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July 8, 2022



Mr. Steve Kahl  
Director of Administration/Executive Secretary  
North Dakota Public Service Commission  
State Capitol  
600 East Boulevard, Dept. 408  
Bismarck, ND 58505-0408

**PUBLIC DOCUMENT-NOT PUBLIC  
(OR PRIVILEGED) DATA HAS BEEN EXCISED**

**RE: In the Matter of Otter Tail Power Company's Application for Approval of the  
Initial Rate of the Advanced Grid Infrastructure Cost Recover Rider, Rate  
Schedule 13.11  
Case No. PU-22-  
Initial Filing**

Dear Mr. Kahl:

Enclosed are an original and copies of Otter Tail Power Company's (Otter Tail's) Application for Approval of its Initial Rate for the Advanced Grid Infrastructure Cost Recovery Rider (AGI Rider), along with a check in the sum of \$10,000. This Application is an initial filing which sets the AGI Rider Charge for recovery of the implementation of Advanced Metering Infrastructure (AMI), Outage Management System (OMS), and Demand Response (DR) projects.

Portions of Otter Tail's Application contain trade secret information. In accordance with N.D. Admin. Code § 69-02-09-02, an Application for Trade Secret Protection is being provided along with a single copy of the trade secret version of the Application and supporting testimony in a sealed envelope marked **PROTECTED INFORMATION – PRIVATE**.

An electronic copy of this filing is being sent to the North Dakota Public Service Commission at [ndpsc@nd.gov](mailto:ndpsc@nd.gov).

Should you have any questions, please feel free to contact me at 218-739-8042 or [pfoster@otpc.com](mailto:pfoster@otpc.com).

Sincerely,  
/s/ PAULA FOSTER  
Paula Foster  
Supervisor, Regulatory Analysis  
Regulatory Administration

vjm  
Enclosures  
By electronic filing and US mail

STATE OF NORTH DAKOTA  
BEFORE THE  
NORTH DAKOTA PUBLIC SERVICE COMMISSION

**In the Matter of Otter Tail Power  
Company's Application for Approval  
of the Initial Rate of the  
Advanced Grid Infrastructure Cost  
Recovery Rider, Rate Schedule 13.11 (NEW)**

**Case No. PU-22-  
  
APPLICATION**

**I. INTRODUCTION/EXECUTIVE SUMMARY**

Otter Tail Power Company (Otter Tail or Company) respectfully submits this Application to the North Dakota Public Service Commission (Commission) for an eligibility determination and approval to implement a new Advanced Grid Infrastructure Cost Recovery Rider (AGI Rider or Rider).

1. This filing is Otter Tail's initial filing for the AGI Rider to recover forecasted costs through December 2023 for the following projects:
  - Advanced Metering Infrastructure (AMI),
  - Demand Response (DR), and
  - Outage Management System (OMS)
2. Otter Tail proposes a rate implementation date of January 1, 2023.
3. The North Dakota projected revenue requirement for the January 2023 to December 2023 recovery period is \$3,062,505, with residential customers seeing a monthly bill increase of approximately \$1.71.
4. The AMI and DR projects included in this Application received an Advance Determination of Prudence approval from the Commission<sup>1</sup> on September 22, 2021.
5. As proposed in this filing, implementing cost recovery for these multi-year projects while the projects are constructed will mitigate the magnitude of a rate increase at project completion.
6. The fundamental goals of these projects are to:
  - Improve reliability and safety of the Otter Tail system,
  - Improve customer engagement, and
  - Improve business processes.

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<sup>1</sup> Case No. PU-21-83, Order, September 22, 2021.

## II. GENERAL FILING INFORMATION

Pursuant to § 69-02-02-04 of the Commission's Rules of Practice and Procedure, the following information is provided:

**A. Name, address, and telephone number of the utility making the filing**

Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8200

**B. Name, address, and telephone number of utility attorney**

Cary Stephenson  
Associate General Counsel  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8956

**C. Title of utility employee responsible for filing**

Paula Foster  
Supervisor, Regulatory Analysis, Regulatory Administration  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8042

**D. The date of filing and the date changes will take effect**

The date of this filing is July 8, 2022. Otter Tail proposes a rate effective date of January 1, 2023.

**E. Other requirements of North Dakota Rules Part 69-02-02-04**

A certified copy of Otter Tail's Articles of Incorporation is on file with the Commission, as is an original certificate of good standing.

**F. Customer Notification**

Otter Tail will include a notice of the proposed AGI Rider to North Dakota customers on July customer bills. Attachment 14 provides a sample of the bill message that will be included. Otter Tail will also include a bill insert implementation notice to North Dakota customers once the Commission approves the new AGI Rider. Attachment 15 is a sample of the bill insert implementation notice.

### III. DESCRIPTION AND PURPOSE OF FILING

#### A. Introduction

Otter Tail has spent the past several years evaluating and planning its approach to grid modernization as part of the Company’s “Innovation 2030” (I2030) initiative – a portfolio of projects focused on upgrading the Company’s communications and technology assets to improve system data communications and allow better identification of issues and improve system performance. I2030 has three main objectives: (1) improve reliability and safety of the Otter Tail system, (2) improve customer engagement, and (3) improve business processes.

Projects comprising the overall I2030 initiative includes: (1) Advanced Metering Infrastructure (AMI); (2) Demand Response (DR) System replacement; (3) Telecommunications Infrastructure; (4) Outage Management System (OMS) with required Geographic Information System (GIS) enhancements; (5) Transmission and Distribution replacement programs as well as grid technologies; and (6) a Work Asset Management System (WAMS). The AMI and Telecommunications projects have the largest scope, and implementation of them will occur over multiple years.

The AGI projects included in the Rider align with Otter Tail’s I2030 objectives mentioned above, while allowing the Company to continue providing low cost, reliable service. In this filing, Otter Tail requests the establishment of the AGI rider for recovery of the following projects from the overall I2030 initiative:

1. AMI
2. OMS Project
3. DR System

Cost recovery through this Rider, and recovery of revenue requirements for the new investment, is under the authority granted to the Commission under N.D.C.C. Chapters 49-02, 49-05, and 49-06. On September 22, 2021, the Commission approved Otter Tail’s application for Advance Determination of Prudence in Case No. PU-21-83.

Otter Tail’s Application for approval of the proposed recovery mechanism includes the following information:

- Overview of Projects Included in this Filing
- Otter Tail’s Evaluation Process
- Business Case
- Implementation Schedule
- Proposed Recovery Mechanism

**B. Overview of Projects included in this Filing**

This section contains information about each of the three projects for which Otter Tail is seeking recovery outside of a general rate case.

**1. Advanced Metering Infrastructure**

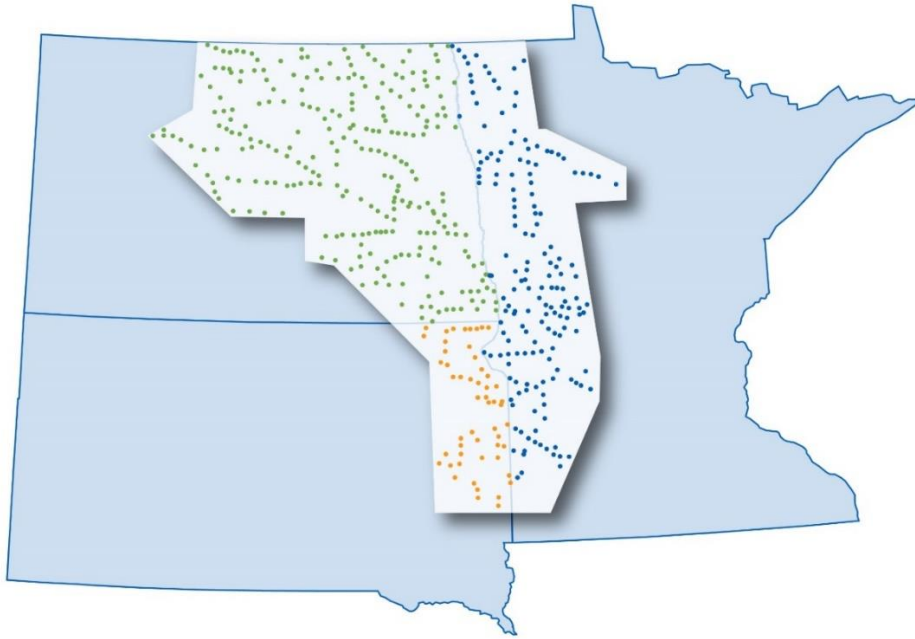
AMI is a foundational part of the I2030 initiative and will involve the deployment of the following infrastructure: (1) approximately 170,000 AMI meters, of which approximately 76,000 will be located in North Dakota; (2) local data collectors in a Field Area Network (FAN) that will collect and transmit meter data back to Otter Tail; and (3) a head-end system and Meter Data Management System (MDM) where data will be routed and stored, as needed, to facilitate automated meter reading, DR, and automated distribution control in the Company's provision of electric service.

Otter Tail provides retail electric service to approximately 133,000 customers, including approximately 62,000 customers in Minnesota, 59,000 customers in North Dakota, and 12,000 customers in South Dakota. Currently, about 99 percent of Otter Tail's customer meters are a combination of electromechanical and digital meters that are manually read each month.<sup>2</sup> This means that Otter Tail employees or a contracted meter reading service provider must physically visit almost all of our customers' premises to read their meters, which is a significant expense given Otter Tail's rural 70,000 square-mile service territory. Full implementation of AMI will enable two-way communication between the Company and the meters, allowing Otter Tail to read meters, turn service on and off, and check meter status remotely. This will reduce costs and safety risks by reducing driving miles and the need to be physically on customer property for these utility functions. Figure 1 provides an overview of the communities Otter Tail serves.

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<sup>2</sup> The Company has a small number of AMI meters that are used for interruption monitoring purposes, and a small number of automatic meter reading (AMR) meters in use for some larger customers and substations.

**Figure 1**  
**Overview of the Communities Served by Otter Tail**



AMI meters, and their associated communications infrastructure and software, have significant benefits over Otter Tail’s existing equipment and processes. By deploying AMI meters along with the associated communications network and enabling software, not only will Otter Tail enhance its visibility into its distribution network and increase safety and reliability, but Otter Tail will also realize significant operations and maintenance (O&M) savings. AMI voltage readings will be a foundation for potential future grid modernization functions such as Voltage and Reactive Power (Volt/Var) optimization, or automated system restoration which would rely on a communication network.

AMI will allow for improved outage communications with customers as well as give customers access to usage information online, whether it is via a future Otter Tail platform or third-party applications enabled by AMI. Additionally, AMI investments will benefit customers by enabling the Company to create new rate offerings and support customer located generation. AMI will also make numerous conservation and clean energy resource programs possible, including time-differentiated rates that can encourage efficient use of resources and incorporation of energy conserving consumer technologies.

The implementation schedule for AMI is discussed in section E below.

## 2. Outage Management System

Throughout the OMS project, Otter Tail has interviewed neighboring peers and others within the industry. From these interviews and research, Otter Tail has determined the Company is an outlier by operating without an OMS today. Nearly all utilities, from large Investor-Owned Utilities to small co-ops and municipalities, utilize an OMS to improve service to customers. While Otter Tail has provided excellent service to customers without an OMS, this project will address shortcomings identified through customer satisfaction surveys, including requests for improved outage transparency and communication.

Otter Tail's planned OMS project offers many operational and customer benefits related to outage response as well as a foundation that will be beneficial in future grid modernization plans. An OMS will allow Otter Tail to identify outages more rapidly and deploy crews more efficiently to reduce the number and length of outages, and it will allow Otter Tail to better communicate with customers during outage events, such as notifying them of the estimated time of restoration, etc. Completion of the OMS project will result in the following realized benefits:

- a. Outage Restoration & Reliability:** The connectivity model will allow Otter Tail to understand outage extents and provide the ability to respond to interruptions quicker when they do occur on the system. The most critical aspect for a well-functioning OMS is the electrical network model. Without a solid representation of the system within the model, the OMS prediction algorithms do not work properly. In addition to quicker restoration and improved reliability during outages, the OMS will house much more granular information related to system outages than Otter Tail is able to track today. This information will be used by Otter Tail engineers to plan and design reliability improvements.
- b. Customer Engagement and Communication:** An OMS will allow Otter Tail to provide more information to customers during outages.
  - i. Outage Notifications:** With the OMS, Otter Tail will receive information regarding the extent of predicted outages on the electrical network based on reported outages by customers and will be able to initiate communication to individual customers who are experiencing outages. This prediction will be further

enhanced when AMI is installed and the meters report outages before any customers report their outage. Otter Tail is currently not able to provide this to customers today outside of mass communications on social media.

- ii. Planned Outage Notifications:** With the OMS, planned outages are scheduled, which allows Otter Tail to communicate ahead of an outage with customers who will be impacted. This is not currently possible outside of mass communications on social media with tools Otter Tail has today.
  - iii. Estimated Time of Restoration:** The OMS will calculate the estimated time of restoration (ETR) for each outage event. The ETR can also be updated by OMS operators or field employees. The initial ETR and any subsequent ETR updates can be communicated to customers in real time to keep them informed about their outage. In addition to ETRs, the OMS will allow other status updates to be shared with the customer, such as when a crew is dispatched, when a crew has arrived onsite, and when the power outage is restored. Otter Tail is unable to provide this to customers today.
  - iv. Outage Reporting:** Customers will be able to report their outage through an Interactive Voice Response system, online, or via text. Today, customers can only report an outage by directly calling Otter Tail. This multi-channel aspect for reporting outages will drastically improve the speed of reporting an outage as well as increase the ease of use for customers.
  - v. Outage Viewing:** Today's outage map published on Otter Tail's website is only for feeder level outages due to the lack of an OMS. Once Otter Tail has deployed an OMS, all outage activity, regardless of size, will be published on the public outage map. The current high-level reporting has led to frustration and confusion with customers.
- c. Safety:** The connectivity model will be updated in real time by both field employees and OMS operators. This is a key safety improvement to ensure all stakeholders responding to an outage understand the current state of the electrical system.

- d. AMI/Meter Data Management (MDM) Tools:** The scope of the AMI project includes the utilization of a connectivity model. The following are related benefits:
- i. Facility Loading Report:** This will allow facility loading reports on assets, such as transformers, feeders, or sub-feeders. For a loading report to work, it must understand the electrical equipment hierarchy that comes from the connectivity model.
  - ii. Reliability Planning:** One of the MDM tools in the scope for the AMI project is a Reliability Planner. This tool takes outage information from OMS and pairs it with the connectivity model to estimate reliability improvements from standard mitigation measures such as vegetation management, lateral tap fusing, etc.
- e. Future Smart Grid Applications:** Although Otter Tail’s near-term implementation timeline does not include the following applications, the connectivity model is foundational to tools such as Fault Location, Isolation and Service Restoration technology, Volt/VAR automation, Conservation Voltage Reduction, as well as more granular DR control algorithms.
- f. Outage Metrics:** The connectivity model paired with the OMS will allow Otter Tail to report industry reliability metrics such as the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), etc. The OMS metrics will be more granular than Otter Tail is able to report with its current Interruption Monitoring System. This change will lead to more detailed metrics in the future.
- g. System Studies:** Presently, when an Otter Tail engineer requests a system study for a portion of the distribution system, assumptions must be made related to attribution and connectivity. When the OMS project is complete, the accuracy of these reports will increase and the time to create the models for these studies will be greatly reduced.

As part of the OMS project, Otter Tail is developing the electrical connectivity model from meter to substation and specific attribution data of Otter Tail’s GIS features. The data collection effort will ensure the Company has accurate and complete data and can track how each customer on the

delivery system is connected from the meter to a delivery transformer, to a feeder, and finally to a distribution substation. This updated data will facilitate better outage response when outage information is sent to the OMS. The GIS work is being performed by a third-party vendor that has extensive experience updating GIS models in preparation for grid modernization tools. In addition, the attribution data will be leveraged by Otter Tail engineers to refine various asset health programs, such as underground cable replacement and overhead line replacement projects. The connectivity model will also be utilized by the MDM for operational and planning tools and will be available for future tools, such as Volt/Var optimization, DR controls, and automated system reconfiguration. As such, the GIS effort is foundational to the I2030 initiative.

Lastly, the implementation of AMI will enhance the speed in which the OMS receives outage information and therefore improve restoration times even further. The individual meters will provide power-off and power-on notifications to be utilized by the OMS.

A pilot for the GIS update portion of the project began in August 2021. The work done by the contractor for the pilot was approved and work on the full system began in October 2021. The GIS updates are projected to be completed by the end of 2022. The vendor contract for the OMS project was signed in April 2022 with Milsoft, and project completion is estimated by early 2023.

### **3. Demand Response System**

Otter Tail's DR programs are a core Company service offering utilized by nearly one-third of Otter Tail customers, making Otter Tail's DR portfolio one of the largest in the country by customer adoption. Strong customer participation in DR allows Otter Tail to control between 10-15 percent of total winter peak load, reducing overall system capacity needs, and materially lowering costs for customers. However, a large part of the Company's existing DR infrastructure is either approaching end of life or already functionally obsolete, threatening the Company's ability to continue to offer and utilize DR options in the future. DR programs reduce individual customer energy costs and allow Otter Tail to lower overall system energy and fuel costs for all customers and create efficiencies to the grid and generators. Other DR benefits for customers include, avoided generation

capacity, avoided energy and transmission, frequency regulation, and emergency system protection.

The Company's DR program uses a communications network, load control switches, and a software platform to interface with customers' devices and reduce load during peak events for customers participating in DR programs. This allows Otter Tail and its customers, to save costs by shifting and reducing load during periods of high market prices or to support system reliability.

Otter Tail procured its current DR software in 2003 and as of January 1, 2022, almost 20 years later, the software system is no longer supported by its vendor in any functionality. Necessary components of Otter Tail's current DR System, such as communications equipment and load control switches, are either limited in availability or no longer sold or supported.. As a result, the DR system is rapidly becoming obsolete, which limits Otter Tail's ability to grow and enhance its DR offerings.

A two-way communications network will be utilized to support the continued long-term functionality of the Company's DR programs and enable their improvement and expansion. Further, because Otter Tail receives capacity accreditation for the amount of interruptible load on its system, the future expansion and modernization of the Company's DR System is expected to generate additional benefits by potentially delaying the need for new resources.

Replacement of the DR System is currently in the RFP phase. Installation is expected to begin in 2024 with full implementation being completed in 2027.

### **C. Otter Tail's Evaluation Process**

For several years, Otter Tail has monitored and evaluated the evolution of Automatic Meter Reading (AMR) and AMI technology. AMR meters provide one-way communication from the meter to the utility, either via a handheld meter reading device or through radio frequency communications, powerline communication systems, or cellular communications networks. Otter Tail did not invest in AMR when that technology was introduced in the 1990s because the business case (cost benefit analysis) for doing so was not yet strong enough to justify it. However, in recent years, customers' expectations have changed and the technology advantages of AMI, along with the need to address our aging DR system, have increased, and it now makes sense to deploy AMI meters system

wide. According to the Energy Information Administration (EIA) advanced metering data report from 2017,<sup>3</sup> more than 99.9 percent of the meters in North Dakota, outside of Otter Tail’s service territory, were AMR or AMI meters as of January 2017. Otter Tail believes the time is right to meet the new industry standard.

During the evaluation phase for AMI over the past few years, the Otter Tail team evaluated AMI functions and requirements, use case development, business case development, and considered procurement options. Otter Tail hired a consultant in early 2018 for guidance in completing a benefit analysis, completing vendor discovery, developing requests for proposals, and negotiating contracts. An additional consultant was hired in late 2019 to update current business practices with proposed business practices.

The findings from discussions with external resources and other utilities stressed the importance of integrating the AMI system with plans for improvements to our DR system and implementation of an OMS.

There are many key project features included for customers. With AMI, Otter Tail will automatically be informed when power is out at customer locations, allowing the Company to be more efficient in addressing outage issues. Customers will have information available to help them conserve energy, and they will be able to monitor the benefits of their efforts on the Otter Tail website. Otter Tail will be able to offer more flexible pricing, which will give customers options for reducing bills if customers choose to use more electricity during off-peak hours. With this type of rate structure, prices will be higher during times of high system demand. In addition, Otter Tail will use both AMI and OMS to focus maintenance efforts to the areas of highest significance.

AMI enables a holistic system for OMS, future grid modernization, and DR projects. Otter Tail has contracted with Landis + Gyr (L+G) to purchase the most advanced AMI meters available today. With an estimated useful life of 20 years, the meters will enable Otter Tail to continue to implement other useful and more efficient advanced technologies. Otter Tail expects to use the data from the AMI system to assess loading on specific assets, such as transformers and electric lines, and to use this information to help avoid overloading conditions. This data may also help the Company find ways to change usage patterns that may enable it to keep low rates.

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<sup>3</sup> U.S. Energy Information Administration, Form EIA-861M, Advanced Metering Data (2017), available at [Form EIA-861M \(formerly EIA-826\) detailed data](#).

**D. Business Case**

**1. Advanced Metering Infrastructure**

As mentioned earlier, as of January 2017, the vast majority of the meters outside the Otter Tail service territory in North Dakota were AMR or AMI meters. Otter Tail is lagging behind its neighboring utilities in adopting and implementing advanced metering technology.

The Edison Foundation website contains an infographic of “Smart Meters at a Glance”,<sup>4</sup> which provides data showing that electric companies had installed more than 107 million AMI meters by the end of 2020, covering 75 percent of U.S. households. The publication projected that by the end of 2021, approximately 115 million AMI meters would be deployed nationwide. Although AMR and AMI systems have been available for many years, state-of-the-art AMI meters introduced in recent years provide a step-change in capability over prior models.

The Company expects the capital cost of the AMI project to be \$56.1 million on a company-wide basis. Otter Tail staff worked with outside consultants who have prior experience with AMI implementation to develop this cost estimate based on industry standards and known pricing of AMI infrastructure. The Company has validated these estimates using the initial information received in the responses to its RFP process. Figure 2 provides a breakdown of the estimated capital costs of the AMI project.

**Figure 2:  
Estimated Capital Costs of AMI Project (in millions) OTP Total**

	A	B
1 AMI Meters		\$ 46.7
2 Field Area Network (FAN)		\$ 2.5
3 Software		\$ 6.9
4 Project Total		\$ 56.1

Consistent with past practice for meter-related expenses, the Company plans to allocate system wide costs of the AMI Project to the North Dakota jurisdiction pursuant to allocations approved by the Commission in the Company’s most recent general rate case.

<sup>4</sup> [IEI Smart Meter Report April 2021.ashx \(edisonfoundation.net\)](http://www.edisonfoundation.net/IEI_Smart_Meter_Report_April_2021.ashx).

Significant cost savings are expected as a result of the AMI implementation. These savings largely result from Otter Tail no longer having to manually read meters across its large and sparsely populated service area in Minnesota, North Dakota, and South Dakota.<sup>5</sup> Savings also include the associated costs for field and office work and lower meter reading system and equipment costs. In addition, Otter Tail will realize savings on meter replacement costs that would normally have occurred for older meters still in use.

While there are O&M costs associated with AMI meters and other components of the AMI Project, those costs are less than the Company's current O&M costs with existing meters due to the reduction in meter reading costs and other associated meter expenses. Measured incremental savings realized by the AMI deployment will be passed through the AGI rider decreasing the amount to be collected from customers. These measured savings will include avoided contracted meter reading costs and net avoided maintenance expenses. Avoided maintenance expenses would be the net of expenses attributed to hand-held meter reading devices and the new AMI O&M costs incurred and attributable to the new AMI system. Long term savings realized by impacts to internal labor through employee reductions from attrition will be captured in rates set in each future rate case when AMI recovery becomes part of base rates. As discussed below, Otter Tail expects to experience overall net savings beginning in 2027.

Figure 3 below illustrates the net expenses projected through 2045 for the AMI project. The Company estimates that implementation of AMI will result in average annual O&M savings of approximately \$6.61 million (OTP Total) / \$2.95 (OTP ND) from the beginning of initial deployment in 2022 through 2045 as shown in Figure 3, Columns E and F, Line No. 14.

“Other Expenses” on lines 3, 7, 11 and 15 in Figure 3 include the following annual expenses: O&M, depreciation, property tax, and income tax. The net expense savings (O&M Cost/(Benefit) less Other Expenses) are estimated to begin in 2027 when they will be (\$0.33)<sup>6</sup> million (OTP Total) / (\$0.15) million (OTP ND) and will then increase annually thereafter as Otter Tail avoids the projected inflation in O&M costs for the manually read meters as shown in Figure 3, Column G, Line No. 4.

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<sup>5</sup> Otter Tail intends to manage the impact to its workforce of this automation through attrition and reassignment of personnel.

<sup>6</sup> Figure 3, Column G, Line No. 4

**Figure 3**  
**AMI Project Estimate of Annual Expenses (in millions)**

Line	A	B	C	D	E	F	G	H	I
1	<b>AMI Project (OTP Total)</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>
2	O&M Cost/(Benefit)	\$ 0.35	\$ 0.32	\$ (3.38)	\$ (5.40)	\$ (5.45)	\$ (5.74)	\$ (5.92)	\$ (5.98)
3	Other Expenses	\$ 0.09	\$ 2.30	\$ 4.60	\$ 5.55	\$ 5.48	\$ 5.41	\$ 4.10	\$ 3.43
4	<b>Net Expenses</b>	<b>\$ 0.44</b>	<b>\$ 2.62</b>	<b>\$ 1.22</b>	<b>\$ 0.15</b>	<b>\$ 0.03</b>	<b>\$ (0.33)</b>	<b>\$ (1.82)</b>	<b>\$ (2.55)</b>
5	<b>AMI Project (OTP Total)</b>	<b>2030</b>	<b>2031</b>	<b>2032</b>	<b>2033</b>	<b>2034</b>	<b>2035</b>	<b>2036</b>	<b>2037</b>
6	O&M Cost/(Benefit)	\$ (6.30)	\$ (6.49)	\$ (6.56)	\$ (6.90)	\$ (7.12)	\$ (7.20)	\$ (7.57)	\$ (7.80)
7	Other Expenses	\$ 3.40	\$ 3.36	\$ 3.32	\$ 3.28	\$ 3.24	\$ 3.21	\$ 3.17	\$ 3.13
8	<b>Net Expenses</b>	<b>\$ (2.90)</b>	<b>\$ (3.13)</b>	<b>\$ (3.24)</b>	<b>\$ (3.62)</b>	<b>\$ (3.87)</b>	<b>\$ (3.99)</b>	<b>\$ (4.40)</b>	<b>\$ (4.67)</b>
9	<b>AMI Project (OTP Total)</b>	<b>2038</b>	<b>2039</b>	<b>2040</b>	<b>2041</b>	<b>2042</b>	<b>2043</b>	<b>2044</b>	<b>2045</b>
10	O&M Cost/(Benefit)	\$ (7.89)	\$ (8.29)	\$ (8.55)	\$ (8.65)	\$ (9.09)	\$ (9.37)	\$ (9.66)	\$ (9.95)
11	Other Expenses	\$ 3.09	\$ 3.06	\$ 3.02	\$ 2.98	\$ 2.94	\$ 2.78	\$ 1.47	\$ 0.79
12	<b>Net Expenses</b>	<b>\$ (4.80)</b>	<b>\$ (5.24)</b>	<b>\$ (5.53)</b>	<b>\$ (5.67)</b>	<b>\$ (6.14)</b>	<b>\$ (6.58)</b>	<b>\$ (8.18)</b>	<b>\$ (9.16)</b>
		<b>Time Period Annual Average</b>							
		<b>Total 2022-2045 (OTP Total)</b>	<b>Total 2022-2045 (OTP ND)*</b>		<b>2022-2045 (OTP Total)</b>	<b>2022-2045 (OTP ND)*</b>			
13	<b>AMI Project (OTP Total)</b>								
14	O&M Cost/(Benefit)	\$ (158.60)	\$ (70.86)		\$ (6.61)	\$ (2.95)			
15	Other Expenses	\$ 77.23	\$ 34.51		\$ 3.22	\$ 1.44			
16	<b>Net Expenses</b>	<b>\$ (81.37)</b>	<b>\$ (36.35)</b>		<b>\$ (3.39)</b>	<b>\$ (1.51)</b>			

\*Based on OTP's C6 jurisdictional allocation of 44.69 percent as approved in Docket No. PU-17-398

Figure 4 below presents the revenue requirement impacts of the scenario in which the AMI Project is implemented. It shows total revenue requirement net savings of approximately \$41.80 million (OTP Total) / \$18.68 million (OTP ND) over the 20-year life of the meters, using North Dakota's 44.68 percent C6 allocation factor approved by the Commission in Otter Tail's last general rate case.<sup>7</sup>

<sup>7</sup> Case No. PU-17-398.

**Figure 4**  
**AMI Project Estimate of Annual Revenue Requirements (in millions)**  
**OTP Total**

Line	A	B	C	D	E	F	G	H	I
1	<b>AMI Project (OTP Total)</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>
2	Return on Rate Base	\$ 0 40	\$ 2 36	\$ 3 65	\$ 3 66	\$ 3 34	\$ 3 03	\$ 2 77	\$ 2 57
3	Net Expenses (Savings)	\$ 0 44	\$ 2 62	\$ 1 22	\$ 0 15	\$ 0 03	\$ (0 33)	\$ (1 82)	\$ (2 55)
4	<b>Annual Revenue Requirement</b>	\$ 0 84	\$ 4 98	\$ 4 87	\$ 3 82	\$ 3 37	\$ 2 70	\$ 0 95	\$ 0 02
5	<b>AMI Project (OTP Total)</b>	<b>2030</b>	<b>2031</b>	<b>2032</b>	<b>2033</b>	<b>2034</b>	<b>2035</b>	<b>2036</b>	<b>2037</b>
6	Return on Rate Base	\$ 2 40	\$ 2 22	\$ 2 05	\$ 1 87	\$ 1 70	\$ 1 53	\$ 1 35	\$ 1 18
7	Net Expenses (Savings)	\$ (2 90)	\$ (3 13)	\$ (3 24)	\$ (3 62)	\$ (3 87)	\$ (3 99)	\$ (4 40)	\$ (4 67)
8	<b>Annual Revenue Requirement</b>	\$ (0 50)	\$ (0 91)	\$ (1 20)	\$ (1 75)	\$ (2 17)	\$ (2 47)	\$ (3 05)	\$ (3 49)
9	<b>AMI Project (OTP Total)</b>	<b>2038</b>	<b>2039</b>	<b>2040</b>	<b>2041</b>	<b>2042</b>	<b>2043</b>	<b>2044</b>	<b>2045</b>
10	Return on Rate Base	\$ 1 00	\$ 0 83	\$ 0 66	\$ 0 48	\$ 0 31	\$ 0 15	\$ 0 04	\$ 0 01
11	Net Expenses (Savings)	\$ (4 80)	\$ (5 24)	\$ (5 53)	\$ (5 67)	\$ (6 14)	\$ (6 58)	\$ (8 18)	\$ (9 16)
12	<b>Annual Revenue Requirement</b>	\$ (3 80)	\$ (4 41)	\$ (4 87)	\$ (5 19)	\$ (5 83)	\$ (6 44)	\$ (8 14)	\$ (9 15)
		<b>Total 2022-2045 (OTP Total)</b>	<b>Total 2022-2045 (OTP ND)*</b>						
13	<b>AMI Project (OTP Total)</b>								
14	Return on Rate Base	\$ 39 56	\$ 17 68						
15	Net Expenses (Savings)	\$ (81 37)	\$ (36 35)						
16	<b>Annual Revenue Requirement</b>	\$ (41 80)	\$ (18 68)						

\*Based on OTP's C6 jurisdictional allocation of 44.68 percent as approved in Docket No. PU-17-398

The estimated projected cost/(benefit) per meter is shown on lines 5 and 10 in Figure 5 below. Early years of project implementation include higher depreciation expense due to the five-year depreciation schedule for software. The Field Area Network collectors and routers will be depreciated over 15 years, and the meters will be depreciated over 20 years. The Otter Tail employee reductions achieved as part of AMI implementation are largely due to automation, which will almost completely eliminate the need for employees to physically read customer meters. This employee reduction is expected to be accomplished through attrition, and Otter Tail anticipates the total reduction between 2022 and 2032. Pro-rated meter reading costs are also still included in the implementation years until full implementation has occurred and Otter Tail can discontinue the manual activities that drive these costs. The full credit to expenses will not happen immediately but will be reflected in the tracker and on customer bills as the savings are realized by Otter Tail.

**Figure 5**  
**AMI Project Annual Revenue Requirement - Monthly Cost/(Benefit) Per Meter**

Line

1	<b>AMI Project (OTP Total)</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>
2	Return on Rate Base	\$ 396,770	\$ 2,363,067	\$ 3,645,647	\$ 3,662,938	\$ 3,340,247	\$ 3,033,321
3	Expenses (Savings)	\$ 435,972	\$ 2,623,650	\$ 1,218,837	\$ 153,886	\$ 32,159	\$ (328,403)
4	<b>Annual Revenue Requirement</b>	<b>\$ 832,742</b>	<b>\$ 4,986,717</b>	<b>\$ 4,864,484</b>	<b>\$ 3,816,824</b>	<b>\$ 3,372,406</b>	<b>\$ 2,704,918</b>
5	Monthly Cost / (Benefit) Per Meter	0.40	2.42	2.36	1.85	1.64	1.31
6	<b>AMI Project (OTP Total)</b>	<b>2028</b>	<b>2029</b>	<b>2030</b>	<b>2031</b>	<b>2032</b>	<b>2022-2032</b>
7	Return on Rate Base	\$ 2,772,872	\$ 2,573,178	\$ 2,396,376	\$ 2,221,778	\$ 2,047,787	\$ 28,453,981
8	Expenses (Savings)	\$ (1,818,167)	\$ (2,548,338)	\$ (2,900,719)	\$ (3,134,592)	\$ (3,242,898)	\$ (9,508,612)
9	<b>Annual Revenue Requirement</b>	<b>\$ 954,705</b>	<b>\$ 24,840</b>	<b>\$ (504,343)</b>	<b>\$ (912,814)</b>	<b>\$ (1,195,111)</b>	<b>\$ 18,945,368</b>
10	Monthly Cost / (Benefit) Per Meter	0.46	0.01	(0.25)	(0.44)	(0.58)	

Along with the estimated cost savings in Figure 5, AMI implementation brings the benefit of increased safety of Company employees by vastly reducing the in-person visits to customer locations. This will reduce the possibilities for slips, trips, falls, and even dog bites while on customer property. Additionally, AMI will eliminate the need for Company employees to enter customer buildings and structures on a monthly basis to read meters that are located inside.

AMI enhances reliability by providing the utility with improved system awareness and planning insight, as well as providing the network communication system that could allow the Company to eventually automate the distribution system at the substation and circuit level using smart devices. This will allow Otter Tail to identify and respond to outages more quickly, thereby improving overall reliability. Additionally, the near real-time data provided by the AMI system will allow the Company to predict and plan for potential loading-related outages and will enable the reduction in response times for outages that do occur on the system. The AMI system will improve reliability and safety by providing better and more reliable alarms for tampering and overheating of Company equipment.

Other devices, when added to the Company's distribution system, can also benefit from the deployment of the FAN, including fault indicators, switch controls, and regulator controls with the ability to enable programs such as Conservation Voltage Reduction, where the Company can use AMI voltage data to automatically adjust the voltage in a distribution system and potentially optimize the voltage and reduce customers' energy consumption.

## **2. Outage Management Project**

Otter Tail is also deploying an OMS, which will allow the Company to identify outages more accurately and rapidly and deploy crews more efficiently to reduce the duration of outages. This in turn will improve reliability metrics of CAIDI and SAIDI. Otter Tail's processes for responding to outages on the system have served customers well but are out of date. An OMS will greatly improve the organization of disparate data that exists during outages within today's processes, which will allow restorations to occur more quickly. The OMS will also greatly improve how the Company can communicate outage information with customers to keep them apprised of restoration efforts.

Currently, a customer will call to report an outage and must speak to a live call agent. The call agent or on-call management then must compile data from calls, field devices, and employees and dispatch a field crew to respond to the information. With an OMS, all outage related data will funnel into the system, including field updates, and automated outage call information received from customers through an outage Interactive Voice Response (IVR) system. This will allow better management of the outage response as well as provide much desired information to customers. This desire for outage and restoration information has been reflected in the Company's past few customer satisfaction surveys.

As briefly mentioned, the GIS data collection effort improvements, as well as outage information recorded and organized in the OMS, will allow Company asset planners to develop more refined asset health programs, which will further improve reliability of the Transmission and Distribution systems.

The OMS total Company project cost is estimated at approximately \$4.2 million in capital, plus up to \$725 thousand in annual O&M costs to run the system. These costs reflect the GIS enhancements and the OMS implementation with the outage IVR. Otter Tail proposes to begin recovery on the OMS project as costs are incurred, but not earlier than January 2023.

## **3. Demand Response System**

Through strong customer engagement, Otter Tail has built a robust DR portfolio over many decades. Otter Tail customers have invested in heating, water heating, and cooling technologies that provide the Company with substantial DR capabilities. The Company offers several rates in each

jurisdiction that incorporate DR, providing flexibility and savings for residential, commercial, and industrial customers.

Otter Tail's DR program also provides the Company with the ability to economically assess the cost of serving load in organized electricity markets. The Company can choose to either buy the energy at market cost or interrupt customers during periods of higher prices. In general, the Company's DR system shifts or reduces load when called upon by activating load control switches located at customer homes, businesses, or on their appliances, such as air conditioners. The ability to reduce load in this way allows the Company to realize economic efficiencies for customers by offering them a lower rate in return for the ability to reduce their load during certain times. Customers are also able to reduce their bills by taking advantage of time of use (TOU) rates which match customer electric use with the pricing of electricity at particular times of day, thereby encouraging customers to shift electric use to times when it is cheaper to provide.

The ability to reduce load also provides reliability benefits for the grid by providing an additional tool to address high-demand situations, which in turn can generate capacity benefits for the Company and customers. The amount of DR based interruptible load on the Company's system, can be used to fulfill a portion of the Company's annual capacity requirement set by the Midcontinent Independent System Operator (MISO) under Module E of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Maintaining and expanding Otter Tail's DR capability will allow the Company to continue to reduce overall system energy and fuel costs for customers.

Much of the hardware and software used to support the existing DR system is antiquated and/or obsolete. The radio communication system that forms the backbone of the Company's DR program is approaching its obsolescence. Much of the hardware used to support the current radio system and its associated load control switches is antiquated and/or obsolete.

Most of the software that supports the DR system was procured in 2003 and is currently unsupported by the vendor, putting it at risk of losing functionality. As a result, the legacy DR system is essentially limited to existing functionality, limiting Otter Tail's ability to grow and enhance its DR offerings.

Several specific hardware components of the DR system are no longer available for sale, which means replacement units cannot be purchased, and/or are no longer supported by their manufacturers. For example, the Company uses discontinued Palm Pilot devices to program and control load control switches. Palm Pilot devices have not been supported by the manufacturer since 2011, and of the 16 Palm Pilots that Otter Tail originally purchased, only 6 remain operational. The communications system installed as part of the AMI Project may provide the foundation for upgrading to a new two-way communications network which will maintain the functionality of Otter Tail's DR programs and allow for potential improvement and expansion of the Company's DR offerings in the future. The cost for new hardware and software to continue the DR program is estimated at **[PROTECTED DATA BEGINS...  
...PROTECTED DATA ENDS]**

#### **E. Implementation Schedule**

The Company is planning to roll out the AMI Project in phases. Phase 1 is complete and entailed issuing RFPs, evaluating bids, contract negotiations with suppliers, implementation and deployment planning, proof of concept, and internal project staffing. The Company competitively bid all aspects of the Project. Phase 2 of the AMI Project is currently underway and began in the fourth quarter of 2021 and will continue through the fourth quarter 2022 or first quarter 2023. This phase entails business process development, system integrations, and initial deployment for proof of concept. Phase 3 is set to run from early 2023 to the third quarter of 2024. Full deployment occurs in Phase 3, including the AMI meters, the FAN, and the MDM. To summarize, the current estimated timeline is as follows:

- AMI
  - Phase 1: Selection of 1 preferred vendor and finalized contracts are complete;
  - Phase 2: Business process development, system integration and initial deployment from Q1 2022 to Q1 2023; and,
  - Phase 3: Full Deployment from Q2 2023 and to Q4 2024.
- The OMS is currently in the initial part of execution.
- The DR project will follow the development of the AMI project and is currently in the RFP development phase

## F. Proposed Recovery Mechanism

Revenue, Revenue Requirements Summary, Rate Design, and Tracker Summary calculations used for Otter Tail's rate submittal can be found in Attachments 1-4. Attachments 5-7 provide the revenue requirement calculations for the Projects for which Otter Tail requests AGI recovery. Attachment 8 provides the AMI adjustment reflecting the O&M savings due to the AMI implementation in North Dakota.

Specifically, the calculations of the revenue requirement in this Application include the following:

- *Rate base section.* This section provides details on the amount of plant in service, accumulated depreciation (if applicable), construction work in progress (CWIP), accumulated deferred taxes including the effect of proration on Federal amounts, and a 13-month average rate base calculation.
- *Expense section.* The expenses applicable to a project are listed here and include operating costs, property taxes, depreciation, and income taxes.
- *Revenue requirements section.* This section shows the components of the revenue requirements, including expenses and return on rate base.
- *Return on investment (cost of capital).* The return on investment utilizes the return on equity approved in Otter Tail's last Rate Case.
- *Depreciation expense.* Depreciation expense is calculated using the Company's current estimated depreciation rates.
- *Property taxes.* The property tax calculation is based on a weighted average of Otter Tail's composite tax rate for the jurisdictions using a weight of 50 percent (MN), 40 percent (ND) and 10 percent (SD) and applied in accordance with the procedures specified by the states.
- *Operation and maintenance expense.* Once the project is in service, Otter Tail will track operation and maintenance costs specifically related to each project in Attachments 5-7. Annual O&M expenses related to these projects include operating costs, property taxes, and depreciation.
- *Operation and maintenance savings.* Once the projects are in service, Otter Tail will track operation and maintenance savings specifically related to this project in Attachment 8. Annual O&M savings related to AGI implementation primarily include costs related to manual meter reading, of which a certain portion is completed by third party contract services and a certain portion conducted internally by service reps across Otter Tail's system.
- *Proration of Federal Accumulated Deferred Income Taxes (ADIT).* Once the project is in service, Otter Tail will include proration of Federal ADIT, as shown in Attachment 9. The methodology used for proration of Federal ADIT is in adherence to United States Internal

Revenue Service (IRS) rules related to proration, including recently issued IRS private letter rulings. Otter Tail interprets this to include proration of Federal ADIT for the (forward-looking) recovery period and, in future filings, preserving the effect of the application of the proration methodology for the true-up period. This calculation methodology is necessary in order to comply with Section 1.167(l)-1(h)(6)(ii) of the IRS regulations and to avoid a tax normalization violation.<sup>8</sup> In annual Updates, Otter Tail will include a workpaper with the details of the calculation of the proration of Federal ADIT for the recovery period and whether it results in an increase or decrease to the revenue requirement.

- *Jurisdictional Allocation Factors.* Jurisdictional allocators are used to allocate system cost among jurisdictions. The Commission approved Otter Tail's North Dakota jurisdictional allocations for the 2018 Test Year in the Rate Case.

#### **IV. RATE DESIGN**

Otter Tail proposes to use a monthly per meter charge rate design for the AGI Rider. The proposed rate calculation starts with the determination of the average cost per meter for materials and labor for each customer class. The weighted average cost per customer class is then used to determine the percentage of AMI, OMS, and DR project costs to be charged to each class. The weighted average project costs per class is divided by the average annual number of meters per class to calculate a monthly per meter charge for each customer class. Attachment 1 summarizes the proposed monthly rate per meter, number of meters, and the estimated annual AGI revenue for each customer class.

#### **V. REVENUE REQUIRMENT, RATE APPLICATION AND IMPACT**

Otter Tail proposes to collect a total annual revenue requirement of \$3,062,505 for the recovery period of January 2023 through December 2023. Recovery under the AGI Rider would be a per meter monthly charge determined by rate class and displayed as a separate line item on customer bills. North Dakota residential customers will see a monthly bill increase of approximately \$1.71. The customer Notice and Rate Impact for each class is contained in Attachment 15.

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<sup>8</sup> See Treas. Reg. SS 1.167(l)-1(h)(6)(ii).

## VI. AGI COST RECOVERY RIDER RATE SCHEDULE

Otter Tail's new AGI Rider tariff sheet (Section 13.11) is Attachment 13 to this Application. The rates listed in the RATE section of the tariff sheet are established to reflect the AGI per meter charge as described in this Application.

## VII. CONCLUSION

Based on the information provided in this filing, Otter Tail requests that the Commission:

1. Approve the recovery of the AMI, OMS and DR projects in the AGI Rider.
2. Approve the proposed AGI Rider that will allow Otter Tail to recover rate of return, incremental property taxes, and incremental depreciation expense associated with AMI and OMS implementation and DR System replacement effective January 2023.
3. Approve Otter Tail's initial rates to be recovered in the AGI Rider effective January 1, 2023.

Date: July 8, 2022

Respectfully submitted:  
OTTER TAIL POWER COMPANY

/s/ PAULA FOSTER

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## **Attachments**

Attachment 1	Projection of Revenue
Attachment 2	Summary of Revenue Requirements
Attachment 3	Class Allocation and Rate Design
Attachment 4	Advanced Grid Infrastructure Tracker
Attachment 5	Advanced Metering Infrastructure
Attachment 6	Outage Management System
Attachment 7	Demand Response Revenue
Attachment 8	AMI Cost Savings Adjustment
Attachment 9	Impact of Federal ADIT Proration on Revenue Requirement
Attachment 10	North Dakota Electric Rate Schedule Index
Attachment 11	Mandatory Riders Applicability Matrix, Electric Rate Schedule 13.00
Attachment 12	Reserved for Future Use, Electric Rate Schedules 13.02, 13.03, 13.09, and 13.10
Attachment 13	Advanced Grid Infrastructure Cost Recovery Rider, Electric Rate Schedule 13.11
Attachment 14	Sample Bill Message
Attachment 15	Notice to Customers

Projected Revenue for January 2023 to December 2023 Recovery Period

Line No.	Class	Meters (Yearly Count)	Monthly Rate per Unit	Amount
1	Residential	519,621	\$1.7093	\$888,189
2	Residential RDC	39,848	\$4.2773	\$170,444
3	Farm	13,384	\$4.3341	\$58,008
4	General Service	145,918	\$6.6149	\$965,229
5	General Service - TOU	36	\$13.8740	\$499
6	Large General Service - Primary	169	\$71.7559	\$12,127
7	Large General Service - Secondary	3,085	\$16.3079	\$50,310
8	Irrigation	529	\$11.1347	\$5,890
9	Outdoor Lighting	1,598	\$4.4129	\$7,052
10	OPA	6,807	\$4.4250	\$30,121
11	Controlled Service - Water Heating	73,354	\$4.2773	\$313,760
12	Controlled Service - Interruptible Small Dual Fuel	90,765	\$4.3346	\$393,429
13	Controlled Service - Interruptible Large Dual Fuel	6,637	\$17.7446	\$117,771
14	Controlled Service - Deferred Load	9,359	\$5.3080	\$49,677
15	Total revenue			<u>\$3,062,505</u>

Summary of Revenue Requirements

Line No.	Revenue Requirements	January 2023 - December 2023
1	Advanced Metering Infrastructure	2,967,316
2	Outage Management / GIS Updates	790,882
3	Demand Response	60,819
4	O&M Savings due to AMI Implementation	(745,620)
5	Carrying Charge	(10,892)
6	True-Up	0
7	Net Revenue Requirement	<u>\$3,062,505</u>

Class Allocation and Current Rate Design

Line No.		January 2023 - Decemeber 2023	Percent of Total	Annual Meter Count	Per Meter Charge	Revenue Requirements by Class
1	Total 2022-2023 North Dakota Revenue Requirements	\$3,062,505				
2	Residential		29.00%	519,621	\$1.7093	\$888,189
3	Residential RDC		5.57%	39,848	\$4.2773	\$170,444
4	Farm		1.89%	13,384	\$4.3341	\$58,008
5	General Service		31.52%	145,918	\$6.6149	\$965,229
6	General Service - TOU		0.02%	36	\$13.8740	\$499
7	Large General Service - Primary		0.40%	169	\$71.7559	\$12,127
8	Large General Service - Secondary		1.64%	3,085	\$16.3079	\$50,310
9	Irrigation		0.19%	529	\$11.1347	\$5,890
10	Outdoor Lighting		0.23%	1,598	\$4.4129	\$7,052
11	OPA		0.98%	6,807	\$4.4250	\$30,121
12	Controlled Service - Water Heating		10.25%	73,354	\$4.2773	\$313,760
13	Controlled Service - Interruptible Small Duel Fuel		12.85%	90,765	\$4.3346	\$393,429
14	Controlled Service - Interruptible Large Duel Fuel		3.85%	6,637	\$17.7446	\$117,771
15	Controlled Service - Deferred Load		1.62%	9,359	\$5.3080	\$49,677
16	Total North Dakota Revenue Requirements		100.00%	911,110	\$171	\$3,062,505

Rate Impact				
	Meter Count (Month)	Current Rate (\$ per meter)	Proposed Rate (\$ per meter)	Monthly Impact (Increase or decrease from prior rate)
Residential	43,302	0.000	\$1.7093	\$1.7093
Residential RDC	3,321	0.000	\$4.2773	\$4.2773
Farm	1,115	0.000	\$4.3341	\$4.3341
General Service	12,160	0.000	\$6.6149	\$6.6149
General Service - TOU	3	0.000	\$13.8740	\$13.8740
Large General Service - Primary	14	0.000	\$71.7559	\$71.7559
Large General Service - Secondary	257	0.000	\$16.3079	\$16.3079
Irrigation	44	0.000	\$11.1347	\$11.1347
Outdoor Lighting	133	0.000	\$4.4129	\$4.4129
OPA	567	0.000	\$4.4250	\$4.4250
Controlled Service - Water Heating	6,113	0.000	\$4.2773	\$4.2773
Controlled Service - Interruptible Small Duel Fuel	7,564	0.000	\$4.3346	\$4.3346
Controlled Service - Interruptible Large Duel Fuel	553	0.000	\$17.7446	\$17.7446
Controlled Service - Deferred Load	780	0.000	\$5.3080	\$5.3080
	75,926			

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected
	<b>Revenue Requirements</b>													
1	Advanced Metering Infrastructure	181,028	181,328	181,467	181,756	269,057	270,099	270,506	285,817	286,089	286,521	286,731	286,919	2,967,316
2	Outage Management System	65,907	65,907	65,907	65,907	65,907	65,907	65,907	65,907	65,907	65,907	65,907	65,907	790,882
3	Demand Response	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	60,819
4	<b>Total Revenue Requirements</b>	252,003	252,303	252,442	252,731	340,032	341,074	341,481	356,792	357,064	357,496	357,706	357,894	3,819,017
5	<b>ADIT Preservation of Proration</b>													
6	<b>O&amp;M Savings due to AMI Implementation</b>	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(62,135)	(745,620)
7	<b>Net Revenue Requirement</b>	189,868	190,168	190,307	190,596	277,897	278,939	279,346	294,657	294,929	295,361	295,571	295,759	3,073,397
8	Billed (forecast meter x adj factor)	255,209	255,209	255,209	255,209	255,209	255,209	255,209	255,209	255,209	255,209	255,209	255,209	3,062,505
9	Monthly Revenue Difference	(65,341)	(65,041)	(64,902)	(64,613)	22,688	23,731	24,137	39,448	39,720	40,152	40,362	40,551	10,892
10	Carrying Charge	0	(416)	(833)	(1,252)	(1,671)	(1,537)	(1,396)	(1,251)	(1,008)	(761)	(510)	(257)	(10,892)
11	Life-to-Date Revenue Requirement (Cumulative Difference)	(65,341)	(130,798)	(196,532)	(262,397)	(241,380)	(219,186)	(196,445)	(158,248)	(119,536)	(80,146)	(40,294)	0	0
12	Carrying Charge Calculation	(416)	(833)	(1,252)	(1,671)	(1,537)	(1,396)	(1,251)	(1,008)	(761)	(510)	(257)	0	
13	Cumulative Carrying Charge	(416)	(1,249)	(2,501)	(4,172)	(5,709)	(7,105)	(8,356)	(9,364)	(10,125)	(10,635)	(10,892)	(10,892)	
14	Carrying cost rate	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	
15	Forecasted Meter Count	75,926	75,926	75,926	75,926	75,926	75,926	75,926	75,926	75,926	75,926	75,926	75,926	911,110

SUMMARY	January 2023 - December 2023
	Revenue requirements
Carrying Charge	(10,892)
True-up	0
<b>Total requirements</b>	<b>\$3,062,505</b>
Sep 2022 - Aug 2023 projected meter count	911,110
Average Rate	\$3.36129





Otter Tail Power Company  
North Dakota- Advanced Grid Infrastructure (AGI)  
Advanced Metering Infrastructure Revenue Requirements

Line No.	Year-->	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023
		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total	
<b>RATE BASE</b>															
1	Plant Balance	0	0	0	27,076,635	27,174,422	27,202,892	35,477,789	35,483,336	35,516,352	35,521,898	35,527,444	46,556,142	46,556,142	46,556,142
2	Accumulated Depreciation	0	0	0	0	(197,756)	(396,826)	(596,054)	(829,275)	(1,062,528)	(1,296,269)	(1,530,041)	(1,763,844)	(1,763,844)	(1,763,844)
3	Net Plant in Service	0	0	0	27,076,635	26,976,665	26,806,066	34,881,736	34,654,060	34,453,824	34,225,629	33,997,403	44,792,298	44,792,298	44,792,298
4	CWIP	17,199,809	20,355,702	23,676,415	0	2,694,120	5,632,910	0	2,520,957	4,970,914	7,005,267	9,014,209	0	0	0
5	ADIT - NOL DTA														
6	Reversal of ADIT - NOL DTA														
7	ADIT Proration Factors	0.9178	0.8411	0.7562	0.6740	0.5890	0.5069	0.4219	0.3370	0.2548	0.1699	0.0877	0.0027		
8	ADIT - Federal & State Depreciation	0	0	0	(60,798)	(83,853)	(104,360)	(129,019)	(146,620)	(161,595)	(173,822)	(183,432)	(208,384)	(208,384)	(208,384)
9	Ending rate base	17,199,809	20,355,702	23,676,415	27,015,837	29,586,932	32,334,617	34,752,717	37,028,397	39,263,143	41,057,074	42,826,180	44,583,914	44,583,914	44,583,914
11	Average rate base	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842	2,576,842
13	Return on Rate Base	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922
14	Available for return (equity portion of rate base)	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173
15	EXPENSES														
16	O&M and Depreciation														
18	Operating Costs	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069	172,069
19	Property Tax	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282	2,282
20	Book Depreciation	0	0	0	0	197,756	199,070	199,228	233,222	233,253	233,741	233,772	233,803	233,803	233,803
22	Total O&M and Depreciation Expense	174,351	174,351	174,351	174,351	372,108	373,421	373,579	407,573	407,604	408,093	408,123	408,154	408,154	408,154
23	Income before Taxes														
25	Available for return (from above)	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173	132,173
26	Taxable Income (grossed up)	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843	174,843
27	Income Taxes														
28	Current Income Tax	42,670	42,670	42,670	(40,439)	7,824	8,144	(4,389)	3,908	3,915	4,034	4,042	(96,833)	(96,833)	18,218
29	Deferred Income Tax	0	0	0	83,109	34,847	34,526	47,059	38,763	38,795	38,636	38,628	139,503	139,503	493,825
31	Total Income Tax Expense	42,670	42,670	42,670	42,670	42,670	42,670	42,670	42,670	42,670	42,670	42,670	42,670	42,670	512,043
32															
33															
34	REVENUE REQUIREMENTS														
35	Expenses	217,022	217,022	217,022	217,022	414,778	416,091	416,249	450,243	450,274	450,763	450,794	450,824	450,824	450,824
36	Return on rate base	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922	196,922
37	Subtotal revenue requirements	413,944	413,944	413,944	413,944	611,700	613,013	613,172	647,166	647,196	647,685	647,716	647,747	647,747	647,747
38	Adjustments														
39	Total revenue requirements	413,944	413,944	413,944	413,944	611,700	613,013	613,172	647,166	647,196	647,685	647,716	647,747	647,747	647,747
40															
41	North Dakota share - Meters (C6)	102,509	111,119	116,601	123,042	190,322	198,897	205,142	222,170	226,915	230,884	234,346	237,416	237,416	2,199,363
42	North Dakota share - FAN (P60)	25,912	22,161	19,281	17,089	23,208	21,418	19,877	19,631	18,460	17,616	16,839	16,161	16,161	237,654
43	North Dakota share - Software (P90)	52,606	48,047	45,585	41,625	55,527	49,785	45,487	44,015	40,714	38,021	35,545	33,343	33,343	530,300
44	Total North Dakota Share	181,028	181,328	181,467	181,756	269,057	270,099	270,506	285,817	286,089	286,521	286,731	286,919	286,919	2,967,316

SUPPORTING INFORMATION / DATA															
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure	Ratio	Cost	WA Cost				Property tax				1.18%			
3	Debt	47.50%	5.29%	2.51%				2023 composite rate							
4	Preferred equity	0.00%	0.00%	0.00%											
5	Common equity	52.50%	9.77%	5.13%											
6	Total	100.00%		7.64% Overall Return											
7															
8															
9															
10	Project life (years)	Book	Tax												
11		20	20-year MACRS												
12				Fed Portion	State Portion										
13	Statutory Tax Rate	24.40%	20.09%	4.31%											
14	Tax conversion factor	1.32284													
15	ND share - C6 factor	44.680%													
16	ND share - P90 factor	41.079%													
17	ND share - P60 factor	45.903%													
18	Deferred Tax														
19	Book depreciation	0	0	0	197,756	199,070	199,228	233,222	233,253	233,741	233,772	233,803	1,763,844	1,763,844	1,763,844
20	Tax depreciation-Federal	0	0	0	340,541	340,541	340,541	392,053	392,053	392,053	392,053	392,053	805,421	805,421	3,787,310
21	Tax depreciation-SD	0	0	0	340,541	340,541	340,541	392,053	392,053	392,053	392,053	392,053	805,421	805,421	3,787,310
22	Federal deferred income taxes	0	0	0	(68,431)	(28,693)	(28,429)	(38,748)	(31,917)	(31,911)	(31,813)	(31,806)	(114,866)	(114,866)	(406,613)
23	State deferred income taxes	0	0	0	(14,677)	(6,154)	(6,097)	(8,311)	(6,846)	(6,844)	(6,823)	(6,822)	(24,637)	(24,637)	(87,211)



Otter Tail Power Company  
North Dakota- Advanced Grid Infrastructure (AGI)  
Outage Management Project Revenue Requirements

Line No.	Year-->	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Projected May	Projected Jun	Projected Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total	
<b>RATE BASE</b>															
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	4,197,599	4,197,599
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	4,197,599	4,197,599
4	<b>CWIP Calculation:</b>														
5	Beginning Balance	386,606	518,381	586,042	872,880	1,015,504	1,328,249	1,692,319	2,077,862	2,464,919	2,893,089	3,321,259	3,759,429		
6	Additional CWIP	129,953	65,260	283,807	138,943	308,170	358,170	378,170	378,170	428,170	428,170	438,170	438,170		
7	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	0		
8	AFDUC	1,822	2,401	3,031	3,681	4,575	5,900	7,373	8,887					(4,197,599)	
9		518,381	586,042	872,880	1,015,504	1,328,249	1,692,319	2,077,862	2,464,919	2,893,089	3,321,259	3,759,429	0		0
10	ADIT Federal Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		
11	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0	(341,439)	(341,439)
12	Ending rate base	518,381	586,042	872,880	1,015,504	1,328,249	1,692,319	2,077,862	2,464,919	2,893,089	3,321,259	3,759,429	3,856,160		
13															
14	Average rate base	158,799	158,799	158,799	158,799	158,799	158,799	158,799	158,799	158,799	158,799	158,799	158,799		1,905,592
15															
16	Return on Rate Base	12.135	12.135	12.135	12.135	12.135	12.135	12.135	12.135	12.135	12.135	12.135	12.135		145,625
17															
18	Available for return (equity portion of rate base)	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145		97,743
19															
<b>EXPENSES</b>															
20	<b>O&amp;M and Depreciation</b>														
21	Operating Costs	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	320,695
23	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Total O&M and Depreciation Expense	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	26,725	320,695
26															
27	<b>Income before Taxes</b>														
28	Available for return (from above)	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145	8,145		97,743
29	Taxable Income (grossed up)	10,775	10,775	10,775	10,775	10,775	10,775	10,775	10,775	10,775	10,775	10,775	10,775		129,298
30															
31	<b>Income Taxes</b>														
32	Current Income Tax	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	(338,810)	(309,884)
33	Def Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	341,439	341,439
34	Total Income Tax Expense	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630	2,630		31,555
35															
36															
<b>REVENUE REQUIREMENTS</b>															
37	Expenses	29,354	29,354	29,354	29,354	29,354	29,354	29,354	29,354	29,354	29,354	29,354	29,354		352,250
38	Return on rate base	12,135	12,135	12,135	12,135	12,135	12,135	12,135	12,135	12,135	12,135	12,135	12,135		145,625
40	Subtotal revenue requirements	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490		497,875
41	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0		0
42	Total revenue requirements	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490	41,490		497,875
43															
44	North Dakota share - P90 Factor	17,043	17,043	17,043	17,043	17,043	17,043	17,043	17,043	17,043	17,043	17,043	17,043		204,521
<b>SUPPORTING INFORMATION / DATA</b>															
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>											
4	Debt	47.50%	5.29%	2.51%											
5	Preferred equity	0.00%	0.00%	0.00%											
6	Common equity	52.50%	9.77%	5.13%											
7	Total	100.00%		7.64%	Overall Return										
8															
9															
10	Project life (years)		<b>Book</b>	<b>Tax</b>											
11			5	3-year MACRS											
12															
13			<b>Fed Portion</b>	<b>State Portion</b>											
14	Statutory Tax Rate		24.40%	20.09%											
15	Tax conversion factor		1.32284	4.31%											
16	ND share - P90 factor		41.079%												
17	<b>Deferred Tax</b>														
18	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	0	1,399,060	1,399,060
20	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	0	1,399,060	1,399,060
21	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	(281,140)	(281,140)
22	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	(60,299)	(60,299)





Otter Tail Power Company  
North Dakota- Advanced Grid Infrastructure (AGI)  
Demand Response System Revenue Requirements

Line No.	Year>>	2023 Projected Jan	2023 Projected Feb	2023 Projected Mar	2023 Projected Apr	2023 Projected May	2023 Projected Jun	2023 Projected Jul	2023 Projected Aug	2023 Projected Sep	2023 Projected Oct	2023 Projected Nov	2023 Projected Dec	2023 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>CWIP Calculation:</b>														
4	Beginning Balance	0	0	0	0	420,567	841,133	1,261,700	1,682,267	2,102,833	2,523,400	3,043,967	3,564,533	4,085,100
5	Additional CWIP	0	0	0	420,567	420,567	420,567	420,567	420,567	420,567	520,567	520,567	520,567	4,085,100
6	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
7	AFDUC	0	0	0	0	0	0	0	0	0	0	0	0	0
8														
9	ADIT Federal Proration Factors	0.9178	0.8411	0.7562	0.6740	0.5890	0.5069	0.4219	0.3370	0.2548	0.1699	0.0877	0.0027	0
10	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Ending rate base	0	0	0	420,567	841,133	1,261,700	1,682,267	2,102,833	2,523,400	3,043,967	3,564,533	4,085,100	4,085,100
12														
13	Average rate base	125,163	125,163	125,163	125,163	125,163	125,163	125,163	125,163	125,163	125,163	125,163	125,163	1,501,962
14														
15	Return on Rate Base	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	114,780
16														
17	Available for return (equity portion of rate base)	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	77,039
18														
19														
<b>EXPENSES</b>														
<b>O&amp;M and Depreciation</b>														
20	Operating Costs (annual fees)	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
24														
25	Income before Taxes	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	77,039
26	Available for return (from above)	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	6,420	77,039
27	Taxable Income (grossed up)	8,493	8,493	8,493	8,493	8,493	8,493	8,493	8,493	8,493	8,493	8,493	8,493	101,911
28														
29	Income Taxes	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	24,871
30	Current Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Def Income Tax	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	24,871
32	Total Income Tax Expense	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	24,871
33														
34														
35														
<b>REVENUE REQUIRMENTS</b>														
36	Expenses	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	2,073	24,871
37	Return on rate base	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	9,565	114,780
38	Subtotal revenue requirements	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	139,651
39	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total revenue requirements	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	11,638	139,651
41														
42	North Dakota share - C9 factor	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	5,068	60,819
43														

Line No.	SUPPORTING INFORMATION / DATA
1	
2	ND Cap Structure with allowed ROE per order.
3	Capital Structure
4	Debt
5	Preferred equity
6	Common equity
7	Total
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	<b>Deferred Tax</b>
18	Book depreciation
19	Tax depreciation-Federal
20	Tax depreciation-ND
21	Federal deferred income taxes
22	State deferred income taxes

Ratio	Cost	WA Cost	Property tax
47.50%	5.29%	2.51%	2023 composite rate
0.00%	0.00%	0.00%	1.18%
52.50%	9.77%	5.13%	
100.00%		7.64% Overall Return	

Book	Tax
15	15-year MACRS

Fed Portion	State Portion
24.40%	4.31%
1.32284	
43.551%	

Otter Tail Power Company  
North Dakota- Advanced Grid Infrastructure (AGI)  
North Dakota  
O&M Savings due to AMI Implementation

Line No.	A	B	C	D	E
		Year>>	2022 Projected	2023 Projected	2024 Projected
1	<b>SAVINGS</b>				
2	<i>O&amp;M</i>				
3	Operations and Maintenance		0	1,744,453	5,390,360
4				0	0
5				0	0
6	Total O&M		0	1,744,453	5,390,360
7					
8	North Dakota - C7 Meter Reading Allocation Factor		42.74%	42.74%	42.74%
9	O&M (OTP ND)		0	745,620	2,303,966
10					
11	<b>REVENUE REQUIREMENTS</b>				
12	Total Revenue Requirements (OTP ND) - Line 12 + Line 22		0	745,620	2,303,966
13					
14	Revenue Requirement Share back		0	745,620	2,303,966

Federal ADIT Proration

January 2023 - December 2023 Recovery Period				
A	B	C	D	E
Month	All Projects' Revenue Requirements without ADIT Prorated	All Projects' Revenue Requirements with ADIT-Prorated	Difference due to Federal ADIT Proration (B - A)	
1				
2				
3	Jan-23	\$251,622	\$252,003	\$381
4	Feb-23	\$251,921	\$252,303	\$382
5	Mar-23	\$252,060	\$252,442	\$382
6	Apr-23	\$252,348	\$252,731	\$382
7	May-23	\$339,649	\$340,032	\$383
8	Jun-23	\$340,691	\$341,074	\$383
9	Jul-23	\$341,097	\$341,481	\$384
10	Aug-23	\$356,408	\$356,792	\$384
11	Sep-23	\$356,680	\$357,064	\$384
12	Oct-23	\$357,111	\$357,496	\$384
13	Nov-23	\$357,321	\$357,706	\$385
14	Dec-23	\$357,510	\$357,894	\$385
15		\$3,814,417	\$3,819,017	\$4,600

16	Revenue Requirement Related to Federal ADIT Proration-Projection	\$4,600
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Attachment 10  
Legislative and Non-Legislative Versions of  
North Dakota Electric Rate Schedule Index

Section

Item

**11.00 OTHER SERVICES**

11.01	Standby Service
11.02	Irrigation Service
11.03	Outdoor Lighting – Energy Only Dusk to Dawn
11.04	Outdoor Lighting Dusk to Dawn
11.05	Municipal Pumping Service
11.06	Civil Defense - Fire Sirens
11.07	LED Street and Area Lighting – Dusk to Dawn

**12.00 PURCHASE POWER RIDERS & APPLICABILITY MATRIX**

12.01	Small Power Producer Rider Occasional Delivery Energy Service (Net Energy Billing Rate)
12.02	Small Power Producer Rider Time of Delivery Energy Service
12.03	Small Power Producer Rider Dependable Service

**13.00 MANDATORY RIDERS & APPLICABILITY MATRIX**

13.01	Energy Adjustment Rider <ul style="list-style-type: none"> <li>Applicable to <u>all</u> services and riders unless otherwise stated in the mandatory riders matrix</li> </ul>
<u>13.02</u>	<u>Reserved for Future Use</u>
<u>13.03</u>	<u>Reserved for Future Use</u>
13.04	Renewable Resource Cost Recovery Rider
13.05	Transmission Cost Recovery Rider
13.06	Generation Cost Recovery Rider
13.07	N/A (reserved for future use)
13.08	Environmental Cost Recovery Rider
<u>13.09</u>	<u>Reserved for Future Use</u>
<u>13.10</u>	<u>Reserved for Future Use</u>
<u>13.11</u>	<u>Advanced Grid Infrastructure (AGI) Cost Recovery Rider</u>

Section

Item

**11.00 OTHER SERVICES**

11.01	Standby Service
11.02	Irrigation Service
11.03	Outdoor Lighting – Energy Only Dusk to Dawn
11.04	Outdoor Lighting Dusk to Dawn
11.05	Municipal Pumping Service
11.06	Civil Defense - Fire Sirens
11.07	LED Street and Area Lighting – Dusk to Dawn

**12.00 PURCHASE POWER RIDERS & APPLICABILITY MATRIX**

12.01	Small Power Producer Rider Occasional Delivery Energy Service (Net Energy Billing Rate)
12.02	Small Power Producer Rider Time of Delivery Energy Service
12.03	Small Power Producer Rider Dependable Service


**13.00 MANDATORY RIDERS & APPLICABILITY MATRIX**

13.01	Energy Adjustment Rider • <i>Applicable to <u>all</u> services and riders unless otherwise stated in the mandatory riders matrix</i>	
13.02	Reserved for Future Use	N
13.03	Reserved for Future Use	N
13.04	Renewable Resource Cost Recovery Rider	
13.05	Transmission Cost Recovery Rider	
13.06	Generation Cost Recovery Rider	
13.07	N/A (reserved for future use)	
13.08	Environmental Cost Recovery Rider	
13.09	Reserved for Future Use	N
13.10	Reserved for Future Use	N
13.11	Advanced Grid Infrastructure (AGI) Cost Recovery Rider	N

Attachment 11  
Legislative and Non-Legislative Versions of  
Mandatory Riders Applicability Matrix  
Electric Rate Schedule 13.00

### MANDATORY RIDERS - APPLICABILITY MATRIX

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.

 <b>Applicability Matrix</b>		<b>Mandatory Riders</b>	Energy Adjustment Rider by Service Category	Reserved for Future Use	Reserved for Future Use	Renewable Resource Cost Recovery Rider	Transmission Cost Recovery Rider	Generation Cost Recovery Rider	Reserved for Future Use	Environmental Cost Recovery Rider	Reserved for Future Use	Reserved for Future Use	Advanced Grid Infrastructure Cost Recovery Rider
<b>Base Tariffs</b>		Section Number	13.01	13.02	13.03	13.04	13.05	13.06	13.07	13.08	13.09	13.10	13.11
<b>RESIDENTIAL &amp; FARM SERVICES</b>													
Residential Service	9.01												
Residential Demand Control Service	9.02												
Farm Service	9.03												
Reserved for Future Use	9.04												
<b>GENERAL SERVICES</b>													
Small General Service (Less than 20 kW)	10.01												
General Service (20 kW or Greater)	10.02												
General Service - Time of Use	10.03												
Large General Service	10.04												
Large General Service - Time of Day	10.05												
Super Large General Service	10.06												
<b>OTHER SERVICES</b>													
Standby Service	11.01												
Irrigation Service	11.02												
Outdoor Lighting - Energy Only	11.03												✓
Outdoor Lighting	11.04												
Municipal Pumping Service	11.05												
Fire Sirens - Civil Defense	11.06												
LED Street and Area Lighting	11.07												
Key:		✓ = May apply	■ = Mandatory	□ = Not Applicable									

NORTH DAKOTA PUBLIC SERVICE COMMISSION  
Dakota  
Case No. PU-22-1-439  
Approved by order dated

EFFECTIVE for bills rendered on and after ~~January 1, 2023~~<sup>December 26, 2021</sup>, in North

APPROVED: Bruce G. Gerhardson  
Vice President, Regulatory Affairs



		Mandatory Riders	Energy Adjustment Rider by Service Category	Reserved for Future Use	Reserved for Future Use	Renewable Resource Cost Recovery Rider	Transmission Cost Recovery Rider	Generation Cost Recovery Rider	Reserved for Future Use	Environmental Cost Recovery Rider	Reserved for Future Use	Reserved for Future Use	Advanced Grid Infrastructure Cost Recovery Rider
Applicability Matrix		Section Number	13.01	13.02	13.03	13.04	13.05	13.06	13.07	13.08	13.09	13.10	13.11
<b>Base Tariffs</b>													
<b>MANDATORY RIDERS</b>													
Energy Adjustment Rider by Service Category	13.01												
Reserved for Future Use	13.02												
Reserved for Future Use	13.03												
Renewable Resource Cost Recovery Rider	13.04												
Transmission Cost Recovery Rider	13.05												
Generation Cost Recovery Rider	13.06												
Reserved for Future Use	13.07												
Environmental Cost Recovery Rider	13.08												
Reserved for Future Use	13.09												
Reserved for Future Use	13.10												
Advanced Grid Infrastructure Cost Recovery Rider	13.11												
<b>VOLUNTARY RIDERS</b>													
Water Heating Control Rider	14.01												
Real Time Pricing Rider	14.02												
Large General Service Rider	14.03	✓											
Controlled Service - Interruptible Load CT Metering Rider	14.04												
Controlled Service - Interruptible Load Self-Contained Metering Rider	14.05												
Controlled Service Deferred Load Rider	14.06												
Fixed Time of Service Rider	14.07												
Air Conditioning Control Rider	14.08												
Voluntary Renewable Energy Rider	14.09												
WAPA Bill Crediting Program Rider	14.10												
Reserved for Future Use	14.11												
Bulk Interruptible Service Application and Pricing Guidelines	14.12												✓
Economic Development Plate Rider - Large General Service	14.13												
<b>Key:</b>		✓ = May apply	■ = Mandatory	□ = Not Applicable									

NORTH DAKOTA PUBLIC SERVICE COMMISSION  
 Dakota  
 Case No. PU-~~22-17-398~~  
 Approved by order dated ~~September 26, 2018~~

EFFECTIVE for bills rendered on  
 and after ~~January 1, 2023~~ ~~February 1, 2019~~, in North  
 APPROVED: Bruce G. Gerhardson  
 Vice President, Regulatory Affairs





## Attachment 12

### Non-Legislative Version

Reserved for Future Use Electric Rate Schedule 13.02

Reserved for Future Use Electric Rate Schedule 13.03

Reserved for Future Use Electric Rate Schedule 13.09

Reserved for Future Use Electric Rate Schedule 13.10



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**Section 13.02 RESERVED FOR FUTURE USE**

**N**

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NORTH DAKOTA PUBLIC  
SERVICE COMMISSION  
Case No. PU-22-  
Approved by order dated

EFFECTIVE with bills rendered on  
and after January 1, 2023, in North Dakota

APPROVED: Bruce G. Gerhardson  
Vice President, Regulatory Affairs



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**Section 13.03 RESERVED FOR FUTURE USE**

**N**

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NORTH DAKOTA PUBLIC  
SERVICE COMMISSION  
Case No. PU-22-  
Approved by order dated

EFFECTIVE with bills rendered on  
and after January 1, 2023, in North Dakota

APPROVED: Bruce G. Gerhardson  
Vice President, Regulatory Affairs



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**Section 13.09 RESERVED FOR FUTURE USE**

**N**

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NORTH DAKOTA PUBLIC  
SERVICE COMMISSION  
Case No. PU-22-  
Approved by order dated

EFFECTIVE with bills rendered on  
and after January 1, 2023, in North Dakota

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Vice President, Regulatory Affairs



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**Section 13.10 RESERVED FOR FUTURE USE**

**N**

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NORTH DAKOTA PUBLIC  
SERVICE COMMISSION  
Case No. PU-22-  
Approved by order dated

EFFECTIVE with bills rendered on  
and after January 1, 2023, in North Dakota

APPROVED: Bruce G. Gerhardson  
Vice President, Regulatory Affairs

Attachment 13  
Non-Legislative Versions of  
Advanced Grid Infrastructure Cost Recovery Rider  
Electric Rate Schedule 13.11

**ADVANCED GRID INFRASTRUCTURE (AGI) COST RECOVERY RIDER** N

DESCRIPTION	RATE CODE	N
Residential	NAGRS	N
Residential RDC	NAGRC	N
Farm	NAGFM	N
General Service	NAGGS	N
General Service TOU	NAGGU	N
Large General Service – Primary / Transmission	NAGLP	N
Large General Service – Secondary	NAGLS	N
Irrigation Service	NAGIR	N
Outdoor Lighting (Metered)	NAGLT	N
OPA (Metered)	NAGOP	N
Controlled Service Water Heating	NAGWH	N
Controlled Service Interruptible – Small Dual Fuel	NAGCS	N
Controlled Service Interruptible – Large Dual Fuel	NAGCT	N
Controlled Service Deferred	NAGCD	N

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

**APPLICATION OF RIDER:** This rider is applicable to electric service under all of the Company’s metered retail rate schedules. N  
N

**COST RECOVERY CHARGE:** There shall be included on each North Dakota customer’s monthly bill an Advanced Grid Infrastructure (AGI) Cost Recovery Per Meter 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  
N

NORTH DAKOTA PUBLIC  
SERVICE COMMISSION  
Case No. PU-22-  
Approved by order dated

EFFECTIVE with bills rendered on  
and after January 1, 2023, in North Dakota

APPROVED: Bruce G. Gerhardson  
Vice President, Regulatory Affairs

**RATE:**

Service Category	Section	Per Meter Charge
Residential	9.01	\$1.71
Residential RDC	9.02	\$4.28
Farm	9.03	\$4.33
General Service	10.01, 10.02	\$6.61
General Service -TOU	10.03	\$13.87
Large General Service - Primary / Transmission	10.04, 10.05, 10.06, 11.01	\$71.76
Large General Service - Secondary	10.04, 10.05, 11.01	\$16.31
Irrigation Service	11.02	\$11.13
Outdoor Lighting (Metered)	11.03	\$4.41
OPA (Metered)	11.05	\$4.43
Controlled Service Water Heating	14.01	\$4.28
Controlled Service Interruptible - Small Dual Fuel	14.05	\$4.33
Controlled Service Interruptible - Large Dual Fuel	14.04, 14.12	\$17.74
Controlled Service Deferred	14.06, 14.07	\$5.31

**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 rider. See sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

On July 6, 2022, we filed an application with the North Dakota Public Service Commission to implement a new Advanced Grid Infrastructure (AGI) Cost Recovery Rider. We developed the AGI Rider to recover costs associated with Advanced Metering Infrastructure, an Outage Management System, and Demand Response investments.

This proposed rate would be a monthly per meter charge that would go into effect January 1, 2023. Residential customers would see an increase of approximately \$1.71 on monthly bills while Large General Service customers would see an increase of approximately \$71.76 on monthly bills. This change is proposed only and will not be effective until the Commission takes action.

For more information contact Customer Service at 800-257-4044 or visit [otpc.com](http://otpc.com).

The North Dakota Public Service Commission approved our request to implement a new Advanced Grid Infrastructure (AGI) Cost Recovery Rider. The approved per meter charges become effective January 1, 2023, for all classes of customers.

The AGI Rider allows us to recover costs associated with Advanced Metering Infrastructure, an Outage Management System, and Demand Response investments.

Class	Section	January 2023 - December 2023 Per meter charge
Residential	9.01	\$1.71
Residential RDC	9.02	\$4.28
Farm	9.03	\$4.33
General Service	10.01, 10.02	\$6.61
General Service TOU	10.03	\$13.87
Large General Service – Primary / Transmission	10.04, 10.05, 10.06, 11.01	\$71.76
Large General Service – Secondary	10.04, 10.05, 11.01	\$16.31
Irrigation Service	11.02	\$11.13
Outdoor Lighting (Metered)	11.03	\$4.41
OPA (Metered)	11.05	\$4.43
Controlled Service Water Heating	14.01	\$4.28
Controlled Service Interruptible - Small Dual Fuel	14.05	\$4.33
Controlled Service Interruptible - Large Dual Fuel	14.04, 14.12	\$17.74
Controlled Service Deferred	14.06, 14.07	\$5.31

For more information contact Customer Service at 800-257-4044 or visit [otpc.com](http://otpc.com).