Appendix C: Existing Resources

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Existing Resources

Otter Tail Power Company has a variety of existing resources available to meet the energy needs of its customers, both reliably and economically. These resources consist of existing generating facilities, the radio load management system, the Midcontinent Independent System Operator (MISO), purchases from other utilities, customer owned generation, the transmission and distribution network, and current Company sponsored conservation programs.

Table 1-1 shows a listing of the Company's resources and their capacity ratings for the 2023/2024 Planning Year. The capacity ratings data provided is based on current MISO ratings under Module E's resource adequacy requirements in effect for the Planning Year June 1, 2023, through May 31, 2024.

Table 1-1: 2023 Otter Tail Capacity Resources

Capacity - Owned Resources	ICAP (MW)	SAC (Summer)	SAC (Fall)	SAC (Winter)	SAC (Spring)
Coal					
Big Stone Plant	257.7	269.3	275.3	267.5	269.2
Coyote	149.1	144.9	127.5	138.9	141.7
Gas CT					
Astoria	249.7	238.5	246.9	257.9	274.1
Solway 1	42.4	44.8	48.6	42.9	47.4
Wind					
Ashtabula	48.0	8.4	11.6	25.2	10.2
Ashtabula III	62.4	12.1	16.2	34.5	12.9
Langdon I	40.5	7.0	11.7	22.6	10.7
Luverne	49.5	10.1	15.6	27.8	11.0
Merricourt	150.0	37.4	36.9	78.0	53.5
Solar					
Hoot Lake Solar	49.9	Deferred	Deferred	2.5	25.0
Hydro					
Garrison Hydro	4.3	4.3	4.3	4.3	4.3
Garrison Hydro 2	4.4	4.4	4.4	4.4	4.3
Dayton Hollow Hydro 1	0.5	0.5	0.5	0.5	0.5
Dayton Hollow Hydro 2	0.4	0.5	0.4	0.5	0.5
Hoot Lake Hydro	0.5	0.6	0.6	0.6	0.7
Pisgah Hydro	0.7	0.5	0.6	0.6	0.6
Taplin Gorge Hydro	0.5	0.5	0.5	0.5	0.5
Wright Hydro					
Oil					
Lake Preston	19.4	20.3	23.0	25.0	23.1
Jamestown 1	20.6	21.2	25.7	25.6	25.2
Jamestown 2	20.4	18.7	25.0	25.0	24.3
Load Control					
Otter Tail Load Control	Varies	125.5	139.1	248.7	153.0
Total Owned:	1170.9	969.5	1014.4	1233.5	1092.7

Capacity Purchased Resource	ICAP (MW)	SAC (Summer)	SAC (Fall)	SAC (Winter)	SAC (Spring)
Wind					
Edgeley (ND Wind II)	21.0	2.8	4.1	4.2	3.4
Langdon II	19.5	3.6	5.8	10.1	5.3
Customer Owned	4.3	3.9	4.1	3.9	4.3
Total Purchased:	44.8	10.3	14.0	18.2	13.0

1.1 Hydroelectric Facilities

Otter Tail Power Company has 6 units located at five dams on the Otter Tail River near Fergus Falls, MN. These hydro units were constructed in the early 1900's and were the backbone of the generating resources for Otter Tail for many years in the early days of the Company. The total capability of all of the hydro units is about 3.7 MW.

The hydro units located on the Otter Tail River are under FERC jurisdiction and were licensed for the first time in 1991. All of these units were built prior to licensing requirements. The units are predominantly operated in run of river mode without pondage capability except for Hoot Lake and Wright Lake behind the Hoot Lake Hydro. Prior to the FERC licensing, there was a small amount of pondage and cycling capability with these units that increased the amount of energy obtained from the water flow. The FERC license required a change to strict run of river operation.

All of the hydro units in run of river mode have had updated reservoir level monitoring systems installed to aid in complying with the operating requirements of the FERC license. Automatic level control systems have also been installed at a number of the units to control the reservoir level using the signal from the reservoir level monitoring system. Significant other equipment upgrades were completed in the past 15 years to upgrade electrical control and protection equipment.

The FERC re-licensing process is approximately 5 years. OTP submitted the Notice of Intent (NOI) and Project Application Document (PAD) on June 3, 2016 with FERC. FERC issued a public notice of the PAD and NOI on July 29, 2016. Otter Tail received new licenses on February 17, 2022 for our hydroelectric facilities.

Dayton Hollow Hydro
Dayton Hollow Dam was built in 1909 with two generators installed. A third generator was added in 1917. One of the original generators was retired and removed in 1964. The Unit #2 turbine and generator were refurbished in 2006 and the turbine also had a major repair in 2008 – 2009. Annual generation from the Dayton Hollow units is about 5,000 – 7,000 MWh.

Hoot Lake Hydro
The Hoot Lake Hydro was built in 1914. The hydro originally had two units, but one unit was retired with the addition of the Hoot Lake #3 steam unit in 1964. The Hoot Lake Hydro is part of a system that was developed to make further use of the Otter Tail River. Diversion Dam was built on the Otter Tail River and part of the water from the river is diverted through an underground tunnel to Hoot Lake that flows into Wright Lake. The two lakes were created from the diverted water. The water from Wright Lake flows through the Hoot Lake structure, and is used in the hydro unit and for cooling water for the Hoot Lake steam units. Hoot Lake Hydro has been generating about 3,000 - 4,000 MWh annually. The City of Fergus Falls also makes use of the Diversion Dam system as water supply for the city.

Pisgah Hydro
Pisgah Hydro was built in 1918. The generator stator and rotor was rewound in 2001. The turbine was rebuilt in 2005. This unit provides about 3,500 – 4,500 MWh during normal years.

Taplin Gorge (Friberg) Hydro
Taplin Gorge, also known as Friberg, was constructed in 1925. The structure is well known in the Fergus Falls area because the powerhouse is a replica of the tomb of the former Italian ruler, Theodoric. The generator was rewound in 1999. Annual generation is in the 3,000 – 4,200 MWh range.

Wright (Central) Hydro
Wright Dam (also called Central) is located in downtown Fergus Falls, and has been the location of a dam since the 1880's. It originally provided power via drive belts to industries located nearby. The current structure was built in 1922. The turbine was rebuilt and the generator cleaned and rewedged in 2002 – 2003. Annual generation is in the range of 2,000 – 3,000 MWh.

1.2 Peaking Facilities

Otter Tail Power Company has a number of peaking units on the system. Some are internal combustion units, but most of the capacity is comprised of combustion turbines. Astoria and Solway are frequently dispatched by the MISO centralized market. Otter Tail's other peaking units operate on a very limited basis annually, either for emergency or extreme peak times, or for testing purposes.

Astoria Station
Astoria Station is a natural gas fired, Mitsubishi 501GAC, combustion turbine that was placed into service in 2021. Astoria Station's summer rating is 245 MW. At colder ambient temperatures, the Unit can generate up to its transmission interconnection limit of 286 MW. Astoria Station was designed with fast start capability; allowing it to achieve 80% load within 10 minutes from the initiation of a start command.

Jamestown Combustion Turbines
Otter Tail has two fuel oil-fired combustion turbines located at Jamestown, ND. These units are of 1976 and 1978 vintage. These units are operated for emergency, peaking, and testing situations, as well as for economy during periods when market prices support it. The Frame 5 units at Jamestown operate a very limited number of hours during the year.

Lake Preston Combustion Turbine
Lake Preston is a third combustion unit, identical to the Jamestown units, located at Lake Preston, SD. This unit was installed in 1978. This unit is also fired with fuel oil and has limited operation. The unit usually operates for emergencies, peak loads, and testing, but is also used for area voltage support under certain transmission line switching and outage scenarios. The Frame 5 unit at Lake Preston operates a very limited number of hours during the year.

Solway Combustion Turbine Plant
Otter Tail brought on-line a General Electric LM6000 dual-fuel combustion turbine just prior to the 2003 summer season. The unit includes inlet chilling to improve the summer rating and efficiency, as well as water injection for NOX control and increased output. Interruptible natural gas is the primary fuel with fuel oil as the back-up fuel supply. The combustion turbine also includes a clutch to allow synchronous condensing service to support the transmission system. The LM6000 is an aeroderivative machine, powered by a Boeing 747 engine.

Big Stone Diesel
The Big Stone Plant has an internal combustion emergency diesel unit. This unit operates only for extreme emergency or testing purposes, but can synchronize with the system and is submitted as a capacity resource. The unit was installed in 1975 with the construction of the Big Stone Plant.

1.3 Baseload Resources

Otter Tail Power has partial or full ownership of three coal-fired generators, all at different locations. Until 1988 Otter Tail's coal-fired units had burned primarily North Dakota lignite.

Some early units, long since retired, had used eastern coals, but lignite had been the fuel of choice for many years. Following a fuel switch in 1995 at Big Stone Plant to low-sulfur western sub-bituminous coal, Coyote is the only plant still burning lignite coal. The coal-fired units also use fuel oil for startup, and flame stabilization at times. The use of fuels at each facility is discussed in the following sections.

Otter Tail is always reviewing opportunities to improve the efficiency and operation of its units. The improvements and conservation efforts within the generating stations have helped Otter Tail maintain some of the lowest system heat rates in its history.

Big Stone Plant
The Big Stone Plant, of which Otter Tail owns 53.9 percent, became commercial on May 1, 1975. Improvements have come about as the result of conservation, operational efforts, and equipment updates within the plant. The current output rating for the Big Stone Plant is 475,000 kw (total plant).

The switch to sub-bituminous coal in late 1995 helped to reduce the plant net heat rate. Other efficiency improvements, and the installation of a new low-pressure rotor in 1996, have also helped to lower the heat rate level at Big Stone Plant. A new high-pressure/intermediate pressure rotor was installed in 2005 and improved efficiency by about two percent.

The POET Bio-refining ethanol plant (formerly Northern Lights Ethanol) is located on the Big Stone Plant site. Big Stone Plant supplies steam for ethanol production. The steam is extracted part of the way through the electrical production process, so by serving the ethanol plant, Big Stone is truly a cogeneration plant involving the sequential use of the energy for two different purposes. The cogeneration operation does not impact the plant’s ability to generate electricity.

In 2015, the largest capital project in Otter Tail Power history, at that time, was undertaken as the AQCS project was installed at Big Stone Plant to meet the regional haze rule requirements. The AQCS project was a project to install controls for NOx (SCR and SOFA), SO2 (circulating dry fluidized bed scrubber), particulate (baghouse) and Hg control (activated carbon injection to meet MATS rule). The original budget for the AQCS project was $491 million, and through efforts related to project team management and overall project timing, the final cost of the project was about $384 million.

Coyote Station
The Coyote Station, located near Beulah, ND is a lignite-fired mine mouth facility. Otter Tail owns 35 percent of this unit. The Coyote Station was declared commercial on May 1, 1981 and is equipped with a flue gas desulfurization unit and a baghouse. Otter Tail became the operating agent of the facility on July 1, 1998. The other co-owners of this facility are Northern Municipal Power Agency, Montana-Dakota Utilities, and Northwestern Public Service. Minnkota Power Cooperative acts as the agent for Northern Municipal Power Agency.
The Coyote Station is a sister unit to Big Stone, but six years newer. The Coyote Station approved outlet rating is limited to 427,000 kW due to transmission limitations. The facility also has two emergency diesel generators that are not accredited in MISO due to the transmission limitations.

Coyote completed a high-pressure/intermediate pressure rotor replacement in 2009 that resulted in about a two percent increase in efficiency. It also increased the UCAP rating of the plant by about 6,000 kW.

Coyote completed the installation of activated carbon injection for Hg control in 2015 as well as a SOFA (separated over-fire air) system for NOx reduction during 2016.

Additionally, the Owners of Coyote Station entered into a 25-year lignite supply agreement with Coyote Creek Mining Company to supply the Coyote Station with lignite from a new, efficient mine.

1.4 Demand Resources

Otter Tail Power Company has two demand resources that can be registered under Module E with the MISO. Both resources are load modifying resources (LMR) that are netted from the demand forecast and available to MISO in emergency events. These resources are obligated to provide sustained load reduction for up to 4 hours at a time and be available sixteen times a year to MISO in the event of an emergency. This obligation does not preclude the Company from relying on these resources to control for capacity events or economic reasons outside of a MISO emergency event.

Direct Load Control – The Radio Load Management System
The first resource, "Direct Load Control", represents the Company's extensive radio load management system that is used to control customer load during economic or capacity events. Otter Tail has approximately 129,800 customers and approximately 42,000 of those customers have some type of load control. The level of control that is available can vary with temperature, customer behavior, and load control responsiveness. For example, more load control is available during extremely cold temperatures in the winter than during moderate temperatures and customers with dual-fuel load may choose to switch to an alternate fuel, particularly during a period of lower prices.

Winter season manageable loads are in several categories and can reach as high as 130 MW. These manageable loads include water heaters, thermal storage, residential demand controllers, commercial time of use rates, small dual fuel heating systems, and large dual fuel (industrial and bulk interruptible loads). The radio load management system also has the capability of interrupting as much as 15 MW of peak load in the summer-season months, June through September. These summer loads consists primarily of water heaters, large dual fuel industrials, small dual fuel and deferred load heat pumps used for cooling, and standard air conditioning. Otter Tail continues to add customers to the direct load control rates to maintain and grow manageable loads.

Although measurement data shows the load management system as able to achieve higher levels than the level accredited, those higher levels are related to peak control levels during a minimum number of hours and were impacted by weather and load diversity. Those higher levels do not represent the typical levels of control that Otter Tail is confident can be sustained. The measurement and verification requirements for continued accreditation and the risk of potential penalties were also significant factors in the lower accreditation level registered by the Company.

Firm Service Level – Customer Contracts
The second demand resource registered with MISO is a "Firm Service Level" resource that represents Otter Tail's contract with a large industrial customer to shed load to a firm service level in the event of a capacity event. Unlike the "Direct Load Control" resource that reduces load when called upon by our load management system, this resource must demonstrate that it did not exceed the registered load level during a capacity event.

1.5 Transactions

Otter Tail has a number of large commercial customers that are shared loads with local rural electric cooperatives. These loads are in areas that may be in one utility's service territory, but are located where the other utility already had the necessary facilities to handle the load. In order to reduce costs and avoid duplication of facilities, these loads have been shared. In the accounting process, these loads are usually served as if they are Otter Tail customers, and then 50 percent of the energy is purchased wholesale from the other utility at the retail rate used to serve the customer. All of the retail energy shows up as Otter Tail energy with a 50 percent wholesale energy purchase, even though Otter Tail only served half of the load.

WAPA Allocation to Native American Tribes

The Western Area Power Administration (WAPA) is a federal Power Marketing Agency that provides capacity and energy from hydroelectric facilities located on the Missouri River to preference customers. Otter Tail does not qualify as a preference customer. Native American tribes are preference customers eligible to receive the federal power. The tribes, however, are not utilities in the same manner as typical WAPA preference customers such as municipals and rural electric cooperatives. The tribal lands are typically served by a combination of existing utilities.

In order to facilitate the delivery of the electricity to the tribes, or the economic benefits of the low-cost federal electricity, WAPA developed a process in which the electricity is delivered to the utilities providing electric service on tribal lands. Each tribe has the right to determine which tribal entities receive the benefits. For the customers designated by the tribe as receiving the benefits, WAPA delivers the electricity to Otter Tail at the WAPA rate, and then Otter Tail provides a bill credit to the customer. The bill credit is essentially equal to the difference in cost between the WAPA power and the embedded Otter Tail cost of generation, less expenses to administer the program. Otter Tail has filed the appropriate information with and received approval from the state regulatory commissions in the states involved.

Otter Tail has five tribes that receive the benefits of the WAPA power. The current capacity amount varies monthly from a low of 4.3 MW to a high of 5.6 MW, with annual energy of 32,158,236 kWh. Otter Tail also receives the load based reserve margin benefit with the capacity. Because the tribes have the right to change who receives the benefit and such changes may move benefits from tribal customers served by Otter Tail to tribal customers served by another utility, the amount of capacity and energy received for the tribal loads may vary over time. The current amount of tribal allocation that is received through Otter Tail is included in all analysis scenarios. None of the WAPA power qualifies for compliance with the Minnesota Renewable Energy Objective, as all of the WAPA hydroelectric facilities are greater than 100 MW when considering all units at a specific location.

Customer Owned Generation

Otter Tail has worked with several customers who desired to install small diesel generators for back-up emergency power. These units are owned by the customers and capable of being interconnected to Otter Tail's system. The capacity from these units is purchased by Otter Tail and submitted as behind the meter capacity resources registered with MISO. Currently the NDC rating of these units is 4,300 kW in total.

On March 3, 2010 the U.S. Environmental Protection Agency issued new national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The new standards include emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements. Effective May 1, 2016 all of Otter Tail's engines affected by the RICE Rule are considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests.

Otter Tail also has power purchase agreements with several wind generation facilities as described in the following section.

1.6 Wind and Solar Generation Resources

Otter Tail has nearly 450 MW of wind/solar generation on the system, including utility owned and contracted generation. The Company owns 350 MW of wind generation.

Langdon Wind Energy Center
Otter Tail owns 40.5 MW of wind generation located south of Langdon, ND consisting of 27 1.5MW GE wind turbines. This facility began operation in January 2008.

Ashtabula Wind Energy Center
Otter Tail owns 48.0 MW of wind generation located in Barnes County, ND consisting of 32 1.5MW GE wind turbines. This facility began operation in November 2008.

Ashtabula III Wind Energy Center
Otter Tail owns 62.4 MW of wind generation located in Barnes County, ND consisting of 39 1.5MW GE wind turbines. This facility began operation in December 2010.

Luverne Wind Energy Center
Otter Tail owns 49.5 MW of wind generation located in Steele County, ND consisting of 33 1.5MW GE wind turbines. This facility began operation in September 2009.

Merricourt Wind Energy Center
Otter Tail owns 150 MW of wind generation located approximately fifteen miles south of Edgeley, North Dakota in McIntosh and Dickey Counties, consisting of 75 2 MW Vestas wind turbines. This facility became commercially operational in December 2020.

Approximately 55 MW of wind/solar generation is purchased by Otter Tail from customers or other entities and is identified in Table 1-2. Customer owned units do not have the ownership name included to protect customer information. Often generation from smaller, customer owned units is used to serve the customer and only the surplus generation is sold to Otter Tail.

Table 1-2: Contracted Wind Generation Facilities

Name and Owner	State	kW Rating
FPL Energy ND Wind II - NextEra	ND	21,000
Langdon Wind Energy Center – NextEra	ND	19,500
Various Small Wind/solar Producers	ND	3,318
Various Small Wind/solar Producers	MN	10,620
Various Small Wind/solar Producers	SD	154

1.7 Energy Efficiency Programs

Otter Tail Power Company operates a number of Demand-Side Management Programs in its service territory. In Minnesota, some of these projects are part of the Company's Conservation Improvement Program (CIP) filing, Docket No. E017/CIP-20-475. The Company also operates an energy efficiency program in South Dakota; Otter Tail's 2021 Energy Efficiency Plan (EEP) status report and annual filing was filed in Docket No. EL21-015. North Dakota does not have a formal energy efficiency program. The Company's Minnesota and South Dakota energy efficiency results have been on target with the energy efficiency goals in historical integrated resource plan filings.

This resource plan reflects an average annual energy savings of 1.86 percent, which exceeds the newly established 1.75 percent goal in Minnesota's Energy Conservation and Optimization Act of 2021.

1.8 Midcontinent Independent System Operator, Inc. (MISO)

Otter Tail continues to play an active role in the regional transmission planning efforts. While Otter Tail still leads and conducts studies to ensure the adequacy of the transmission system to serve its customers, all transmission planning activities related to regional transmission are coordinated with the MISO and the surrounding non-MISO transmission owners.

Transmission planning occurs through the course of performing transmission studies at several different levels, from individual utility plans, to joint utility plans with utility neighbors, to broad regional studies. Regardless of the type of studies, the forum for which these studies are discussed is through a regional transmission planning process. Otter Tail actively participates in several MISO study groups, such as the West Subregional Planning Meetings (WSPM) and the West Technical Study Task Force meetings (WTSTF). These groups provide forums for regional transmission planners to discuss the needs and projects related to the transmission system in the Otter Tail and surrounding area that are within the western footprint of the MISO region.

Otter Tail closely coordinates its transmission planning efforts with MISO. For transmission planning purposes, MISO performs three primary functions. The first two are federally mandated processes established by FERC, generator interconnection and delivery service, and the third process is related to expansion planning.

MISO administers and processes requests to use the transmission system of the MISO transmission owners. MISO has established procedures for processing generation interconnection and delivery service transmission requests of generators and market participants. Through this FERC mandated process, MISO offers the area utilities opportunities to participate in "ad-hoc" study groups to provide input and review of the technical studies completed for generation interconnection or delivery service. In addition to these FERC mandated requirements, MISO also performs expansion planning studies on an annual basis. These expansion planning studies are referred to as the MISO Transmission Expansion Plan (MTEP) and focuses on a variety of studies, from reliability assessments to targeted studies focused on a particular issue or item. Otter Tail's transmission system falls within the MISO West region. Through the MTEP process, MISO completes a reliability analysis assessing the transmission system performance against transmission owner's reliability criteria. In the event that reliability criteria is not met, additional analysis is completed to find mitigation to a particular system issue. Otter Tail actively participates in the MTEP, generator interconnection, and delivery service efforts by attending meetings, reviewing study results and providing input into the study process.

MISO has also sponsored targeted studies in the region as part of the MTEP process. Otter Tail actively participates in many of these targeted studies, including the Long-Range Transmission Plan (LRTP) and Joint Targeted Interconnection Queue (JTIQ) studies, as well as other targeted studies. Through these various study efforts, Otter Tail attends meetings, reviews study results, and provides input into the study processes.

In addition to the specific study opportunities, the MISO conducts meetings of several stakeholder groups, which include the Planning Subcommittee (PSC), the Planning Advisory Committee (PAC), the Regional Expansion Criteria and Benefits Working Group (RECB WG), the Interconnection Process Working Group (IPWG), the Resource Adequacy Sub-committee (RASC), and several others. These meetings are attended by various representatives of the different stakeholder groups at MISO. These meetings act as a forum between MISO staff and the stakeholders to provide input into the processes of MISO. Otter Tail regularly attends several of these meetings to stay engaged within the MISO transmission planning process as well as provide input and feedback to MISO.

All of these transmission planning activities are then combined into, and are consistent with, the MN state transmission planning process.

Transmission Interconnections
On May 9, 2002, the Commission gave conditional authority to Otter Tail to transfer operating control of certain transmission facilities to MISO. Since joining MISO and transferring operational control of its high voltage transmission facilities to MISO, Otter Tail has seen positive benefits in this relationship regarding the generator interconnection processes.

Since Otter Tail joined MISO, numerous generators have successfully interconnected to the Otter Tail electric system under MISO's generator interconnection procedures. Under MISO's Open Access Transmission and Energy Markets Tariff (TEMT), all generator interconnection requests (regardless of generator size or interconnecting voltage level) are required to abide by the MISO generator interconnection process if the generator intends on engaging in wholesale transactions. The MISO, as an independent system operator, ensures comparable treatment for all customers and it is staffed to provide and administer this service. Otter Tail receives value and efficiencies from the MISO process given that MISO is staffed to administer its procedures and, as an independent organization, ensures comparable treatment to all parties involved. Additionally, Otter Tail stays actively engaged in several MISO studies and provides information regarding the transmission system when reviewing study results and giving direction for future studies. This is an efficient process and a benefit to all parties since Otter Tail has ultimate knowledge and familiarity with its system and most efficiently and effectively provides this service. Project coordination, administration, and filing requirements fall upon MISO, thus freeing up Otter Tail's resources to focus on its key priority of providing clean, efficient, and low cost energy to its customers.

In the recent years, an unprecedented amount of renewable generation has been requested to be added to the MISO system. The increase in requests and generators interconnecting to the MISO system has caused congestion that has been reflected in the MISO interconnection queue. Due to the large amount of requests and recent generator interconnections, transmission interconnection costs for new resources are very high and impact the economic feasibility of adding new generation units of all types. Some of the challenges include additional uncertainties, large queue cycles, delayed studies, and very high interconnection costs. Recently, MISO has provided two alternative methods for interconnecting new resources. The two new interconnection methods are replacement interconnection and surplus interconnection. Both alternatives prevent having to go through the traditional MISO interconnection queue process. Replacement interconnection resources reuse the existing interconnection rights of an existing resource that is retiring. Surplus interconnection resources are built alongside an existing resource and share the interconnection rights while not exceeding the total output of the existing interconnection. Both interconnection methods are studied to confirm that there are no reliability impacts to the transmission system, and if issues are identified, the request goes to the standard queue.

Locational Marginal Pricing (LMP) Energy Market and Ancillary Services Market (ASM)
The MISO Locational Marginal Pricing (LMP) energy market was introduced on April 1, 2005. MISO subsequently introduced the Ancillary Services Market (ASM) on January 6, 2009. Both market introductions went well, but utility operations and market functions have changed significantly.

Many of the key preparations and day-to-day activities since commencement of the markets include:

- Development of software interfaces and procuring or developing new software systems.
- Training of employees.
- Developing after-the-fact data flows to ensure a seamless transition in the accounting and regulatory areas.
- Active involvement in filings related to the Energy Market at the Federal Energy Regulatory Commission (FERC) and state commissions. This includes settlement proceedings for the non- MISO Load Serving Entities located within the Otter Tail Power Company Control Area.
- Nominating and receiving Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTR) allocations to safeguard Otter Tail's native load.
- Developing business practices, strategies and risk management policies to accommodate an LMP and ASM Market.
- Actively participating in the numerous MISO committees seeking to ensure that Otter Tail's best interests and the interests of its customers were not adversely impacted by decisions and policies resulting out of these committees.

Market operations continue to go smoothly, and the company is generally pleased with the transition to the centralized energy and ancillary services markets.

MISO Resource Adequacy (Module E)
Otter Tail's reserve requirements are established by MISO under Module E of the MISO Tariff.

MISO currently operates in a seasonal construct with a system wide coincident peak occurring across the four seasons; summer, fall, winter, and spring.

Resource accreditations change annually and are based on seasonal ratings. Ratings for non-wind generators are based on MISO's recently established Seasonal Accreditation Construct (SAC).

Wind generation is accredited based on MISO's effective load carrying capability (ELCC) metric at the class level and performance during peak hours at the unit level.

1.9 Transmission Facilities

See Initial Filing.

Appendix D: Potential Resources

Table of Contents

SUPPLY-SIDE GENERATION **1**

1.1 Technology options included in the model 2

1.2 Technology options not allowed in the model 2

Potential Resources

This appendix provides a description of the resources that were evaluated in the development of the 2021 Integrated Resource Plan by Otter Tail. The development of the resource plan focused on the evaluation of resources that are available to the Company, taking into account a number of factors. These factors include available size increments of the technology, the maturity and commercial availability of the technology, the availability of interested co-owners of large facilities, operational parameters, and available data. Not every resource that was evaluated was included in the Company's model. In order to reduce run time of the EnCompass software, an initial screening was performed to limit the number of potential new resources that would be made available for the model to select.

Specific cost and performance data used for modeling came from a variety of sources and is provided in detail in Appendix F: Assumptions for EnCompass Modeling Assumptions.

Supply-Side Generation

A discussion of each of the coal- and gas-fired technologies and other supply-side technologies is included in the following pages. The technologies are grouped into the following two categories:

<u>Generation Alternatives in the Model</u>

- Firm Dispatchable Alternatives (Large and Small)
- Wind
- Solar Photovoltaic
- Battery Storage

<u>Pre-screened Generation Alternatives Not in the Model</u>

- Nuclear
- Pulverized Coal - Subcritical
- Atmospheric Circulating Fluidized Bed Coal (ACFB)
    - Integrated Gasification Combined Cycle (IGCC)
    - Phosphoric Acid Fuel Cell (PAFC)
- Pulverized Coal – Supercritical and Ultra-supercritical (green field site)
- Supercritical Coal, using a brown field site
- Reciprocating Engine Plants
- Hydro (owned projects)
- Heat Recovery
- Anaerobic Digestion
- Landfill Gas
- Microturbines
- Biomass
- Geothermal

Whether a technology was pre-screened or included in the model for capacity expansion evaluation is indicated in the text. The effort on screening resources was necessary to develop a useful modeling tool that was practical in terms of run-time while simultaneously comprehensive in evaluating the forward-looking resource mix. It is important to note that any resource used as a potential future addition in the EnCompass model was intended to be generic and representative of the Company's needs. In no way do the alternatives selected for modeling purposes exclude future consideration of competing options in similar generation categories.

1.1 Technology options included in the model

Firm Dispatchable Alternative - Large
Today, the most cost effective option is a simple cycle combustion turbine and for this reason we modeled the large firm dispatchable project with the natural gas combustion parameters. In the future there will likely be other firm dispatchable options available. The modeled simple cycle combustion turbine is a heavy-duty frame unit with an ISO rating of about 248 MW. The heavy-duty frame units are characterized by a lower capital cost per kW and lower maintenance cost.

Firm Dispatchable Alternative – Small
As is the case with the large firm dispatchable alternative, Otter Tail expects in the future there will likely be other firm dispatchable options available. In this model, the the firm dispatchable parameters are based on the existing GELM6000 aeroderivative technology that Otter Tail currently owns and operates at Solway, MN. As the name implies, aero derivative electric generation units were derived from gas turbine development for the aircraft industry. The traits of aeroderivative units compared to the frame-style gas turbines are typically, faster starts, higher efficiency, smaller overall size, and higher capital cost in $/kw. However, frame CT technology has advanced, and it should be noted that start times and efficiency have dropped in recent years, as now some frame CT suppliers are offering units that can meet the 10 minute start time that was the hallmark of aero derivative units in the past.

Wind Generation
Wind generation was made available to the model in 50 MW blocks throughout the study period modeled as a purchased power transaction.

Solar Generation
Solar generation was made available to the model in 25 MW blocks throughout the study period modeled as a purchased power transaction.

Battery Storage
4-hour battery storage was made available to the model in 25 MW blocks throughout the study period modeled as a purchased power transaction.

Paired Battery Storage
4-hour paired battery storage was made available to the model in 10 MW blocks throughout the study period modeled as a purchased power transaction. This resource could only be selected in combination with a 25 MW solar resource.

1.2 Technology options not allowed in the model

Combined Cycle Gas Turbine (CCGT)
The basic principle of the Combined Cycle Gas Turbine is to use a gaseous fuel such as natural gas, or a liquid fuel such as no. 2 fuel oil, to produce power in a gas turbine and to use the hot exhaust gases from the gas turbine to produce steam in a Heat Recovery Steam Generator (HRSG). The steam is used to generate electric power with a steam driven turbine-generator set. Typical CCGT units operate with natural gas as the operating fuel, but often dual-fuel capability with oil as a backup is used to increase the availability of the generation when natural gas supplies are curtailed. Given the size of Otter Tail's system and the lack of a significant capacity need during the planning period it was decided that a large CCGT unit would not be a reasonable option and was removed from the model.

Nuclear
Electricity from a nuclear power plant remains a very clean and safe form of electrical generation in the United States and the world. In 1994, the Minnesota Legislature passed a law

that created a moratorium on the construction of new nuclear generation facilities in Minnesota (216B.243, subd. 3b). Nuclear energy was not considered as a resource alternative because of the law listed above, and what appear to be very high costs related to siting, permitting, and construction. Additionally, the Company is not aware of any nuclear project under development soliciting joint ownership. Due to the factors listed above, the addition of nuclear generation was not included in the model.

Carbon Capture and Sequestration (CCS)
Otter Tail continues to consider CCS and currently does not allow CCS as a project in the modeling. There is significant research and development underway related to carbon dioxide capture and sequestration from fossil-fuel electric generating units; however, currently only two commercial power plants have been equipped with this technology worldwide. While there is much information in the public domain about development work, demonstration projects, and future-looking analysis for resource planning purposes, it is the position of Otter Tail that CCS development needs to continue to develop to understand cost certainty and feasibility. Additionally, it is Otter Tail's understanding that the current CCS technologies require very high levels of control of sulfur-dioxide prior to routing the flue gas to the CCS equipment. Therefore, the Coyote Station sulfur-dioxide scrubber would first need to be upgraded to the high-control scenario being considered by the Regional Haze Rule, which would result in additional capital and operational costs, before employing carbon capture technology (if the addition of CCS became viable). Otter Tail has not included CCS as an option to the resource planning model. If MISO requirements, or the MISO market changes, and if CCS cost estimates and operational efficiencies are proven acceptable, the Company will reconsider this position.

Pulverized Coal - Subcritical
Pulverized coal boiler technology is a mature and reliable energy producing technology around the world. The operating pressure of conventional coal-fired power plants can be classified as sub-critical and super-critical. Sub-critical and super-critical technologies refer to the state of the water that is used in the steam generation process. The critical point of water is 3208.2 psia and 705.47° F. At this critical point, there is no difference in the density of water and steam. At pressures of about 3208.2 psia, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. A sub-critical pulverized coal unit was eliminated from consideration as an option because of higher emissions and a less efficient heat rate.

Pulverized Coal – Supercritical and Ultra-Supercritical
The current Minnesota Next Generation Act of 2007 eliminates any reasonable chance of construction of coal-fired generation for Minnesota and was not made available to the model. Super-critical pulverized coal units have been part of the U.S. power generation mix since the mid-1950's. Since the 1980's, the development of high strength materials and Distributed Control Systems (DCS) have helped to make supercritical units easier to control and operate. Supercritical units typically operate at 3500 psig and up to 1050° F or 1080° F. at the steam turbine inlet. In addition, while there is no current technical definition of an ultra-supercritical unit, it seems to be generally accepted that units designed to operate at 1100° F or higher are ultra-supercritical. There is currently at least one new unit that is being constructed in the United States where the design steam temperatures are above 1100° F. Heat rates for supercritical or ultra-supercritical units can be lower than 9,000 btu/kWh. If the average heat rate of the current coal fleet is 11,500 btu/kWh, use of a modern supercritical or ultra-supercritical unit would result in over 20% less coal being burned per MWh or 20% less CO_2 emissions per MWh.

Atmospheric Circulating Fluidized Bed Coal (ACFB)
The consideration of a baseload coal-fired unit at the Big Stone Plant (BSP) site included evaluation of a large ACFB facility. The combustion within a fluidized bed boiler occurs in a suspended bed of solid particles in the lower section of the boiler. Combustion within the bed occurs at a slower rate and lower temperature than a conventional pulverized coal-fired boiler.

Deviations in fuel type, size, or Btu content have minimal effect on the furnace performance characteristics. The bed allows for re-injection of a sorbent, such as fly ash or limestone, to reduce SO_2 emissions. This type of operation requires approximately 1.5 times the quantity of limestone to achieve a reduction in SO_2 similar to that of a wet limestone scrubber.

One of the benefits of an ACFB facility would have been an increased ability to use biomass fuels. The BSP unit already has an alternative fuels handling facility and the capability to burn alternate fuels. There has been difficulty in expanding the use of biomass fuels at BSP due to cost and availability. The benefit of being able to use biomass fuels was outweighed by a number of other factors, and a large fluidized bed unit was eliminated from consideration. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 emissions. Any ACFB alternative would require CCS to be installed in order to serve load in Minnesota. Otter Tail Power's view of CCS is that it is a promising technology but not currently commercial.

Integrated Gasification Combined Cycle (IGCC)
IGCC technology produces a low energy value syngas from coal or solid waste, for firing in a conventional combined cycle plant. The gasification process in itself is a proven technology having been previously used extensively for production of chemical products such as ammonia for use in fertilizer. The U.S. Department of Energy (DOE) has jointly funded several power plant facilities through the U.S.
The majority of the DOE test facilities use entrained flow gasification design with coal as feedstock. In that process, coal is fed in conjunction with water and oxygen from an air separation unit, into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exists at around 2400° F. and is then cooled to less than 400° F. in a gas cooler, which produces additional steam for both the steam turbine and the gasification process. Particulate, ammonia (NH_3), hydrogen chloride, and sulfur are then removed from the raw syngas stream. The cooled and treated syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific value syngas. Exhaust heat from the gas turbine then generates steam in a HRSG which in turn powers a steam turbine.
It is recognized that IGCC, in theory, shows potential to become a reliable, low emission source of electrical energy in the future that more easily adapts to the potential of CCS. Compared to supercritical pulverized coal, IGCC projects appear to have higher upfront capital costs, variable O&M, and fixed O&M. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 emissions. Any IGCC alternative would require CCS to be installed. Otter Tail Power's view of CCS is that it is a promising technology but appear to not be economically viable today. Based on all of these considerations, Otter Tail did not include IGCC as an option in the planning model.

Reciprocating Engine Plants
Large-scale reciprocating engine power plants have begun to gain in popularity in some areas of the country in recent years. A reciprocating engine plant is constructed of incrementally sized engines (2 MW – 16 MW each). Most large-scale reciprocating engine plants are fueled with natural gas only. However, some systems may be dual fuel (natural gas and fuel oil). Typically speaking, the construction costs of a reciprocating engine plant are more expensive than a simple cycle combustion turbine (perhaps 10 percent – 20 percent higher). However, on a unit-to-unit comparison, the reciprocating engine is more efficient than a typical aeroderivative combustion turbine. If you consider partial load operation, the overall fuel savings can be considerable. Some energy providers have viewed the installation of reciprocating engine plants as a good fit to a region with high wind or other intermittent energy resources. A generation resource that is capable of high efficiency through a wide range of output may become attractive enough to overcome initial higher installation costs. Through the prescreening process, reciprocating engines were excluded from the alternatives made available to EnCompass, largely due to the higher O&M and capital costs.

Phosphoric Acid Fuel Cell (PAFC)
The model evaluation excluded the option to select fuel cells due to the resource's higher costs compared to other units of similar technology. Fuel cells function by converting hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cells can sustain high efficiency operation even under partial load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size facilities according to power requirements. One of the most significant benefits to fuel cells is the lack of emissions. The only significant emissions are water and carbon dioxide.

Hydro
For past resource plan filings Otter Tail has reviewed the potential for cost-effective small hydro development within its service territory. A Minnesota Department of Natural Resources (DNR) survey of potential sites within the state served as a basis for that review. The DNR conclusion was that the existing economic sites had already been developed. For that reason, Otter Tail did not include any potential development of small hydro within the model.

Even if potential sites existed within the Company's service territory, it is unlikely that they would be economic for development if the sites were under FERC jurisdiction. If a waterway has a designation as a navigable stream, then it falls under FERC jurisdiction. Otter Tail's small hydros on the Otter Tail River near Fergus Falls were all built prior to FERC licensing requirements. The Otter Tail River was designated as a navigable stream because in the 1800's it was used for transportation and to float logs to the sawmill. In the late 1980's and early 1990's, Otter Tail was ordered to obtain FERC licensing on these units. The licensing process took several years and cost about $400/kW, for existing units. The licensing cost for developing a new site is likely to be so high as to make the process uneconomic.

Anaerobic Digestion
Previous study work within Otter Tail concluded the amount of potential generation from anaerobic digestion within Otter Tail's system may result in minimal (less than 5 MW) opportunity and too small to be of consequence to this resource plan filing. Anaerobic digestion was not included as a generation option within the model.

Landfill Gas
According to an EPRI report completed in the late 1990's, the Otter Tail Service territory does not include any landfills of sufficient size to support a landfill gas generating facility. The only two landfills in the area that were identified as having sufficient size are located at Fargo and Grand Forks, both served by another utility. Fargo now has a unit installed. Each of those landfills was identified as having the potential to support two 2 MW generators. Landfill gas was not included as an option within the model.

Microturbines
Microturbines are miniature combustion turbines, similar in concept to the large combustion turbines used in conventional utility power plants. Whereas large combustion turbines range from 20,000 to over 330,000 kW, microturbines fit into the 25 to 400 kW range. The waste heat from the turbine exhaust can be collected to supply a useful thermal load, which improves the overall cycle efficiency and the economics. However, the capital costs are still higher than the cost of a standard utility size combustion turbine and the efficiencies are much worse. At this point in time, potential economic applications are somewhat limited. The model did not include consideration of microturbines due to their small size, limited application at this time, and high cost.

Biomass
Since the early 1990's Otter Tail has made an effort to use renewable fuels in its existing coal-fired plants. The Big Stone Plant has burned a number of renewable and alternate fuels over the years and has an alternative fuels handling facility to aid in blending such fuels in with coal. Some of the renewable fuels that have been tried or researched over the years include spoiled or

research corn seed, wood waste in various types, soybeans, sunflower hulls, and similar agricultural wastes. Some of these materials caused significant problems in test burns by either plugging fuel handling systems (bark wood waste) or plugging boilers (soybeans). Sunflower hulls and soybeans have proven to be problematic due to their high content of potassium. As of January 1, 2010, Big Stone Plant has stopped the alternative fuel program. The primary reasons were the limited availability of fuel and the high cost of maintenance of the handling facilities.

Otter Tail did not include any other additional biomass alternatives in the model. As the cost of fossil fuels increases, other markets develop for biomass fuels such as wood waste. In many cases, the wood products companies that create the waste use it as fuel in their own process. Otter Tail has worked with customers on potential wood waste-fired biomass facility investigations. The fuel supply is limited, and the costs of such facilities are high. The development potential of these facilities is limited and very site specific. To date, Otter Tail has not found other opportunities for development of such facilities with costs being close to economic.

Geothermal
Otter Tail has worked with the Geology Dept. at the University of North Dakota on investigating the potential for geothermal energy. Western North Dakota has geothermal resources in temperature ranges that would be suitable for binary cycle geothermal technologies. A binary cycle facility typically pumps natural water or brine from underground that has been heated by the earth to moderate temperature ranges of 200° F. - 500° F. The heat in the fluid is transferred to another working fluid such as iso-pentane which is used in place of water in a normal vaporization/condensation cycle. The brine is then reinjected back into the earth. The extraction and reinjection wells are typically from 1,000 – 3,000 feet deep and require significant horsepower to extract the fluid and then reinject it. The resources in western North Dakota are located much too deep to be economic for binary cycle operation, typically in the 10,000 – 12,000 foot range. Otter Tail did not include any geothermal options as potential generating resources in the model.

Otter Tail does have geothermal heat pumps as programs within its CIP process.

Appendix I: Integrated Resource Plan

Sensitivity Summary

NPVRR Comparison			A	A.1	B	C	D	E	F	G	H	I	J
IRP Refresh No Externalities Included			2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,742,670	$2,764,110	$2,999,270	$3,163,944	$2,173,232	$2,798,479	$3,218,073	$2,818,342	$3,236,851	$3,025,644	$3,495,792
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,714,497	$2,724,103	$2,972,047	$3,164,174	$2,131,738	$2,714,497	$3,164,174	$2,714,497	$3,164,174	$3,011,694	$3,502,295
	2028 Difference from 2040 Exit NPVRR	($000)	-$28,173	-$40,007	-$27,223	$230	-$41,494	-$83,982	-$53,899	-$103,845	-$72,677	-$13,950	$6,503

Annual Resource Additions - Exit Coyote 12/31/2040			A	A.1	B	C	D	E	F	G	H	I	J
			2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
3		2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
4		2024											
5		2025	Wind Repowers	Wind Repowers	Wind Repower 400 MW Sur Solar	Wind Repower 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers 75 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind
6		2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 75 MW Sur Solar	Astoria Onsite Fuel
7		2027		100 MW Sur Solar	50 MW Gen Wind								
8		2028		100 MW Sur Solar							50 MW Gen Wind		50 MW Gen Wind
9		2029		200 MW Gen Wind		50 MW Gen Wind			50 MW Gen Wind			50 MW Gen Wind	
10		2030											
11		2031			50 MW Gen Wind							50 MW Gen Wind	
12		2032	325 MW Sur Solar 200 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	150 MW Gen Wind	100 MW Gen Wind		350 MW Sur Solar 200 MW Gen Wind	100 MW Gen Wind	325 MW Sur Solar 200 MW Gen Wind	100 MW Gen Wind	150 MW Sur Solar 150 MW Gen Wind	50 MW Sur Battery 25 MW Gen Solar 150 MW Gen Wind
13		2033											
14		2034											
15		2035											
16		2036											
17		2037										50 MW Rep Wind	

Annual Resource Additions - Exit Coyote 12/31/2028			A	A.1	B	C	D	E	F	G	H	I	J
			2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
18		2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
19		2024											
20		2025	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers 75 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind
21		2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 75 MW Sur Solar	Astoria Onsite Fuel
22		2027		100 MW Sur Solar	50 MW Gen Wind								
23		2028		100 MW Sur Solar									50 MW Gen Wind
24		2029	50 MW Sur Solar 300 MW Gen Wind	200 MW Gen Wind	250 MW Gen Wind	150 MW Gen Wind		50 MW Sur Solar 300 MW Gen Wind	150 MW Gen Wind	50 MW Sur Solar 300 MW Gen Wind	150 MW Gen Wind	50 MW Sur Battery 250 MW Gen Wind	25 MW Sur Battery 200 MW Gen Wind
25		2030		100 MW Sur Solar									
26		2031	25 MW Sur Battery	150 MW Gen Wind	50 MW Gen Wind	100 MW Gen Wind		25 MW Sur Battery	100 MW Gen Wind	25 MW Sur Battery	100 MW Gen Wind	50 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind
27		2032	25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	50 MW Sur Battery 50 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind		25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind	25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind	50 MW Gen Battery 175 MW Sur Solar 100 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind
28		2033											
29		2034					248 MW Firm Dispatchable						
30		2035											
31		2036										25 MW Rep Battery	
32		2037			50 MW Rep Wind								25 MW Rep Solar

NPVRR Comparison			K	L	M	N	O	P	Q	R	S	T	U
IRP Refresh No Externalities Included			25% Increased Load	25% Increased Load NGEM +100%	High Renewable Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$3,501,204	$4,029,495	$2,725,995	$2,848,225	$3,118,304	$2,843,108	$3,434,742	$2,728,735	$2,924,406	$3,574,435	$2,919,805
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$3,534,590	$4,048,011	$2,674,770	$2,885,307	$2,983,391	$2,880,639	$3,476,938	$2,695,743	$2,885,307	$3,534,590	$2,880,639
	2028 Difference from 2040 Exit NPVRR	($000)	$33,386	$18,516	-$51,225	$37,082	-$134,913	$37,531	$42,196	-$32,992	-$39,099	-$39,845	-$39,166

Annual Resource Additions - Exit Coyote 12/31/2040		K	L	M	N	O	P	Q	R	S	T	U
		25% Increased Load	25% Increased Load NGEM +100%	High Renewable Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
3	2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
4	2024											
5	2025	Wind Repowers 125 MW Sur Solar 250 MW Gen Wind	Wind Repowers 400 MW Sur Solar 400 MW Gen Wind 25 MW Sur Battery	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers 150 MW Sur Solar 50 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 100 MW Sur Solar 250 MW Gen Wind	Wind Repowers
6	2026	Astoria Onsite Fuel 25 MW Sur Battery 25 MW Sur Solar 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 125 MW Sur Solar	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 25 MW Sur Battery	Astoria Onsite Fuel 25 MW Sur Battery 50 MW Gen Wind	Astoria Onsite Fuel
7	2027	50 MW Gen Wind			50 MW Sur Solar	250 MW Sur Solar		50 MW Sur Solar	225 MW Sur Solar	25 MW Sur Solar	25 MW Sur Battery 50 MW Gen Wind	
8	2028				50 MW Sur Battery	25 MW Sur Solar		50 MW Gen Wind	25 MW Sur Solar	25 MW Sur Battery		
9	2029	25 MW Sur Battery	50 MW Gen Wind								50 MW Sur Solar	
10	2030											
11	2031	50 MW Gen Wind	25 MW Sur Battery								50 MW Gen Wind	
12	2032	175 MW Sur Solar 100 MW Gen Wind	50 MW Gen Battery 100 MW Gen Solar 100 MW Gen Wind	325 MW Sur Solar 200 MW Gen Wind	325 MW Sur Solar 150 MW Gen Wind	300 MW Gen Wind	100 MW Gen Wind	100 MW Sur Solar 150 MW Gen Wind	150 MW Sur Solar 200 MW Gen Wind	350 MW Sur Solar 150 MW Gen Wind	200 MW Sur Solar 100 MW Gen Wind	100 MW Gen Wind
13	2033											
14	2034	50 MW Rep Battery									50 MW Rep Battery	
15	2035				50 MW Rep Wind					50 MW Rep Wind		50 MW Rep Wind
16	2036						50 MW Rep Wind					
17	2037	50 MW Rep Wind									50 MW Rep Wind	

Annual Resource Additions - Exit Coyote 12/31/2028		K	L	M	N	O	P	Q	R	S	T	U
		25% Increased Load	25% Increased Load NGEM +100%	High Renewable Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
18	2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
19	2024											
20	2025	Wind Repowers 150 MW Sur Solar 150 MW Gen Wind	Wind Repowers 400 MW Sur Solar 400 MW Gen Wind 25 MW Sur Battery	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers	Wind Repowers 150 MW Sur Solar 50 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 400 MW Gen Wind 25 MW Sur Battery	Wind Repowers
21	2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 125 MW Sur Solar	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel
22	2027				100 MW Sur Solar	200 MW Sur Solar		75 MW Sur Solar	225 MW Sur Solar	100 MW Sur Solar		
23	2028		25 MW Gen Solar		50 MW Sur Solar			50 MW Gen Wind	25 MW Sur Solar	50 MW Sur Solar	25 MW Gen Solar	
24	2029	248 MW Firm Dispatchable	25 MW Sur Battery 50 MW Gen Battery 75 MW Gen Solar 200 MW Gen Wind	125 MW Sur Solar 150 MW Gen Wind		300 MW Gen Wind		200 MW Gen Wind	25 MW Sur Battery 200 MW Gen Wind		25 MW Sur Battery 50 MW Gen Battery 75 MW Gen Solar 200 MW Gen Wind	
25	2030			25 MW Sur Solar								
26	2031	50 MW Gen Wind	50 MW Gen Battery 50 MW Gen Wind	50 MW Gen Wind		50 MW Gen Wind		50 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind		50 MW Gen Battery 50 MW Gen Wind	
27	2032	250 MW Sur Solar 200 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind	175 MW Sur Solar 150 MW Gen Wind	250 MW Sur Solar 200 MW Gen Wind	50 MW Sur Battery 75 MW Sur Solar 100 MW Gen Wind	250 MW Gen Wind	50 MW Sur Battery 150 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar 150 MW Gen Wind	250 MW Sur Solar 200 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind	250 MW Gen Wind
28	2033											
29	2034				248 MW Firm Dispatchable					248 MW Firm Dispatchable		
30	2035											
31	2036						50 MW Rep Wind					50 MW Rep Wind
32	2037							50 MW Rep Wind				

	NPVRR Comparison		A	A.1	B	C	D	E	F	G	H	I	J
	IRP Refresh Externalities Included Attorney-Client Privileged: Internal Work Product		2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$3,257,885	$3,312,474	$3,458,755	$2,622,123	$2,815,524	$3,308,230	$3,664,671	$3,331,920	$3,683,471	$3,560,161	$3,968,310
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$3,152,731	$3,199,210	$3,378,245	$2,568,090	$2,708,651	$3,152,731	$2,568,090	$3,152,731	$2,568,090	$3,455,493	$3,903,745
	2028 Difference from 2040 Exit NPVRR	($000)	-$105,154	-$113,264	-$80,510	-$54,033	-$106,873	-$155,499	-$1,096,581	-$179,189	-$1,115,381	-$104,668	-$64,565

	Annual Resource Additions - Exit Coyote 12/31/2040	A	A.1	B	C	D	E	F	G	H	I	J
		2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
3	2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
4	2024											
5	2025	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers	Wind Repowers 400 MW Sur Solar 250 MW Gen Wind	Wind Repowers 400 MW Sur Solar 300 MW Gen Wind	Wind Repowers	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 350 MW Gen Wind	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 350 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind	Wind Repowers 400 MW Sur Solar 350 MW Gen Wind 50 MW Gen Wind
6	2026	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 100 MW Gen Wind	Astoria Onsite Fuel 25 MW Gen Solar	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel 25 MW Gen Solar	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind
7	2027		100 MW Sur Solar		25 MW Gen Solar			25 MW Gen Solar		25 MW Gen Solar		25 MW Gen Solar
8	2028		100 MW Sur Solar								50 MW Gen Wind	
9	2029		200 MW Gen Wind									
10	2030			50 MW Gen Wind	50 MW Gen Wind							
11	2031	50 MW Gen Wind							50 MW Gen Wind			
12	2032	150 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	50 MW Gen Solar 50 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind	150 MW Sur Solar 150 MW Gen Wind	150 MW Gen Wind	50 MW Sur Battery 25 MW Gen Solar 50 MW Gen Wind	150 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 50 MW Gen Wind	150 MW Gen Wind	50 MW Sur Battery 50 MW Gen Solar 150 MW Gen Wind
13	2033											
14	2034											
15	2035											
16	2036											
17	2037											

	Annual Resource Additions - Exit Coyote 12/31/2028	A	A.1	B	C	D	E	F	G	H	I	J
		2023 Base Case	Preferred Plan	Natural Gas & Energy Markets (NGEM) +50%	NGEM +100%	NGEM -50%	Regional Haze (RH) Mid Cost	RH Mid Cost NGEM +100%	RH High Cost	RH High Cost NGEM +100%	10% Increased Load	10% Increased Load NGEM +100%
18	2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
19	2024											
20	2025	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers	Wind Repowers 400 MW Sur Solar 250 MW Gen Wind	Wind Repowers 400 MW Sur Solar 300 MW Gen Wind	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 300 MW Gen Wind	Wind Repowers	Wind Repowers 400 MW Sur Solar 300 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind	Wind Repowers 400 MW Sur Solar 50 MW Gen Solar 400 MW Gen Wind
21	2026	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 25 MW Gen Solar
22	2027		100 MW Sur Solar		25 MW Gen Solar			25 MW Gen Solar		25 MW Gen Solar	50 MW Gen Wind	
23	2028		100 MW Sur Solar		25 MW Gen Solar			25 MW Gen Solar		25 MW Gen Solar	50 MW Gen Wind	25 MW Gen Solar
24	2029	150 MW Gen Wind	200 MW Gen Wind	25 MW Gen Solar 100 MW Gen Wind	75 MW Gen Solar 100 MW Gen Wind	25 MW Sur Battery 250 MW Gen Wind	150 MW Gen Wind	75 MW Gen Solar 100 MW Gen Wind	150 MW Gen Wind	75 MW Gen Solar 100 MW Gen Wind	25 MW Sur Battery 150 MW Gen Wind	75 MW Gen Solar 100 MW Gen Wind
25	2030		100 MW Sur Solar									25 MW Sur Battery
26	2031	25 MW Sur Battery	150 MW Gen Wind			50 MW Gen Wind	25 MW Sur Battery		25 MW Sur Battery		25 MW Sur Battery 50 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind
27	2032	25 MW Sur Battery 150 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	50 MW Sur Battery 100 MW Gen Solar 100 MW Gen Wind	50 MW Sur Battery 50 MW Gen Battery 100 MW Gen Solar 50 MW Gen Wind	150 MW Sur Solar 50 MW Gen Wind	25 MW Sur Battery 150 MW Gen Wind	50 MW Sur Battery 50 MW Gen Battery 100 MW Gen Solar 50 MW Gen Wind	25 MW Sur Battery 150 MW Gen Wind	50 MW Sur Battery 50 MW Gen Battery 100 MW Gen Solar 50 MW Gen Wind	50 MW Gen Battery 50 MW Gen Wind	50 MW Gen Battery 75 MW Gen Solar 50 MW Gen Wind
28	2033											
29	2034											
30	2035											
31	2036											25 MW Rep Battery
32	2037					50 MW Rep Wind						

NPVRR Comparison			K	L	M	N	O	P	Q	R	S	T	U
IRP Refresh Externalities Included Attorney-Client Privileged: Internal Work Product			25% Increased Load	25% Increased Load NGEM +100%	High Accreditation	Low Accreditation	Carbon Tax	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$4,038,165	$4,538,132	$3,232,192	$3,338,489	[redacted]	$3,477,757	$3,960,946	$3,232,715	$3,406,080	$4,105,072	$3,551,416
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$3,940,865	$4,492,412	$3,118,049	$3,312,192	[redacted]	$3,392,485	$3,936,893	$3,119,057	$3,312,192	$3,940,865	$3,392,485
	2028 Difference from 2040 Exit NPVRR	($000)	-$97,300	-$45,720	-$114,143	-$26,297	[redacted]	-$85,272	-$24,053	-$113,658	-$93,888	-$164,207	-$158,931

Annual Resource Additions - Exit Coyote 12/31/2040			K	L	M	N	O	P	Q	R	S	T	U
			25% Increased Load	25% Increased Load NGEM +100%	High Accreditation	Low Accreditation	[redacted]	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
3		2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	[redacted]	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
4		2024					[redacted]						
5		2025	Wind Repowers 375 MW Sur Solar 450 MW Gen Wind	Wind Repowers 400 MW Sur Solar 125 MW Gen Solar 450 MW Gen Wind	Wind Repowers 400 MW Sur Solar 150 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind	[redacted]		300 MW Sur Solar 250 MW Gen Wind	400 MW Sur Solar 100 MW Gen Wind	400 MW Sur Solar 200 MW Gen Wind	375 MW Sur Solar 450 MW Gen Wind	
6		2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	[redacted]	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel 25 MW Sur Solar	Astoria Onsite Fuel
7		2027	25 MW Sur Solar	50 MW Gen Solar		50 MW Gen Wind	[redacted]		25 MW Sur Solar		50 MW Gen Wind		
8		2028					[redacted]		25 MW Sur Solar	25 MW Gen Solar 50 MW Gen Wind			
9		2029	25 MW Sur Battery				[redacted]						
10		2030					[redacted]				50 MW Gen Wind		
11		2031	100 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind		25 MW Sur Battery	[redacted]				25 MW Sur Battery	50 MW Sur Battery 50 MW Gen Wind	
12		2032	25 MW Sur Battery	25 MW Sur Battery 50 MW Gen Battery 100 MW Gen Solar 50 MW Gen Wind	150 MW Gen Wind	25 MW Sur Battery 100 MW Gen Wind	[redacted]	150 MW Sur Solar 250 MW Gen Wind	50 MW Sur Solar 100 MW Gen Wind	50 MW Gen Solar 100 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind	50 MW Gen Wind	150 MW Sur Solar 250 MW Gen Wind
13		2033					[redacted]						
14		2034	25 MW Rep Battery				[redacted]					25 MW Rep Battery	
15		2035		50 MW Sur Wind			[redacted]				50 MW Rep Wind		
16		2036				50 MW Rep Wind	[redacted]					50 MW Rep Wind	
17		2037					[redacted]						

Annual Resource Additions - Exit Coyote 12/31/2028			K	L	M	N	O	P	Q	R	S	T	U
			25% Increased Load	25% Increased Load NGEM +100%	High Accreditation	Low Accreditation	[redacted]	Renewable High Cost	Renewable High Cost NGEM +100%	Solar and Battery Low Cost (40% ITC)	Low Accreditation RH High	25% Increased Load RH High	Renew High Cost RH High
18		2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	[redacted]	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
19		2024					[redacted]						
20		2025	Wind Repowers 400 MW Sur Solar 450 MW Gen Wind	Wind Repowers 400 MW Sur Solar 125 MW Gen Solar 450 MW Gen Wind	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind	[redacted]	Wind Repowers	Wind Repowers 300 MW Sur Solar 250 MW Gen Wind	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers 400 MW Sur Solar 200 MW Gen Wind	Wind Repowers 400 MW Sur Solar 450 MW Gen Wind	Wind Repowers
21		2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	[redacted]	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel
22		2027		25 MW Gen Solar		50 MW Gen Wind	[redacted]		25 MW Sur Solar		50 MW Gen Wind		
23		2028		25 MW Gen Solar	50 MW Gen Wind		[redacted]		25 MW Sur Solar	50 MW Gen Wind			
24		2029	50 MW Sur Battery 25 MW Gen Battery 200 MW Gen Wind	25 MW Sur Battery 50 MW Gen Battery 50 MW Gen Solar 200 MW Gen Wind	50 MW Gen Wind	50 MW Sur Battery 150 MW Gen Wind	[redacted]	300 MW Gen Wind	50 MW Sur Solar 50 MW Gen Wind	100 MW Gen Wind	50 MW Sur Battery 150 MW Gen Wind	50 MW Sur Battery 25 MW Gen Battery 200 MW Gen Wind	300 MW Gen Wind
25		2030					[redacted]						
26		2031	50 MW Gen Battery 50 MW Gen Wind	50 MW Gen Battery 25 MW Sur Battery			[redacted]	100 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind		50 MW Gen Battery 50 MW Gen Wind	100 MW Gen Wind
27		2032	75 MW Gen Battery 50 MW Gen Solar	50 MW Gen Battery 100 MW Gen Solar 50 MW Gen Wind	25 MW Gen Solar 150 MW Gen Wind		[redacted]	150 MW Sur Solar 50 MW Sur Battery 50 MW Gen Wind	50 MW Sur Battery 100 MW Gen Wind	50 MW Sur Battery 75 MW Gen Solar 100 MW Gen Wind		75 MW Gen Battery 50 MW Gen Solar	150 MW Sur Solar 50 MW Sur Battery 50 MW Gen Wind
28		2033					[redacted]						
29		2034					[redacted]						
30		2035				50 MW Rep Wind	[redacted]				50 MW Rep Wind		
31		2036					[redacted]						
32		2037					[redacted]			25 MW Rep Battery			

Appendix K: Mine Mouth Plants

Mine Mouth Plants

Otter Tail Power Company (Otter Tail) is a co-owner in two coal fired generation plants: (1) Coyote Station (Coyote), which is a mine-mouth plant, and (2) Big Stone Plant (Big Stone), which is a delivered fuel plant. There are key distinctions between these two types of plants.

Mine mouth facilities are found only in states with coal supplies. There are six mine mouth plants in North Dakota, including Coyote. It is our understanding that mine-mouth plants also exist in Montana, Wyoming, Colorado, and in several states in the eastern U.S. There are no mine-mouth plants located in Minnesota. In states without coal deposits, coal generators all must be delivered-fuel plants, meaning the fuel is shipped to the plant from elsewhere, typically by rail.

Coyote was designed and constructed as a mine-mouth plant, with a coal supply adjacent to the plant site. At Coyote, the mine exists to mine and haul coal to the Coyote, therefore all the infrastructure in place, the labor to mine, and the on-going costs of fuel and operation must be recovered through Coyote. This is typical for mine-mouth plants.

This difference between mine-mouth plants and delivered-fuel plants matters because mine-mouth plants, like Coyote were conceived, sited, designed, and constructed with an understanding that they would have long-term integrated relationships with an immediately adjacent mine. The mine is typically intended to serve just the mine-mouth plant with which it contracts, and it is therefore typically much smaller than the large mines that serve numerous delivered-fuel plants, such as the mines in the Powder River Basin that serve Big Stone.

One of the primary benefits of a mine-mouth plant, in contrast to a delivered-fuel plant, is that it is not dependent on the rail systems or other transportation systems, over which the coal necessary to fuel the plant must be transported. Of course, without having a secure and consistent long-term relationship with the adjacent mine, a mine-mouth plant would be exposed to fuel shortages; conversely, without a long-term relationship, the supplying mine would typically not make investments necessary to ensure the extraction of a consistent supply of coal necessary to fuel the plant. Without consistent fuel, the plant would not be reliable and would not be accreditable for capacity.

The benefit of not being dependent on fuel transportation is not just an abstract one. In late 2013 and into 2014, there were significant rail system constraints in our region caused by oil and agricultural deliveries and those cause significant concern for fuel supplies at delivered fuel plants.[1] Those constraints did not affect the reliability of mine-mouth plants like Coyote Station. This occurrence in 2013/2014 illustrates the benefits of the fuel delivery diversity that was understood when OTP and the plant owners originally chose to have interests in both Big Stone and Coyote, instead of having a larger interest in just one of the plants.

Because of the difference in the relationship, the mine/plant contracts for mine-mouth plants also have very different fixed/variable components when contrasted with delivered-fuel plants. These differences are because of the nature of the relationship and what each party requires from the relationship. The mine, in the case of a mine-mouth plant, must recoup its fixed costs (the costs of investments in opening the mine, the equipment, reclamation, etc.) and its variable costs (certain costs that vary with the volumes produced) generally from a single customer with which it has a long-term relationship. The larger fixed components of these contracts when compared to delivered fuel contracts are not because the transacting parties have different desires about the way the plant should operate, etc. Similarly, the plant requires a long-term relationship with its supplier, to ensure a consistent supply of fuel at a known cost (it cannot replace that fuel from the market if the supplier were to increase its prices or become unreliable in some other way).

These are the practical realities of mine-mouth plants, and they are the reasons for the differences in fuel contracts. These economic realities in the relationship are not different from a wind PPA, where the purchasing utility generally agrees upon fixed per-kwh pricing (or with slight escalation) so that the seller is assured of recouping its investment. This one-to-one relationship is different from the seller-buyer relationship

[1] MPUC Docket No. E999/AA-14-579, Department of Commerce Comments filed May 19, 2015, summarized the rail delivery issues experienced by Minnesota utilities in 2013 and 2014.

for a delivered fuel plant and the mine that supplies it. And it results in larger non-volumetric (fixed) costs in the pricing. But fixed costs are not something incorrect that should be changed—not for the mine-mouth plant nor for the wind PPA. They are less flexible because of it, but it is inherent in the nature of what was intended in their original design and construction.

The fuel contract for Coyote is not uncommon, which can be seen in the length of contracts for the other mine-mouth plants operating near Coyote Station. In 2019 they all reported having contracts with remaining terms between 2037 and 2045.5

The commercial differences between delivered-fuel and mine-mouth plants are commonly understood and have been regularly discussed in the industry press and academic literature. Examples of this information being discussed in academic literature can be found in the following:

a. Numerous academic works of Oliver E. Williamson, e.g. Williamson, Oliver E.. “The Vertical Integration of Production: Market Failure Considerations.” *American Economic Review*, 61(2): 112–23, 1971
b. Bruce W. Smith. “Analysis of the Location of Coal-Fired Power Plants in the Eastern United States,” *Economic Geography*, Vol. 49, No. 3, Jul., 1973
c. Paul L. Joskow, “Contract Duration and Relationship-Specific Investments: Empirical Evidence from Coal Markets,” *The American Economic Review*, Vol. 77, No. 1, Mar., 1987.
d. Joe Kerkvliet, “Efficiency and Vertical Integration: The Case of Mine-Mouth Electric Generating Plants,” *The Journal of Industrial Economics*, vol 39, No 5, Sept., 1991.