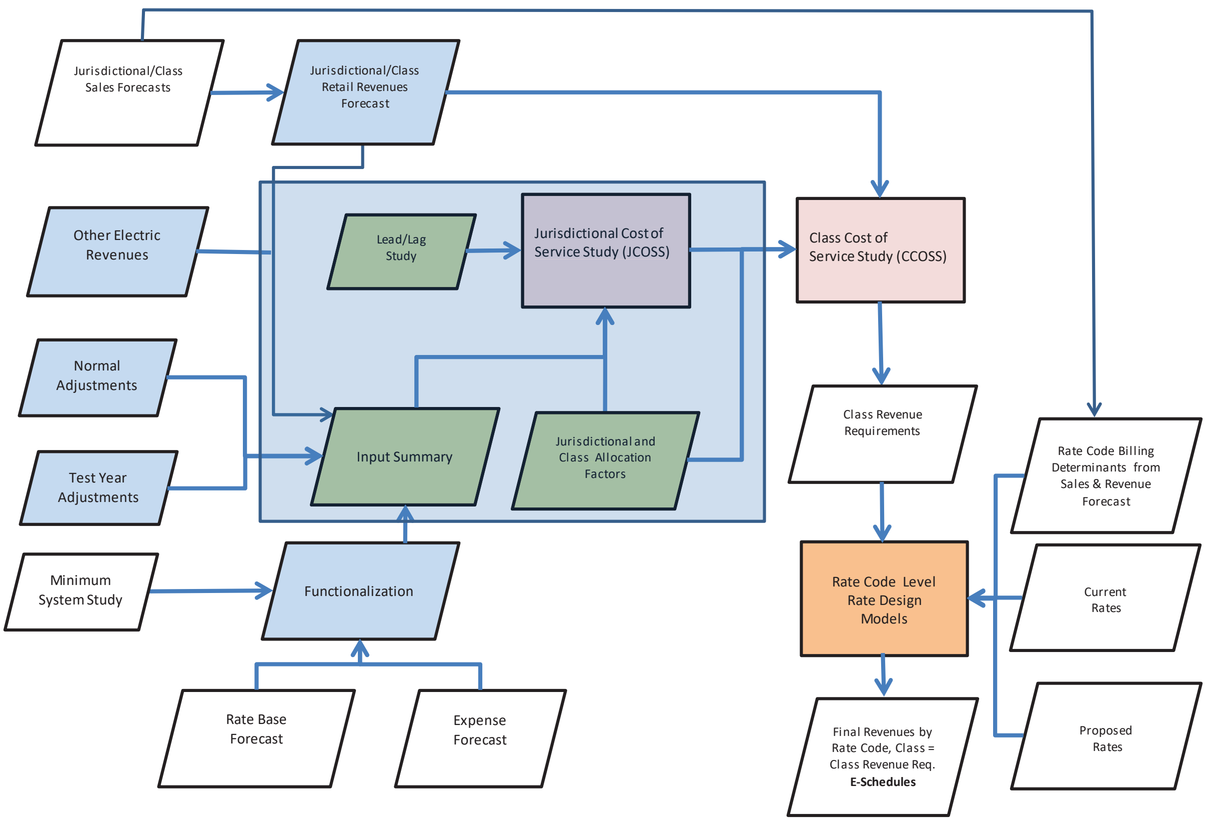
   a. **B-Summary 1** - This is a bridge schedule which starts with Total Company annual Operating Statement amounts in Column A. These amounts originate from the Functionalization schedule as well as amounts from work paper schedules, as footnoted in the Input summary schedule. Subsequent columns in the B-Summary-1 schedule incorporate the Normal Adjustments necessary to determine OTP's Total Company Unadjusted amounts in the last column of the schedule. These operating statement amounts reflect the values that would be input into the JCOSS Model to compute OTP's Unadjusted JCOSS based on currently approved methodologies and normal adjustments.

   b. **B-Summary 2** - This is a bridge schedule which starts with Total Company Unadjusted Operating Statement amounts in Column A as computed in the A-Summary-1. Subsequent columns in the B-Summary 2 schedule incorporate the Test Year Adjustments necessary to determine OTP's Total Company Adjusted amounts in the last column of the schedule. These amounts reflect the values that would be input into the JCOSS Model to compute OTP's Test Year JCOSS.

Jurisdictional Cost of Service Study Model (JCOSS)

The purpose of JCOSS model is to compute OTP's total Available for Return and compare that amount to the current authorized/proposed return and computes incremental amount of revenue surplus or deficiency necessary to meet that authorized return.   The key Inputs into the JCOSS are:

1. Input Summary Amounts
2. Lead-Lag Study Amounts
3. Jurisdictional Allocation Factors



The **JCOSS is found in Volume 4A for the Test Year**. The following table aligns the JCOSS Pages to the respective Input Summary, Lead-Lag, and Allocation Factor Schedules. All Summary pages in the JCOSS model have references to the respective detailed sections of the JCOSS.

JCOSS Page	Description	Source	Source Pages
1-1	**JCOSS Summary of Deficiency**	JCOSS Detail Pages	Pages 2, 7, 17
2-1	**Rate Base Summary**	JCOSS Detail Pages	Pages 3, 4, 5, 6
3-1	Total Plant in Service	Input Summary A-2	Page 1
4-1	Accumulated Depreciation Plant Held for Future Use	Input Summary A-2	Page 2 Page 2
5-1	CWIP Materials & Supplies, Fuel Stocks Prepayments Customer Advances Cash Working Capital	Input Summary A-2	Page 3 Page 4 Page 4 Page 4 Page 4 Page 4
6-1	Accumulated Deferred Income Taxes	Input Summary A-2	Page 4
7-1	**Operating Statement Summary**	JCOSS Detail Pages	Pages 8,9,10,11,12
8-1	Operating Revenues	Input Summary B-2	Page 1
9-1	Production Expenses Transmission Expenses Distribution Expenses Customer Accounting Expenses	Input Summary B-2	Page 2 Page 2 Page 2 Page 2
10-1	Customer Service & Information Expenses Sales Expenses Admin & General Expenses	Input Summary B-2	Page 2 Page 3 Page 3
11-1	Depreciation Expense	Input Summary B-2	Page 4
12-1	General Taxes Investment Tax Credits Deferred Income Taxes Current Income Taxes- Federal Current Income Taxes –MN Current Income Taxes – ND AFDC	Input Summary B-2 Input Summary B-2 Input Summary B-2 JCOSS Detail JCOSS Detail JCOSS Detail Input Summary	Page 4 Page 4 Page 4 Page 13-1 Page 14-1 Page 14-1 Page 5
13-1	Federal Income Taxes	JCOSS Calculation	Page 13-a
14-1	Minnesota State Income Tax Expense North Dakota State Income Tax Expense	JCOSS Calculation	Page 14-a
15-1	Jurisdictional Allocation Factors	Required Schedules C-9	Page 4
16-1	Secondary Allocation Factors	JCOSS Calculation Required Schedules – C-9	Page 16-a Page 5
17-1	Capital Structure – Requested	Required Schedules – D-1-a	Page 17-1 Page 17-a
18-1	Cash Working Capital Revenue Lead Days	Lead Lag Study Required Schedules – B-2-e	Summary – Page 1 Page 1
19-1	Cash Working Capital - MN Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
20-1	Cash Working Capital - ND Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
21-1	Cash Working Capital - SD Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
22-1	Cash Working Capital - FERC Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
23-1	Cash Working Capital- Total Company	JCOSS Calculation	Sum of Jurisdictional totals 19-1 to 22-1

Lead-Lag Study Reference Table

The following table provides a cross reference of the various Lead-Lag study values found in the JCOSS to the respective page in the Lead-Lag Study.

JCOSS Page 18-1

Line No.	Revenue Lead Days from Service to Collection	Revenue Lead Days	Lead Lag Study Page	Notes:
23	Computer Maintained Billings	43.4	1	
24	Manually Maintained Billings	41.3	1	
25	Cost of Energy Adjustment Revenues	127.7	37	
26	Sales for Resale	23.1	40	
27	Rent from Electric Property	-92.4	42	
28	Miscellaneous	34.9	51	
29	ITA Deficiency Payments	48.4	56	
30	Wheeling	35.8	60	
31	Load Control and Dispatch	27.9	1	Line 21
32	Rent from Electric Property - Big Stone	39.9		Calculated in COSS
33	Rent from Electric Property - Coyote	39.9		Calculated in COSS
34	Profit on Materials and Supplies	39.9		Calculated in COSS
35	Miscellaneous Services	39.9		Calculated in COSS
36	Loan Pool Interest	39.9		Calculated in COSS

JCOSS Page 20-1

Line No.	Item	Expense Lag Days	Lead Lag Study Page	Notes:
3	Fuel - Coal	15.5	69	
5	Fuel - Oil	11.2	69	
7	Purchased Power	31.6	69	
9	Labor and Associated Payroll Expense	15.1	69	
11	All Other O&M Expense	13.1	69	Line 19
13	Property Taxes (Excl Coal Conversion Taxes)	299.5	157	Calculated in COSS
15	Coal Conversion Taxes	33.3	171	
17	Federal Income Taxes	0.0	172	
19	State Income Taxes	0.0	172	
21	Incremental Federal Income Taxes	0.0	172	
23	Incremental State Income Taxes	0.0	172	
25	Bank Balances	n/a		
27	Special Deposits	n/a		
29	Working Funds	n/a		
31	Tax Collections Avail - FICA Withholding	0.0	175	
33	Tax Collections Avail - Federal Withholding	0.0	175	
35	Tax Collections Avail - State Withholding- MN	1.9	175	
37	Tax Collections Avail - State Withholding- ND	69.1	175	
39	Tax Collections Available - State Sales Tax	23.8	175	
41	Tax Collections Available - Franchise Taxes	0	175	

JCOSS pages 1-a to 18-a contain the jurisdictional breakdowns of the JCOSS information as listed on pages 1-1 to 18-1 on the table above.

Allocation Factors

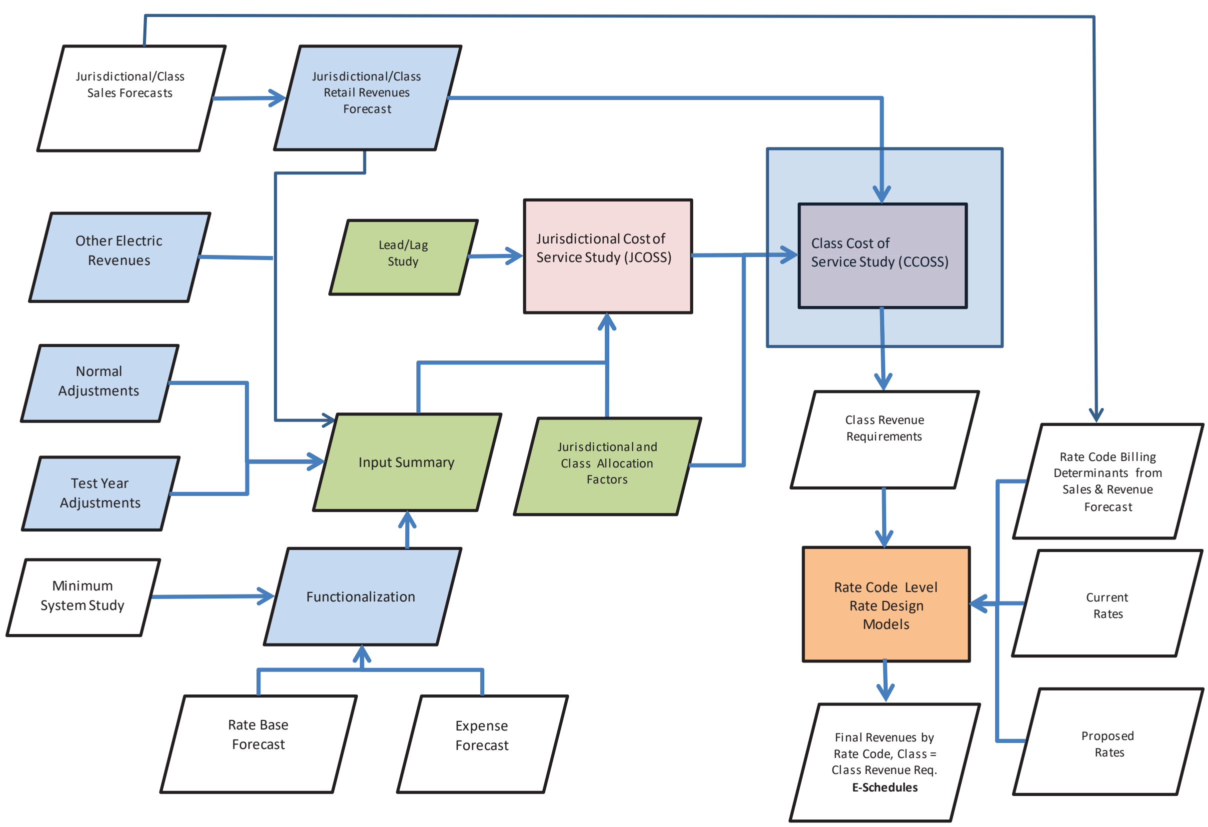
As reflected in the flow chart and listed on page 15-1 of the CCOSS, jurisdictional allocation factors are applied to various costs (rate base and expense) to allocate total company costs to the jurisdiction. Details on both jurisdictional and class allocation factors are outlined in OTP's Cost Allocation Procedures Manual and in OTP's Forecast Cost Allocation Procedures Manual Supplement. Required schedules C-9 and Work Papers Volume 4, C-3 provide additional detail as well.

JCOSS Summary

The results of the JCOSS, as summarized on page 1-1, is the determination of a (surplus) or deficiency in revenue needed to achieve the rate of return authorized or requested within the jurisdiction. The respective **jurisdictional amounts** within the study **serve as the primary inputs** into the **CCOSS model**, with allocations of those costs and associated class revenue requirements distributed to each customer class.

Class Cost of Service (Volume 4A)

OTP's CCOSS model establishes the revenue requirements for each of OTP's 10 customer classes based on the allocation of jurisdictional costs using the **class allocation factors detailed on page 15-2** and the **secondary class allocation factors detailed on page 16-2**.



The **key inputs** into the CCOSS model are:

1. Current North Dakota Class Revenues
2. JCOSS North Dakota results – Pages 1-1 to 16-1
3. Class Allocation Factors
    a. Primary Allocators by class (D Factors, E8760 Factors, C Factors) Page 15-2
    b. Secondary – Page 16-2

The CCOSS pages 1-2 to 16-2 align with the pages 1-1 to 1-16 of the JCOSS.

The **key output** of the CCOSS is the determination of **class revenue requirements** based on the embedded costs and revenues attributable to each class. The CCOSS serves as a guide in the determination of proposed class rate increases necessary to collect the jurisdictional revenue increase required. The Summary of each class's deficiency is provided on page 1-2 of the CCOSS.

Class	CCOSS Output	Source
Residential	Class Revenue Deficiency	CCOSS Page 1-2
Farms	Class Revenue Deficiency	CCOSS Page 1-2
General Service	Class Revenue Deficiency	CCOSS Page 1-2
Large General Service	Class Revenue Deficiency	CCOSS Page 1-2
Irrigation	Class Revenue Deficiency	CCOSS Page 1-2
Outdoor Lighting	Class Revenue Deficiency	CCOSS Page 1-2
OPA	Class Revenue Deficiency	CCOSS Page 1-2
Controlled Service Water Heating	Class Revenue Deficiency	CCOSS Page 1-2
Controlled Service Interruptible	Class Revenue Deficiency	CCOSS Page 1-2
Controlled Service Deferred	Class Revenue Deficiency	CCOSS Page 1-2
Total Jurisdiction	**Sum of Class Revenue Deficiencies**	**Ties to JCOSS Deficiency Page 1-1**

Rate Design (Volume 3 Section E)

The JCOSS determines the jurisdictional revenue requirement and related deficiency in revenue. The CCOSS determines each class's responsibility for that deficiency based on the embedded costs included in the studies. Ultimately, the company develops a proposal for each class's share of the overall jurisdictional revenue requirement to eliminate the deficiency and develops proposed rates within each class to collect that deficiency. **Total Test Year Current and Proposed Revenues by Class are provided in Volume 3 Schedule E-1.**

Class	Current Revenues	Source	Proposed Revenues	Source	Class Revenue Increase
Residential	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Farms	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
General Service	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Large General Service	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Irrigation	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues

Outdoor Lighting	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
OPA	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Controlled Service Water Heating	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Controlled Service Interruptible	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Controlled Service Deferred	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Total Jurisdictional	**Total Current Revenue**	JCOSS	**Total Revenue Required**	JCOSS	**Total Increase in Revenue**

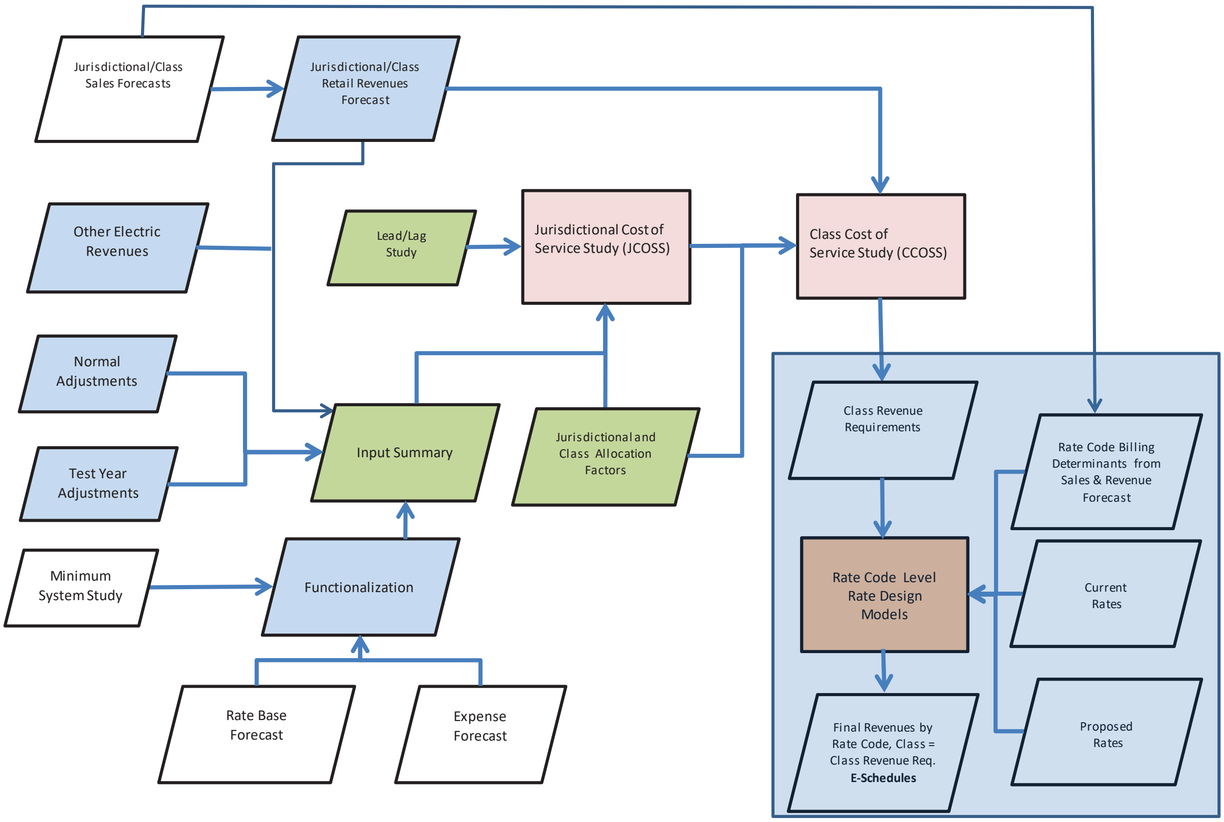
Following the development of proposed class revenue responsibilities, the next step in the process is rate design.

Key Components / Inputs in the Rate Design Process

The purpose of the rate design process is to develop new rates and associated rate structures that result in the collection of the proposed class revenue requirement based on the billing determinants included in the forecast. Rate design is completed at a rate code level. Class revenue requirements are distributed to the rate code level. The allocation of class revenue to rate code level is completed using an Equivalent Percent of Marginal Cost (EPMC) allocation.

The following inputs are key to completing rate design in the rate design models at a rate code level:

1. **Billing Determinants** – These are the various billing determinants which were developed and included in the Sales and Revenue forecast process. Billing determinants include such things as forecasted kWhs, kW, number of customers, and number of meters. The sales and revenue forecast process develops billing determinates at a rate group level and then further allocates those determinants to a rate code level.
2. **Current Rates**- Current rates applied to the billing determinants yield the current level of revenues for the particular rate code. The result of this is the calculation of current revenues from existing rates.
3. **Proposed Rates-** Based on forecasted billing determinants described above, proposed rates are adjusted to yield the total revenue required from that rate to meet its contribution to the class revenue requirement.



Key Outputs of Rate Design Process:

The **key output of the Rate Design process** is a **new set of proposed rates** that within their respective customer class, collects the amount of revenue equal to the proposed class revenue requirement. The sum of revenues derived by all rates across all classes equals the total jurisdictional revenue requirement. As noted earlier, the **results of the rate design** process are **summarized in Volume 3 Schedule E-1**. **Details of the changes from current rates to proposed rates are found in Volume 3 Schedule E-2.**

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
SUMMARY OF REVENUE REQUIREMENTS
Proposed Test Year 2024

Line No.	Description	North Dakota Jurisdiction Test Year 2024
1	Average Rate Base	$661,733,555
2	Total Available for Return (Line 2 + Line 3 + Rounding)	$21,208,695
3	Overall Rate of Return (Line 4 / Line 1)	3.21%
4	Required Rate of Return	7.85%
5	Operating Income Requirement (Line 1 x Line 6)	$51,946,084
6	Income Deficiency (Line 7 - Line 4)	$30,737,389
7	Gross Revenue Conversion Factor	1.322837
8	Revenue Deficiency (Line 8 x Line 9)	$40,660,558

Line No.	Description	(A) Most Recent Actual Year 2022	(B) Current Period 2023	(C) Unadjusted Year 2024	(D) Regulatory Year 2024	(E) Test Year 2024
1	Average Rate Base	$557,200,061	$687,918,709	$764,291,404	$651,646,255	$661,733,555
2	Total Available for Return (Line 2 + Line 3 + Rounding)	$35,187,011	$38,783,318	$54,305,184	$42,604,666	$21,208,695
3	Overall Rate of Return (Line 4 / Line 1)	6.31%	6.60%	7.11%	6.54%	3.21%
4	Required Rate of Return	7.26%	7.33%	7.85%	7.41%	7.85%
5	Operating Income Requirement (Line 1 x Line 6)	$40,452,724	$43,094,441	$59,996,875	$48,286,988	$51,946,084
6	Income Deficiency (Line 7 - Line 4)	$5,265,714	$4,311,124	$5,691,691	$5,682,322	$30,737,389
7	Gross Revenue Conversion Factor	1.322837	1.322837	1.322837	1.322837	1.32284
8	Revenue Deficiency (Line 8 x Line 9)	$6,965,681	$5,702,914	$7,529,180	$7,516,785	$40,660,558

Otter Tail Power Company Actual versus Budget O&M ($millions)

Total O&Ms minus Schedule 26, 26A and CIP expenses

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2022	$128.97	$142.70	$13.74	10.65%
2021	$131.14	$127.45	-$3.69	-2.81%
2020	$121.69	$120.16	-$1.53	-1.25%
Three - Year Total	**$381.80**	**$390.32**	**$8.52**	**2.23%**

2022: Higher spend due to unplanned outage in Big Stone along with some additional tree trimming and higher employee expenses.

2021: Lower labor loadings offset somewhat by Big Stone Plant outage costs.

2020: Tracking close to budget.

Otter Tail Power Company Actual versus Budget Capital ($millions)

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2022	$148.71	$146.76	-$1.95	-1.31%
2021	$112.88	$116.02	$3.14	2.78%
2020	$368.76	$347.96	-$20.80	-5.64%
Three - Year Total	**$630.35**	**$610.73**	**-$19.62**	**-3.11%**

2022: Delays versus budgeted progress on the AMI project (-13.4M) was offset by capital investments supporting new load, asset replacement programs, and large spring storm restoration efforts.

2021: Reductions in estimated costs of the Astoria Station and Mericourt Wind projects (-5.6M and -5.1M respectivly) were largly offset by increased capital investment supporting new load and asset replacement and reliability programs.

2020: Variance is driven by reductions in the total estimated cost on Astoria Station (remaining estimates were lower for 2020 and 2021 than budgeted in the 2020 approved budget). Rider recovery limited to actual costs incurred.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE SUMMARY

Case No. PU-23-
Exhibit ___ (CLP-1), Schedule 6

		(A)	(B)	(C)	(D)	(E)
Line No.	**Description**	**Most Recent Actual Year 2022**	**Current Period 2023**	**Unadjusted Year 2024**	**Regulatory Year 2024**	**Test Year 2024**
1	Electric Plant in Service	$1,041,850,025	$1,129,321,851	$1,383,996,534	$1,249,259,535	$1,259,341,147
2	Less: Accumulated Depreciation	(391,231,179)	(419,687,343)	(471,567,693)	(461,085,772)	(461,242,346)
3	Net Electric Plant in Service	$650,618,846	$709,634,508	$912,428,841	$788,173,763	$798,098,801
	Other Rate Base Components:					
4	Plant Held for Future Use	$12,897	$13,352	$4,921	$4,921	$4,921
5	Construction Work in Progress	7,674,957	140,127,964	780,995	780,990	780,995
6	Materials and Supplies	12,184,922	11,101,870	14,737,569	14,737,248	14,737,569
7	Fuel Stocks	4,092,023	5,660,200	4,495,117	4,495,117	4,495,117
8	Prepayments	9,181,902	1,364,417	18,630,686	18,601,559	18,630,686
9	Customer Advances	(572,270)	(1,131,222)	(710,769)	(709,657)	(710,769)
10	Cash Working Capital	2,530,836	1,070,605	1,464,907	1,304,936	1,464,908
11	Accumulated Deferred Income Taxes	(128,524,052)	(157,975,556)	(187,378,675)	(175,742,621)	(175,768,672)
12	TOTAL	$557,200,061	$709,866,137	$764,453,592	$651,646,256	$661,733,556

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENTS
Unadjusted Year 2024 to Regulatory Year 2024

			Adjustments					
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Description	Unadjusted Year 2024	GIPs Projects	Hoot Lake Solar	Transmission Recovery	Electric Vehicles	Changes in Allocations Due to Effect of Test Year Adjustments	Regulatory Year 2024
	Utility Plant in Service:							
1	Production	$658,582,109		($26,462,276)				$632,119,833
2	Transmission	$323,246,976	($19,287,409)		($88,138,714)			215,820,853
3	Distribution	$330,597,673				(846,512)	$1	329,751,162
4	General	$53,300,696						53,300,696
5	Intangible	$18,266,991						18,266,991
6	**TOTAL Utility Plant in Service**	$1,383,994,445	($19,287,409)	($26,462,276)	($88,138,714)	($846,512)	$1	$1,249,259,535
	Accumulated Depreciation							
7	Production	($246,215,224)		$568,838				($245,646,386)
8	Transmission	($72,478,191)	$1,212,465		$8,657,099			(62,608,627)
9	Distribution	($123,426,235)				42,659		(123,383,576)
10	General	($21,909,007)						(21,909,007)
11	Intangible	($7,538,176)						(7,538,176)
12	**TOTAL Accumulated Depreciation**	($471,566,833)	$1,212,465	$568,838	$8,657,099	$42,659		($461,085,772)
13	**NET Utility Plant in Service**							
14	Production	$412,366,885		($25,893,438)				$386,473,447
15	Transmission	250,768,785	(18,074,944)		(79,481,615)			153,212,226
16	Distribution	207,171,438				(803,853)	$1	206,367,586
17	General	31,391,689						31,391,689
18	Intangible	10,728,815						10,728,815
19	**NET Utility Plant in Service**	$912,427,612	($18,074,944)	($25,893,438)	($79,481,615)	($803,853)	$1	$788,173,763
20	Utility Plant Held for Future Use	4,921						4,921
21	Construction Work in Progress	780,990						780,990
22	Materials and Supplies	14,737,248						14,737,248
23	Fuel Stocks	4,495,117						4,495,117
24	Prepayments	18,601,559						18,601,559
25	Customer Advances & Deposits	(709,657)						(709,657)
26	Cash Working Capital	1,304,936						1,304,936
27	Accumulated Deferred Income Taxes	(187,351,325)	1,425,013	2,633,993	7,549,696		$2	(175,742,621)
28	**Total Average Rate Base**	$764,291,401	($16,649,931)	($23,259,445)	($71,931,919)	($803,853)	$3	$651,646,256

			Adjustments		
		(A)	(B)	(C)	(D)
Line No.	Description	Regulatory Year 2024	Normalize Langdon Upgrade Project	Changes in Allocations Due to Effect of Test Year Adjustments	Test Year 2024
	Utility Plant in Service:				
1	Production	$632,119,833	$10,079,520		$642,199,353
2	Transmission	215,820,853			215,820,853
3	Distribution	329,751,162			329,751,162
4	General	53,300,696		$1,555	53,302,251
5	Intangible	18,266,991		$533	18,267,524
6	**TOTAL Utility Plant in Service**	$1,249,259,535	$10,079,520	$2,088	$1,259,341,143
	Accumulated Depreciation				
7	Production	($245,646,386)	($155,713)		($245,802,099)
8	Transmission	(62,608,627)			(62,608,627)
9	Distribution	(123,383,576)			(123,383,576)
10	General	(21,909,007)		($640)	(21,909,647)
11	Intangible	(7,538,176)		($220)	(7,538,396)
12	**TOTAL Accumulated Depreciation**	($461,085,772)	($155,713)	($859)	($461,242,344)
13	**NET Utility Plant in Service**				
14	Production	$386,473,447	$9,923,807		$396,397,254
15	Transmission	153,212,226			153,212,226
16	Distribution	206,367,586			206,367,586
17	General	31,391,689		916	31,392,605
18	Intangible	10,728,815		314	10,729,129
19	**NET Utility Plant in Service**	$788,173,763	$9,923,807	$1,229	$798,098,799
20	Utility Plant Held for Future Use	$4,921			$4,921
21	Construction Work in Progress	780,990		$5	780,995
22	Materials and Supplies	14,737,248		$321	14,737,569
23	Fuel Stocks	4,495,117			4,495,117
24	Prepayments	18,601,559		$29,127	18,630,686
25	Customer Advances & Deposits	(709,657)		($1,112)	(710,769)
26	Cash Working Capital	1,304,936		$159,971	1,464,907
27	Accumulated Deferred Income Taxes	(175,742,621)		($26,051)	(175,768,672)
28	**Total Average Rate Base**	$651,646,256	$9,923,807	$163,490	$661,733,553

Line No.	Description	(A) Most Recent Actual Year 2022	(B) Current Period 2023	(C) Unadjusted Year 2024	(D) Regulatory Year 2024	(E) Test Year 2024
	OPERATING REVENUES					
1	Retail Revenue	$186,549,483	$194,336,780	$203,210,040	$205,989,209	$182,686,888
2	Other Electric Operating Revenue	18,158,019	13,185,392	26,709,463	12,976,906	12,979,433
3	**TOTAL OPERATING REVENUE**	$204,707,501	$207,522,172	$229,919,503	$218,966,115	$195,666,321
	OPERATING EXPENSES					
4	Production Expenses	$80,952,165	$78,192,135	$85,426,089	$86,694,044	$87,108,465
5	Transmission Expenses	14,387,811	14,184,319	13,847,298	13,847,298	14,086,555
6	Distribution Expenses	7,838,847	7,648,887	7,972,703	7,972,703	8,393,231
7	Customer Accounting Expenses	6,186,536	6,709,753	7,035,433	7,035,433	7,295,595
8	Customer Service and Information Expenses	1,168,276	1,235,785	1,315,049	1,315,049	1,331,017
9	Sales Expenses	41,797	50,689	142,408	135,872	135,872
10	Administration and General Expenses	20,082,182	20,152,628	20,022,371	17,534,200	20,775,268
11	Charitable Contributions	0	0	0	0	0
12	Depreciation Expense	26,709,167	29,426,229	35,004,108	32,603,918	33,093,414
13	General Taxes	6,464,014	6,437,388	8,019,087	7,102,692	7,103,488
14	**TOTAL OPERATING EXPENSES**	$163,830,794	$164,037,814	$178,784,546	$174,241,209	$179,322,905
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$40,876,707	$43,484,358	$51,134,957	$44,724,906	$16,343,416
16	**INCOME TAX EXPENSE**					
17	Investment Tax Credit	($2,295,960)	($2,405,524)	($8,230,037)	($2,939,568)	($2,939,781)
18	Deferred Income Taxes	7,985,656	7,106,564	5,059,809	5,059,809	(1,925,497)
19	Income Taxes	0	0	0	0	0
20	**TOTAL INCOME TAX EXPENSE**	$5,689,696	$4,701,040	($3,170,228)	$2,120,241	($4,865,278)
21	**NET OPERATING INCOME**	$35,187,011	$38,783,318	$54,305,184	$42,604,666	$21,208,696
22	Allowance for Funds Used During Construction	0	0	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$35,187,011	$38,783,318	$54,305,184	$42,604,666	$21,208,695

		(A)	(B)	(C)	(D)
		Test Year 2024			
Line No.	Description	Regulatory Total Utility	Regulatory ND Jurisdiction	Adjustments	Test Year ND Jurisdiction
	OPERATING EXPENSES				
1	Production Expenses	$195,857,531	$86,694,044	$414,421	$87,108,465
2	Transmission Expenses	35,329,066	13,847,298	239,257	14,086,555
3	Distribution Expenses	17,553,489	7,972,703	420,528	8,393,231
4	Customer Accounting Expenses	16,028,499	7,035,433	260,162	7,295,595
5	Customer Service and Information Expenses	12,470,633	1,315,049	15,968	1,331,017
6	Sales Expenses	583,457	135,872	0	135,872
7	Administration and General Expenses	43,893,859	17,534,200	3,241,068	20,775,268
8	Depreciation Expense	79,405,970	32,603,918	489,496	33,093,414
9	General Taxes	18,693,896	7,102,692	796	7,103,488
10	**TOTAL OPERATING EXPENSES**	$419,816,401	$174,241,209	$5,081,696	$179,322,905

			Adjustments																
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Line No.	Description	Unadjusted Year 2024	**Advertising Expenses**	**Fuel Expense - Hoot Lake Solar**	**Non-Employee Director Restricted Stock**	**Economic Development Costs**	**Employe Recognition and Gifts**	**ESSRP**	**Electric Vehicles**	**GIPs**	**Hoot Lake Solar**	**Incentive Compensation**	**Investor Relations**	**Long-Term Incentive**	**PTC GAAP Provision**	**Rider CWIP Projects**	**Transmission Recovery**	Changes in Allocations due to Effect of Normal Adjustments	Regulatory Year 2024
1	**OPERATING REVENUES**																		
2	Retail Revenue	$203,210,040		$1,313,314											4,186,187	($2,720,332)		$0	$205,989,209
3	Other Electric Operating Revenue	$26,713,530								(1,688,273)							(12,044,474)	($3,877)	$12,976,906
4	**TOTAL OPERATING REVENUE**	$229,923,570	$0	$1,313,314	$0	$0	$0	$0	$0	($1,688,273)	$0	$0	$0	$0	$4,186,187	($2,720,332)	($12,044,474)	($3,877)	$218,966,115
5	**OPERATING EXPENSES**																		
6	Production Expenses	$85,426,089		$1,267,955														$0	$86,694,044
7	Transmission Expenses	$13,847,298																$0	$13,847,298
8	Distribution Expenses	$7,972,710																($7)	$7,972,703
9	Customer Accounting Expenses	$7,035,433																$0	$7,035,433
10	Customer Service and Information Expenses	$1,315,049																$0	$1,315,049
11	Sales Expenses	$142,408	(594)			(5,943)												$1	$135,872
12	Administration and General Expenses	$20,028,034	($377,812)		(262,850)		(96,967)	(61,296)				(365,447)	(102,431)	(1,221,363)				($5,668)	$17,534,200
13	Charitable Contributions	$0																$0	$0
14	Depreciation Expense	$35,004,220							(78,037)	(311,858)	(685,029)						(1,325,266)	($112)	$32,603,918
15	General Taxes	$8,019,985															(916,394)	($899)	$7,102,692
16	**TOTAL OPERATING EXPENSES**	$178,791,226	($378,406)	$1,267,955	($262,850)	($5,943)	($96,967)	($61,296)	($78,037)	($311,858)	($685,029)	($365,447)	($102,431)	($1,221,363)	$0	$0	($2,241,660)	($6,685)	$174,241,209
17	**NET OPERATING INCOME BEFORE INCOME TAXES**	$51,132,344	$378,406	$45,359	$262,850	$5,943	$96,967	$61,296	$78,037	($1,376,415)	$685,029	$365,447	$102,431	$1,221,363	$4,186,187	($2,720,332)	($9,802,814)	$2,808	$44,724,906
18	**INCOME TAX EXPENSE**																		
19	Investment Tax Credit	($8,230,453)									$279,699				$5,010,974			$212	($2,939,568)
20	Deferred Income Taxes	($1,925,497)																$6,985,306	$5,059,809
21	Income Taxes	$0	$92,350	$11,070	$64,148	$1,450	$23,665	$14,959	$19,045	($335,913)	$167,181	$89,187	$24,998	$298,072	$1,021,635	($663,894)	($2,392,367)	$1,564,414	$0
22	**TOTAL INCOME TAX EXPENSE**	($10,155,950)	$92,350	$11,070	$64,148	$1,450	$23,665	$14,959	$19,045	($335,913)	$446,880	$89,187	$24,998	$298,072	$6,032,609	($663,894)	($2,392,367)	$8,549,932	$2,120,241
23	**NET OPERATING INCOME**	$61,288,294	$286,056	$34,289	$198,702	$4,493	$73,302	$46,337	$58,992	($1,040,502)	$238,149	$276,260	$77,433	$923,291	($1,846,422)	($2,056,438)	($7,410,447)	($8,547,124)	$42,604,665
24	Allowance for Funds Used During Construction	$0																$0	$0
25	**TOTAL AVAILABLE FOR RETURN**	$61,288,294	$286,056	$34,289	$198,702	$4,493	$73,302	$46,337	$58,992	($1,040,502)	$238,149	$276,260	$77,433	$923,291	($1,846,422)	($2,056,438)	($7,410,447)	($8,547,124)	$42,604,665

OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE
Regulatory Year 2024 to Test Year 2024

			Adjustments										
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(k)	(L)
Line No.	Description	Regulatory Year 2024	**Rate Case Expenses**	**Normalize Langdon Upgrade Project**	**Normalize Pension and PRM**	**Non-Employee Director Restirced Stock**	**Rider Roll-In**	**ESSRP**	**Employe Recognition and Gifts**	**Investor Relations**	**Long-Term Inventive**	Changes in Allocations due to Effect of Test Year Adjustments	Test Year 2024
1	**OPERATING REVENUES**												
2	Retail Revenue	$205,989,209					($23,302,321)					$0	$182,686,888
3	Other Electric Operating Revenue	$12,976,906										$2,527	$12,979,433
4	**TOTAL OPERATING REVENUE**	$218,966,115	$0	$0	$0	$0	($23,302,321)	$0	$0	$0	$0	$2,527	$195,666,321
5	**OPERATING EXPENSES**												
6	Production Expenses	$86,694,044			414,420							$1	$87,108,465
7	Transmission Expenses	$13,847,298			239,257							$0	$14,086,555
8	Distribution Expenses	$7,972,703			420,521							$7	$8,393,231
9	Customer Accounting Expenses	$7,035,433			260,162							($0)	$7,295,595
10	Customer Service and Information Expenses	$1,315,049			15,968							$0	$1,331,017
11	Sales Expenses	$135,872										($0)	$135,872
12	Administration and General Expenses	$17,534,200	$359,404		1,131,083	262,850		61,296	96,967	102,431	1,221,363	$5,674	$20,775,268
13	Charitable Contributions	$0										$0	$0
14	Depreciation Expense	$32,603,918		489,384								$112	$33,093,414
15	General Taxes	$7,102,692										$796	$7,103,488
16	**TOTAL OPERATING EXPENSES**	$174,241,209	$359,404	$489,384	$2,481,411	$262,850	$0	$61,296	$96,967	$102,431	$1,221,363	$6,590	$179,322,905
17	**NET OPERATING INCOME BEFORE INCOME TAXES**	$44,724,906	($359,404)	($489,384)	($2,481,411)	($262,850)	($23,302,321)	($61,296)	($96,967)	($102,431)	($1,221,363)	($4,063)	$16,343,416
18	**INCOME TAX EXPENSE**												
19	Investment Tax Credit	($2,939,568)										($213)	($2,939,781)
20	Deferred Income Taxes	$5,059,809										($6,985,306)	($1,925,497)
21	Income Taxes	$0	($87,712)	($136,495)	($605,586)	($64,148)	($5,686,908)	($14,959)	($23,665)	($24,998)	($298,072)	$6,942,544	($0)
22	**TOTAL INCOME TAX EXPENSE**	$2,120,241	($87,712)	($136,495)	($605,586)	($64,148)	($5,686,908)	($14,959)	($23,665)	($24,998)	($298,072)	($42,975)	($4,865,278)
23	**NET OPERATING INCOME**	$42,604,665	($271,692)	($352,889)	($1,875,825)	($198,702)	($17,615,413)	($46,337)	($73,302)	($77,433)	($923,291)	$38,912	$21,208,694
24	Allowance for Funds Used During Construction	$0										$0	$0
25	**TOTAL AVAILABLE FOR RETURN**	$42,604,665	($271,692)	($352,889)	($1,875,825)	($198,702)	($17,615,413)	($46,337)	($73,302)	($77,433)	($923,291)	$38,912	$21,208,694

[PROTECTED DATA BEGINS...

Schedule 13 – Mercer March 2023 Five Year Expense Estimate

to

Direct Testimony of Christy L. Petersen

In the Matter of the Application of Otter Tail Power Company

For Authority to Increase Rates for Electric Utility Service in North Dakota

THIS DOCUMENT IS NOT PUBLIC IN ITS ENTIRETY

...PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS…

Schedule 14 – Mercer September 2023 Five Year PRM Expense Estimate

to

Direct Testimony of Christy L. Petersen

In the Matter of the Application of Otter Tail Power Company

For Authority to Increase Rates for Electric Utility Service in North Dakota

THIS DOCUMENT IS NOT PUBLIC IN ITS ENTIRETY

…PROTECTED DATA ENDS]

Volume 2A

Direct Testimony and Supporting Schedules:

Paula M. Foster

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

TRANSITION OF CAPITAL PROJECTS FROM RIDERS TO BASE RATES

Direct Testimony and Schedules of

PAULA M. FOSTER

November 2, 2023

TABLE OF CONTENTS

ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My Name is Paula Foster. I am employed by Otter Tail Power Company (OTP).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Supervisor of Regulatory Analysis. My primary responsibilities in this position are to lead the work team responsible for the preparation and financial analysis used to determine revenue requirements associated with various state and federal cost recovery mechanisms and to lead development of regulatory filings associated with these cost recovery mechanisms.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(PMF-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony describes OTP's proposal regarding treatment of certain riders and associated costs in the 2024 Test Year and adjustments to those riders as the result of moving cost recovery from riders and into base rates.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. OTP proposes to move certain investments currently being recovered in the Renewable Resource Cost Recovery Rider (RRCR Rider), Transmission Cost Recovery Rider (TCR Rider), Metering & Distribution Technology Cost Recovery Rider (MDT Rider),[1] and Generation Cost Recovery Rider (GCR Rider) into base rates as part of this case. This proposal does not increase customers' overall bills, though it does change the particular mechanism through which costs are recovered. In connection with the movement of costs into base rates, OTP is proposing to reset RRCR Rider, TCR Rider, MDT Rider, and GCR Rider rates effective January 1, 2024.

[1] The Commission requested a name change in Case No. PU-23-283 from Advanced Metering and Distribution Technology (AMDT) to Metering & Distribution Technology.

III. MOVING CAPITAL PROJECTS FROM RIDERS INTO BASE RATES

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY.

A. This section of my Direct Testimony explains the mechanics of OTP's proposal to transfer recovery of certain costs presently recovered in riders into base rates. OTP witness Ms. Christy L. Petersen quantifies the impact of this proposal on the 2024 Test Year revenue requirement.

Q. DOES THE MOVEMENT OF PROJECTS FROM RIDERS TO BASE RATES IMPACT CUSTOMERS' OVERALL BILLS?

A. No. The Company's proposal to move costs out of riders and into base rates changes the mechanism through which costs are recovered, but it does not impact customers' overall bills.

Q. WILL THESE RIDERS REMAIN IN EFFECT FOLLOWING THE CONCLUSION OF THIS CASE?

A. The Company proposes that each of the riders remain in effect going forward, though the GCR Rider will be set to a rate of $0.00 as a January 1, 2024, as discussed below.

A. RRCR Rider

Q. WHAT IS THE RRCR RIDER?

A. The RRCR Rider allows a public utility (in this case, OTP) to recover jurisdictional capital costs and associated operating expenses of certain renewable resource additions outside of a rate case. OTP's RRCR Rider was established in Case No. PU-06-466.[2]

Q. PLEASE IDENTIFY OTP'S PAST RRCR RIDER FILINGS.

A. OTP's prior RRCR Rider filings are shown in table 1 below:

[2] Commission's May 21, 2008 Order approving OTP's Renewable Resource Rider Application in Case No. PU-06-466.

Table 1
RRCR Rider History

RRCR Filing	Case Number	Commission Approved	Effective Date
RRCR Establish Application	PU-06-466	May 21, 2008	No rate established
Original RRA Rate and Mechanism	PU-08-742 PU-08-862	January 14, 2009	February 1, 2009
First Update	PU-10-18	August 4, 2010	September 1, 2010
Second Update*	PU-12-24	March 21, 2012	April 1, 2012
Third Update	PU-13-16	July 10, 2013	April 1, 2013
Fourth Update	PU-14-14	March 12, 2014	April 1, 2014
Fifth Update	PU-15-14	March 25, 2015	April 1, 2015
Sixth Update	PU-16-14	June 22, 2016	July 1, 2016
Seventh Update	PU-17-016	March 15, 2017	April 1, 2017
Eighth Update	PU-17-398	December 20, 2017	January 1, 2018
Ninth Update	PU-17-398	February 27, 2019	March 1, 2018
Tenth Update	PU-17-398	December 19, 2018	February 1, 2019
Eleventh Update	PU-19-17	May 1, 2019	June 1, 2019
Twelfth Update	PU-19-387	March 18, 2020	April 1, 2020
Thirteenth Update	PU-21-30	March 17, 2021	April 1, 2021
Fourteenth Update	PU-22-19	February 2, 2022	April 1, 2021
Fifteenth Update	PU-22-429	April 27, 2023	May 1, 2023
Sixteenth Update	PU-23-XXX	Open Proceeding	April 1, 2024**

*Established the collection timeline of April through March of the following year.
**Proposed

Q. WHAT PROJECTS ARE CURRENTLY INCLUDED IN OTP'S RRCR RIDER?

A. OTP's RRCR Rider currently recovers costs associated with OTP's investments in the Merricourt Wind Energy Center (Merricourt) and Ashtabula III wind farm (Ashtabula III), both located in North Dakota. OTP received an Advanced Determination of Prudence for Merricourt and a Certificate of Public Convenience and Necessity for Ashtabula III.[3] Both Merricourt and Ashtabula III are in service and will move into base rates concurrently with the implementation of interim rates.

[3] *See* Case Nos. PU-17-141 and PU-17-143 (Merricourt) and PU-22-27 (Ashtabula III).

Q. HAS OTP REQUESTED APPROVAL TO INCLUDE ADDITIONAL PROJECTS IN ITS RRCR RIDER?

A. Yes. On November 2, 2023, OTP filed its Sixteenth RRCR Rider Update. In that filing OTP proposes to include costs associated with the Wind Energy Facility Equipment Upgrade (Upgrade Project), which consists of the repowering of the Langdon, Luverne, Ashtabula I, and Ashtabula III Wind Energy Facilities (the Langdon Upgrade, the Luverne Upgrade, the Ashtabula I Upgrade and the Ashtabula III Upgrade).

Q. PLEASE DESCRIBE THE UPGRADE PROJECT.

A. The Langdon, Luverne, Ashtabula I, and Ashtabula III Wind Energy Facilities each qualify for production tax credits (PTCs) through the Inflation Reduction Act (IRA). OTP will be making upgrades to each facility in 2024 and 2025. These upgrades involve removing and replacing the existing General Electric blades, hub, and gearbox with upgraded technology and increased blade rotor diameters. The 131 turbines repowered will reuse the existing 80-meter structural steel towers and existing nacelles. OTP plans to use the existing turbine foundations (with reinforcement, if needed), collection and communication systems, and permanent access roads. Other associated facilities will remain unchanged. Installation of the upgraded equipment is expected to increase energy generation at the facilities by more than 20 percent annually. Total capital costs for the Upgrade Project are estimated to be $230 million (OTP Total). OTP expects that the Upgrade Project, collectively, will generate more than $23 million (OTP Total)[4] in PTCs annually.

Q. HAVE THE LANGDON UPGRADE, THE LUVERNE UPGRADE, THE ASHTABULA I UPGRADE, AND THE ASHTABULA III UPGRADE BEEN APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION?

A. Yes. The various components of the Upgrade Project were approved by the North Dakota Public Service Commission in siting application Case Nos. PU-23-86, PU-23-176, PU-23-252, and PU-23-256.

[4] 832,000 MWh x $28/MWh PTC rate = $23,296,000.

Q. WHEN DOES OTP EXPECT THE COMPONENTS OF THE UPGRADE PROJECT TO BE PLACED IN SERVICE?

A. The Langdon Upgrade is expected to be completed in the third quarter of 2024. The Luverne, Ashtabula I, and Ashtabula III Upgrades are expected to be completed in the second and third quarters of 2025.

Q. WHAT IS OTP'S PROPOSAL REGARDING RRCR RIDER PROJECTS?

A. OTP requests that RRCR Rider projects that currently are in-service (i.e., Merricourt and Ashtabula III) be rolled into base rates at the time interim rates go into effect. Projects that will be placed in service during 2024 (i.e. the Langdon Upgrade) will remain in the RRCR Rider while this case proceeds and will move into base rates when final rates go into effect.

Q. WILL THE RRCR RIDER REMAIN IN EFFECT FOLLOWING THE CONCLUSION OF THIS CASE?

A. Yes. As discussed below, OTP proposes that PTCs associated with Merricourt and the Langdon Upgrade be credited to customers through the RRCR Rider on a going forward basis. Also, the non-Langdon components of the Upgrade project that are expected to be placed into service in 2025 will remain in the RRCR Rider until OTP's next North Dakota rate case.

1. Test Year Revenue Requirement

Q. HOW HAVE MERRICOURT, ASHTABULA III, AND THE LANGDON UPGRADE COSTS BEEN HANDLED IN THE 2024 TEST YEAR?

A. The Merricourt, Ashtabula III, and Langdon Upgrade (collectively, the RRCR Projects) investments are part of the rate base used to determine the 2024 Test Year revenue requirement. For Merricourt and Ashtabula III, this includes all gross plant in service, accumulated depreciation, and associated deferred income tax balances as of December 31, 2024. Because the Langdon Upgrade is expected to be in service at the end of 2024, OTP has included an adjustment to annualize the costs associated with the project into the 2024 Test Year. Ms. Petersen describes the mechanics of this adjustment in her Direct Testimony.

Q. HOW HAS OTP TREATED PROJECTED 2024 RRCR RIDER REVENUES IN THE 2024 TEST YEAR CALCULATIONS?

A. Projected 2024 RRCR Rider revenues associated with the Langdon Upgrade are not included in the calculation of present revenues for the 2024 Test Year. The exclusion of the RRCR Rider revenues associated with the Langdon Upgrade accounts for approximately $1.3 million (OTP ND) of the 2024 Test Year base rate revenue deficiency.

The 2024 Test Year present revenues also do not include RRCR Rider revenues associated with Merricourt and Ashtabula III. The exclusion of RRCR Rider revenues associated with Merricourt and Ashtabula III accounts for approximately $15.6 million (OTP ND) of the 2024 Test Year base rate revenue deficiency. As discussed above, however, the movement of projects from riders to base rates does not impact customers' bills, only the sections of the bill through which costs are recovered.

Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE AFFECTED BY INCLUDING THE RRCR PROJECTS IN BASE RATES?

A. The primary rate base components are: (i) gross plant in service; (ii) accumulated depreciation; and (iii) accumulated deferred income taxes. The primary operating expense components that are affected include: (i) depreciation and (ii) general tax expenses.

Q. WHAT LEVEL OF RRCR PROJECT INVESTMENT IS REFLECTED IN THE 2024 TEST YEAR?

A. The 2024 Test Year rate base for the RRCR Projects is approximately $229.7 million (OTP Total) and $86.3 million (OTP ND). A detailed list of the rate base amounts moving from the RRCR Rider to base rates is included as Exhibit___(PMF-1), Schedule 2.

Q. HOW DID OTP DEVELOP THE 2024 TEST YEAR INVESTMENT LEVELS FOR THE RRCR PROJECTS?

A. The 2024 Test Year investment levels for Merricourt and Ashtabula III are based on actual in-service amounts. The Langdon Upgrade investment has been annualized, reflecting a full year of operations.

Q. WHY IS OTP ANNUALIZING THE LANGDON UPGRADE INVESTMENT FOR THE 2024 TEST YEAR?

A. The Langdon Upgrade is anticipated to be placed in service in the third quarter of 2024. This means the project will be available and providing service to customers during the period rates from this case are in effect. Annualizing the project investment (and other rate base and income statement components) in the 2024 Test Year ensures the cost of service appropriately reflects the benefits received by customers during the period when final rates will be in effect.

Q. WILL OTP UPDATE THE LANGDON UPGRADE ANNUALIZATION ADJUSTMENT AS THE CASE DEVELOPS?

A. Yes. The adjustment reflects the current capital spending schedule and anticipated project in-service date. We will continue to provide information regarding the schedule and anticipated in-service date as the case develops so that final rates will reflect the updated project costs.

Q. HOW DOES THE FINAL COST OF MERRICOURT COMPARE TO THE ESTIMATES FROM CASE NOS. PU-17-140, 17-141 AND 17-143?

A. Merricourt was placed into service December 19, 2020, at a final cost of $262.8 million (OTP Total) / $118.2 million (OTP ND). This is lower than the Merricourt Authorized Amount, as defined in the September 29, 2017 Settlement Agreement in Case Nos. PU-17-140, 17-141 and PU-17-143, which was approved by the Commission in its November 3, 2017 Order on Settlement in those same cases. Under that Order, costs up to the Merricourt Authorized Amount have been deemed reasonable and prudent for cost recovery.

2. Interim Rate Revenue Requirement

Q. HOW ARE THE RRCR PROJECTS BEING RECOVERED DURING THE INTERIM RATE PERIOD?

A. As discussed above, OTP proposes to transfer project costs for Merricourt and Ashtabula III out of the RRCR Rider and into base rates at the time interim rates go into effect. From that point forward, recovery of Merricourt and Ashtabula III costs will be in base rates.

Costs associated with the Langdon Upgrade will remain in the RRCR Rider during this case and will transfer into base rates at the time final rates go into effect. From that point forward, recovery of the Langdon Upgrade will be in base rates.

Q. IS OTP MAKING AN INTERIM RATE ADJUSTMENT FOR THE RRCR PROJECTS?

A. Yes. The interim rate adjustment adds the Langdon Upgrade RRCR Rider present revenue, removes the revenue associated with CWIP, and removes the annualization adjustment for the project from the interim cost of service. Merricourt and Ashtabula III are included in the interim cost of service. Additional detail on this adjustment can be found in Volume 1, Notice of Change in Rates and Interim Rate Petition, Interim Rate Supporting Schedules and Volume 4a Workpapers.

3. Production Tax Credits

Q. WHAT ARE PRODUCTION TAX CREDITS?

A. PTCs are tax credits authorized by the Internal Revenue Code 26 USC § 45. Owners of PTC-eligible wind turbines can claim a tax credit, a reduction to tax expense, based on the amount of energy produced from those turbines. PTCs are available for ten years after production begins.

Q. DOES OTP CURRENTLY RECEIVE PTCS FOR THE ENERGY PRODUCTION FROM ITS WIND PROJECTS?

A. Yes. OTP currently receives PTCs for Merricourt. OTP will also earn PTCs for each wind farm included in the Upgrade Project. Each wind farm will begin earning PTCs once the various components are placed into service at that wind farm.

Q. HOW DOES OTP RECOMMEND THAT CUSTOMERS RECEIVE THE BENEFITS ASSOCIATED WITH PTCS?

A. OTP recommends that customers continue to receive the benefits of PTCs through the RRCR Rider and that no PTCs be incorporated into base rates.

Q. WHY DOES OTP RECOMMEND THAT PTCS REMAIN IN THE RRCR RIDER?

A. Actual PTCs (and therefore customer benefits) are dependent on actual operations (kwh output) of the PTC-eligible facilities. OTP has a long history of using the RRCR Rider to address any differences between projected and actual PTCs and will continue to use the RRCR Rider to address these differences on a going forward basis, regardless of whether PTCs are or are not included in base rates. Given the RRCR Rider will be used to address differences between projected and actual PTCs on a going forward basis, it is administratively more efficient to keep all PTCs in the RRCR Rider.

Q. HOW DOES OTP RECOMMEND THAT PTCS BE HANDLED IN THE RRCR RIDER?

A. OTP recommends that Merricourt PTCs, which are currently levelized, continue to be levelized. For the Upgrade Projects, OTP recommends that PTCs not be levelized, but rather, included in the RRCR rider rate calculation as OTP earns the credits. In its order in Case No. PU-19-387, the Commission required OTP to levelize the Merricourt PTCs over the life of the project.[5] Levelization, for ratemaking purposes, delays crediting of some of the tax benefit to spread it over the entire depreciable life of an asset (35 years). Under this approach, Merricourt will earn PTCs over its first ten years of operation, but customers will not see the full crediting of those tax credits until year 35. In financial terms, OTP forecasts that the project will generate approximately $155.5 million (OTP Total) / $69.9 million (OTP ND) of PTCs in its first 10 years of production (the period facilities are eligible to earn PTCs). As a result, OTP has included an approximately $4.4 million (OTP Total) / $2.0 million (OTP ND) credit annually in its RRCR Rider revenue requirement calculations. These credits are subject to true-up based on actual production. OTP recommends that Merricourt PTCs remain levelized in the RRCR Rider going forward, to comply with the Commission's order.

OTP recommends crediting PTCs to the rider as they are earned for the Langdon Upgrade and other components of the Upgrade Project. Under this approach, PTCs reduce tax expense as the PTCs are generated. This means that PTCs will reduce revenue requirements (and rates) for the first 10 years of a project, the period when its revenue requirements would otherwise be at their highest. After ten years, a significant amount of depreciation will have accrued, which will itself result in a reduction to revenue requirements. The forecasted Upgrade Project PTCs and actual PTCs will be trued up in annual RRCR Rider filings.

---

[5] *See* Case No. PU-19-387.

Q. WHY DOES OTP RECOMMEND INCLUDING PTCS FOR THE LANGDON UPGRADE IN THE RIDER AS THEY ARE EARNED?

A. Including the credits in the rider as they are earned results in them being credited to customers faster than would otherwise occur under the levelized method, providing more immediate benefits to customers. As noted above, the PTCs will apply during the period when revenue requirements would otherwise be at their highest. After ten years, a significant amount of depreciation will have accrued, which will itself result in a reduction to revenue requirements.

OTP's recommendation also matches PTC crediting with actual facility operations and avoids revenue normalization adjustments (discussed below). That being said, customers receive the full benefits of PTCs generated by the facility regardless of the method chosen; the difference is merely one of timing. Still, our preference is to credit the PTCs to customers as they are earned for the reasons explained above.

Q. DOES LEVELIZING THE MERRICOURT PTCS REQUIRE AN ADJUSTMENT TO THE 2024 TEST YEAR COST OF SERVICE?

A. Yes. Levelization means that OTP has earned more PTCs than have been credited to customers through the RRCR Rider. The excess is incorporated into Accumulated Deferred Income Tax balances as a regulatory liability, reflecting future amounts that will be credited to customers over the useful life of the project. The Company is adjusting the 2024 Test Year to remove the difference between the generated PTCs for Merricourt and the levelized PTC amount in the rider. Ms. Petersen describes the mechanics of this adjustment in her Direct Testimony.

Q. WILL CUSTOMERS RECEIVE CREDIT FOR ALL PTCS RELATED TO MERRICOURT AND THE LANGDON UPGRADE?

A. Yes. OTP proposes to continue tracking PTC activity through the RRCR Rider and true up actual PTCs to those included in RRCR Rider rates through updates to the RRCR Rider.

4. RRCR Rider Rate Update

Q. IS OTP UPDATING ITS RRCR RIDER RATES CONCURRENTLY WITH THIS FILING?

A. Yes. OTP's Sixteenth Update filing proposes that RRCR Rider rates be adjusted to remove the rate base balances and operating expenses of Merricourt and Ashtabula

III as of the implementation of interim rates. This update ensures there is no double-recovery of the Merricourt and Ashtabula III costs during the interim rate period.

Q. IS OTP PROPOSING ANY OTHER UPDATES TO THE RRCR RATE AT THIS TIME?

A. Yes. OTP's current RRCR Rider rate was approved in Case No. 22-429.[6] The current approved RRCR Rider rate is based on the rate of return and North Dakota allocation factors approved in OTP's last general rate case.[7] In addition to removing Merricourt and Ashtabula III costs from the RRCR Rider revenue requirement, the Sixteenth Update incorporates costs from the Upgrade Project, the 2024 Test Year North Dakota allocation factors, proposed capital structure with the return on equity approved in OTP's last general rate case, and projected sales and revenues from this case. Exhibit___(PMF-1), Schedule 3 provides the revised RRCR Rider rate calculation, to be effective April 1, 2024. These updates to the RRCR Rider result in a decrease to the RRCR Rate from 12.157 percent of bill to 1.728 percent of bill.

Because OTP's Sixteenth Update to the RRCR Rider has a proposed effective date of April 1, 2024, OTP requests the RRCR Rider be set to zero during the period of January 1, 2024, when interim rates begin, through March 31, 2024. The Merricourt PTCs accrued during this time are included in the true-up of the proposed RRCR Rate calculation in the filing submitted on November 2, 2023.

Q. WHY IS IT REASONABLE TO UPDATE THE RRCR RIDER EFFECTIVE JANUARY 1, 2024?

A. Updating the RRCR Rider effective January 1, 2024 ensures there is no double recovery of costs during the interim rate period. If the updated rate is not implemented, OTP will over-collect revenues during the interim rate period, requiring a subsequent true-up.

[6] Commission's April 27, 2023 Order approving OTP's 2023 Renewable Resource Cost Recovery Adjustment Factor in Case No. PU-22-429 and an RRCR rate of 12.157 percent of bill.
[7] Commission's September 26, 2018 Order on Settlement in Case No. PU-17-398 for OTP's Electric Rate Increase Application.

Q. WILL THE RRCR RIDER RATE BE UPDATED AT THE CONCLUSION OF THIS CASE?

A. Yes. Upon implementation of final rates in this case, OTP will update the RRCR Rider to: (1) remove Langdon Upgrade costs from the RRCR Rider; and (2) update the RRCR Rider capital structure and cost of capital to reflect the Commission's final order of this case. The adjustment to the authorized capital structure and cost of capital will be effective as of January 1, 2024.

Q. WILL THE RRCR RIDER REMAIN IN EFFECT AFTER THE CONCLUSION OF THIS CASE?

A. Yes. As discussed above, OTP proposes to keep the RRCR Rider in effect going forward to address issues associated with PTCs and to collect costs associated with the Ashtabula I, Ashtabula III, and Luverne portions of the Upgrade Project. Any remaining RRCR Rider tracker account balance as of the implementation of final rates will also be trued up through the RRCR Rider. OTP proposes that the tracker account balance be recovered from or returned to customers through the RRCR Rider over the subsequent 12 months following implementation of final rates.

B. TCR Rider

Q. WHAT IS THE TCR RIDER?

A. N.D.C.C. § 49-05-04.3 and N.D.C.C. § 49-5-06 authorize the Commission to approve a rider to recover capital costs related to transmission investments and for the recovery of costs assigned by regional transmission organizations (RTOs) for projects subject to cost sharing. OTP's TCR Rider is such a rider.

Q. PLEASE IDENTIFY OTP'S PAST TCR RIDER FILINGS.

A. OTP's prior TCR Rider filings are shown in Table 2 below:

Table 2
TCR Rider History

TCR Rider Filing	Case Number	Commission Approved	Effective Date
Initial TCR Rider Rate and Mechanism	PU-11-153 PU-11-682	April 25, 2012	May 1, 2012
First Update	PU-12-702	December 12, 2012	January 1, 2013
Second Update	PU-13-755	December 30, 2013	January 1, 2014
Third Update	PU-14-690	December 17, 2014	January 1, 2015
Fourth Update	PU-15-661	December 16, 2015	January 1, 2016
Fifth Update	PU-16-624	December 14, 2016	January 1, 2017
Sixth Update	PU-17-340	November 29, 2017	January 1, 2018
Seventh Update	PU-18-329	December 6, 2018	January 1, 2019
Eighth Update	PU-19-311	December 18, 2019	January 1, 2020
Ninth Update	PU-20-383	November 18, 2020	January 1, 2021
Tenth Update	PU-21-376	December 1, 2021	January 1, 2022
Eleventh Update	PU-22-335	December 14, 2022	January 1, 2023
Twelfth Update	PU-23-306	Open Proceeding	January 1, 2024*

*Proposed

Q. WHAT PROJECTS CURRENTLY ARE BEING RECOVERED IN THE TCR RIDER?

A. Exhibit___(PMF-1), Schedule 4 identifies the projects currently included in OTP's TCR Rider (collectively, the TCR Rider Projects).

Q. WHAT IS OTP'S PROPOSAL REGARDING TCR RIDER PROJECTS?

A. OTP proposes to move the 40 TCR Rider Projects that are expected to be in service as of December 31, 2023 into base rates concurrently with the implementation of interim rates. These projects are identified in Schedule 4 with a "Base Rates" designation in the Proposed Recovery column.

Q. WILL THE TCR RIDER REMAIN IN EFFECT FOLLOWING THE CONCLUSION OF THIS CASE?

A. Yes. As indicated in the Proposed Recovery column of Schedule 4, several projects will remain in the TCR Rider following the conclusion of this case. These projects will not be in-service by the end of 2023 and will remain in the TCR Rider. Thus, OTP proposes that the TCR Rider be maintained following the conclusion of this case.

1. Test Year Revenue Requirement

Q. HOW HAVE THE TCR RIDER PROJECTS BEEN HANDLED IN THE 2024 TEST YEAR?

A. The TCR Rider Projects forecasted to be in service as of December 31, 2023 are part of the rate base used to determine the 2024 Test Year revenue requirement. This includes all gross plant in service, accumulated depreciation, and accumulated deferred income tax balances as of December 31, 2024.

Q. HOW HAS OTP TREATED PROJECTED 2024 TCR RIDER REVENUES IN THE 2024 TEST YEAR CALCULATIONS?

A. Projected 2024 TCR Rider revenues associated with the TCR Rider Projects that will remain in the TCR Rider are included in the calculation of present revenues for the 2024 Test Year. The 2024 Test Year present revenues do not include TCR Rider revenues associated with the TCR Rider Projects moving into base rates as part of this case, as those projects are included in interim rates. The exclusion of TCR Rider revenues associated with the TCR Rider Projects moving into base rates accounts for approximately $3.5 million (OTP ND) of the 2024 Test Year base rate revenue deficiency.[8] As discussed above, however, the movement of projects from riders to base rates does not impact customers' bills, only the sections of bills through which costs are recovered.

Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE AFFECTED BY INCLUDING CERTAIN TCR RIDER PROJECTS IN BASE RATES?

A. The primary rate base components are: (i) gross plant in service; (ii) accumulated depreciation; and (iii) accumulated deferred income taxes. The primary operating expense components that are impacted include: (i) depreciation and (ii) general tax expenses.

[8] In the process of finalizing its Direct Testimony, OTP determined that TCR Rider present revenues used in this calculation may be misstated, which, all else equal, would change the portion of the base rate revenue deficiency attributable to moving TCR Rider projects into base rates. This does not impact the overall 2024 Test Year revenue requirement, only the portion of the deficiency related to TCR Rider projects moving into base rates.

Q. WHAT LEVEL OF TCR RIDER PROJECT INVESTMENT IS REFLECTED IN THE 2024 TEST YEAR?

A. The 2024 Test Year rate base for the TCR Rider Projects moving into base rates is approximately $172.2 million (OTP Total) and $68.2 million (OTP ND). A summary of the TCR Rider Projects rate base amounts moving into base rates in included as Exhibit___(PMF-1), Schedule 2.

Q. HOW DID OTP DEVELOP THE 2024 TEST YEAR INVESTMENT LEVELS FOR THE TCR RIDER PROJECTS MOVING INTO BASE RATES?

A. The 2024 Test Year investment levels are based on actual in-service amounts.

2. Interim Rate Revenue Requirement

Q. HOW ARE THE TCR RIDER PROJECTS BEING RECOVERED DURING THE INTERIM RATE PERIOD?

A. As discussed above, OTP proposes to transfer all TCR Rider Projects in-service as of December 31, 2023 into base rates at the time interim rates go into effect. Costs associated with TCR Rider Projects projected to go into service January 1, 2024 and thereafter will remain in the TCR Rider.

Q. IS OTP MAKING AN INTERIM RATE ADJUSTMENT FOR THE TCR RIDER PROJECTS?

A. No. TCR Rider Projects projected to go into service on or before December 31, 2023 are included in the interim cost of service. Other TCR Rider projects not yet completed will remain in the TCR Rider during the interim rate period.

3. TCR Rider Rate Update

Q. IS OTP UPDATING ITS TCR RIDER RATES CONCURRENTLY WITH THIS FILING?

A. Yes. OTP submitted a supplemental filing in its open TCR Rider proceeding, Case No. PU-23-306.[9] The supplemental filing updates TCR Rider rates to remove the rate base balances and operating expenses of the TCR Rider Projects projected to be in service on or before December 31, 2023. These new rates would be effective January 1, 2024, and would ensure there is no double-recovery of the TCR Rider Projects that are included in interim rates.

[9] OTP Initial Filing in PU-23-306 submitted September 15, 2023, with proposed rate update to be implemented January 1, 2024.

Q. IS OTP PROPOSING ANY OTHER UPDATES TO THE TCR RIDER RATE AT THIS TIME?

A. Yes. The supplemental filing also includes the 2024 Test Year North Dakota allocation factors, proposed capital structure with the return on equity approved in OTP's last general rate case, and projected sales and revenues from this case. Exhibit___(PMF-1), Schedule 5 provides the revised TCR Rider rate calculation, to be effective January 1, 2024. These updates to the TCR Rider result in a decrease to the average current TCR Rider rate from $0.00443 per kWh to $0.00172 per kWh.

Q. WILL THE TCR RIDER CALCULATION BE UPDATED AT THE CONCLUSION OF THIS CASE?

A. Yes. Upon implementation of final rates in this case, OTP will update the TCR Rider capital structure and cost of capital to reflect the Commission's final order in this case. The adjustment to the authorized capital structure and cost of capital would be effective as of January 1, 2024, and would be reflected in the true-up in the next TCR Rider annual filing.

Q. WILL THE TCR RIDER REMAIN IN EFFECT AFTER THE CONCLUSION OF THIS CASE?

A. Yes. As discussed above, OTP proposes to continue recovering the TCR Rider Projects not yet in service on December 31, 2023 through the TCR Rider. Annual updates will continue to be made in the TCR Rider in compliance with N.D.C.C. § 49-05-04.3 and Ordering Paragraph 6 of the Commission's April 5, 2012 Order in Case Nos. PU-11-153 and PU-11-682.

C. MDT Rider

Q. WHAT IS THE MDT RIDER?

A. The MDT Rider was approved by the Commission on November 10, 2022 in Case No. PU-22-312. It allows OTP to recover costs associated with the Advanced Metering Infrastructure (AMI), Demand Response (DR), and Outage Management System (OMS) projects.

Q. PLEASE IDENTIFY OTP'S PAST MDT RIDER FILINGS.

A. OTP's prior MDT filings are shown in Table 3 below.

Table 3
MDT Rider History

MDT Rider Filings	Case Number	Commission Approved	Effective Date
Initial MDT Rider Rate and Mechanism	PU-22-312	November 10, 2022	January 1, 2023
First Update	PU-23-283	Open proceeding	January 1, 2024*

*Proposed

Q. WHAT PROJECTS CURRENTLY ARE INCLUDED IN OTP'S MDT RIDER?

A. There are currently three projects included in OTP's MDT Rider: (1) AMI; (2) DR; and (3) OMS. The AMI project involves the deployment of AMI meters, local data collectors in a Field Area Network (FAN), a head-end system, and a Meter Data Management System (MDM).

The DR project replaces end of life or functionally obsolete infrastructure and software, which allows OTP to continue to offer its DR programs. DR is a core Company service utilized by nearly one-third of OTP customers, making OTP's DR portfolio one of the largest in the country by customer adoption.

The OMS project improves OTP's ability to accurately and rapidly identify and respond to outages and allows OTP to more effectively communicate outages and estimated time of restoration to customers.

Q. WHAT IS OTP'S PROPOSAL REGARDING MDT RIDER PROJECTS?

A. OTP proposes that costs associated with the OMS project be rolled into base rates at the time interim rates go into effect, as all components of that project will be in service by December 31, 2023. AMI and DR projects will remain in the MDT Rider through and after the conclusion of this case.

Q. WILL THE MDT RIDER REMAIN IN EFFECT FOLLOWING THE CONCLUSION OF THIS CASE?

A. Yes. OTP proposes that the MDT Rider be maintained following the conclusion of this case.

1. Test Year Revenue Requirement

Q. HOW HAVE OMS COSTS BEEN HANDLED IN THE 2024 TEST YEAR?

A. The OMS investments are part of the rate base used to determine the 2024 Test Year revenue requirement. This includes all gross plant in service, accumulated depreciation, and associated deferred income tax balances as of December 31, 2024.

Q. HOW HAS OTP TREATED PROJECTED 2024 MDT RIDER REVENUES IN THE 2024 TEST YEAR CALCULATIONS?

A. Projected 2024 MDT Rider revenues associated with the AMI and DR projects are included in the calculation of present revenues for the 2024 Test Year, as those projects will remain in the MDT Rider during the case.

The 2024 Test Year present revenues do not include MDT Rider revenues associated with OMS project. The exclusion of MDT Rider revenues associated with OMS project accounts for approximately $0.6 million (OTP ND) of the 2024 Test Year base rate revenue deficiency. As discussed above, however, the movement of projects from riders to base rates does not impact customers' bills, only the section of the bill through which costs are recovered.

Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE AFFECTED BY INCLUDING THE OMS PROJECT IN BASE RATES?

A. The primary rate base components are: (i) gross plant in service; (ii) accumulated depreciation; and (iii) accumulated deferred income taxes. The primary operating expense components that are impacted include: (i) depreciation and (ii) general tax expenses.

Q. WHAT LEVEL OF OMS INVESTMENT IS REFLECTED IN THE 2024 TEST YEAR?

A. The 2024 Test Year rate base for the OMS project is approximately $3.5 million (OTP Total) and $1.5 million (OTP ND). A detailed list of rate base amounts moving from the MDT Rider to base rates is included as Exhibit___(PMF), Schedule 2.

Q. HOW DID OTP DEVELOP THE 2024 TEST YEAR INVESTMENT LEVELS FOR OMS?

A. The 2024 Test Year investment levels for the OMS project are based on actual in-service amounts.

2. Interim Rate Revenue Requirement

Q. HOW ARE THE MDT RIDER PROJECTS BEING RECOVERED DURING THE INTERIM RATE PERIOD?

A. As discussed above, OTP proposes to transfer OMS project costs into base rates at the time interim rates go into effect. Costs associated with the AMI and DR projects will remain in the MDT Rider.

Q. IS OTP MAKING AN INTERIM RATE ADJUSTMENT FOR THE MDT RIDER PROJECTS?

A. No. OMS project costs are included in the interim cost of service. AMI and DR project costs will remain in the MDT Rider during the interim rate period.

3. MDT Rider Update

Q. IS OTP UPDATING ITS MDT RIDER RATES CONCURRENTLY WITH THIS FILING?

A. Yes. OTP has submitted a supplemental filing in its open MDT Rider proceeding, Case No. PU-23-283. The supplemental filing updates the MDT Rider rates to remove the rate base balances and operating expenses of the OMS project. These new rates are proposed to be effective January 1, 2024 and ensure there is no double-recovery of OMS project costs during the interim rate period.

Q. IS OTP PROPOSING ANY OTHER UPDATES TO THE MDT RIDER RATE AT THIS TIME?

A. Yes. The supplemental filing also includes the 2024 Test Year North Dakota allocation factors, proposed capital structure with the return on equity approved in OTP's last general rate case, and projected sales and revenues from this case. Exhibit___(PMF-1), Schedule 6 provides the revised MDT Rider rate calculation, to be effective January 1, 2024. These updates to the MDT Rider result in a decrease to the MDT Rider residential rate from $1.71 to $0.73 and a decrease to the MDT Rider large general service rate from $71.76 to $21.07.

Q. WILL THE MDT RIDER RATE BE UPDATED AT THE CONCLUSION OF THIS CASE?

A. Yes. Upon implementation of final rates in this case, OTP will update the MDT Rider capital structure and cost of capital to reflect the Commission's final order of this case. The adjustment to the authorized capital structure would be effective as of January 1, 2024, and will be reflected in the true-up in the next annual MDT Rider filing.

Q. WILL THE MDT RIDER REMAIN IN EFFECT AFTER THE CONCLUSION OF THIS CASE?

A. Yes. As discussed above, OTP proposes to continue recovering the AMI and DR projects through the MDT Rider. Further, the MDT Rider will continue to be used to reflect offsets to operations and maintenance cost savings attributable to manual meter reading and customer service, as required by the Commission's November 10, 2022 Order in case No. PU-22-312. Savings credited to customers in the rider will not exceed the expense included in base rates.

D. GCR Rider

Q. WHAT IS THE GCR RIDER?

A. The GCR Rider allows OTP to recover costs associated with certain generation resources outside of a rate case. The GCR Rider was established in OTP's last North Dakota general rate case, Case No. PU-17-398.

Q. PLEASE IDENTIFY OTP'S PAST GCR RIDER FILINGS.

A. OTP's prior GCR Rider filings are shown in Table 4 below.

Table 4
GCR Rider History

GCR Rider Filing	Case Number	Commission Approved Date	Effective Date	Approved Rate
Original GCR Rider Rate and Mechanism	PU-17-398	September 26, 2018	February 1, 2019	0.000%
First Update	PU-19-91	May 15, 2019	July 1, 2019	2.547%
Second Update	PU-20-91	June 10, 2020	July 1, 2020	6.041%
Third Update	PU-21-92	May 5, 2021	July 1, 2021	5.179%
Fourth Update	PU-22-87	May 25, 2022	July 1, 2022	2.982%
Fifth Update	PU-23-83	June 28, 2023	July 1, 2023	2.026%

Q. WHAT PROJECTS CURRENTLY ARE INCLUDED IN OTP'S GCR RIDER?

A. OTP's GCR Rider currently includes the cost of Astoria Station, a natural gas-fired, simple cycle combustion turbine that was placed into service in 2021. The GCR Rider also includes credits related to the retirement of Hoot Lake Plant.

Q. WHAT IS OTP'S PROPOSAL REGARDING GCR RIDER PROJECTS?

A. OTP requests to move Astoria Station project costs into base rates and discontinue the Hoot Lake Plant credit concurrently with the implementation of interim rates.

Q. WILL THE GCR RIDER REMAIN IN EFFECT FOLLOWING THE CONCLUSION OF THIS CASE?

A. Yes. OTP proposes that GCR Rider be maintained following the conclusion of this case, but that the rate be set to $0.00 upon the implementation of interim rates.

1. Test Year Revenue Requirement

Q. HOW HAVE ASTORIA STATION COSTS BEEN HANDLED IN THE 2024 TEST YEAR?

A. The Astoria Station investments are part of the rate base used to determine the 2024 Test Year revenue requirement. This includes all gross plant in service, accumulated depreciation, and associated deferred income tax balances as of December 31, 2024.

Q. DOES THE 2024 TEST YEAR REVENUE REQUIREMENT INCLUDE ANY CREDITS ASSOCIATED WITH THE CLOSURE OF THE HOOT LAKE PLANT?

A. No. The Settlement Agreement in OTP's last rate case required that the GCR Rider include "retirement-related changes to costs of service … until those changes to costs are reflected in base rates in a general rate case."[10] This provision was intended to capture the difference between then-existing base rates, which reflected ongoing, representative costs of normal operation of Hoot Lake Plant and lower costs that would be incurred following retirement. Hoot Lake Plant ceased operations May 27, 2021, and, beginning with the Third GCR Rider Update, OTP initiated a credit in the GCR Rider calculations to reflect the reduction in Hoot Lake Plant operating costs. Now that base rates are being reset, however, there is no need to continue the credit, as the 2024 Test Year does not include any costs associated with Hoot Lake Plant.

Q. HOW HAS OTP TREATED PROJECTED 2024 GCR RIDER REVENUES FOR ASTORIA STATION IN THE 2024 TEST YEAR CALCULATIONS?

A. The 2024 Test Year present revenues do not include GCR Rider revenues associated with Astoria Station. The exclusion of GCR Rider revenues associated with Astoria Station accounts for approximately $3.6 million (OTP ND) of the 2024 Test Year base rate revenue deficiency. As discussed above, however, the movement of projects from riders to base rates does not impact customers' bills, only the section of the bill through which costs are recovered.

Q. WHAT ARE THE PRIMARY TEST YEAR COST COMPONENTS THAT ARE AFFECTED BY INCLUDING ASTORIA STATION IN BASE RATES?

A. The primary rate base components are: (i) gross plant in service; (ii) accumulated depreciation; (iii) accumulated deferred income taxes; and (iv) a long-term service agreement with Mitsubishi. The primary operating expense component impacted is (i) depreciation and (ii) general taxes.

---

[10] Commission's September 26, 2018 Order on Settlement in Case No. PU-17-398, Settlement Agreement at 9.

Q. WHAT LEVEL OF ASTORIA STATION PROJECT INVESTMENT IS REFLECTED IN THE 2024 TEST YEAR?

A. The 2024 Test Year rate base for Astoria Station is approximately $132.9 million (OTP Total) / $53.0 million (OTP ND). The Astoria Station rate base amounts moving from the GCR Rider to base rates is included as Exhibit___(PMF-1), Schedule 2.

Q. HOW DID OTP DEVELOP THE 2024 INVESTMENT LEVEL OF ASTORIA STATION?

A. The 2024 Test Year investment level for Astoria Station is based on actual project investment.

Q. HOW DOES THE FINAL COST OF ASTORIA STATION COMPARE TO THE ESTIMATES FROM CASE NO. PU-17-140?

A. Astoria Station was deemed "in-service" for accounting purposes as of February 2021 and was declared commercially operational in April 2021. While final close-out items continued into mid-2023, Astoria Station has been dispatched regularly since April 2021 and was completed one month prior to being needed as a generating resource. Ultimately, the final cost of Astoria Station was $152.1 million (OTP Total) / $60.0 million (OTP ND), significantly less than the $181.5 million (OTP Total) capital expenditure cost (excluding AFUDC) deemed reasonable and prudent in Case No. PU-17-140.

2. Interim Rate Revenue Requirement

Q. HOW ARE THE GCR RIDER PROJECTS BEING RECOVERED DURING THE INTERIM RATE PERIOD?

A. As discussed above, OTP proposes to transfer all Astoria Station project costs into base rates at the time interim rates go into effect.

Q. IS OTP MAKING AN INTERIM RATE ADJUSTMENT FOR THE GCR RIDER PROJECTS?

A. No. The Astoria Station project costs are part of the interim rate cost of service, and the Hoot Lake Plant costs that were being credited to customers are no longer included in the cost of service.

3. GCR Rider Update

Q. IS OTP UPDATING ITS GCR RIDER RATES CONCURRENTLY WITH THIS FILING?

A. Yes. OTP proposes to remove rate base balances and operating expenses of Astoria Station from the GCR Rider, discontinue the Hoot Lake Plant credit and zero out the GCR Rider rate. The new zero percent of bill rate would be effective January 1, 2024 and would ensure there is no double-recovery of the Astoria Station costs during the interim rate period. The final tracker balance will be collected from or refunded to customers through the interim refund. Exhibit___(PMF-1), Schedule 7 provides the estimated GCR Rider tracker balance as of December 31, 2023.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Ms. Paula M. Foster
Supervisor, Regulatory Analysis, Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8042

CURRENT RESPONSIBILITIES: (March 2022 to Present)

Provide leadership for rates analysts for the preparation and financial analysis used to determine revenue requirements associated with various state and federal cost recovery mechanisms and to lead development of regulatory filings associated with these cost recovery mechanisms. Primary state responsibilities are related to the Renewable Resource Cost Recovery Rider, Transmission Cost Recovery Rider, Advanced Meter and Distribution Technology Cost Recovery Rider, and Generation Cost Reocvery Rider.

PREVIOUS POSITIONS:

Otter Tail Power Company

2022 - Present	Supervisor, Regulatory Analysis, Regulatory Economics
2019 - 2022	Rates Analyst, Regulatory Administration
2016 - 2019	CISone Finance Lead, CISone Project
2012 - 2016	Supervisor, Cash Management, Accounting
2007 - 2012	Cash and Accounts Receivable Lead, Accounting

Carlson Highland & Company, Fergus Falls, MN

2005 - 2007	Senior Auditor
2000 - 2005	Auditor

EDUCATION

Northland Community and Technical College, Thief River Falls, MN – Associate of Applied Science, Associate of Accounting

CERTIFICATIONS

Certified Public Accountant

Otter Tail Power Company
Electric Utility - State of North Dakota
Rider Roll-in Rate Base Summary Schedule

	A	B	C
		2024 Test Year	
Line		**13MA**	**13MA**
No.	**Description**	**OTP Total**	**OTP ND**
1	***RRCR Projects***		
2	Ashtabula III	43,390,954	16,305,167
3	Merricourt Wind Project	186,286,657	70,001,574
4	**Total RRCR Projects**	**229,677,611**	**86,306,741**
5			
6	***GCR Projects***		
7	Astoria Station	132,938,069	52,963,128
8	**Total GCR Projects**	**132,938,069**	**52,963,128**
9			
10	***MDT Projects***		
11	OMS - Innovation 2030	3,546,984	1,457,057
12	**Total MDT Projects**	**3,546,984**	**1,457,057**
13			
14	***TCR Projects***		
15	Alice-Enderlin Rebuild	367,200	145,407
16	Bagley 115kv Switch Station	2,387,102	945,266
17	Bemidji-Cass Lake Extenda-Life	315,381	124,888
18	Blair Substation Improvements	849,890	336,547
19	Bottineau-Dunseith Extenda-Life	124,237	49,196
20	BSSE-Big Stone South-Ellendale 345	90,610,625	35,880,817
21	Buffalo-Lisbon 115kV re-insulate	1,087,197	430,518
22	Crookston-CB-655 Extenda-Life	784,483	310,647
23	Denhoff-McClusky Rebuild	1,053,661	417,238
24	Donaldson 115 kV Capacitor Bank	579,154	229,339
25	Donaldson CB-235 Life Extension	61,399	24,313
26	Doyon/Bartlett - Rebuild 41.6kV Lin	816,339	323,262
27	Erie 230/115kV Substation	7,480,298	2,962,116
28	Fertile-Twin Valley Extenda-Life	45,604	18,059
29	Finley/McVille - Rebuild 41.6 kV	1,192,167	472,085
30	Granville-Granville Station Rebuild	1,679,085	664,899
31	Grenville-Veblen Rebuild	1,458,066	577,378
32	Hoot Lake 115/43/13.8kV Transformer	1,291,747	511,518
33	Hoot Lake Sub Add 115kV Cap Banks	726,463	287,671
34	Jamestown 345 kV Sub-Add 345 Bkr	1,094,164	433,277
35	Jamestown New 115/41.6kV Source	3,346,569	1,325,205
36	Lake Norden Area Trans - Phase I	9,216,492	3,649,630
37	Lake Norden Area Trans -115 kV Line	16,397,941	6,493,405
38	Lake Norden-Astoria -Phase III	1,680,356	665,403
39	Langdon 885-Extenda-Life/Bury UB	462,369	183,093
40	Max-Ryder 41.6 kV line upgrades	1,929,333	763,995
41	New Effington 230/41.6kV Substation	4,805,205	1,902,809
42	Norcross 115kV Line-115/41.6kV Sub	4,205,164	1,665,199
43	Oslo-Gilby Extenda-Life	652,807	258,504
44	Plummer 115kV Sub UVLS	637,945	252,619

45	Plummer-CB-425 Extenda-Life	509,777	201,866
46	Plummer-Gentilly Extenda-Life	343,726	136,112
47	Purchase CPEC Substations	1,792,318	709,738
48	Summit - WAPA Summit Tie Rebuild	716,492	283,723
49	Turtle Lk/Mercer - Rebuild 41.6 kV	1,177,362	466,223
50	Ulrich-Ogema Extenda-Life	562,946	222,920
51	Veblen Relay Upgrades - Cap Bank	945,800	374,526
52	Verdi-Lake Benton Extenda-Life	423,155	167,565
53	Washburn 555 - Extenda-Life	282,765	111,972
54	Waubay-Enemy Swim Extenda-Life	190,831	75,567
55	Winger 230/115kV Transformer	7,293,995	2,888,342
56	Winger-Ogema Extenda-Life	650,677	257,661
57	**Total TCR Projects**	**172,228,285**	**68,200,519**

Otter Tail Power Company
Renewable Rider Tracker
North Dakota

Line No.	*TRACKER SUMMARY* *Requirements Compared to Billed:*	2024 Test Year January Forecast	February Forecast	March Forecast	April Forecast	May Forecast	June Forecast	July Forecast	August Forecast	September Forecast	October Forecast	November Forecast	December Forecast	Year-End Forecast	January Forecast	February Forecast	March Forecast	Period Recovery
	Revenue Requirements																	
1	Langdon - DTA only effective 02/01/19																	
2	Ashtabula - DTA only effective 02/01/19																	
3	Merricourt Wind Energy Center																	
4	Ashtabula III - Effective January 2023																	
5	Merricourt PTCs Only	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(166,495)	(1,997,946)	(166,495)	(166,495)	(166,495)	(1,997,946)
6	Luverne Wind Energy Center Repower	107,344	107,344	107,344	107,344	107,344	107,344	107,344	107,344	107,344	107,344	(99,557)	(76,794)	897,091	(94,540)	(104,465)	(27,504)	348,550
7	Ashtabula I Wind Energy Center Repower	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	38,590	463,076	132,178	132,178	132,178	743,841
8	Langdon Wind Energy Center Repower	54,554	54,554	54,554	54,554	54,554	54,554	54,554	54,554	54,554	54,554	54,554	54,554	654,649	162,084	162,084	162,084	977,238
9	Ashtabula III Wind Energy Center Repower	50,482	50,482	50,482	50,482	50,482	50,482	50,482	50,482	50,482	50,482	50,482	50,482	605,787	166,739	166,739	166,739	954,556
10	Total Revenue Requirements	84,475	84,475	84,475	84,475	84,475	84,475	84,475	84,475	84,475	84,475	(122,426)	(99,663)	622,658	199,965	190,039	267,000	1,026,238
11																		
12	Preservation of ADIT Proration				-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																		
14	Renewable Energy Certificate Sales													-				
15																		
16	Net Revenue Requirement	84,475	84,475	84,475	84,475	84,475	84,475	84,475	84,475	84,475	84,475	(122,426)	(99,663)	622,658	199,965	190,039	267,000	1,026,238
17																		
18																		
19	Billed (forecast kWh x adj factor)	-	-	-	140,215	132,737	158,909	174,540	173,755	166,896	150,307	162,889	177,662	1,437,910	180,792	165,823	158,990	1,943,515
20	ND ECRR Balance Transfer- Dec 2019 only																	
20																		
21	Monthly Revenue Difference	88,420	88,843	89,391	(50,272)	(43,104)	(69,543)	(85,602)	(85,345)	(79,013)	(62,912)	(282,783)	(276,538)		18,253	23,409	107,347	
22	Cumulative Difference	707,869	796,712	886,104	835,832	792,727	723,184	637,582	552,237	473,223	410,312	127,529	(149,010)		(130,756)	(107,347)	0	
23	Carrying Cost Adj. for rate calculation	-	-	284	-	-	-	-	-	-	-	-	-	284	-	-	(5,468)	(5,468)
24	Adjusted Cumulative Difference	713,053	801,896	891,572	841,300	798,195	728,652	643,050	557,705	478,692	415,780	132,997	(143,541)		(125,288)	(101,879)	0	
25																		
26																		
27	Carrying Charge Calculation	4,368	4,917	5,468	5,158	4,892	4,463	3,935	3,408	2,920	2,532	787	(920)	41,928	(807)	(662)	0	
28	Cumulative Carrying Charge	613,679	618,596	624,064	629,222	634,114	638,577	642,511	645,919	648,839	651,371	652,158	651,239		650,432	649,769	649,769	
29	Carrying Cost	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%		7.41%	7.41%	7.41%	
30	Monthly Rate	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%	0.61710%		0.61710%	0.61710%	0.61710%	
31																		
32	Life-to-Date Revenue Requirement	712,238	801,629	891,572	840,989	797,619	727,647	641,517	555,645	476,144	412,844	128,316	(149,929)		(131,563)	(108,010)	0	
33																		
34	Forecasted Revenue	$ 10,303,500	$ 9,455,043	$ 9,045,045	$ 8,113,241	$ 7,680,557	$ 9,194,958	$ 10,099,380	$ 10,053,946	$ 9,657,085	$ 8,697,182	$ 9,425,236	$ 10,280,059	$ 112,005,232	$ 10,461,165	$ 9,595,020	$ 9,199,643	$ 112,457,472

Approved by ND PSC on [DATE] in Case No. PU-

Rate Calculation - Effective April 2024 Test Year	**April 2024 - March 2025**
Revenue Requirements	$ 1,026,238
Carrying Charge	25,705
Cumulative True-up	891,572
Total Requirements	$ 1,943,515
Revenue	$ 112,457,472
New Rate	1.728%

A	B	C	D	E
Line	Project	Approved for Rider Recovery	In Service Date	Proposed Recovery
1	BSSE-Big Stone South-Ellendale 345	PU-12-702	Mar-19	Base Rates
2	Max-Ryder 41.6 kV Line Upgrade	PU-16-624	Oct-15	Base Rates
3	Bagley 115 kV Switch Station	PU-17-340	Dec-18	Base Rates
4	Lake Norden Area Transmission	PU-18-329	Feb-19	Base Rates
5	Donaldson 115 kV Cap Bank	PU-19-311	Sep-19	Base Rates
6	Northwest MN UVLS	PU-19-311	Mar-21	Base Rates
7	Blair 230 kV Substation	PU-19-311	Jul-19	Base Rates
8	Veblen 41.6 kV Cap Bank	PU-19-311	Aug-19	Base Rates
9	New Effington 230/41.6 kV Line	PU-19-311	May-21	Base Rates
10	Jamestown Substation	PU-19-311	Nov-20	Base Rates
11	CPEC Purchase	PU-19-311	Oct-20	Base Rates
12	Erie 230/115kV Substation	PU-20-383	May-23	Base Rates
13	Norcross 115kV Line-115/41.6kV Sub	PU-20-383	Sep-21	Base Rates
14	Winger 230/115kV Transformer	PU-20-383	Dec-23	Base Rates
15	Jamestown 41.6 kV Source	PU-20-383	Jun-22	Base Rates
16	Hoot Lake Capacitor	PU-20-383	Oct-21	Base Rates
17	Finley/McVille 41.6 kV Rebuild	PU-20-383	Nov-21	Base Rates
18	Turtle Lake/Mercer 41.6 kV Rebuild	PU-20-383	Oct-21	Base Rates
19	Doyon/Bartlett 41.6 kV Rebuild	PU-20-383	Oct-21	Base Rates
20	Hoot Lake Transformer	PU-21-376	Dec-22	Base Rates
21	Wabek-Parshall Rebuild	PU-21-376	Dec-29*	TCRR
22	Pickert-McVille Rebuild	PU-21-376	Dec-26*	TCRR
23	Denhoff-McClusky Rebuild	PU-21-376	Sep-23	Base Rates
24	Granville-Granville Station Rebuild	PU-21-376	Dec-23	Base Rates
25	Grenville-Veblen Rebuild	PU-21-376	Dec-29*	TCRR
26	Michigan-Mapes Rebuild	PU-21-376	Dec-24*	TCRR
27	Summit – WAPA Summit Tie Rebuild	PU-21-376	Nov-22	Base Rates
28	Buffalo Lisbon Rebuild	PU-21-376	Dec-22	Base Rates
29	Alice-Enderlin Rebuild	PU-21-376	Dec-23	Base Rates
30	Fertile-Twin Valley Rebuild	PU-21-376	Dec-24*	TCRR
31	Oslo-Gilby Extenda-Life	PU-21-376	Mar-24*	TCRR
32	Winger-Ogema Extenda-Life	PU-21-376	Apr-22	Base Rates
33	Verdi-Lake Benton Extenda-Life	PU-21-376	Feb-23	Base Rates
34	Waubay-Enemy Swim Extenda-Life	PU-21-376	Jun-23	Base Rates
35	Bottineau-Dunseith Extenda-Life	PU-21-376	Dec-23	Base Rates
36	Plummer-Gentilly Extenda-Life	PU-21-376	Apr-23	Base Rates
37	Ulrich-Ogema Extenda-Life	PU-21-376	Mar-22	Base Rates
38	Bemidji-Cass Lake Extenda-Life	PU-21-376	Dec-24*	TCRR
39	Langdon Extenda-Life	PU-22-335	Dec-23	Base Rates
40	Gackel Rural Loop	PU-22-335	Dec-27*	TCRR
41	Washburn Extenda-Life	PU-22-335	Dec-23	Base Rates
42	Plummer Extenda-Life	PU-22-335	Mar-24*	TCRR
43	Crookston Extenda-Life	PU-22-335	Sep-24*	TCRR
44	Donaldson Extenda-Life	PU-22-335	Dec-24*	TCRR
45	Oslo Breaker Ring Bus	PU-22-335	Dec-24*	TCRR
46	Casselton CAP Bank	PU-22-335	Dec-23	Base Rates
47	Cooperstown – Relocate 41.6kV	PU-22-335	Dec-24*	TCRR
48	2021 Transmission Rebuild Projects	PU-21-376		
49	2021 Transmission Extenda-Life Projects	PU-21-376		

*Estimate

**Proposed Project in ND Docket PU-17-340

		2024 Test Year												
	TRACKER SUMMARY	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**YE**
Line No.	***Requirements Compared to Billed:***	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**	**Projected**
	Revenue Requirements													
1	Transmission Line Replacement Program	23,666	23,668	23,669	23,671	23,673	23,674	23,676	23,677	23,679	23,681	24,429	24,430	285,592
2	Transmission Extenda-Life Program	8,124	8,124	8,124	8,124	8,124	8,124	8,124	8,124	8,124	8,124	8,373	8,373	97,987
3	Cooperstown 41.6 kV Relocate	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	19,717
4	Oslo 115 kV 5 Breaker Ring Bus	22,712	22,712	22,712	22,712	22,712	22,712	22,712	22,712	22,712	22,712	22,712	22,712	272,545
5	Casselton 115 kV Capacitor Bank	5,468	5,468	5,468	5,468	5,468	5,468	5,468	5,468	5,468	5,468	5,468	5,468	65,614
6	Milbank Area Reliability Project	34,652	34,652	34,652	34,652	34,652	34,652	34,652	34,652	34,652	34,652	34,652	34,652	415,829
7	Big Stone South to Alexandria 345kV (BSSa)	224	224	224	224	224	224	224	224	224	224	224	224	2,684
8	Alexandria to Big Oaks 345kV double circuit (BSSa)	327	327	327	327	327	327	327	327	327	327	327	327	3,926
9	Jamestown to Ellendale 345kV (JETx)	396	396	396	396	396	396	396	396	396	396	396	396	4,750
10	Maple River Substation Addition (JETx)	228	228	228	228	228	228	228	228	228	228	228	228	2,730
11	Jamestown 345 Substation Addition (JETx)	2	2	2	2	2	2	2	2	2	2	2	2	30
12	Twin Brooks Reactor Addition (JETx)	53	53	53	53	53	53	53	53	53	53	53	53	639
13	**Total Revenue Requirements**	97,495	97,497	97,499	97,500	97,502	97,504	97,505	97,507	97,509	97,510	98,507	98,508	1,172,043
14														
15	**ADIT Preservation of Proration**													
16														
17	**MISO & SPP Expenses**													
18	MISO Schedule 26 Expense	391,091	391,091	391,091	391,091	391,091	391,091	391,091	391,091	391,091	391,091	391,091	391,091	4,693,096
19	MISO Schedule 26A Expense	318,230	318,230	318,230	318,230	318,230	318,230	318,230	318,230	318,230	318,230	318,230	318,230	3,818,755
20	SPP Schedule 9 Expense	65,671	65,671	65,671	65,671	65,671	65,671	65,671	65,671	65,671	65,671	68,318	68,318	793,347
21	SPP Schedule 11 Expense	9,441	9,441	9,441	9,441	9,441	9,441	9,441	9,441	9,441	9,441	9,822	9,822	114,053
22	**Total MISO & SPP Expenses**	784,433	784,433	784,433	784,433	784,433	784,433	784,433	784,433	784,433	784,433	787,460	787,460	9,419,251
23														
24	**MISO Revenues**													
25	MISO Schedule 9 Revenue	(71,583)	(46,135)	(57,553)	(14,618)	(8,547)	(1,658)	(12,449)	1,276	(24,101)	(24,457)	(37,691)	(50,424)	(347,939)
26	MISO Schedule 26 Revenue	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(330,677)	(3,968,122)
27	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
28	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
29	MISO Schedule 26A Revenue	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(116,430)	(1,397,155)
30	MISO MVP ARR Revenue	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(10,891)
31	**Total MISO Revenues**	(519,597)	(494,149)	(505,567)	(462,632)	(456,561)	(449,672)	(460,463)	(446,738)	(472,115)	(472,471)	(485,705)	(498,438)	(5,724,108)
32														
33	**Net Revenue Requirement**	362,332	387,781	376,365	419,301	425,374	432,264	421,475	435,201	409,826	409,472	400,261	387,531	4,867,185
34														
35	Billed (forecast kWh x adj factor)	452,639	413,460	400,559	355,605	331,289	317,239	343,672	342,521	330,306	354,126	394,478	446,047	4,481,941
36														
37	Difference	(90,307)	(25,679)	(24,194)	63,696	94,086	115,025	77,803	92,681	79,520	55,346	5,783	(58,516)	385,244
38	Carrying Charge	(2,333)	(2,833)	(3,009)	(3,176)	(2,803)	(2,240)	(1,544)	(1,073)	(508)	(20)	321	359	(18,858)
39	Cumulative Difference[1]	(459,026)	(487,537)	(514,740)	(454,221)	(362,938)	(250,153)	(173,893)	(82,286)	(3,273)	52,053	58,157	(0)	(0)
40														
41	Carrying Charge Calculation	(2,833)	(3,009)	(3,176)	(2,803)	(2,240)	(1,544)	(1,073)	(508)	(20)	321	359	(0)	
42	Cumulative Carrying Charge	(386,995)	(390,004)	(393,180)	(395,983)	(398,223)	(399,767)	(400,840)	(401,348)	(401,368)	(401,047)	(400,688)	(400,688)	
43	Carrying cost	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	
44														
45														
46	Forecasted Sales (MWh)	263,003	240,239	232,743	206,622	192,493	184,330	199,689	199,020	191,923	205,763	229,209	259,173	2,604,207
47														

[1]January Cumulative Difference includes estimate of $(366,386) p

SUMMARY	**2024 Test Year**
Revenue requirements	$4,867,185
Carrying Charge	(18,858)
2023 True-Up	(366,386)
Total requirements	$4,481,941
Jan 2024-Dec 2024 projected sales in MWh	2,604,207
Average Rate	$0.00172

Otter Tail Power Company
North Dakota Metering & Distribution Technology

Line No.	*TRACKER SUMMARY* *Requirements Compared to Billed:*	2024 January Projected	2024 February Projected	2024 March Projected	2024 April Projected	2024 May Projected	2024 June Projected	2024 July Projected	2024 August Projected	2024 September Projected	2024 October Projected	2024 November Projected	2024 December Projected	2024 Test Year Projected
	Revenue Requirements													
1	Advanced Metering Infrastructure	193,746	288,344	298,741	305,562	310,584	352,412	315,996	320,189	323,942	327,109	329,264	329,829	3,695,718
2	Demand Response	20,676	22,608	22,608	22,608	22,608	22,608	22,608	22,608	22,608	22,608	22,608	22,608	269,360
3	**Total Revenue Requirements**	214,422	310,952	321,349	328,169	333,192	375,019	338,603	342,797	346,550	349,717	351,871	352,437	3,965,078
5	**ADIT Preservation of Proration**													
6	**O&M Savings due to AMI Implementation**	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(46,973)	(563,670)
7	**Net Revenue Requirement**	167,449	263,979	274,376	281,197	286,219	328,047	291,631	295,824	299,577	302,744	304,899	305,465	3,401,408
8	Billed (forecast meter x adj factor)	108,164	108,164	108,164	108,164	108,164	108,164	108,164	108,164	108,164	108,164	108,164	108,164	1,297,973
9	Monthly Revenue Difference	59,285	155,815	166,212	173,032	178,055	219,882	183,466	187,660	191,413	194,580	196,734	197,300	2,103,435
10	Carrying Charge	(12,830)	(12,145)	(11,259)	(10,303)	(9,298)	(8,257)	(6,951)	(5,862)	(4,740)	(3,588)	(2,409)	(1,210)	(88,851)
11	Life-to-Date Revenue Requirement (Cumulative Difference)	(1,968,128)	(1,824,459)	(1,669,506)	(1,506,776)	(1,338,019)	(1,126,394)	(949,878)	(768,080)	(581,407)	(390,415)	(196,090)	(0)	(0)
12	Carrying Charge Calculation	(12,145)	(11,259)	(10,303)	(9,298)	(8,257)	(6,951)	(5,862)	(4,740)	(3,588)	(2,409)	(1,210)	(0)	
13	Cumulative Carrying Charge	(91,598)	(102,857)	(113,160)	(122,458)	(130,715)	(137,666)	(143,528)	(148,267)	(151,855)	(154,264)	(155,475)	(155,475)	
14	Carrying cost rate	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	
15	Forecasted Meter Count	76,103	76,103	76,103	76,103	76,103	76,103	76,103	76,103	76,103	76,103	76,103	76,103	913,237

SUMMARY	2024 Test Year
Revenue requirements	$3,401,408
Carrying Charge	(88,851)
True-up	(2,014,584)
Total requirements	$1,297,973
Sep 2023 - Aug 2024 projected meter count	913,237
Average Rate	$1.42129

Otter Tail Power Company
North Dakota Generation Cost Recovery Rider Tracker
Tracker Summary

Line No.	*Requirements Compared to Billed:*	2022 Actual Year-End	2023 Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Collection Period	2023 Actual July	Actual August	Actual September	Projected October	Projected November	Projected December	2023 Projected Year-End
	Revenue Requirements															
1	Astoria Station	7,143,189	620,091	627,118	626,007	616,470	627,980	635,783	7,371,364	667,626	599,966	642,130	623,928	620,867	636,597	7,544,563
2	Hoot Lake Plant - Plant Closure	(3,266,296)	(326,980)	(317,779)	(394,188)	(320,906)	(324,498)	(299,542)	(3,897,872)	(283,441)	(327,080)	(313,513)	(309,527)	(349,139)	(287,655)	(3,854,247)
3	Total Revenue Requirements	3,876,893	293,111	309,339	231,819	295,564	303,483	336,241	3,473,492	384,185	272,885	328,617	314,401	271,728	348,943	3,690,316
4																
5	Preservation of ADIT Proration	3,636	28	28	28	28	28	28	339							169
6																
7	Net Revenue Requirement	3,880,529	293,140	309,367	231,847	295,592	303,511	336,269	3,473,831	384,185	272,885	328,617	314,401	271,728	348,943	3,690,485
8																
9	Billed (forecast $ x adj factor)	4,625,167	315,999	289,241	282,430	277,498	242,921	261,960	3,496,869	265,765	199,689	206,238	175,192	189,613	206,521	2,913,068
10																
11	Difference	(744,638)	(22,860)	20,126	(50,583)	18,094	60,589	74,309		118,420	73,196	122,379	139,209	82,115	142,421	777,417
12	Carrying Charge	(52,646)	(6,130)	(6,315)	(6,227)	(6,589)	(6,516)	(6,171)	(73,348)	(5,737)	(5,020)	(4,586)	(3,835)	(2,973)	(2,469)	(62,569)
13	Cumulative Difference (True-Up)	(962,647)	(991,638)	(977,826)	(1,034,636)	(1,023,131)	(969,057)	(900,920)		(788,237)	(720,060)	(602,267)	(466,893)	(387,751)	(247,799)	(247,799)
14																
15	Monthly Carrying Charge		(6,315)	(6,227)	(6,589)	(6,516)	(6,171)	(5,737)		(5,020)	(4,586)	(3,835)	(2,973)	(2,469)	(1,578)	
16	Carrying cost		7.64%	7.64%	7.64%	7.64%	7.64%	7.64%		7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	
17																
18																
19	Forecasted Revenue		1,072,213	971,077	1,124,554	1,115,777	1,167,386	1,178,005	6,629,012	1,249,574	670,742	9,631,278	8,647,209	9,358,979	10,193,556	46,380,349

Filed on March 1, 2022 in Case No. PU-22-87

SUMMARY	**July 2022 - June 2023**
Revenue Requirements	3,932,973
Carrying Charge	(29,866)
True-up (June 2022)	(616,841)
Total Revenue Requirement	3,286,266
July 2022 - June 2023 Projected Revenue	110,205,698
Average Rate	2.982%

Otter Tail Power Company
North Dakota Generation Cost Recovery Rider Tracker
Tracker Summary

Line No.	*Requirements Compared to Billed:*	2024 Projected January	2024 Projected February	2024 Projected March	2024 Projected April	2024 Projected May	2024 Projected June	Collection Period	2024 Projected July	2024 Projected August	2024 Projected September	2024 Projected October	2024 Projected November	2024 Projected December	2024 Projected Year-End
	Revenue Requirements														
1	Astoria Station							3,791,113							-
2	Hoot Lake Plant - Plant Closure							(1,870,355)							-
3	Total Revenue Requirements	-	-	-	-	-	-	1,920,759	-	-	-	-	-	-	-
4															
5	Preservation of ADIT Proration							-							-
6															
7	Net Revenue Requirement	-	-	-	-	-	-	1,920,759	-	-	-	-	-	-	-
8															
9	Billed (forecast $ x adj factor)	-	-	-	-	-	-	1,243,018	-	-	-	-	-	-	-
10															
11	Difference	-	-	-	-	-	-		-	-	-	-	-	-	-
12	Carrying Charge	(1,578)	(1,588)	(1,598)	(1,608)	(1,619)	(1,629)	(34,241)	(1,639)	(1,650)	(1,660)	(1,671)	(1,681)	(1,692)	(19,614)
13	Cumulative Difference (True-Up)	(249,377)	(250,966)	(252,564)	(254,172)	(255,791)	(257,420)		(259,059)	(260,709)	(262,369)	(264,040)	(265,722)	(267,414)	(267,414)
14															
15	Monthly Carrying Charge	(1,588)	(1,598)	(1,608)	(1,619)	(1,629)	(1,639)		(1,650)	(1,660)	(1,671)	(1,681)	(1,692)	(1,703)	
16	Carrying cost	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%		7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	
17															
18															
19	Forecasted Revenue	10,303,500	9,455,043	9,045,045	8,113,241	7,680,557	9,194,958	93,543,682	10,099,380	10,053,946	9,657,085	8,697,182	9,425,236	10,280,059	112,005,231

Filed on March 1, 2023 in Case No. PU-23-83

SUMMARY	**July 2023 - June 2024**
Revenue Requirements	$ 3,266,660
Carrying Charge	(38,379)
True-up (June 2023)	(984,396)
Total Revenue Requirement	$ 2,243,885
July 2023 - June 2024 Projected Revenue	$ 110,754,548
Average Rate	2.026%

Volume 2A

Direct Testimony and Supporting Schedules:

Christopher L. Byrnes

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

CORPORATE COST ALLOCATION, LEAD LAG STUDY, ENERGY ADJUSTMENT RIDER AND OTHER REGULATORY ISSUES

Direct Testimony and Schedules of

CHRISTOPHER E. BYRNES

November 2, 2023

TABLE OF CONTENTS

ATTACHED SCHEDULES

Schedule 1 – Witness Resume/Bio

Schedule 2 – Corporate Cost Allocation Manual

Schedule 3 – Forecast Corporate Cost Allocation Procedures

Schedule 4 – Modifications to Section 13.01 North Dakota Energy Adjustment Rider

Schedule 5 – Steam and Water Sales to POET

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My name is Christopher Byrnes. I am employed by Otter Tail Power Company (OTP or the Company).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Supervisor of Regulatory Analysis. My primary responsibilities in this position are to lead OTP's Regulatory Department's role in the preparation and analysis of annual jurisdictional and class cost of service studies that determine overall utility returns and price levels for actual and forecast test years and to lead the development of the forecasted Energy Adjustment Rider (EAR) rates.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(CEB-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony describes several revenue requirement and regulatory issues associated with this case, including:

- Corporate Cost Allocation
- The Lead Lag Study
- The Energy Adjustment Rider
- Rate Case Expense
- Advertising Expenses
- Electronic Payment Processing Fees

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. My Direct Testimony discusses and supports how Otter Tail Corporation allocates its corporate costs to OTP. I explain the Lead Lag Study that is used to calculate the cash working capital component of rate base for the 2024 Test Year. I also present proposed changes to OTP's EAR that will make fuel costs more transparent for our customers, and OTP's proposed treatment of rate case, advertising and electronic payment processing expenses.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss corporate cost allocations. In Section IV, I discuss the Lead Lag Study. In Section V, I discuss changes to the EAR. Finally, in Section VI, I discuss rate case, advertising, and electronic payment processing expenses.

Q. HOW HAVE YOU LABELED DOLLAR VALUES IN YOUR DIRECT TESTIMONY AND SUPPORTING SCHEDULES?

A. Dollar values presented in my Direct Testimony and schedules that are jurisdictional to North Dakota values are labeled as (OTP ND). Total company costs are labeled (OTP Total). Some costs fall into numerous functions, each with its own jurisdictional allocation, and therefore a straightforward calculation of a jurisdictional amount based on a single allocator is not possible (e.g. labor cost categories, which may include costs functionalized as generation, transmission, distribution, administration, and general, with each function having its own unique jurisdictional allocation). For costs like this, the North Dakota jurisdictional dollar values have been estimated by multiplying the total company costs by a single blended allocator and labeled as (OTP ND EST.).

III. CORPORATE COST ALLOCATION

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will explain how corporate costs that are incurred by Otter Tail Corporation in connection with the services provided by Otter Tail Corporation for the operation of OTP are handled in the 2024 Test Year.

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN OTP AND OTTER TAIL CORPORATION.

A. OTP is a wholly owned subsidiary of Otter Tail Corporation.

Q. WHAT SERVICES DOES OTTER TAIL CORPORATION PROVIDE TO OTP?

A. Otter Tail Corporation provides the following services to OTP: financial reporting, tax planning and reporting, treasury, financial planning, corporate communications, internal audit, benefits plans, safety and risk management, shareholder services and investor relations, aviation, and executive management services.

Q. ARE THESE SERVICES GOVERNED BY ANY AGREEMENTS?

A. Yes. OTP has three agreements with Otter Tail Corporation: (1) an Administrative Services Agreement that describes how services are provided from Otter Tail Corporation to OTP and how costs for such services are assigned and allocated to OTP; (2) a Tax Sharing Agreement that describes how tax obligations and benefits are to be allocated; and (3) a Cash Management Agreement that describes how cash management services can be provided by Otter Tail Corporation to OTP. Currently, no cash management services are being provided by Otter Tail Corporation to OTP.

Q. HOW ARE OTP TAXES COMPUTED UNDER THE TAX SHARING AGREEMENT?

A. OTP computes its taxes on a standalone basis, exclusive of Otter Tail Corporation. All tax calculations included in the 2024 Test Year are based only on OTP financial performance. The tax calculations included in this Test Year are detailed in Volume 3 Schedule C-4.

Q. HOW DID YOU ARRIVE AT THE APPROPRIATE LEVEL OF OTTER TAIL CORPORATION EXPENSES TO INCLUDE IN THE TEST YEAR?

A. Under the Administrative Services Agreement, the costs of corporate functions are allocated using the allocation methodology and specific allocation factors described in the Corporate Cost Allocation Manual (CAM), included as Exhibit___(CEB-1), Schedule 2. I have also included a supplement to the CAM, the Forecast Corporate Cost Allocation Procedures (FCAP) manual, included as Exhibit___(CEB-1), Schedule 3,[1] which describes in more detail how forecasted corporate cost allocation factors are developed. Allocation factors were applied to forecasted 2024 corporate expenses, adjusted for certain corporate expenses which have either been capped or disallowed in prior Commission orders.

[1] Schedule 2 and Schedule 3 are the red-line version of the CAM and FCAP.

Q. HOW WERE THE COST ALLOCATION METHODOLOGIES DEVELOPED?

A. The corporate cost allocation methodology was developed based on the following goals:

(1) The result should fully allocate costs;

(2) Costs are directly assigned where possible;

(3) If direct assignment is not possible, an indirect allocation will be made if there is a cost causative link to another cost category for which direct assignment is used;

(4) When neither direct nor indirect cost causation can be found, a representative general allocator is used;

(5) The result is equitable for customers and shareholders;

(6) The method is easy to administer – no additional studies or data gathering is needed; and

(7) The allocators have components that are based on verifiable public information, to the extent possible.

Q. PLEASE EXPLAIN THE CORPORATE COST ALLOCATION PROCESS IN MORE DETAIL.

A. Otter Tail Corporation costs can be charged to OTP or to Otter Tail Corporation's non-utility operations. The allocation process uses three steps. First, all labor and other costs that are appropriate for direct assignment to OTP or non-utility operations are identified and directly assigned. Members of the Corporate Group use timesheets to directly assign labor. Invoices and other costs are directly assigned as appropriate. In the 2024 Test Year, approximately 57 percent of all Otter Tail Corporation costs were allocated to OTP or non-utility operations using direct assignment.

Second, indirect allocators are used for certain functions. Indirect allocators are used where an indirect-cost causative linkage to another cost category or group of cost categories exists. About 9 percent of corporate costs were allocated to OTP or non-utility operations using indirect allocators.

The remaining 34 percent of corporate costs are not appropriate for either direct assignment or indirect allocation. These costs are allocated to OTP or non-utility operations using the general allocator that is composed of revenues, assets and labor dollars, equally weighted.

Q. HOW MUCH OF THE TOTAL OTTER TAIL CORPORATION COST IS ALLOCATED TO OTP IN THE 2024 TEST YEAR?

A. Table 1, below, shows the allocation of Otter Tail Corporation costs for the 2024 Test Year.

Table 1
Otter Tail Corporation Cost Allocation

	Otter Tail Corporation 2024 Costs		**ND Share**
Allocated to OTP	$13,143,692	44.6%	$5,463,509
Allocated to Non-Utility	$16,321,685	55.4%	
Total Corporate Costs	$29,465,377	100.0%	

Q. HOW WERE THESE 2024 CORPORATE COST ESTIMATES DEVELOPED?

A. The 2024 corporate costs were developed following the procedures outlined in the FCAP manual. Those costs were then allocated between utility and non-utility entities based on the methods outlined in the CAM.

Q. DOES THE ALLOCATION IN TABLE 1 REFLECT THE COMPANY'S PROPOSED TREATMENT OF INCENTIVE COMPENSATION?

A. Yes. The Otter Tail Corporation costs allocated to OTP in the 2024 Test Year reflect the Company's proposal to limit executives' bonuses and incentive compensation at 25 percent of base salary. OTP witness Mr. Peter E. Wasberg discusses these limits in his Direct Testimony.

Q. DO THE AMOUNTS IN TABLE 1, ABOVE, INCLUDE INVESTOR RELATIONS EXPENSES?

A. Yes. While 50 percent of North Dakota's allocation of investor relations costs were not included in the 2018 Test Year revenue requirement established in the Settlement Agreement to OTP's last North Dakota rate case (Case No. PU-17-398), OTP has included all its North Dakota allocation of such costs in the 2024 Test Year.

Q. WHY IS OTP PROPOSING TO RECOVER ALL ITS NORTH DAKOTA ALLOCATION OF INVESTOR RELATIONS COSTS IN THIS PROCEEDING?

A. As discussed by OTP witness Mr. Todd R. Wahlund, OTP is in the midst of a significant period of capital spending. Investor relations expenses are directed at making sure OTP obtains the most cost-effective financing to support this investment.

Q. PLEASE DESCRIBE THE INVESTOR RELATIONS SERVICES OTTER TAIL CORPORATION PROVIDES TO OTP.

A. Investor relations involves administrative activities that are required for publicly traded companies. This includes payment of dividends, coordinating dividend reinvestments, annual reports, shareholder recordkeeping, required annual meetings, and Securities and Exchange Commission compliance. It also involves managing and coordinating relationships with equity and debt investors.

Q. DO INVESTOR RELATIONS ACTIVITIES BENEFIT RATEPAYERS?

A. Yes. Investor relations helps the Company effectively compete for capital and educates the investment community about the risks, rewards, and performance inherent in our equity and debt securities. The work of the investor relations group involves developing and supporting strong relationships with both the debt and equity capital markets for purposes of raising the necessary funds to support the Company's capital funding needs.

In addition to raising capital, investor relations efforts are spent on maintaining solid credit ratings for OTP, which reduces the cost of our debt and is a direct benefit to ratepayers. OTP's cost to serve its customers relies on both the debt and equity capital markets to provide adequate funding. Each source of funding has a cost associated with securing and administering that funding.

These informational and relationship functions, coupled with shareholder relationships, help OTP obtain the most cost-effective financing, thereby helping to control costs to the benefit of customers.

Q. HOW MUCH OF THE INVESTOR RELATIONS EXPENSES IS ALLOCATED TO OTP IN THE 2024 TEST YEAR?

A. Table 2, below, shows the allocation of Otter Tail Corporation costs for Investor Relations expenses in the 2024 Test Year. These costs were allocated to OTP consistent with the FCAP manual and the CAM.

Table 2
Otter Tail Corporate Investor Relations Cost Allocation

	2024 Otter Tail Corporation Investor Relations Costs		ND Share
Allocated to OTP	$472,534	52.6%	$204,869
Allocated to non-utility	$426,167	47.4%	
Total Corporate Cost	$898,107	100.0%	

OTP's share of Otter Tail Corporation investor relations cost is $472,534 or approximately 52.6 percent. The remaining $426,167 or 47.4 percent is allocated to non-utility operations. The North Dakota share of OTP's allocated costs is $204,869 which represents only 22.8 percent of the total corporate investor relations costs. Thus, OTP's North Dakota customers pay a relatively small portion of the total investor relations expense.

Q. DO THE AMOUNTS IN TABLE 1, ABOVE, INCLUDE COSTS ASSOCIATED WITH NON-EMPLOYEE[2] DIRECTOR RESTRICTED STOCK?

A. Yes. These costs were not part of the 2018 Test Year revenue requirement, established pursuant to the Settlement Agreement in Case No. PU-17-398. As discussed below, however, they are appropriate for inclusion in the 2024 Test Year revenue requirement.

Q. WHY IS OTP PROPOSING TO INCLUDE EXPENSE OF DIRECTOR RESTRICTED STOCK IN THE 2024 TEST YEAR REVENUE REQUIREMENT?

A. In order to attract and retain qualified professionals to serve on its Board of the Directors, Otter Tail Corporation must provide compensation commensurate with other boards of directors in the utility industry.

Q. WHY DOES OTTER TAIL CORPORATION HAVE A BOARD OF DIRECTORS?

A. My understanding is that Otter Tail Corporation is required to have a board of directors pursuant to the laws applicable to corporations.

[2] The President and CEO of Otter Tail Corporation is the only employee member of the Board of Directors and does not receive non-employee director compensation for his service as a member of the Board of Directors as per the 2023 Proxy Statement

Q. DOES OTTER TAIL CORPORATION COMPENSATE THE NON-EMPLOYEE MEMBERS OF ITS BOARD OF DIRECTORS?

A. Yes. Providing compensation to the non-employee members of the Otter Tail Corporation Board of Directors in exchange for the work they perform is reasonable and consistent with how boards of directors of other corporations are treated, including in the utility industry. These are necessary costs of Otter Tail Corporation being the parent company of OTP.

Q. WHAT PROCESS IS USED TO DEVELOP THE COMPENSATION THAT THE NON-EMPLOYEE MEMBERS OF THE BOARD OF DIRECTORS EARN?

A. Just as with our non-bargaining employee compensation, we also base our non-employee director compensation on the market. As described in the 2023 Proxy Statement for Otter Tail Corporation, the Compensation and Human Capital Management Committee for the Board of Directors periodically reviews compensation practices to determine their competitiveness with market practices. A market analysis of director compensation was conducted in 2022 by the Compensation and Human Capital Management Committee's consultant, WTW, using data from the National Association of Corporate Directors and a peer group (listed on page 29 of the 2023 Proxy Statement).

Q. HOW IS THE COMPENSATION PROVIDED TO THE NON-EMPLOYEE MEMBERS OF THE BOARD OF DIRECTORS?

A. The compensation provided to the non-employee members of the Board of Directors consists of two components: (1) an annual retainer; and (2) an annual, fixed equity grant of restricted stock, vesting over a period of three years (33.3 percent, per year), granted under the terms of the 2023 Stock Incentive Plan on the date of the Annual Meeting. Like most other boards of publicly held companies, the Board Chair and those with committee assignments qualify for limited additional grants of restricted stock but on the same vesting schedule and voting rights as the base stock grant. I would also note that OTP customers are not paying for all these costs because the blended North Dakota jurisdictional allocator of approximately 43.79 percent is applied to these reasonable and required costs and only the allocated percentage is included in our North Dakota rates. Thus, OTP customers receive the benefit of the Board, but only pay for a percentage based on the blended allocator.

Q. IS PROVIDING COMPENSATION TO THE NON-EMPLOYEE DIRECTORS THROUGH CASH AND EQUITY A REASONABLE APPROACH?

A. Yes. This approach is consistent with industry best practices used by other utilities.

Q. ARE THE COSTS REFLECTED IN TABLE 1 REASONABLE AND APPROPRIATE FOR INCLUSION IN THE 2024 TEST YEAR?

A. Yes. All costs have been allocated in a manner consistent with prior cases. The Otter Tail Corporation costs reflected in Table 1 are reasonable and appropriate for inclusion in the 2024 Test Year.

IV. LEAD LAG STUDY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will explain OTP's Lead Lag Study.

Q. WHAT IS THE PURPOSE OF THE LEAD LAG STUDY?

A. The Lead Lag Study is a widely used and accepted method for developing the cash working capital (CWC) component of rate base in connection with the determination of revenue requirements. This study analyzes the lapse of time between the average day on which a utility incurs expenses to serve its customers and the average day on which cash is received from customers in payment of that service. Lead days refer to the days between incurring an expense and paying for it. Lag days refer to the days between rendering a service and receiving payment for that service.

Q. HAS OTP'S LEAD LAG STUDY BEEN UPDATED SINCE THE LAST RATE CASE?

A. Yes. OTP updated its Lead Lag Study in 2021 using data from 2020. A copy of the study is provided in Volume 4B.

Q. IS THE CASH WORKING CAPITAL DETERMINATION METHODOLOGY CONSISTENT WITH OTP'S LAST RATE CASE?

A. Yes. The study and procedures used to calculate the working capital requirement are consistent with the approach and methodology used in OTP's last North Dakota rate case. OTP reviewed the procedures used in the Lead Lag Study filed in that case and concluded no significant changes in policies or procedures had occurred and conducted the current study using those same procedures.

Q. HAVE THE RESULTS OF THE LEAD LAG STUDY BEEN INCORPORATED INTO THE CWC CALCULATIONS?

A. Yes, the results of the Lead Lag Study are included in the CWC calculations provided in Volume 3, Schedule B-2e. OTP witness Ms. Christy L. Petersen discusses the overall calculation of CWC and its inclusion in Rate Base in her Direct Testimony.

V. ENERGY ADJUSTMENT RIDER ISSUES

A. Asset-Based Margins

Q. HOW DOES OTP CURRENTLY TREAT ASSET-BASED MARGINS IN THE ENERGY ADJUSTMENT RIDER?

A. In OTP's 2008 Rate Case, Case No. PU-08-862, the parties agreed for OTP to credit 85 percent of all asset-based margins through the EAR. OTP retained 15 percent of those margins.

Q. WHAT IS OTP PROPOSING FOR ASSET-BASED MARGINS?

A. OTP is proposing to credit 100 percent of asset-based margins to customers through the EAR. Effectively, all revenues received from the sales of energy from OTP resources into the Midcontinent Independent System Operator (MISO) market and all associated costs of operating those resources will flow through the EAR to the benefit of customers. OTP proposes that this change to the benefit of customers becomes effective with the implementation of interim rates in this rate case.

Q. WHY IS OTP PROPOSING TO CREDIT ALL ASSET-BASED MARGINS TO CUSTOMERS THROUGH THE EAR?

A. There was significant complexity in initially developing and subsequently maintaining the software that allows OTP to track and allocate asset-based sales and associated margin between the Company and customers. That software is approaching end of life and would need to be re-developed to continue. Rather than incurring the cost needed to find a new software solution, OTP believes it is more prudent to end the sharing and credit all asset-based margins to customers through the EAR. I also note that asset-based sales and associated margins have declined in recent years as the MISO market has evolved, and OTP generation resources and loads have changed. Finally, the proposal would result in consistent treatment of asset-based sales and margins across OTP's retail jurisdictions.

Q. HOW HAVE ASSET-BASED MARGINS HISTORICALLY BEEN CALCULATED?

A. OTP internally developed a program with the implementation of the MISO Day 2 market back in 2005 that estimated the costs associated with OTP's energy supply resource (OTP Resources) stack for each hour of the day relative to OTP retail load for those respective hours. Revenue received from MISO for the share of OTP Resources that served retail load is accounted for in a Resource Book, which tracks all EAR costs and revenues necessary to serve retail load. Fuel and purchased power costs are also allocated to the Resource Book based on the level of retail load for every given hour. The revenues associated with the sale of energy from OTP Resources, in excess of retail load for any given hour, are deemed asset-based sales and allocated to a Marketing Book, along with the estimated fuel and purchased power costs attributable to those sales. OTP's internal program also calculated an estimated share of MISO costs across the various MISO charge types that would be attributable to serving retail load and allocated to the Resource Book vs. excess asset-based sales that were charged to the Marketing Book. The net of revenues and costs allocated to the Marketing Book yielded the asset-based margin.

Q. WILL PASSING BACK 100 PERCENT OF ASSET-BASED MARGINS SIMPLIFY TRACKING THESE REVENUES AND COSTS?

A. Yes. As a MISO member, the procurement of energy for OTP's retail customers and the offering of OTP's generation and other purchased power into the MISO market are separate and distinct transactions from which the associated costs and revenues are netted against each other and recovered through the EAR, along with the cost of fuel to operate the plants and the cost of any purchased power. OTP does not see a need to continue to have a program, as discussed above, to allocate revenues and costs between two accounting books (Resource Book and Marketing Book), when 100 percent of those revenues and costs would flow back to customers in the EAR. All costs and revenues would simply be accounted for in the Resource Book.

Q. DOES OTP PROPOSE ANY OTHER SIMPLIFICATIONS TO THE EAR DUE TO THE PROPOSED TREATMENT OF ASSET-BASED MARGINS?

A. Yes. Currently in OTP's monthly EAR calculations, based on a four-month averaging of costs and kWh sales, OTP includes a forecast of estimated asset-based sales and associated margins, along with a true-up of prior monthly forecasted amounts. All other EAR costs and revenues simply flow through the monthly EAR calculation as they are incurred. It has been difficult to accurately predict these amounts and in recent years, and the amounts have become less material. OTP recommends eliminating this forecast and true-up process since 100 percent of revenues and costs will flow back through the EAR and simply account for (pass through) all actual EAR approved revenues and costs each month as they occur. OTP believes this modification would simplify the calculation while not having a material impact on any given month's EAR calculation.

Q. IS OTP PROPOSING ANY RELATED MODIFICATIONS TO SECTION 13.01 OF ITS NORTH DAKOTA ELECTRIC RATE SCHEDULE?

A. Yes. Exhibit___(CEB-1), Schedule 4 reflects proposed language to be added to Section 13.01[3] to reflect 100 percent of the energy related revenues and costs being included in the EAR. The revised language will be effective with the implementation of interim rates.

B. POET Steam and Water Sales

Q. WHAT IS OTP PROPOSING WITH REGARDS TO STEAM AND WATER SALES TO POET BIOREFINING?

A. OTP is proposing to include the fuel costs related to steam and water sales to POET Biorefining (POET) in the EAR and to credit the revenues collected from POET steam and water sales to customers through the EAR. OTP proposes that this change become effective with the implementation of final rates in this rate case.

Q. PLEASE SUMMARIZE OTP'S ARRANGEMENT WITH POET.

A. OTP sells steam and water from its Big Stone plant to POET. Currently, fuel and reagent costs associated with those steam and water sales are allocated to other electric expenses and excluded from the EAR calculation. Revenues recovered from steam sales are recorded as other electric revenue.

Q. HOW MUCH REVENUE AND NET MARGIN ASSOCIATED WITH STEAM AND WATER SALES TO POET HAS OTP REALIZED IN RECENT YEARS?

A. As reflected in Exhibit___(CEB-1), Schedule 5 to my Direct Testimony, OTP's share of steam and water sales to POET averaged approximately $1.18 million (OTP Total)/ $0.40 million (OTP ND) a year from 2020-2022 and yielded average

[3] The red-line version of Section 13.01 is provided in Schedule 4 for this testimony.

net margins of approximately $0.83 million (OTP Total)/$0.37 million (OTP ND) per year.

Q. WHY IS THE EAR APPROPRIATE FOR RECOVERY OF FUEL COSTS AND REVENUES FROM STEAM SALES?

A. Revenues from steam and water sales historically have been relatively stable. In 2020, however, Big Stone plant changed from a consistent "self-schedule" dispatch to an "economic dispatch," as an effective cost-control measure. However, this change also makes it more difficult to forecast Big Stone plant's availability to produce and sell steam to POET.[4] To address this increased volatility, OTP is proposing to incorporate those fuel costs and associated steam revenues through the EAR where they can be forecast and aligned with the forecasted dispatch of the Big Stone plant. This treatment is similar to how asset-based sales of energy into the MISO market is treated, returning the economic benefit of those sales and corresponding revenues back to customers through the EAR.

Q. PLEASE FURTHER EXPLAIN THE CHANGE TO BIG STONE PLANT'S DISPATCH STATUS.

A. In April 2020, the owners of Big Stone plant began offering the plant into the MISO and Southwest Power Pool (SPP) markets on an economic dispatch basis. All plant owners must agree when to offer the plant into MISO and SPP on an economic dispatch basis. If any owner needs the plant to run and wants to self-schedule the plant, all owners' shares will be self-scheduled. When the plant is on economic dispatch, this means that those markets will only dispatch the plant based on its relative cost position in the supply stack or if either MISO or SPP decides it must be run for reliability reasons. From an economic perspective, the plant will not run if cheaper resources are available. Offering the plant on economic dispatch creates more potential volatility in when the plant is expected to run and correspondingly, the quantity of steam produced and sold to POET on an annual basis.

Q. PLEASE FURTHER EXPLAIN WHY INCLUDING STEAM SALES IN THE EAR IS APPROPRIATE AND BENEFICIAL TO CUSTOMERS.

A. The steam and water sales to POET are variable in nature, directly related to business needs of POET and the operation of Big Stone plant. OTP believes going

[4] OTP and the other Big Stone owners made the decision to move to economic dispatch in order to maintain capacity accreditation of the unit.

forward that the level of sales and revenues will continue to vary, much like OTP has seen with its asset-based sales. This variability will be driven by market economics and the plant's relative cost position within the market. OTP believes that the EAR is the appropriate mechanism to recover the fuel costs associated with these variable steam and water sale expenses, and, moving forward, it is appropriate to treat these the same way as asset-based sales and associated margins are treated. The revenue from steam and water sales that will be credited to the EAR more than offsets the corresponding fuel costs, reducing overall EAR costs to customers.

Q. IS OTP PROPOSING ANY RELATED MODIFICATIONS TO SECTION 13.01 OF ITS NORTH DAKOTA ELECTRIC RATE SCHEDULE?

A. Yes. Exhibit___(CEB-1), Schedule 4 reflects proposed language to be added to Section 13.01 to accommodate the recovery of steam sale costs and revenues through the EAR to be effective with the implementation of final rates.

C. Hoot Lake Solar

Q. HOW DOES OTP ALLOCATE HOOT LAKE SOLAR IN NORTH DAKOTA?

A. On April 29, 2021, the Minnesota Public Utilities Commission authorized OTP's investment in the 49.9-megawatt (MW) Hoot Lake Solar Project (HLS), which is located at the site of OTP's former Hoot Lake power plant in Fergus Falls, Minnesota.[5] In doing so, the Minnesota Public Utilities Commission also authorized 100 percent allocation of all HLS Project costs to Minnesota retail customers. Ms. Petersen explains that as a result, OTP has directly assigned the HLS Project costs to the Minnesota retail jurisdiction for purposes of calculating the 2024 Test Year revenue requirement.

Q. HAS THIS TREATMENT OF HLS IMPACTED THE EAR?

A. Yes. On December 1, 2021, OTP made a filing in Case No. PU-21-443 to demonstrate to the Commission how OTP will properly account for the energy produced by HLS. In this application, OTP requested approval to modify the calculation of costs included in OTP's North Dakota EAR, Rate Schedule 13.01,

---

[5] *In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar* Project, Docket No. M-20-844, ORDER APPROVING PETITION, AUTHORIZING ALLOCATION OF OUTPUT AND COSTS, AUTHORIZING COST RECOVERY, AND REQUIRING COMPLIANCE FILINGS (April 29, 2021).

and received approval in the Order dated March 9, 2022 to account for HLS generation.

Q. PLEASE DESCRIBE THE EAR MODIFICATION APPROVED IN CASE NO. PU-21-443.

A. Under the approach approved in Case No. PU-21-443, OTP quantifies the day-ahead and real-time revenue received from the MISO for HLS's sale of energy into the MISO energy market. The quantified revenue is removed from the calculation of the North Dakota EAR by adding an equal amount of proxy cost into the calculation. This approach removes the impact of HLS from the North Dakota EAR and for North Dakota EAR purposes, treats the facility as if it does not exist. This accounting does not result in an increase in EAR rates for North Dakota customers; rather it avoids an unintended EAR rate decrease and maintains consistency in the EAR rate calculation as if HLS was not included in OTP's generation fleet.

Q. WHAT IS THE ESTIMATED HLS GENERATION PROXY COST IN THE 2024 TEST YEAR?

A. The estimated HLS generation proxy cost for the 2024 Test Year is $2.8 million (OTP Total) / $1.3 million (OTP ND).

Q. HAS OTP MADE A CORRESPONDING ADJUSTMENT TO PRESENT EAR REVENUES FOR THE 2024 TEST YEAR?

A. Yes. Ms. Petersen explains the mechanics of this adjustment in her Direct Testimony.

VI. OTHER REGULATORY ISSUES

A. Rate Case Expense

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will explain the rate case expense included in the 2024 Test Year.

Q. WHAT IS THE ESTIMATED RATE CASE EXPENSE FOR THIS CASE?

A. We estimate the rate case expenses associated with this case to be $1.1 million (OTP ND). This expense includes administrative costs, expected Commission charges, and outside consulting and legal fees.

Q. HOW DID YOU DEVELOP THIS ESTIMATE?

A. Administrative costs and Commission charges are estimated based on fees assessed in other North Dakota rate cases. Consulting fees and outside legal fees estimates were based on information from service providers. The details are reflected in work paper TY-02 2024 Rate Case Expenses Adj in Volume 4A, Workpapers.

Q. WHAT IS THE AMOUNT OF RATE CASE EXPENSE INCLUDED IN THE 2024 TEST YEAR REVENUE REQUIREMENT?

A. The 2024 Test Year revenue requirement includes $359,404 (OTP ND) for rate case expense.

Q. HOW DID YOU DETERMINE THE AMOUNT OF RATE CASE EXPENSE TO INCLUDE IN THE 2024 TEST YEAR?

A. There were two steps. The first step was to develop the estimate of the amount of rate case expense attributable to this case, as discussed above. Second, a portion of that estimated expense was allocated to our unregulated activities. Finally, the total amount allocated to regulated activity is amortized over a period of time.

Q. HOW DID YOU ALLOCATE A PORTION OF THE RATE CASE EXPENSES TO OTP'S UNREGULATED ACTIVITIES?

A. We allocated a portion of the estimated rate case expense to our unregulated activities based on a ratio of OTP's unregulated revenues to regulated revenues. This is the same methodology used by OTP in its last North Dakota rate case.

Q. WHAT AMORTIZATION PERIOD DID YOU USE?

A. We used a three-year amortization period.

Q. WHY ARE RATE CASE EXPENSES AMORTIZED OVER A PERIOD OF TIME?

A. The rate case expense is a one-time expense. Absent an amortization, the revenue requirement would inappropriately treat the expense as recurring each year. Therefore, it is appropriate to amortize those expenses over the period of time expected before OTP's next rate case. Based on what we know today, we believe OTP will likely file its next rate case in three years.

B. Advertising Expense

Q. PLEASE DESCRIBE OTP'S TREATMENT OF ADVERTISING EXPENSE IN THE 2024 TEST YEAR.

A. According to Commission Rule 69-09-02-38, paragraph 2, any expenditure by a utility for institutional, promotional, or political advertising shall be excluded from operating expenses in the cost of service determination for ratemaking purposes. Paragraph 3 of this same rule allows advertising expenditures which are reasonable in amount, and which are not excluded under paragraph 2 to be included as operating expenses in the cost of service determination for ratemaking purposes.

OTP excluded $859,117 (OTP ND) in advertising expenses allocated to North Dakota from the 2024 Test Year to comply with paragraph 2 of Commission Rule 69-09-02-38.

C. Electronic Payment Processing Fees

Q. THROUGH WHAT PAYMENT PLATFORMS CAN OTP CUSTOMERS PAY THEIR ELECTRIC BILLS?

A. OTP customers can pay their electric bills through credit and debit card, automated clearing house (ACH) payments, home banking through the customer's online bank, through other third-party electronic payment processors, or by check.

Q. ARE THERE FEES ASSOCIATED WITH THESE VARIOUS PAYMENT MECHANISMS?

A. Yes. All payment channels come with a cost. For example, processing a check involves labor, software, banking fees, and equipment costs. OTP recently calculated the cost to process a check at $0.56 per check. Further, customers paying by check overwhelmingly receive paper bills,[6] which adds an additional cost of $0.70 to the payment transaction (accounting for printing, envelopes, and mailing).[7]

---

[6] Currently, 96 percent of customers paying by check receive a bill statement in the mail, whereas only 18 percent of customers paying through an electronic channel receive a bill statement in the mail.

[7] In the future, OTP plans to offer additional electronic payment options to customers, including Apple Pay, Google Pay, and Venmo. OTP has also negotiated a $1.99 convenience fee per transaction for these options, and OTP will likely add more options as customer expectations evolve and electronic payment channels become more affordable.

Q. ARE THERE COSTS ASSOCIATED WITH ELECTRONIC PAYMENT METHODS?

A. Yes. OTP currently incurs a $1.99 convenience fee per transaction each time a customer chooses to pay with a credit card, or though other third-party electronic processor channels such as PayPal, Walmart Pay, or Amazon Pay. OTP negotiated this fee with its electronic payment processor and OTP does not keep any proceeds from this fee.

Q. IS THERE CURRENTLY A DIFFERENCE BETWEEN HOW THESE COSTS ARE RECOVERED?

A. Yes. Currently, the costs of processing non-electronic payments are part of the cost of service and recovered through base rates. Since July 2022, however, OTP has not been recovering the cost of electronic payments, either through base rates or directly from customers.

Q. WHY IS THERE A DIFFERENCE IN COST RECOVERY BETWEEN ELECTRONIC AND NON-ELECTRONIC PAYMENT CHANNELS?

A. Costs associated with non-electronic payment channels always have been part of the cost of service and therefore recovered through base rates. Prior to July 2022, OTP charged customers directly for electronic payment processing fees at the time of the transaction. OTP changed this policy in July 2022.

Q. WHY DID OTP CHANGE ITS POLICY IN 2022?

A. Following OTP's 2020 Minnesota Rate Case (Minnesota Public Utilities Commission Docket No. E017/GR-20-719), OTP began to recover electronic payment processing fees for Minnesota customers in Minnesota base rates. This change went into effect in July 2022. OTP's previous electronic payment processor could not, however, distinguish between OTP customers located in Minnesota, North Dakota, and South Dakota. Because of this limitation, OTP began absorbing the electronic payment processing fees for all customers, even though OTP could only recover electronic payment processing fees for its Minnesota customers through base rates.

Q. HOW MANY NORTH DAKOTA CUSTOMERS CURRENTLY PAY THEIR BILL THROUGH ELECTRONIC PAYMENT?

A. Currently, 41 percent of OTP's North Dakota customers use an electronic channel or IVR system to pay their electric bill. This represents 390,263 transactions annually by OTP's North Dakota customers, with an annual expense of $153,797.

Q. ARE THESE COSTS PART OF THE PROVISION OF UTILITY SERVICE?

A. Yes. Billing and collection costs are reasonably considered to be part of providing utility service. It is for this reason that OTP (and other utilities) have included the labor, software, banking fees, and equipment costs of non-electronic payments in the cost of service for many years.

Q. IS IT REASONABLE TO DIFFERENTIATE COST RECOVERY BY THE TYPE OF PAYMENT CHANNEL?

A. No. As noted above, over 40 percent of North Dakota customers utilize electronic payment channels, yet they contribute to the payment of the costs of non-electronic payment processing through their base rates. Again, payment processing costs, whether they be for electronic or non-electronic payments are part of the cost of providing utility service and therefore should be recovered from customers. As a result, OTP proposes that it be permitted to recover electronic payment processing fees for its North Dakota customers as an O&M expense in the 2024 Test Year revenue requirement.

Q. WHAT IS THE ALTERNATIVE TO RECOVERING ELECTRONIC PAYMENT PROCESSING FEES THROUGH BASE RATES?

A. If OTP is not able to recover electronic payment processing fees for its North Dakota customers through base rates, OTP could return to its former policy and require customers to pay electronic payment processing fees directly at the time of the transaction.[8] As noted above, however, this would essentially mean that these customers would be paying both for costs of non-electronic payments (because those costs are included in base rates), and also for the costs of their individual electronic payments (which would be directly paid by them).

[8] OTP is able to re-institute this policy because OTP's new electronic payment processor will be able to distinguish between OTP customers located in Minnesota, North Dakota, and South Dakota, which would allow OTP to re-institute its policy of requiring North Dakota customers to directly reimburse payment processing fees.

Q. DO OTHER NORTH DAKOTA ELECTRIC SERVICE PROVIDERS REQUIRE CUSTOMERS TO PAY ELECTRONIC PAYMENT PROCESSING FEES DIRECTLY AT THE TIME OF THE TRANSACTION?

A. No. OTP confirmed that rural electric cooperatives (1) Cass County Electric Cooperative, (2) Nodak Electric Cooperative, and (3) Capital Electric Cooperative do not require customers to pay electronic payment processing fees directly at the time of the transaction.

Q. IS OTP'S PROPOSAL RESPONSIVE TO CUSTOMER EXPECTATIONS?

A. Yes. OTP learned through market research surveys of customers, and from other customer interactions that occurred before July 2022, that eliminating the credit card processing fee was consistently among the top items requested to improve the customer experience. Customers expressed significant frustration that they had to pay this processing fee for credit card payments to OTP when other businesses do not charge a similar fee. This proposal would provide customers with a similar paying experience to what they encounter while conducting other commerce in their daily lives.

Q. WHAT IS THE 2024 TEST YEAR O&M EXPENSE FOR ELECTRONIC PAYMENT PROCESSING FEES?

A. OTP has included a test year expense of $153,797 (OTP ND) for recovery of electronic payment processing fees (credit or debit card, ACH and home banking) in this rate case, which is based on customer usage rates from September 2022 through August 2023. We have used this historic amount to forecast an amount for inclusion in the test year. Of this expense, $113,698 (OTP ND) is for processing credit or debit cards.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Mr. Christopher E. Byrnes
Supervisor, Regulatory Analysis, Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota, 56537
218-739-8282

CURRENT RESPONSIBILITIES (April 2023 to Present)

Lead Regulatory' s role in the preparation and analysis of annual jurisdictional and class cost of service studies that determine overall utility returns and price levels for actual and forecast test years. Lead Regulatory' s analysis of jurisdictional cost recovery impacts of material load changes across our jurisdictions. Lead the development of the Forecasted Energy Adjustment Rider (EAR) filings in Minnesota and monitor potential changes to the market that may impact the FCA/EAR in each jurisdiction. Prepare the economic analysis related to the FCA/EAR and other miscellaneous tariff filings. Analyze issues, participate in strategy development, and provide oral and written testimony in cost recovery filings and general rate cases as appropriate. Monitor activities of state regulatory commissions and other utilities for issues that may impact Otter Tail Power Company.

PREVIOUS POSITIONS:

Otter Tail Power Company

2023-Present	Supervisor Regulatory Analysis, Regulatory Economics
2022-2023	Rates Analyst, Regulatory Economics

Lake Region Electric Cooperative

2018-2021	Operations Supervisor, Engineering and Operations
2010-2018	System Arborist, Engineering and Operations

Army National Guard (Part Time)

2005-2023	Engineer Officer, Various

Education/Certifications

University of Maine- Orono, ME – B.S. in Forestry

Southern New Hampshire University- Manchester, NH- M.S. in Data Analytics

University of North Dakota-Grand Forks, ND- Graduate work in Applied Economics

Corporate Cost Allocation Manual

Last Update: ~~February 2017~~ September 2023

I. INTRODUCTION

The corporate entity ("Corporate") of Otter Tail Corporation provides services to the operating companies that comprise the Corporation. One of three things can occur with costs from Corporate services: 1) allocated to Otter Tail Power Company; 2) allocated to Varistar ~~Inc~~Corporation., or 3) not allocated and remain at Corporate. The purpose of this manual is to detail how costs are being allocated to Otter Tail Power Company.

Otter Tail Power Company (the largest operating company of Otter Tail Corporation) serves retail electric customers in three jurisdictions including Minnesota, North and South Dakota and is governed by the rules and regulations in each jurisdiction. As a regulated utility, Otter Tail Power is allowed to recover prudent and reasonable costs for services it receives from Corporate~~,~~ and reflects the cost of these services in its revenue requirements for setting rates. Costs allocated from Corporate are based on allocation factors that are calculated annually. In Minnesota, a different allocation method for the general allocator has been ordered for regulated reporting; however, this change in percentage is adjusted by Otter Tail Power Company so all costs billed from Corporate are at the same rate, regardless of jurisdiction.

The services provided by Corporate include financial reporting, tax planning and reporting, treasury and cash management, financial planning, internal audit, human resource and labor expertise, benefit plans, corporate communications, safety and risk management, shareholder services and investor relations, aviation and executive management services (CEO, COO, CFO and General Counsel). These services are distinct from and do not duplicate similar services in Otter Tail Power Company. See Section V below for additional information of Corporate services. To support these services, there are specific corporate costs associated with administration and information technology ("IT") that also need to be allocated.

The remainder of this document is devoted to explaining the services being provided and the methodology and allocation factors used to allocate Corporate service costs to Otter Tail Power Company.

II. METHODOLOGY

Corporate identifies costs in three categories: 1) directly assignable costs, 2) indirect costs that are allocated on a department or functional allocation factor, and 3) general costs that are allocated using a general allocation factor.

Directly assignable costs are those costs where the purpose behind the costs can be attributed to a specific operating company. For example, consulting fees to help with a project related to an individual operating company would be directly assigned to that operating company.

Indirect costs have an identifiable cost causation related to another activity or factor. For example, costs for an employee in the Risk Management department of Corporate to attend a seminar on safety would be allocated using a functional allocation factor such as number of employees.

General costs are those costs that cannot be directly assigned or where cost-causation cannot be identified. Examples would include postage, local telephone and communication service costs, time spent preparing the annual report and other SEC filings, preparing to meet with rating agencies, working with and tracking shareholder matters. These types of costs will be allocated on a general allocation factor discussed below.

Allocation factors are updated annually in February with the most recent calendar year's data. The updated allocation factors are then implemented and utilized for all Corporate Costs in February and remain unchanged for 12 months.

Methodology Changes:
Should any adjustments be made to the allocation methodology prescribed herein, notice must be provided to the following employees:

Otter Tail Corporation VP of Accounting
Otter Tail Power Company VP, Regulatory Affairs
Otter Tail Power Company, VP, Finance and CFO

All parties must approve of the methodology change prior to its implementation. "Methodology changes" should be broadly interpreted to ensure appropriate communication and approval of changes by the parties listed above.

III. ALLOCATION FACTORS

Indirect Allocation Factors:

A. IT Factor: This factor is based on the previous year ending December 31 ratio of corporate labor assigned to Otter Tail Power where the numerator is the total Corporate labor (not including bonuses) assigned to Otter Tail Power and the denominator is the total of all Corporate labor (not including bonuses). See Appendix A.

B. HR Factor: This factor is based on the average of the previous year ending December 31 ratio of employees, and the previous year ending December 31 ratio of benefit expenses. For the employee ratio the numerator is full-time employees in electric operations and the denominator is the total number of full-time employees for all of Otter Tail Corporation. For the benefit ratio, the numerator is total benefit costs (including benefit costs cleared through the payroll loading rate) from electric operations, and the denominator is consolidated benefit costs for all of Otter Tail Corporation (including benefit costs cleared through the payroll loading rate). The specific consolidated corporate accounts that will be used to calculate this ratio (including Otter Tail Power benefit costs cleared through payroll loading) are accounts C5030, C5230, C6030, C6530, C7030. See Appendix A.

C. RM Factor: This risk-management factor is the average of the previous year ending December 31 ratio of employees, and the current year ratio of insurance premiums paid. For the employee ratio the numerator is full~~-~~-time employees in electric operations and the denominator is the total number of full~~-~~-time employees for all of Otter Tail Corporation. For the insurance premium ratio, the numerator is the total premiums paid by Otter Tail Power and the denominator is the sum of insurance premiums paid by all operating companies. See Appendix A.

D. Internal Audit Factor: This factor is based on the previous year ending December 31 ratio where the numerator is the total hours spent auditing electric operations and the denominator is the sum of hours auditing electric and non-electric operations. Non-electric operations do not include hours spent auditing Corporate-related matters. See Appendix A.

General Allocation Factor:

This factor is based on a three-factor formula that is comprised of the average ratio of Total Assets, Total Revenues and Total Labor Dollars for the most recent calendar year. The specific consolidated corporate accounts that will be used to calculate the Total Labor Dollars ratio are C5010, C5020, C5030, C5210, C5220, C5230, C6010, C6015, C6020, C6030, C6510, C6520, C6530, C7010, C7020 and C7030. Appendix A shows the computation of this factor based on prior-year audited numbers and shows the source for the information to calculate each ratio.[1]

IV. CLARIFICATION ON CERTAIN COSTS

There are certain costs that need to be discussed in further detail to gain an understanding of exactly how they are being allocated, or in some instances, not being allocated. This section will list each of these costs individually and provide background and instruction on how each is handled for allocation purposes.

A. Labor: Employees at Corporate track their time on a daily basis. Percentages are used to track time between Corporate, Otter Tail Power Company, and Varistar activities. The time designated Otter Tail Power is directly assigned to the power company. The

[1] The Minnesota Public Utilities Commission (PUC) has ordered in Otter Tail Power Company's ~~last~~ rate case (Docket No. E017/GR-07-1178), that the General Allocator calculation method must comply with the PUC's orders in Docket E,G999/CI-90-1008. That docket established a general allocator based on the ratio of regulated to unregulated expenses, excluding fuel, purchased power, and purchased cost of goods sold.

percentage of time being recorded in the Corporate column is allocated based on the employee's position and will use one of the allocation factors discussed above in Section III.

B. Bonuses and Benefits: Cash bonuses are allocated based on each employee's labor ratio from the previous year. An employee's labor ratio reflects both directly assigned and allocated labor. Bonuses are accrued and allocated during the current year, and a true-up is made in the following year after the exact bonus amount is determined and the employee's actual labor ratio from the previous year is available. Benefit costs are allocated on each employee's labor ratio from the most recent 30-day pay period.

C. Contributions: The contributions made by Otter Tail Corporation are not allocated to Otter Tail Power. Each operating company makes its own contributions and those contributions made from a corporation perspective are typically not allocated.

D. Employee Stock Purchase Plan and Deferred Compensation Expense: The costs associated with the Employee Stock Purchase Plan are allocated based on the ratio of Otter Tail Power employee stock purchases to the total of the most recent stock purchase and Deferred Director Compensation expense is allocated to Otter Tail Power based on the general allocator.

E. Stock Option Expense: Under Accounting Standard Codification (ASC) Topic 718 companies are required to record the value of stock options over the period in which the options vest. These expenses are allocated to Otter Tail Power based on the number of options granted to employees in this company. No stock options were granted in ~~2016~~ 2022 and none are expected to be granted to employees in ~~2017~~2023.

F. Restricted Stock and Restricted Stock Units: Under ASC Topic 718 companies are required to record the value of restricted stock and restricted stock units over the period in which the shares vest. Restricted stock and restricted stock unit expense on shares granted to Otter Tail Power employees are directly assigned to Otter Tail Power. The portion of restricted stock or restricted stock units granted to Corporate employees and the Board of Directors is allocated to Otter Tail Power Company based on the general allocator.

G. Executive Stock Performance Award Plan: Under ASC Topic 718 companies are required to record the value of total shareholder return (TSR) portion of incentive stock award, ~~awarded~~ based on the ~~performance of the company's stock price, over the time period used to evaluate performance~~ grant date fair value of the targeted TSR awards and to record the return on equity (ROE) portion of the award based on the grant date fair value of the ROE portion of the award over the grantee's requisite service period. However, the ROE portion of the award must be adjusted for the actual number of shares earned through the end of performance measurement period. Otter Tail Corporation provides incentive stock to the corporate officers as part of their overall compensation package. The costs associated with this plan are allocated based on the prior year time allocations for each executive. In addition, when performance shares are awarded to Otter Tail Power's president the cost related to his award is directly assigned to Otter Tail Power.

H. Bank Charges: Corporate serves as the "Bank" for operating companies and therefore incurs the various fees associated with the accounts maintained by the operating companies. Otter Tail Power is directly charged for its respective fees and the fees associated with Corporate's accounts are allocated using the General Allocation Factor.

I. External Audit Fees: Otter Tail Corporation currently retains an independent registered public accounting firm to audit its financial reports and records. Each year this firm provides to Otter Tail Corporation the number of hours it has assigned to audit electric, non-electric and corporate operations which are used in determining their Client Service Plan and fees for the year. ~~a Client Service Plan that outlines the number of hours it has assigned to audit electric and non-electric operations.~~ Fees from the firm are allocated based on the ratio of assigned hours for electric versus total audit hours on consolidated operations. The hours assigned to corporate are allocated using the general allocator.

J. Meetings: Costs associated with periodic meetings that involve personnel from across the operating companies such as leadership meetings, quarterly accounting and HR meetings are not allocated.

K. Training and Development: Costs associated with training and development are direct charged where possible but otherwise allocated using the appropriate indirect allocator or the general allocator.

L. Travel and meals: With the exception of travel-related expense related to operations of Otter Tail Power's jointly owned generation plants or if corporate ~~employees are~~employees are working specifically for Otter Tail Power, corporate travel expense is not allocated.

M. Aviation Services: Corporate provides air service for the operating companies of Otter Tail Corporation. There is one aircraft available for use which is the King Air. The King Air is~~-~~ owned by Otter Tail Power Company. To help recover the variable costs associated with flying this aircraft, corporate charges hourly rates which are reviewed periodically.[2] (See Appendix B for hourly rates)

Because the King Air is owned by Otter Tail Power, at the end of each quarter the costs associated with the King Air that have not been recovered through the hourly rate are charged to Otter Tail Power. For example, the costs not cleared for the quarter total

[2] The aviation charge rates may be changed during the year to reflect changes in variable costs (i.e., aviation fuel).

$9,000. Otter Tail Power has recorded depreciation expense for the quarter of $1,000 which is added to the $9,000 of un-cleared costs for a total of $10,000. The $10,000 is multiplied by the non-utility usage factor (the percentage of hours flown for operating companies other than Otter Tail Power) and for our example we'll say it's 52%. Otter Tail Power will then be charged $3,800 ($9,000 less $5,200 ($10,000 x 52%)) to reflect the utility-portion of costs not cleared on the King Air.

V. DESCRIPTION AND ALLOCATION OF SERVICES PROVIDED

Further detail is discussed below on the services provided by Corporate. Each service shown below is directly related to an individual cost center at Corporate. For each service a description is provided along with the primary allocation factor that is used to allocate associated costs. Again, costs that can be directly assigned to the various operating companies are directly assigned. Indirect costs are allocated using one of the factors discussed in Section III.

Corporate Overheads

Description: Represents charges for bank charges, building lease and depreciation expense.

Allocation Factor: All costs not directly assigned are allocated on the General Allocation Factor.

A. Executive Management Services

Description: Represents charges for Otter Tail Corporation's executive management team and Contributions.

Allocation Factor: Contributions are not allocated and all other costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

B. Board of Directors

Description: Represents charges for board of director fees, restricted stock, travel and other expenses associated with attending Board meetings or related to being a board member.

Allocation Factor: Fees and restricted stock expense are allocated on the General Allocation Factor. Otter Tail Power is not allocated any costs associated with travel related expenses.

~~C. Corporate Development~~

~~Description: Represents charges for the Corporate Development staff that are responsible for identifying and researching acquisition candidates, due diligence on acquisition targets, and integrating recently acquired companies into Otter Tail Corporation.~~

~~Allocation Factor: All costs are currently being directly assigned to Varistar Corporation but if Otter Tail Power uses these services for an acquisition, the associated costs would be directly billed to Otter Tail Power.~~

~~D.~~C. Platform Leadership

Description: Represents charges for the Platform Leaders and their staff that have oversight responsibilities with the non-electric operating companies.

Allocation Factor: All costs are currently being directly assigned to Varistar Corporation with the exception of the Administrative Assistant position assigned to this department. Since that role not only provides services to the Platform Leadership but to other corporate functions, her time is allocated between Varistar and Otter Tail Power by being directly assigned as appropriate or by the Corporate Allocation Factor.~~.~~

~~E.~~D. Administrative Services

Description: Represents charges for providing administrative support to all the other services, office supplies and office equipment leases.

Allocation Factor: All costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

~~F.~~E. Information Technology

Description: Represents charges for supporting corporate computers, networks, land-based phones and T1 lines, internet, software and other various pieces of hardware. In addition, consulting services are provided as requested to the various operating companies.

Allocation Factor: License and maintenance fees comprise a large portion of the non-labor costs. As much as possible, these costs are directly assigned based on the number of user licenses utilizing the software by each operating company. All costs not directly assigned are allocated on the IT Factor including labor classified as Corporate. The corporate VP of Information Technology is a shared position with Otter Tail Power Company. The specific costs for this position are directly assigned to Otter Tail Power as appropriate.

~~G.~~F. Corporate Accounting

Description: Represents charges for maintaining financial records, statements and systems, SEC filings, tax accounting and filings, cash management and consulting with various operating companies on an as-needed basis.

Allocation Factor: External audit fees are allocated as discussed in Section IV. Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

~~H.~~G. Internal Audit

Description: Represents charges for reviewing internal controls and conducting operation audits at the various companies within Otter Tail Corporation.

Allocation Factor: Costs not directly assigned are allocated on the Internal Audit Factor including labor classified as Corporate.

~~I.~~H. Financial Planning

Description: Represents charges for supporting financial analysis and budgeting at the operating company and corporate level.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

~~J.~~I. Treasury

Description: Represents charges for communicating with both debt and equity analysts, maintaining Otter Tail Corporation's capital structure, monitoring and accessing capital markets and other services as identified by the Chief Financial Officer.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

~~K.~~J. Corporate Communications

Description: Represents charges for corporate communications including, but not limited to, brand strategy and corporate narrative, advertising, press releases, annual report and related annual meeting production, and enterprise news distribution.
~~press releases, advertising and branding and annual report preparation. Another service provided is coordinating and tracking contributions made on behalf of Corporate.~~

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

~~L.~~K. Shareholder Services

Description: Represents charges for maintaining shareholder records, communicating with investors at various fairs, coordinating transfer agents and planning the annual shareholder meeting.

Allocation Factor: Costs not directly assigned are allocated on the General Allocation Factor including labor classified as Corporate.

~~M.~~L. Human Resources/Leadership Development

Description: Represents charges for establishing and maintaining policies related to employment and benefits of corporate employees and executive compensation, searches for candidates for upper-level management positions on behalf of operating companies, organizing and facilitating leadership training, organizing and aiding in the administration of company benefit programs.

Allocation Factor: Costs not directly assigned are allocated on the HR Factor including labor classified as Corporate. In case of leadership and employee development training, costs are allocated based on employees in attendance at training sessions, if possible and otherwise allocated using the HR allocator.

~~N.~~M. Legal Affairs

Description: Represents charges for legal services related to employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other various legal matters.

Allocation Factor: Most costs associated with legal services are directly assigned but if costs cannot be directly charged, the general allocator is used. Typically, labor costs for all corporate lawyers other than the General Counsel are generally assigned to the Varistar companies as Otter Tail Power employs their own attorneys, however, there are times when corporate lawyers perform work for Otter Tail Power which would be assigned as such.

~~O.~~N. Risk Management

Description: Represents charges for assisting operating companies with assessment and management of risks, identifying and implementing loss control strategies to minimize the frequency and financial consequences of accidental losses, assisting operating companies in post loss claim management, overseeing Otter Tail Corporation's consolidated insurance program, and identifying and documenting the environmental conditions during the process of acquiring a new company.

Allocation Factor: Costs not directly assigned are allocated on the RM Factor including labor classified as Corporate.

VI. CONCLUSION

As circumstances arise, such as adding a new service that will be provided by Corporate, appropriate changes will be made to the manual. Appendix A will be updated annually in February when the prior-year audited records are available and Appendix B will be updated as Aviation Rates are changed.

Forecast Corporate Cost Allocation Procedures

Updated: October ~~2017~~2023

I. INTRODUCTION

The corporate entity ("Corporate") of Otter Tail Corporation provides services to the operating companies that comprise the Corporation. One of three things can occur with costs from Corporate services: 1) allocated to Otter Tail Power Company ("OTP"); 2) allocated to Varistar ~~Inc~~Corporation., or 3) not allocated and remain at Corporate. The procedures laid out in this document detail how budgeted/forecasted costs are being allocated to Otter Tail Power Company.

Corporate prepares a budget for the following year during the fourth quarter. For example, the ~~2018~~ 2023 budget is prepared in the fall of ~~2017~~2022. During the budget year (~~2018~~2023), three additional forecasts are made for ~~2018~~2023. The first is in April and covers the remainder of the year and the following year. The second is in July and covers only the remaining months of the current year. The third is in October and forecasts the remaining three months of the current year along with the five-year budget.

Otter Tail Power desires to file any future rate case on a forward-looking test year if the jurisdiction allows this methodology. In order for interim rates to go into effect on January 1, the rate case must be filed on or before November 1. Therefore, it is the updated forecast Otter Tail Power receives from Corporate in April for allocated costs which will most likely be used in the forward-looking test year.

The remainder of this document discusses the methodology and allocation factors used to allocate forecasted corporate service costs to Otter Tail Power Company.

II. LABOR AND BENEFIT ALLOCATION

Corporate identifies costs in three categories: 1) directly assignable costs, 2) indirect costs that are allocated on a department or functional allocation factor, and 3) general costs that are allocated using a general allocation factor.

Directly assignable costs are those costs where the purpose behind the costs can be attributed to a specific operating company. If there is a forecasted cost which is specifically for OTP, then it will be directly assigned in the forecast/budget. For example, any legal fees associated with a project or function identified as strictly for the benefit or need of OTP.

Labor and benefit costs make up 60-65% of Corporate's overall budget or total expenses. Labor and benefit costs are allocated using the same allocation factors as defined in the Corporate Cost Allocation Manual. ~~Corporate employees track their time each pay period and based on how their time is distributed between operating companies, labor and benefit costs are allocated accordingly. For budget/forecast purposes, each employees' time~~

~~allocation over the previous 12 months is used to allocate their respective salary and benefit costs.~~

III. NON-LABOR O&M ALLOCATION

Non-labor O&M in the budget/forecast is allocated using the same allocation factors as defined in the Corporate Cost Allocation Manual ("Manual"). As defined in the Manual, the allocations factors for the current year are based on actual results from the prior year. Since the budget is prepared before actual results are available, the allocation factors for the following year are estimated using the nine months of actual data and three months of forecasted data. The estimates produced have been very comparable to the final allocation factors once the actual results for the year are available. For the forecasts created in April, July and October actual allocation factors from Exhibit A of the Manual are used.

The five allocation factors developed are as follows:

- General Allocator
- IT Allocator
- HR Allocator
- RM Allocator
- Internal Audit Allocator

The rest of this section discusses each service or function/department comprising Corporate and what allocator is used to allocate their respective non-labor O&M costs.

A. Corporate: This department houses all the costs like depreciation expense, rent expense, CAM charges for maintaining and cleaning the space Corporate rents, and costs associated with the Employee Stock Purchase Plan ("ESPP"). In addition, incentive compensation for all Corporate employees is accrued in the department. The allocation of incentive compensation follows how each Corporate employees' labor is allocated. The factor used to allocate costs other than incentive compensation and ESPP is the **General Allocator**.

B. Officers: This department is for all the costs associated with the Officers of Otter Tail Corporation along with Contributions and Long-Term Stock Incentive Compensation costs. The allocation procedures for these two costs are discussed in more detail below. Because of the varying nature of costs recorded in this department, the procedure is to directly assign as many of the budgeted/forecasted costs as possible. All other costs not directly assigned are allocated using the **General Allocator**.

C. Board of Directors: This department tracks costs for board of director fees, restricted stock, travel and other expenses associated with attending Board meetings or related to being a board member. The factor used to allocate costs is the **General Allocator**.

D. ~~Corporate Development and~~ Platform Leadership: ~~These two departments deal~~ This department deals with non-regulated companies or those companies who roll up under Varistar. No costs from ~~these two departments~~this department are charged to OTP except for a small portion of labor and benefit costs associated with an executive assistant who supports the CEO.

E. Administrative: This department is for all costs associated with running and maintaining the office. Costs like postage, office supplies, rent expense for copying machines and printers and other office-related costs. The factor used to allocate these costs is the **General Allocator**.

F. IT: This department tracks all the costs associated with maintaining all the related IT costs like network maintenance, computer supplies, IT support, and other IT-related costs. The factor used to allocate these costs is the **IT Allocator**.

G. External Reporting and Tax: This department is responsible for both internal and external reporting of the consolidated financial results of the Corporation. This includes SEC reporting for the 10Q and 10K, management reporting, accounting for all the transactions at Corporate, and maintaining the allocation manual and methodologies. In addition, all federal and state income taxes are prepared by this group. The factor used to allocate these costs, (except for external audit fees discussed below), is the **General Allocator**.

H. Internal Audit: This department incurs costs associated with performing strategic, financial, compliance and consulting projects in partnership with Otter Tail's operating companies. The factor used to allocate these costs is the **Internal Audit Allocator.**

I. ~~Financial Planning~~Finance: This department is responsible for coordinating and consolidating the financial forecasts for each of the operating companies. It also performs valuation and goodwill testing on those companies having goodwill, maintaining the software used for budgeting and consolidation purposes, monthly operating reviews with each operating companies and any financial analysis as requested by the Chief Financial Officer. ~~The factor used to allocate these costs is the **General Allocator.**~~

~~Treasury:~~ This department is also responsible for all the daily cash management activities, monitoring and accessing equity and debt markets, maintaining the Corporation's capital structure, lease agreements, and Chairing the Investment

Committee responsible for overseeing the pension plan. The factor used to allocate these costs (other than Rating Agency fees discussed below) is the **General Allocator.**

J. Corporate Communications: This department is responsible for communicating the Corporation's strategic plan inside and outside Otter Tail Corporation, shaping, managing and protecting the Corporation's brand, and acting as a spokesperson in relations with media and the public. The factor used to allocate these costs is the **General Allocator.**

K. Shareholder Services: This department is responsible for all costs and services performed on behalf of shareholders, SEC filings on behalf of Corporate Officers, and investor relations. The factor used to allocate these costs is the **General Allocator.**

L. HR and Leadership Development: These two departments are responsible for all HR and benefit-related matters, payroll, maintaining our UltiPro software, consulting with the HR departments at each operating company, and developing the leadership skills of all employees across the corporation. The factor used to allocate these costs ~~(except for various costs discussed below)~~ is the **HR Allocator.**

M. Legal: This department is responsible for all legal matters regarding the Corporation and the operating companies. Any legal matter directly attributable to one of the operating companies is billed directly to the operating company and does not impact Corporate's budget/forecast. All Corporate-related legal matters are allocated using the **General Allocator**.

N. Risk Management: This department manages the insurance program for all Otter Tail Corporation companies. This includes the commercial lines for property, excess GL, Worker Comp, and Auto, D&O, and several other commercial lines. It also manages the captive insurance program for casualty insurance. The factor used to allocate these costs is the **RM Allocator.** Finally, this department also manages the Aviation program for the corporation. This is discussed in more detail below.

IV. CLARIFICATION ON CERTAIN COSTS

There are certain costs that need to be discussed in further detail to gain an understanding of exactly how they are being allocated, or in some instances, not being allocated. This section will list each of these costs individually and provide background and instruction on how each is handled for allocation purposes used in developing the forecast.

~~A. Employee Stock Purchase Plan: The costs associated with this Plan are allocated based on the ratio of Otter Tail Power Company employees stock purchased under the Plan divided by the total stock purchased.~~

~~B.~~A. External Audit Fees: Otter Tail Corporation currently retains an independent registered public accounting firm to audit its financial reports and records. Each year this firm provides to Otter Tail Corporation a Client Service Plan that outlines the number of hours it has assigned to audit electric and non-electric operations. Forecasted Fees from the firm are allocated based on the ratio of assigned hours for Otter Tail Power Company versus total audit hours on consolidated operations. The hours assigned to corporate are allocated using the **General Allocator**.

~~C.~~B. Rating Agency Fees: These fees are allocated based on Otter Tail Power Company's share of long-term debt.~~fees will be direct assigned where applicable. Otherwise, fees for rating on long-term debt are allocated based on Otter Tail Power Company's share of long-term debt relative to consolidated long-term debt. Fees for ratings on the lines of credit are allocated based on Otter Tail Power Company's credit facility amount relative to the consolidated credit facility amount.~~

~~D.~~C. Restricted Stock and Restricted Stock Units: Under ASC Topic 718, *Compensation—Stock Compensation* companies are required to record the value of restricted stock and restricted stock units over the period in which the shares vest. Restricted stock and restricted stock unit expense on shares granted to Otter Tail Power employees are directly assigned to Otter Tail Power. The portion of restricted stock or restricted stock units granted to Corporate employees and the Board of Directors is allocated to Otter Tail Power Company based on the **General Allocator**.

~~E.~~D. Executive Stock Incentive Plan: Under ASC Topic 718, *Compensation—Stock Compensation* companies are required to record the value of incentive stock awarded based on the performance of the company's stock price and ROE over the time period used to evaluate performance. Otter Tail Corporation provides incentive stock to the corporate officers as part of their overall compensation package. The costs associated with this plan are allocated using same allocation factors as defined in the Corporate Cost Allocation Manual ~~based on the prior year time allocations for each executive~~. In addition~~,~~ when performance shares are awarded to Otter Tail Power's president the cost related to his award is directly assigned to Otter Tail Power.

~~F.~~E. Bank Charges: Corporate serves as the "Bank" for operating companies and therefore incurs the various fees associated with the accounts maintained by the operating companies. Otter Tail Power is directly charged for its respective fees and the fees associated with Corporate's accounts are allocated using the General Allocation Factor.

~~G.~~F. Contributions: The contributions made by Otter Tail Corporation are not allocated to Otter Tail Power. Each operating company makes its own contributions and those contributions made from a corporation perspective are typically not allocated.

~~H.~~G. Meetings: Costs associated with periodic meetings that involve personnel from across the operating companies such as leadership meetings, quarterly accounting and HR meetings are not allocated.

~~I.~~H. Travel and meals: Costs associated with ~~With the exception of~~ travel-related ~~expense related to operations of Otter Tail Power's jointly owned generation plants and travel that can be direct assigned, travel~~ expenses ~~is~~are not allocated.

~~J. Leadership Development: These costs are allocated based on Otter Tail Power Company employees in attendance in training sessions divided by the total number of employees attending. Budgeted/Forecasted costs will be allocated based on the actual allocation incurred over the most recent 12-month period.~~

~~K.~~I. Aviation Services: Corporate provides air service for the operating companies of Otter Tail Corporation. There is one aircraft available for use which is the King Air. The King Air is owned by Otter Tail Power Company. To help recover the variable costs associated with flying this aircraft, corporate charges an hourly rate of $~~750~~ 850 which is reviewed periodically.[1]

Because the King Air is owned by Otter Tail Power, at the end of each quarter the costs associated with the King Air that have not been recovered through the hourly rate are charged to Otter Tail Power. For example, the costs not cleared for the quarter total $9,000. Otter Tail Power has recorded depreciation expense for the quarter of $1,000 which is added to the $9,000 of un-cleared costs for a total of $10,000. The $10,000 is multiplied by the non-utility usage factor (the percentage of hours flown for operating companies other than Otter Tail Power) and for our example we'll say it's 52%. Otter Tail Power will then be charged $3,800 ($9,000 less $5,200 ($10,000 x 52%)) to reflect the utility-portion of costs not cleared on the King Air.

VI. CONCLUSION

There is a one-month delay in Corporate costs being billed to Otter Tail Power Company. So for example, January's costs for Corporate are billed to OTP and recorded in February. Therefore, the credit to account 7999 in Corporate's ledger for February reflects the Otter Tail Power Company allocated costs from January.

Corporate and Otter Tail Power Company share common costs like pension expense, post-retirement and post-employment. Coordination takes place each forecast to make sure both entities are reflecting their share of the same total for each of these costs.

[1] The aviation charge rates may be changed during the year to reflect changes in variable costs (i.e., aviation fuel).

Finally, any updates to the Allocation Manual are reviewed quarterly by Financial Planning and the procedures used to allocate budgeted/forecasted costs will try and reflect to the extent possible any changes in allocation methodology.

Legislative Versions of

Interim Tarriff Sheet ND 13.01 - Energy Adjustment Rider by Service Category

Proposed Tariff Sheet ND 13.01 - Energy Adjustment Rider by Service Category

ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY

ENERGY ADJUSTMENT CHARGE: There shall be added to the monthly bill an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing kilowatt hours (kWh) by the customers applicable billed Energy Adjustment Factor (EAF) per kWh. The billed EAF amount per kilowatt-hour (rounded to the nearest 0.001¢) will be the average monthly cost of Energy per kilowatt-hour as determined for that customers service category. The average cost of Energy per kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent four-month period as follows:

Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative Energy costs divided by retail sales for actual months 1, 2, 3, and 4 equals the cost of Energy adjustment for month 6.

ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each Customer service category defined by Customer class. The EAF for each service category is the sum of the Current Period Average Cost of Energy and applicable monthly true-up, multiplied by the applicable EAF Ratio. The applicable EAF for each calendar month will be applied to that calendar month’s daily pro-ration of Energy usage included on the bill.

Service Category	Section	EAF Ratio	
Residential	9.01, 9.02,	1.025	**C**
Farm	9.03	0.969	**C**
General Service	10.01, 10.02, 10.03	1.016	
Large General Service	10.04, 10.05, 10.06, 11.01, 14.13	0.967	**C**
Irrigation Service	11.02	0.937	**C**
Outdoor Lighting	11.03, 11.04, 11.07	0.784	
OPA	11.05	1.011	
Controlled Service -Water Heating	14.01	1.035	**C**
Controlled Service - Interruptible	14.04, 14.05, 14.12	1.037	**C**
Controlled Service - Deferred	14.06, 14.07	0.963	

The average cost of Energy shall be determined as follows:

1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants, and the costs of reagents and emission allowances for the Company to operate its generating plants in compliance with the associated Federal Environmental

Protection Agency rules and regulations. Energy from the Company's hydro generating plants shall be included at zero cost.

2. The Energy cost of purchased power included in Account 555 when such Energy is purchased on an economic dispatch basis, exclusive of Capacity or Demand charges. This includes but is not limited to net costs linked to the utility's load serving obligation, associated with participation in wholesale electric Energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the Energy markets. All ~~Midwest~~Midcontinent Independent System Operator (“MISO”) Energy and Ancillary service market charges and credits relating to retail sales and asset based sales, specifically including (but not limited to) Schedule 16 and 17 charges and credits shall be included in the calculation. **C**

3. The actual identifiable fossil and nuclear fuel costs associated with Energy purchased for reasons other than identified in 2 above.

4. The net Energy cost of Energy purchases from a renewable Energy source, including hydropower, wood, windpower, and biomass.

5. Less the fuel-related costs recovered through intersystem sales.

6. The Energy cost of avoided purchased power resulting from Hoot Lake Solar output.

7. Known MISO Planning Resource Auction capacity costs will be added to the energy adjustment rider or revenues will be credited (flow through) the energy adjustment rider. ~~**N**~~ ~~**N**~~ ~~**N**~~

8. All revenues and associated costs attributable to Asset-based Sales Margins, as defined below and in the amount calculated as described below, shall be ~~reflected as a credit to~~included in the Energy adjustment calculation described in this schedule~~1-6, above~~. **C** **C** **C**

Asset-based Sales Margins: L

Asset-based Sales Margins are defined as wholesale Energy and ancillary services sales revenues from Company-owned generation resources less the sum of fuel, Energy costs (including costs associated with MISO markets that are recorded in FERC Account 555), and any additional transmission or other costs incurred that are required to make such sales (referred to as "margins"). One hundred percent of these actual revenues and costs shall be included in the energy adjustment rider as they are incurred. L L L L L LN N

~~The amount of the Asset-based Sales Margin credit shall be determined as described below:~~ ~~L~~D

~~**Credit calculation:** The credit shall be eighty-five percent (85%) of Asset-based Sales Margins. The Asset-based Sales Margin credit shall be calculated monthly based on a forecast of the margins expected for that month and a true-up shall be made to adjust prior forecasted credits to reflect eighty-five percent (85%) of the actual margins earned in prior months. The true-up adjustments shall be made as soon as reasonably practical after the receipt of actual results and shall reflect MISO and other resettlements that would have impacted prior credits.~~ D D D D D D

Otter Tail Power Company
Fergus Falls, Minnesota

ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY

(Identified on the bill as Fuel & Purchase Power) N

ENERGY ADJUSTMENT CHARGE: There shall be added to the monthly bill an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing ~~k~~Kilowatt hours (kWh) by the customers applicable billed Energy Adjustment Factor (EAF) per kWh. ~~-~~The billed EAF amount per ~~k~~Kilowatt-hour (rounded to the nearest 0.001¢) will be the average monthly cost of Energy per ~~k~~Kilowatt-hour as determined for that customers service category. The average cost of Energy per ~~k~~Kilowatt-hour for the current period shall be calculated from data covering actual costs from the most recent four-month period as follows: C C C C

Energy costs from actual months 1, 2, 3, and 4 plus unrecovered (or less over recovered) prior cumulative Energy costs divided by retail sales for actual months 1, 2, 3, and 4 equals the cost of Energy adjustment for month 6.

ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each Customer service category defined by Customer class. The EAF for each service category is the sum of the Current Period Average Cost of Energy and applicable monthly true-up, multiplied by the applicable EAF Ratio. The applicable EAF for each calendar month will be applied to that calendar month's daily pro-ration of Energy usage included on the bill.

Service Category	Section	EAF Ratio	
Residential	9.01, 9.02,	1.025	~~C~~
Farm	9.03	0.969	~~C~~
General Service	10.01, 10.02, 10.03	1.016	
Large General Service	10.04, 10.05, 10.06, 11.01, 14.13	0.967	~~C~~
Irrigation Service	11.02	0.937	~~C~~
Outdoor Lighting	11.03, 11.04, 11.07	0.784	
OPA	11.05	1.011	
Controlled Service Deferred Load~~-Water Heating~~	14.01	1.035	C
Controlled Service Interruptible	14.04, ~~14.05,~~ 14.12	1.037	C
Controlled Service Off Peak~~-Deferred~~	14.06, 14.07	0.963	C

The average cost of Energy shall be determined as follows: **L**

1. The cost of fossil fuel, as recorded in Account 151, used in the Company's generating plants, and the costs of reagents and emission allowances for the Company to operate its generating plants in compliance with the associated Federal Environmental Protection Agency rules and regulations. Energy from the Company's hydro generating plants shall be included at zero cost. **L L L**

2. The Energy cost of purchased power included in Account 555 when such Energy is purchased on an economic dispatch basis, exclusive of Capacity or Demand charges. This includes but is not limited to net costs linked to the utility's load serving obligation, associated with participation in wholesale electric Energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the Energy markets. All ~~Midwest~~Midcontinent Independent System Operator ("MISO") Energy and Ancillary service market charges and credits relating to retail sales and asset based sales, specifically including (but not limited to) Schedule 16 and 17 charges and credits shall be included in the calculation. **C**

3. The actual identifiable fossil and nuclear fuel costs associated with Energy purchased for reasons other than identified in 2 above.

4. The net Energy cost of Energy purchases from a renewable Energy source, including hydropower, wood, windpower, and biomass.

5. Less the fuel-related costs recovered through intersystem sales.

6. The Energy cost of avoided purchased power resulting from Hoot Lake Solar output.

7. Known MISO Planning Resource Auction capacity costs will be added to the energy adjustment rider or revenues will be credited (flow through) the energy adjustment rider. ~~N~~ ~~N~~ ~~N~~

8. All revenues and associated costs attributable to Asset-based Sales Margins, as defined below and in the amount calculated as described below, shall -be ~~reflected as a credit to~~included in the Energy adjustment calculation described in this schedule~~1-6, above~~. **C C C**

Asset-based Sales Margins: L
Asset-based Sales Margins are defined as wholesale Energy and ancillary services sales revenues from Company-owned generation resources less the sum of fuel, Energy costs (including costs associated with MISO markets that are recorded in FERC Account 555), and any additional transmission or other costs incurred that are required to make such sales (referred to as "margins"). One hundred percent of these actual revenues and costs shall be included in the energy adjustment rider as they are incurred. L L L L LN N N

~~The amount of the Asset-based Sales Margin credit shall be determined as described below:~~ ~~L~~D

~~**Credit calculation:** The credit shall be eighty-five percent (85%) of Asset-based Sales Margins. The Asset-based Sales Margin credit shall be calculated monthly based on a forecast of the margins expected for that month and a true-up shall be made to adjust prior forecasted credits to reflect eighty-five percent (85%) of the actual margins earned in prior months. The true-up adjustments shall be made as soon as reasonably practical after the receipt of actual results and shall reflect MISO and other resettlements that would have impacted prior credits.~~9. The costs of fuel and reagents resulting from steam and water sales and the revenues from steam and water sales shall be included in the energy adjustment rider. D N N

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders. N N N N

Otter Tail Power Company

POET Steam and Water Sales Revenues and Expenses

2020-2022 Actuals

Line No.	Revenue	2020	2021	2022
1	BSP Total Plant	$ (1,497,988)	$ (1,638,146)	$ (3,645,657)
2	OTP Share	$ (772,885)	$ (848,514)	$ (1,930,661)
3	ND Share - Allocator = NEPIS	$ (257,265)	$ (274,158)	$ (681,091)
4				
5	**Fuel Expense**	**2020**	**2021**	**2022**
6	BSP Total Plant	$ 357,737	$ 408,464	$ 1,202,309
7	OTP Share	$ 192,868	$ 220,246	$ 648,158
8	ND Share - Allocator = Blended E1/D1	$ 67,579	$ 76,144	$ 256,001
9				
10	Net OTP Share (Line 2 + Line 7)	$ (580,017)	$ (628,268)	$ (1,282,503)
11	ND Share (Line 3 + Line 8)	$ (189,686)	$ (198,014)	$ (425,090)