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March 31, 2023

OTTER TAIL POWER COMPANY

Mr. Steve Kahl
Director of Admin/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 Submittal of its 2022–2036 Integrated Resource Plan
Case No. PU-21-380

Dear Mr. Kahl:

Enclosed for filing with the North Dakota Public Service Commission is Otter Tail Power Company's (Otter Tail or Company) supplement to its 2021 Integrated Resource Plan (IRP) filing made September 1, 2021 (Initial Filing). The supplement (Supplemental Filing) updates our Initial Filing to account for recent developments which include the following:

- The Midcontinent Independent System Operator's (MISO) adoption of a seasonal resource adequacy construct and capacity requirements that increased planning reserve margins (PRMs) above the quantities included in our Initial Filing and its modeling;
- The enactment of the federal Inflation Reduction Act, which provides renewed and new incentives for wind, solar, clean energy storage, and clean energy manufacturing projects, such as the extension of wind and solar tax incentives that were set to expire and the creation of other new tax credits for renewable energy projects;
- Changes to Otter Tail's load forecasts; and
- MISO's projection for capacity deficits and recent volatility in energy markets

The Supplemental Filing includes a Supplemental Preferred Plan that replaces the Preferred Plan provided in our Initial Filing. The Supplemental Preferred Plan reflects the substantial and on-going changes to the resource planning environment since our Initial Filing. In response to these changes, our Supplemental Preferred Plan supports the addition of more renewable generation resources than proposed in our Initial Filing and a practical approach regarding Coyote Station that provides flexibility to respond to risk in an unsettled environment.

The Supplemental Preferred Plan includes a request for authority to add on-site liquified natural gas (LNG) fuel storage at Astoria Station in 2026[1], add approximately 200 megawatts (MW) of solar generation in the 2027-2028 timeframe, taking initial steps to add approximately 200 MW of wind generation in the 2029 timeframe, and withdrawing from

[1] On February 8, 2023, we filed with the Commission a request for an advance determination of prudence of our proposal to add on-site LNG storage at Astoria Station (Case. No. PU-23-066).

our 35% ownership interest in Coyote Station if the Company is required to make a large, non-routine capital investment in the plant.

The Supplemental Preferred Plan ensures we have the resources necessary to continue providing reliable, low-cost electricity to meet our customers' needs.

Please note that Otter Tail deems the following attachments marked as NOT PUBLIC to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Parties' Confidentiality Agreement.

An original and copies have been sent to you via USPS.

An electronic copy of this filing is being sent to you at ndpsc@nd.gov. Should you have any questions, please contact me at njensen@otpco.com or (218) 739-8989.

Sincerely,

/s/ NATHAN JENSEN
Nathan Jensen
Manager, Resource Planning

jjf
Enclosures
By electronic service and USPS

Application for Supplemental Resource Plan Approval 2023–2037

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SUBMITTED TO

Minnesota Public Utilities Commission: Docket No. E017/RP-21-339
North Dakota Public Service Commission: Case No. PU-21-380
South Dakota Public Utilities Commission

March 31, 2023

OTTER TAIL POWER COMPANY

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1 Summary of Supplemental Filing

This filing supplements and updates Otter Tail Power Company's (Otter Tail or Company) Application for Resource Plan Approval for 2022-2036 (Initial Filing) made September 1, 2021.[1] Specifically, this supplemental filing (Supplemental Filing) addresses changes that have occurred since we made our Initial Filing. These changes include the following:

- The Midcontinent Independent System Operator's (MISO) adoption of a seasonal resource adequacy construct and capacity requirements that increased planning reserve margins (PRMs) above the quantities included in our Initial Filing and its modeling;
- The enactment of the federal Inflation Reduction Act, which provides renewed and new incentives for wind, solar, clean energy storage, and clean energy manufacturing projects, such as the extension of wind and solar tax incentives that were set to expire and the creation of other new tax credits for renewable energy projects;
- Changes to Otter Tail's load forecasts; and
- MISO's projection for capacity deficits and recent volatility in energy markets.

More recently, Minnesota Governor Tim Walz signed into law the 100 percent Clean Energy Law (Minnesota Clean Energy Law) on February 6, 2023. The law requires all Minnesota electric utilities to generate or procure sufficient electricity from carbon-free resources to provide retail customers in Minnesota with 100 percent carbon-free electric energy by 2040.

Collectively these developments present a markedly different planning landscape than the one our Initial Filing addressed. Moreover, these developments occurred over a brief 18-month period since our Initial Filing, demonstrating how quickly key planning assumptions can change and the importance of flexibility in any preferred plan.

Based on the foregoing factors and our forecasted needs, we have updated the preferred plan set forth in our Initial Filing (Initial Preferred Plan). Our updated preferred plan (Supplemental Preferred Plan) set forth herein provides both specific actions that Otter Tail

[1] Otter Tail's Initial Filing was filed concurrently with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (ND PSC), and the South Dakota Public Utilities Commission (SD PUC). This Supplemental Filing is also being filed concurrently with MPUC, ND PSC, and SD PUC.

plans to complete during the first five years of the planning period and potential actions that Otter Tail may take during the subsequent ten years. Accordingly, we are requesting authority to carry out the following key aspects of the Supplemental Preferred Plan in the next five years:

- The addition of onsite liquified natural gas (LNG) fuel storage at Astoria Station in 2026.[2]
- Adding approximately 200 MW of solar generation in the 2027-2028 timeframe.
- Taking the initial steps necessary to add approximately 200 MW of wind generation in the 2029 timeframe.
- Withdrawal from our 35 percent ownership interest in Coyote Station in the event Otter Tail is required to make a major, non-routine capital investment in the plant.[3]

In addition to these actions, we intend to repower most of our existing wind facilities in 2024 and 2025.[4] In the aggregate, the repowering of these facilities will be the equivalent of adding 40 MW of wind generation with a 50 percent capacity factor to our portfolio.

Compared to our Initial Preferred Plan, our Supplemental Preferred Plan proposes to add more renewable generation resources to our portfolio. The most significant change between our Initial Preferred Plan and our Supplemental Preferred Plan concerns Coyote Station. As a winter peaking utility we are particularly concerned about MISO's new seasonal reserve margin requirements, open questions concerning MISO accreditation methodologies, and projected capacity deficits within MISO - especially when we consider changes to our load forecasts. These and other factors discussed herein raise significant concerns about our future capacity position and the degree to which MISO capacity and energy markets will be available to support our fundamental obligation to ensure system resource adequacy at a reasonable cost. In this unsettled environment, the value of existing dispatchable capacity offered by

[2] The issue of onsite fuel storage at Astoria Station is addressed more fully in related filings. On November 1, 2022, the MPUC issued a revised Notice of Comment Period separating the issue of fuel storage at Astoria Station from the Comment period applicable to the balance of Otter Tail's IRP. We anticipate that the issue of fuel storage at Astoria Station will come before the MPUC in May 2023. On February 8, 2023, we filed a request for an advance determination of prudence with the ND PSC for the onsite fuel storage at Astoria Station in Case No. PU-23-066.

[3] A large capital investment supporting withdrawal from Coyote Station must be distinguished from routine capital expenditures necessary for the plant to operate safely, reliably, and in compliance with current regulations. This distinction is discussed in Section 5.4 herein.

[4] As noted in Section 4.3.1. herein we intend to repower our Langdon, Ashtabula, Luverne and Ashtabula III wind facilities, all of which are powered by General Electric turbines. Our Merricourt wind facility is not part of this plan. The repowering of existing wind facilities is not part of Supplemental Preferred Plan for which we seek authority; we reference repowering to provide a full picture of our efforts to deliver cost effective energy to our customers.

Coyote Station augers against a premature and irretrievable withdrawal from the plant that may unnecessarily expose our customers to risk.

Therefore, in this Supplemental Filing we support retaining our ownership interest in Coyote Station unless and until there is a need for a large, non-routine capital investment necessary to operate the plant or to comply with a regulatory requirement, such as may be required by the federal Regional Haze Rule. We indicated in our Initial Filing that there was an especially strong case to exit Coyote Station if we are faced with a situation requiring a large, non-routine capital investment in the plant. Our modeling and analysis on this point have not changed and our Supplemental Preferred Plan seeks such authority. What has changed are the uncertainties and risks our customers now face. In this environment we believe it is in the public interest to retain Coyote Station in our generation portfolio pending the need for large, non-routine capital investment in the plant. Our posture with respect to Coyote Station will be subject to additional evaluation in future IRP filings. In the meantime, we support a prudently deliberate approach that preserves flexibility to respond to uncertainties.

Our Supplemental Preferred Plan accomplishes the following:

- Ensures that Otter Tail will have the resources necessary to continue providing reliable, low-cost electricity to meet our customers' needs, while avoiding adverse impacts;
- Complies with the requirements of applicable statutes and rules, including the Minnesota Clean Energy Law;
- Preserves flexibility to respond to risks in an unsettled planning environment; and
- Accounts for differing energy policies in each of the three states we serve while preserving the customer benefits of system-wide planning and networked assets for a small utility.

2 Procedural Background

Minnesota Procedural Background

Otter Tail submitted its Initial Filing on September 1, 2021.[5] The Minnesota Public Utilities Commission (MPUC) extended the initial comment period several times, and on

[5] Docket No. E017/RP-21-339. In Minnesota, this plan is filed to satisfy the requirements of Minnesota Statute § 216B.2422 and Minnesota Rules, Part 7843.

September 14, 2022, the MPUC issued its Fourth Notice of Extended Comment Period, setting November 14, 2022, as the deadline for initial comments and January 17, 2023, for reply comments.

On October 14, 2022, Otter Tail requested that the MPUC bifurcate the docket to (1) maintain the procedural schedule set forth in the MPUC's Fourth Notice of Extended Comment Period for addressing Otter Tail's proposed onsite fuel inventory system at Astoria Station and (2) amend the procedural schedule for the balance of Otter Tail's resource plan to allow Otter Tail time to update its Initial Filing to account for recent material developments, including the MISO's adoption of a seasonal capacity construct with significant winter and spring reserve planning margins and renewable energy incentives provided by the recently enacted Inflation Reduction Act.[6]

On November 1, 2022, the MPUC issued its Notice of Extended Comment Period granting Otter Tail's bifurcation request, with Astoria Station initial comments due December 1, 2022, (later changed to December 31, 2022) and Otter Tail's supplemental filing for the balance of its resource plan due March 31, 2023.

On November 4, 2022, Otter Tail filed Supplemental Comments summarizing our request for authority to develop an onsite fuel storage system at Astoria Station. On December 30, 2022, the following parties filed Initial Comments on Otter Tail's Astoria onsite fuel storage proposal: (1) Minnesota Department of Commerce (2) the Minnesota Office of the Attorney General – Residential Utilities Division (OAG) (3) Laborers' International Union of North America Minnesota and North Dakota and (4) Operating Engineers Local 49 and North Central States Regional Council of Carpenters. On February 10, 2023, Otter Tail, the Clean Energy Organizations, and the OAG filed Reply Comments concerning fuel storage at Astoria Station. On February 16, 2023, Otter Tail filed a Supplemental Letter concerning the impact of the Minnesota Clean Energy Law on the proposal for fuel storage at Astoria Station.

On March 31, 2023, Otter Tail submitted this Supplemental Filing to address changes outlined in our October 14, 2022, letter filing.

[6] In addition to addressing MISO's seasonal capacity construct and the Inflation Reduction Act we also noted our intent to address changes in MISO Planning Resource Auction (PRA) prices and capacity projections and Otter Tail load forecast changes that have occurred since our Initial Filing.

North Dakota Procedural Background

Otter Tail submitted its Initial Filing on September 1, 2021.[7] On October 14, 2022, Otter Tail filed a supplemental letter to address recent developments that may affect the Initial Filing, including MISO's adoption of a seasonal capacity construct with significant winter and spring reserve planning margins and renewable energy incentives provided by the recently enacted Inflation Reduction Act.[8] Otter Tail requested that the ND PSC delay review of the Initial Filing pending the Company addressing these developments in a supplemental filing on or about March 31, 2023. The Company also indicated its intent to request an Advance Determination of Prudence for that portion of the Initial Filing that sought approval for an onsite fuel storage system at Astoria Station. Otter Tail filed its Application for an Advance Determination of Prudence on February 8, 2023.[9] On March 31, 2023, Otter Tail filed this Supplemental Filing with the ND PSC.

South Dakota Procedural Background

In South Dakota, integrated resource plans are filed to keep the SD PUC apprised of the Company's plans; however, there is not any statute or rule requiring the SD PUC to review or approve resource plans. Otter Tail has filed its Initial Filing and this Supplemental Filing with the SD PUC. While not a resource plan matter, in April 2023 we anticipate filing with the SD PUC a request to modify Otter Tail's Astoria Station site permit to include onsite LNG fuel storage.

3 Supplemental Preferred Plan

The Supplemental Preferred Plan

Our Supplemental Preferred Plan, which replaces our Initial Preferred Plan in its entirety, presents actions that: (a) will ensure that Otter Tail has the resources necessary to continue to provide reliable, low-cost electricity to meet customers' needs, while avoiding adverse impacts; (b) comply with the requirements of applicable statutes and rules, including the Minnesota Clean Energy Law; (c) preserve flexibility to respond to risks in a fluid and uncertain planning environment; and (d) account for differing policies in each

[7] ND PSC Case No. PU-21-380. In North Dakota, the plan is filed pursuant to North Dakota Century Code §§ 49-05-04.4 and 49-05-17.
[8] In addition to addressing MISO's seasonal capacity construct and the Inflation Reduction Act we also noted our intent to address changes in MISO Planning Resource Auction (PRA) prices and capacity projections and Otter Tail load forecast changes that have occurred since our Initial Filing.
[9] *In the Matter of Otter Tail Power Company Advance Prudence Application – Astoria Station Onsite Fuel Inventory System*, ND PSC Case No. PU-23-066.

of the three states we serve while preserving the customer benefits of system-wide planning and networked assets for a small utility.

The Company has determined that it can best satisfy those goals by: (a) modifying Astoria Station to add LNG fuel storage capability; (b) adding solar and wind resources, including approximately 200 MW of solar generation and approximately 200 MW of wind generation (in addition to repowering our existing wind facilities—excluding Merricourt) and (c) retaining Coyote Station in our generation portfolio pending the need for any significant, non-routine capital investment that may be required to continue operating the plant. Our analysis indicates that this combination of actions will provide flexibility, reduce costs, and maintain and enhance the resiliency of our system.

Table 3-1 provides the preferred 15-year resource plan for both the Base Case and our Supplemental Preferred Plan. The Table includes the resource selection and net present value of revenue requirements (NPVRR) both with and without externalities.

Our five-year action plan to add 200 MWs of solar in the 2027/2028 timeframe and to begin activities to add 200 MW of wind in the 2029 timeframe is not altered by any actions we may take concerning Coyote Station. As shown below, if Otter Tail were to withdraw from Coyote Station, in a future resource planning proceeding we would likely request authority to add 100 MW of solar and 150 MW of wind in the 2030/2031 timeframe.

Supplemental Table 3-1 – Supplemental Preferred Plan Summary

	No Externalities		with Externalities	
	Base Case	Preferred Plan*	Base Case	Preferred Plan*
2023	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar	Hoot Lake Solar
2024				
2025	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Sur Solar 100 MW Gen Wind	Wind Repowers
2026	Astoria Onsite Fuel	Astoria Onsite Fuel	ria Onsite Fuel50 MW Gen W	Astoria Onsite Fuel
2027		100 MW Sur Solar		100 MW Sur Solar
2028		100 MW Sur Solar		100 MW Sur Solar
2029	50 MW Sur Solar 250 MW Gen Wind	200 MW Gen Wind	150 MW Gen Wind	200 MW Gen Wind
2030		100 MW Sur Solar		100 MW Sur Solar
2031	25 MW Sur Battery	150 MW Gen Wind	25 MW Sur Battery	150 MW Gen Wind
2032	25 MW Sur Battery 250 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery	25 MW Sur Battery 150 MW Gen Wind	100 MW Sur Solar 25 MW Sur Battery
2033				
2034				
2035				
2036				
2037				
NPVRR	$2,714,497	$2,724,103	$3,152,731	$3,199,210

*Resource additions in 2030 and 2031 are to be determined. 100MW Surplus Solar and 150 MW Generic Wind are needed if Otter Tail withdraws from Coyote at year end 2028.

As provided in the table above, the NPVRR for the Supplemental Preferred Plan is slightly higher than the optimal EnCompass solved Base Case. Our Supplemental Preferred Plan represents a balanced and reasonable approach to addressing the concerns of our regulators and varied stakeholders, which complies with all legal requirements and allows the Company to continue providing reliable, low-cost electricity to meet our customers' needs.

Graphs 3-1 to 3-4 show Otter Tail's position within MISO's current capacity construct for all seasons through 2037 – considering scenarios with Coyote Station included and removed from the resource stack.

Graph 3-1: Supplemental Preferred Plan Accredited Winter Capacity and - PRMR

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Graph 3-2: Supplemental Preferred Plan Accredited Spring Capacity and PRMR

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Graph 3-3: Supplemental Preferred Plan Accredited Summer Capacity and PRMR

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

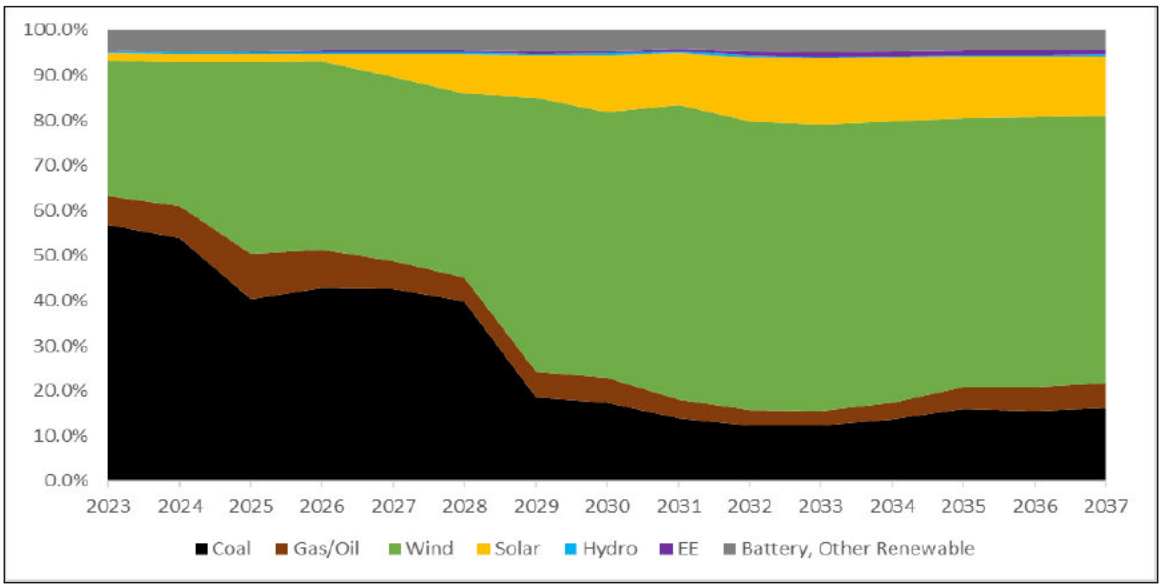
Graph 3-4: Supplemental Preferred Plan Accredited Fall Capacity and PRMR

[PROTECTED DATA BEGINS…

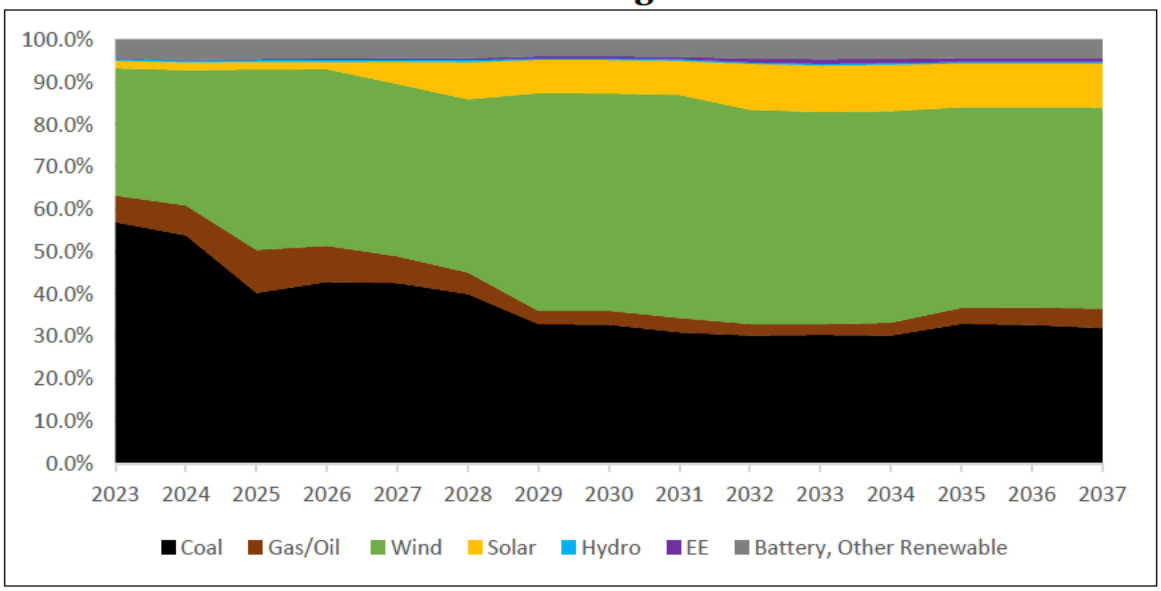
…PROTECTED DATA ENDS]

Graph 3-5 shows the expected energy mix through 2037 for Otter Tail's Supplemental Preferred Plan, considering scenarios with Coyote Station included through 2040 and not included beginning in 2029 (this data is based on Encompass generator output in runs not considering externalities).

Graph 3-5: Supplemental Preferred Plan (Coyote 2028) Energy Generation Percentage



Graph 3-6: Supplemental Preferred Plan (Coyote 2040) Energy Generation Percentage



Otter Tail's approach to planning recognizes that modeling and a corresponding NPVRR analysis, while important, is not the end of the analysis. As noted in our Initial Filing, the Company has historically advocated for what we describe as a "least cost" resource plan. However, the selection of such a plan has always involved more than just selecting the lowest cost option under a single forecasted scenario. Instead, Otter Tail analyzes numerous potential scenarios in a range of possible "futures." By considering a variety of scenarios, the Company's goal has always been to go beyond a single "least cost" consideration to also consider the various *risks* that are inherent in any plan so that we can arrive at a plan that has the greatest likelihood of being "least cost" under the broadest range of possible futures. It might therefore be more accurate to say that Otter Tail's resource planning has been focused on finding the "least cost/least risk" plan. The Supplemental Preferred Plan is such a plan.

Our Supplemental Preferred Plan closely tracks our Initial Preferred Plan. The primary difference concerns Coyote Station. In our Initial Preferred Plan we stated the following:

> In fact, the economic analyses supporting the Preferred Plan is compelling. In almost every scenario and permutation analyzed, the results are clear: It is no longer in customers' best interest for Otter Tail to continue to participate as an owner in Coyote Station. This outcome is true regardless of any future compliance obligation or potential change in law. Should significant investments need to be made at Coyote Station for environmental compliance purposes, the economic analysis is even more compelling.[10]

Based on material changes that have occurred since our Initial Filing we believe our customers are better served by the Company remaining an owner in Coyote Station pending a need for significant investments in the plant, which would most likely be necessary for environmental compliance purposes.[11] Should we determine it necessary to withdraw from Coyote Station, our goal is to do so expeditiously while minimizing potential adverse impacts. Consequently, Otter Tail is seeking authority in its Supplemental Preferred Plan to withdraw from its ownership interest in Coyote Station in the event Otter Tail is required to make a significant, non-routine capital investment in the facility. Pending such a development, Otter Tail believes it prudent not to

[10] Initial Filing at p. 6.
[11] This possibility arises from the EPA's Regional Haze Rule. In its planning, the Company is treating the need for capital investments to comply with that rule as a possibility; however, to be clear, Otter Tail is not taking the position that such capital investments should be required, nor are we providing an estimate of the likelihood of such outcome.

prematurely withdraw from its ownership in Coyote Station, recognizing that our ownership in Coyote Station will be reevaluated in our next resource plan filings.

The risks and uncertainties that inform our view of Coyote Station (discussed in more detail later in this Supplemental Filing) include the following:

- Modeling Changes - In our Initial Filing, there were few scenarios where it was economic to remain in Coyote Station beyond 2028. In nearly every case, even when externalities were not included, the modeling supported withdrawing from Coyote Station. In our updated modeling there are now additional scenarios that support remaining in Coyote Station. These scenarios include a high renewable energy cost scenario and a low renewable accreditation scenario.
- Capacity Accreditation Questions - There remain significant questions about MISO's capacity accreditation for generation resources. MISO is considering several proposals for capacity accreditation and as of the date of this Supplemental Filing it is unclear which standard MISO will adopt.[12]
- Otter Tail's Capacity Position Relative to Load Growth – Otter Tail's updated modeling includes the addition and projected addition of large loads. Some of these loads are agricultural processing facilities similar to what we have seen historically, albeit with different methods, intended to produce carbon neutral products; others are atypical in nature for Otter Tail, such as data processing customers. We expect continued interest from customers in these industries, which could affect our overall capacity position.
- Recent Volatility in MISO Energy Markets and Natural Gas Markets - While we expect these markets to return to more normal conditions in our forecasts, the extreme volatility in these markets that occurred after our Initial Filing demonstrates that forecasting will always have an inherent amount of uncertainty and risk.

[12] Also note that on March 21, 2023, MISO received an order from the Federal Energy Regulatory Commission (FERC) establishing a show cause proceeding in FERC Docket EL23-46-000 regarding Seasonal Accredited Capacity (SAC) ratios for Schedule 53 resources. FERC's order dated March 17, 2023 states that MISO "appears to be violating its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) by failing to update its system-wide Unforced Capacity (UCAP)/Intermediate Seasonal Accredited Capacity (ISAC) ratio (Ratio) for the 2023/24 Planning Resource Auction despite having updated ISAC values for certain resources." In response to FERC's order, MISO will be recalculating the SAC ratios, which is expected to result in reduced SAC values for individual market participants on an aggregate basis. We do not anticipate this development having a material impact on our Supplemental Fling.

- MISO Capacity Position & Regional Resource Assessment –Since our Initial Filing MISO has shifted from capacity surplus to capacity shortfall, and MISO modeling indicates near term capacity risk. MISO's Local Resource Zone 1 of which Otter Tail has 99 percent of its customers, is not isolated from this risk.

In the current planning environment, having Coyote Station part of the Company's portfolio provides a cost-effective hedge against market volatility, unresolved accreditation questions, forecasting uncertainties and related risk of errors, and unforeseen developments. This is a cautious and measured approach that preserves flexibility and limits risk pending more clarity on several fronts.

There is no doubt there will be differences of opinions among our stakeholders, some of whom may view our Supplemental Preferred Plan as a significant departure from our Initial Preferred Plan on the issue of Coyote Station. We do not think that is the case. Our position with respect to Coyote Station tracks closely to that detailed in our Initial Filing; our Supplemental Preferred Plan should be viewed as a cautious pause pending further developments.

Otter Tail's goal is to keep customers' interests in the forefront of this analysis. We know we share this goal with each of our three Commissions. Our Supplemental Preferred Plan strikes a balance between several planning objectives - including arriving at a diversified mix of generation resources that assures reliability, rate stability, environmental responsibility, and the flexibility to respond to risks and opportunities in this rapidly changing environment.

As we noted in our Initial Filing any withdrawal from Coyote Station is complex and challenging. Coyote Station is a key baseload resource for the plant's co-owners. Additionally, Otter Tail is the current operator of the plant and is relied upon by the co-owners for the plant's safe and efficient operation. Further, Coyote Station is a mine-mouth lignite plant, with the adjacent mine serving the plant. There are significant differences between mine mouth plants such a Coyote Station and delivered fuel plants that affect any withdrawal analysis. Appendix K provides a summary of these differences.

The mine is owned by Coyote Creek Mining Company, LLC, a subsidiary of the North American Coal Corporation, which is not affiliated with any of the Coyote Station co-

owners. Finally, Coyote Station is a key source of jobs and tax base in Mercer County and North Dakota. These challenges will require thoughtful consideration and management should circumstance make it necessary to withdraw from Coyote Station.

Table 3-2 below summarizes the key actions in the Supplemental Preferred Plan. Each of the items listed is discussed in greater detail in subsequent sections of this filing.

Table 3-2: Otter Tail 2023-2029 Detailed Action Plan

Year	Actions
2023	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. Wind Equipment Upgrades (in service 2024 & 2025)[13]: Secure necessary siting amendments, equipment and contracting for construction. Onsite Fuel at Astoria Station: Development Activities: Engage engineering firm to complete sufficient design to support permitting, regulatory approvals, and Engineering, Procurement, and Construct (EPC) bid packages. Enter into EPC and fuel supply agreements.
2024	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar (in-service 2027): Development Activities: Secure land, MISO interconnection, Preliminary Design Permitting Onsite Fuel at Astoria Station: EPC contractor completes detailed design, manufacturing and

[13] We reference the repowering of our wind facilities in the Supplemental Preferred Plan to provide a full picture of our efforts to develop cost effective generation and the impact of the IRA. Repowering of these facilities is subject to separate regulatory proceedings outside of this Supplemental Preferred Plan.

Year	Actions
	construction begins.
2025	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar (in-service 2028): Development Activities: Secure land, MISO interconnection, Preliminary Design Permitting Onsite Fuel at Astoria Station: Construction
2026	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar (in-service 2027): Final design and contracting 200 MW Wind (in-service 2029): Development Activities: Secure land, MISO interconnection, Preliminary Design, Permitting
2027	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar 2027 Commercial operation 100 MW Solar (in-service 2028): Final design and contracting 200 MW Wind (in-service 2029): Secure necessary equipment and contracting for construction
2028	Monitor Possible Withdrawal from Coyote Sation: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital

Year	Actions
	investment; withdraw if a large non-routine capital investment is needed. 100 MW Solar 2028 Commercial operation 200 MW Wind (in-service 2029): Construction
2029	Monitor Possible Withdrawal from Coyote Station: Fulfill contractual and legal obligations. Prepare for possible withdrawal from plant pending need for a large, non-routine capital investment; withdraw if a large non-routine capital investment is needed. 200 MW Wind: 2029 commercial operation

4 Recent Developments and Modeling Changes

4.1 Resilient Generation / Reliability Attributes Analysis

Historically, resource plans have focused on energy and capacity metrics to assess a utility's ability to produce electricity cost-effectively and reliably for its customers. With changes that have occurred in the marketplace over the past several years, however, the full scope of generation attributes has grown in significance for resource planning, going beyond just the attributes of capacity and energy. A well-crafted resource plan will consider other important attributes like dispatchability, fuel supply and deliverability, price assurance, and other attributes that contribute to the resilience of the resource portfolio. We have undertaken such an analysis in arriving at our Supplemental Preferred Plan.

These concepts were highlighted during events such as the 2014 Polar Vortex, the 2021 Winter Storm Uri and the 2022 Winter Storm Elliot, where renewable generation was at times not available, natural gas availability was at times limited, and electricity market prices and natural gas prices were at times extremely high.

Recent proposals by MISO highlight its increased awareness of planning attributes beyond capacity accreditation. Long-duration energy and fuel assurance are part of

MISO's six proposed reliability attributes. These attributes are at the forefront of MISO's planning and are part of the discussion to address future requirements.[14] Although MISO is just beginning the process of valuing these various attributes, Otter Tail has consistently emphasized our resilient generation capabilities.

In our Initial Filing we noted the three characteristics that define resilient generation resources: (a) dispatchability, (b) reliable fuel supply, and (c) energy price protection. Table 3-8 of our Initial Filing displays the various resources Otter Tail analyzes for resiliency.[15] Similar to Otter Tail's Initial Filing, Supplemental Table 4-1 compares our total current resilient generation in 2023 to our Supplemental Preferred Plan resilient generation in 2030, assuming for analysis that onsite fuel capability is added at Astoria Station. All four seasons have been included to better reflect MISOs seasonal construct.

Supplemental Table 4-1: Resilient Generation

	2023			
	Summer	Fall	Winter	Spring
Big Stone	256	256	256	256
Coyote	149	149	149	149
Astoria	0	0	0	0
Solway	42	44	46	44
Oil Peakers	59	59	59	59
Controllable Load	115	115	210	115
Total	**621**	**623**	**720**	**623**

	2030 (including Coyote)				2030 (excluding Coyote)			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
Big Stone	256	256	256	256	256	256	256	256
Coyote	149	149	149	149	0	0	0	0
Astoria	248	264	280	264	248	264	280	264
Solway	42	44	46	44	42	44	46	44
Oil Peakers	59	59	59	59	59	59	59	59
Controllable Load	115	115	210	115	115	115	210	115
Total	**869**	**887**	**1000**	**887**	**720**	**738**	**851**	**738**

[14] MISO's September 21, 2022, System Attributes Stakeholder Workshop presentation: https://cdn.misoenergy.org/20220921%20System%20Attributes%20Workshop%20Presentation626391.pdf.

[15] Table 3-8 of our Initial Filing was later amended in subsequent filings concerning Astoria Station fuel storage, as Otter Tail continues to survey and analyze various technologies for consideration within our resource mix. See Otter Tail Power Company Supplemental Comments, MPUC Docket No. E017/RP-21-339, November 4, 2022, at p.5; Initial ADP Filing, ND PSC Case No. PU-23-066, February 8, at p. 13.

Figure 4-1 (below) compares Otter Tail's 2023 forecasted hourly load to existing resilient generation capabilities. The grey area in Figure 4-1 depicts Otter Tail's seasonal load duration curves. A load duration curve illustrates the total amount of load in each hour of the season arranged in order of magnitude. From it, we can consider the maximum amount of load we need to be prepared to serve over the course of a year. The blue line in Figure 4-1 is drawn to show the level of our resilient generation resources. The purpose of this figure is to show the relationship between resilient generation capabilities and forecasted hourly load and potential market exposure if variable resources were not generating at the time load exceeded the resilient generation capabilities. As shown in the figure, we project that 12 percent of our overall load will not be backstopped by resilient resources.

Figure 4-1: 2023 Forecasted Load Relationship with Resilient Generation

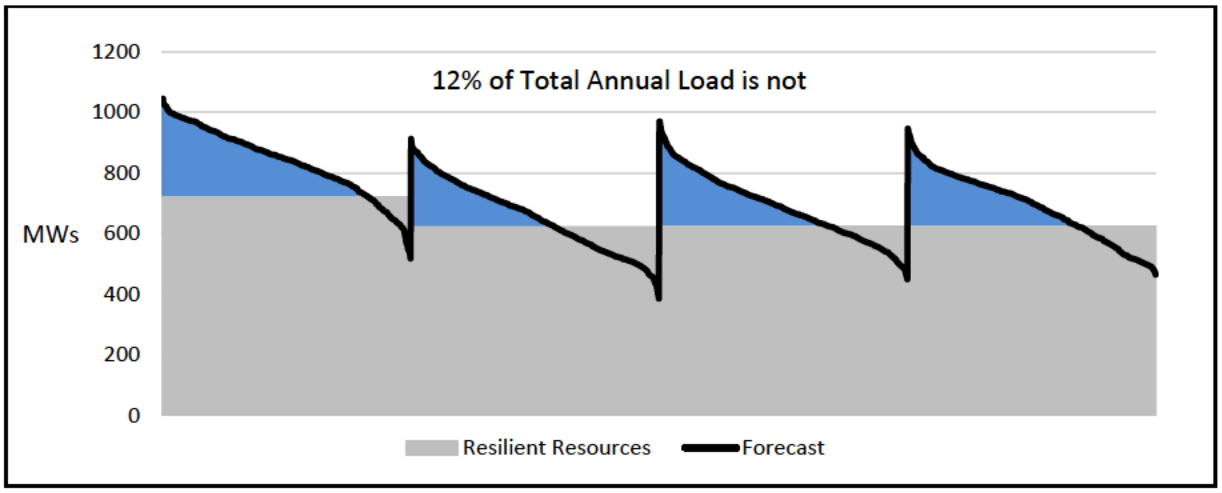


Figure 4-2 similarly compares Otter Tail's 2030 forecasted hourly load with the resilient generation available under the Supplemental Preferred Plan with Coyote Station still in Otter Tail's resource mix. As noted by Figure 3-10 the Supplemental Preferred Plan reduces the amount of load not backed by resilient generation from 12 percent to only 1 percent.

Figure 4-2: 2030 Forecasted Load Relationship with Resilient Generation (including Coyote Station)

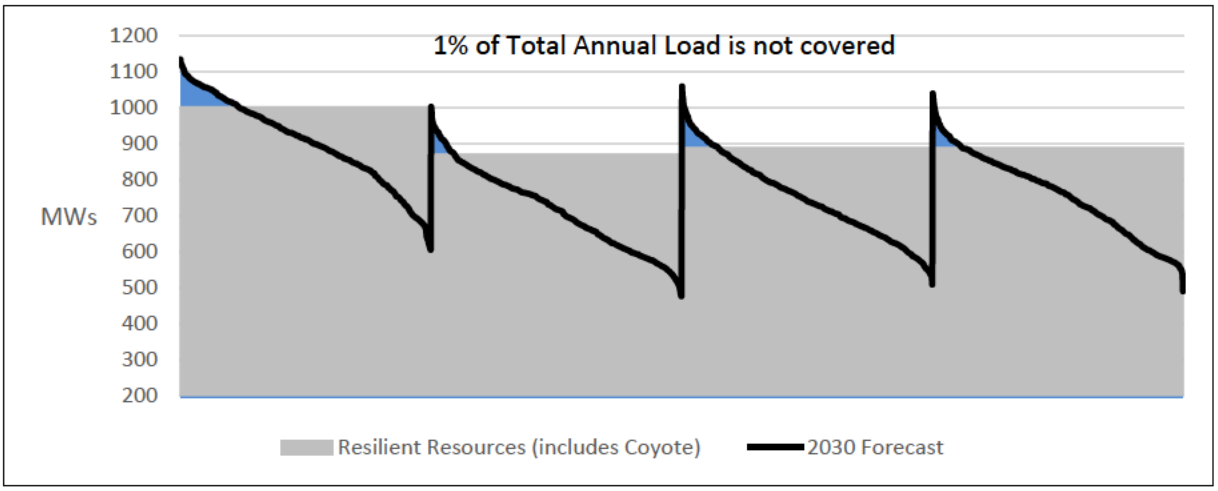
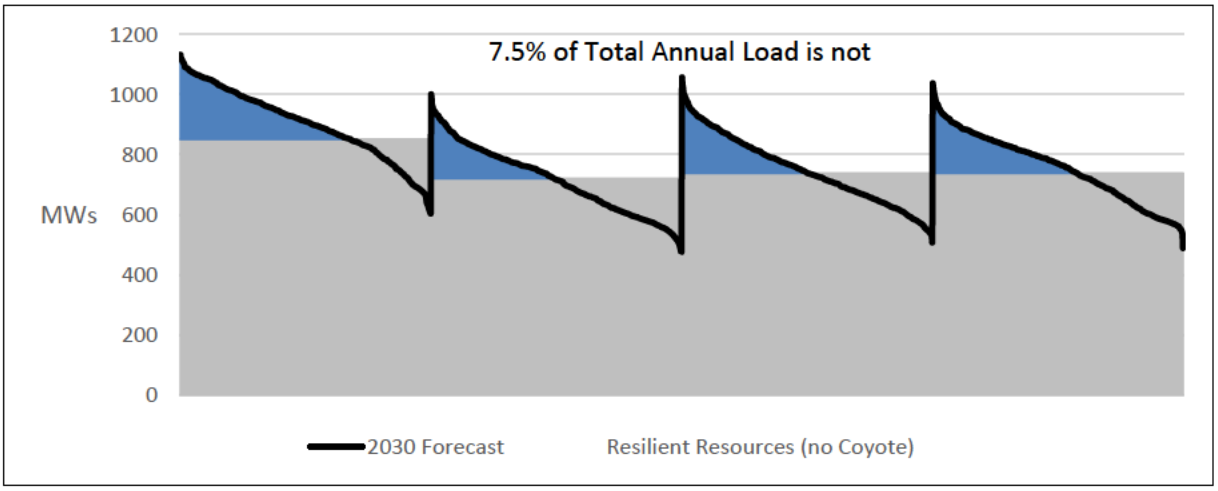


Figure 4-3 is similar to Figure 4-1, with the exception that Coyote Station is removed from Otter Tail's resource mix. In this situation the forecasted 2030 load that is not covered by resilient generation increases from 1 percent when Coyote Station is included to 7.5 percent.

Figure 4-3: 2030 Forecasted Load Relationship with Resilient Generation (Coyote removed)



4.2 MISO Changes

4.2.1 Seasonal Construct

On August 31, 2022, FERC approved MISO Tariff revisions that include the adoption of a seasonal resource adequacy construct and capacity requirements. These changes allow

MISO to move forward with seasonal capacity auctions with each season having its own capacity requirement based on seasonal coincident peak loads and a seasonal reserve margin. The changes also allow MISO to accredit resources based on their historic availability during Resource Adequacy (RA) hours rather than on the forced outage rate methodology where all hours are treated equally. These changes will be implemented in the 2023/2024 planning year.

4.2.2 MISO Planning Reserve Margin Requirements (PRMR) & Subsequent Accreditation

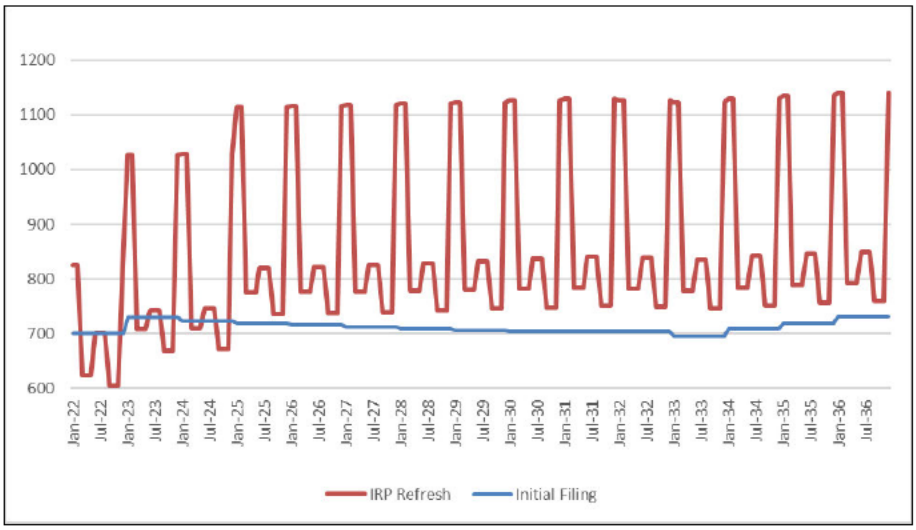
On September 6, 2022, the MISO Loss of Load Expectation Working Group (LOLE Working Group) published draft results for the 2023/2024 Planning Reserve Margin and Local Reliability Requirements. The LOLE Working Group proposed the following planning reserve margins (PRM):

Table 4-2: MISO Seasonal Planning Reserve Margin

Season	PRM Percentage	Otter Tail PRMR
Summer	7.4%	809
Fall	14.9%	729
Winter	25.5%	1,117
Spring	24.5%	775

These reserve margins are significant deviations from MISO's 2022/2023 annual planning reserve margin of 8.7 percent. Of particular consequence for our Company is the PRM percentage of 25.50 percent for the winter season. Otter Tail is a winter peaking utility. Although we have always and continue plan year-round, this magnitude of a reserve margin was not anticipated. Furthermore, at the time we informed our state Commissions of the need to update our Initial Filing, our reserve margins were known but our accreditation values were still unknown. This created concern regarding wintertime exposure risks in MISOs Planning Resource Auction (PRA) that we sought to address in the modeling. The differences between filings are graphically depicted in Graph 4-1 below.

Graph 4-1 Initial Filing vs. Current Filing PRMR[16]



From the same LOLE Working Group presentation wind and solar Effective Load Carrying Capability (ELCC) values were also provided. MISO later established these values as the basis for wind and solar accreditation for the upcoming planning year. Exact accreditation values were unknown at the time of input development for this Supplemental Filing's modeling. Therefore, we used values from MISO's loss of load expectation (LOLE) study for years 2023 through 2030 as well as information from MISO's Regional Resource Assessment (RRA) for years 2031 and beyond. The ELCC of wind and solar are predicted to slowly decrease over time – as is expected with increased penetration of wind and solar. Table 4-3 shows values that were used for wind and solar accreditation within our Supplemental Filing modeling.

Table 4-3: Wind and Solar Accreditation (Percentage of ICAP)

	Summer	Fall	Winter	Spring
Wind (current)	18	23	40	23
Solar (current)	45	25	6	15
Battery* (current)	82	68	82	76
Wind (2031)	18	21	37	12

[16] Otter Tail current customer base includes those that allow for a considerable amount of control for which the load control is registered as a load modifying resource in MISO. Otter Tail's load forecasts in this filing include the net of customer load and the load modifying resources.

	Summer	Fall	Winter	Spring
Solar (2031)	23	18	1	17
Battery (2031) *	82	68	82	76
Wind (2041)	16	21	26	12
Solar (2041)	18	20	11	11
Battery (2041)	100	100	97	64
*Current ELCC not provided by MISO, used RRA 2031 value				

Otter Tail has and will continue to plan for sufficient generation year-round. When we identified the need to update our Initial Filing's modeling the values applicable to our generation fleet's accreditation were unknown. Today, our values for accreditation are known for the upcoming planning year and we have used inputs that are reasonable for this Supplemental Filing. Beyond the upcoming planning year, there are unsettled issues with both the current accreditation methodology and proposed accreditation methodologies. We address these unknowns by running various sensitivities as well as constantly reviewing our generation fleet outside the model (as shown in Section 4.1).

4.2.3 MISO Capacity Position & Regional Resource Assessment

Since our Initial Filing greater uncertainty has developed concerning MISO Planning Resource Auction (PRA)[17] due to a MISO capacity surplus shifting to a capacity shortfall.[18] The Organization of MISO States 2022 survey warns of potential capacity deficits through at least the 2027/2028 planning year depending on the pace of generator retirements and new capacity additions.[19] Furthermore, MISO's 2022 RRA modeling

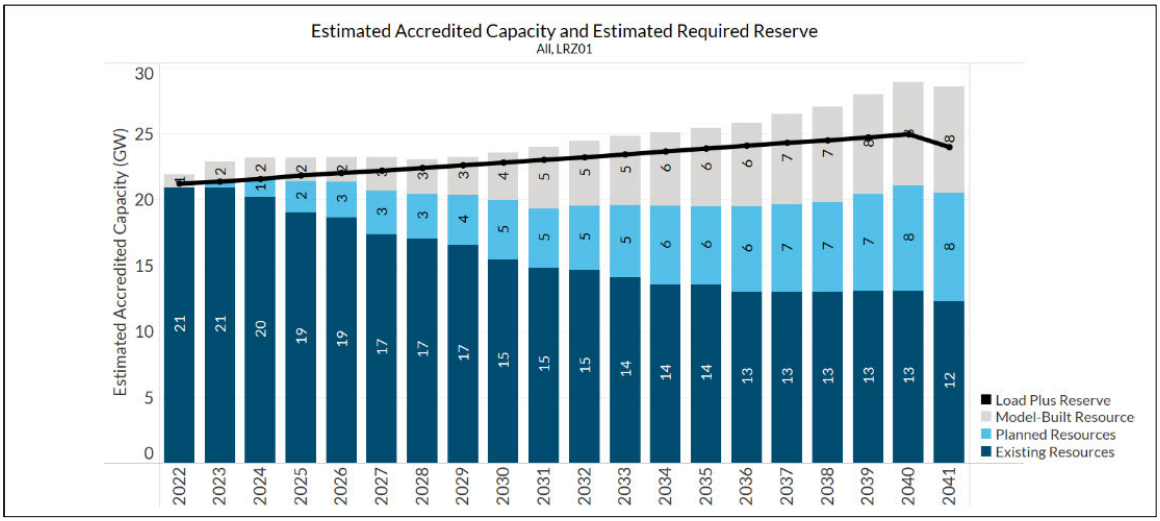
[17] PRA prices for planning year 2022-2023 recently cleared at the cost of new entry (CONE) compared to the much lower historical PRA clearing prices of sub-$5/MW-Day. Clearing prices from MISO's 2022-2023 PRA reflect capacity shortfalls in four zones, exposing nearly 8 GW in MISO North/Central to the Cost of New Entry. For reference, zone 1 auction clearing prices have been no higher than $5.00 per MW-Day since planning year 2017-2018. In 2022 zone 1 auction clearing prices were $236.66 per MW-Day. *MISO Planning Resource Auction (PRA) for Planning Year 2022-2023 Results Posting, May 14, 2022.*

[18] This shift was expressed by MISO in May 2022, when it projected insufficient firm resources to cover peak 2022 summer forecasts under typical demand and generation outages, and that "[e]emergency resources and non-firm energy imports are projected to be needed to maintain system reliability. *MISO Summer Readiness Workshop Summer 2022.*

[19] *2022 OMS-MISO Survey Results Posting June 10, 2022.* These capacity deficits follow a concentrated period of generation plant retirements within MISO. Capacity in the MISO North/Central region fell by 3.2 GW since the last capacity auction. *MISO Planning Resource Auction (PRA) for Planning Year 2022-2023 Results*

"indicates a continued near-term capacity risk, highlighting the immediate importance of coordinated resource planning and additional investment." MISO's Local Resource Zone 1 (LRZ 1), of which Otter Tail has 99 percent of its customers, is not isolated from this risk. Graph 4-2 from the 2022 RRA suggest not only a long-term but also immediate concern regarding capacity and reserves.

Graph 4-2: LRZ 01 Results – Capacity and Reserves



This Supplemental Filing concerns only our future generation fleet. That being said, MISO's capacity deficit projections inform our view about an unsettled planning environment that may affect our customers.

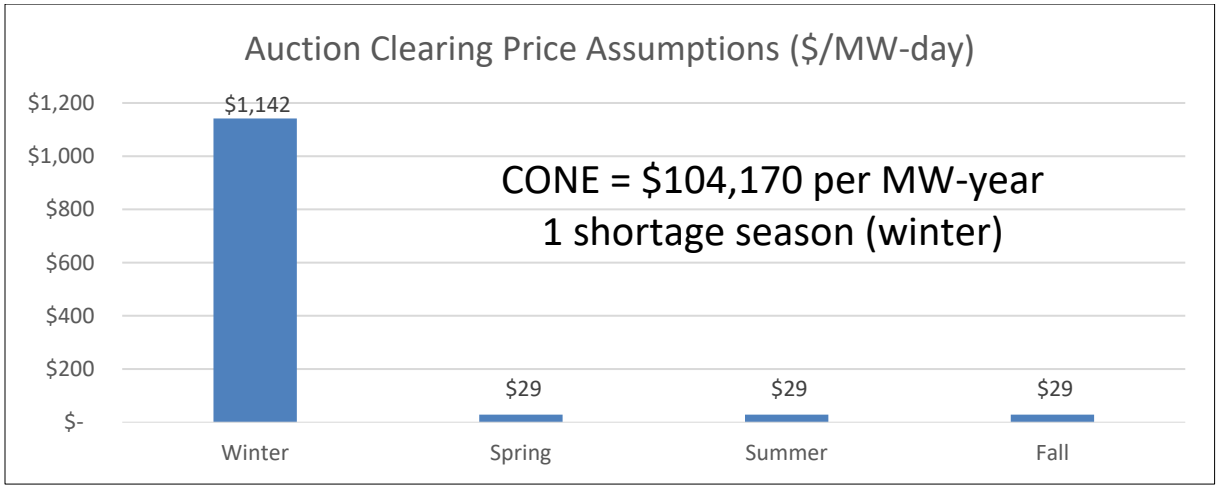
4.2.4 Auction Clearing Mechanism as Established within MISO's Seasonal Construct

Within our modeling we do not allow capacity to be sold to the market to ensure capacity is built only for our customers. This is how we have traditionally modeled excess capacity for resource plans. However, our modeling does put a cost to firm capacity imports when they are necessary to meet our PRMR. The new seasonal construct within MISO comes with nuances regarding the auction clearing prices themselves. One such nuance is the potential for the entirety of Cost of New Entry (CONE) to fall within one season. We determined it was reasonable to assign CONE in its entirety to the winter season given our limited excess capacity for the winter season. Graph 4-3 shows how the inputs were

Posting May 14, 2022. MISO notes that unless more reliable generation is built shortfalls such as this will continue.

established for our Supplemental Filing.

Graph 4-3: Assigned Auction Clearing Prices within Planning Resource Auction



The values shown above are for 2023 and escalate at the inflation rate used throughout Encompass. This cost is a conservative but realistic outcome that could occur within MISO's planning resource auction to disincentivize the model from selecting imports over additional capacity. This change from our Initial Filing was a result of the information described within this section as well as the seasonal nature of the auction as noted above.

4.2.5 Potential future policy changes (sloped demand curve, D-LOL, etc.)

MISO is actively developing a reliability-based demand curve for likely implementation in the 2024/2025 PRA. For modeling purposes, a reliability-based demand curve was not considered for the reasons mentioned in Section 4.2.4 regarding capacity purchases and sales.

We did not use the pending direct loss of load non-thermal accreditation (D-LOL) methodology when determining modeling inputs for this Supplemental Filing. The proposed D-LOL methodology has only been revealed at its highest level. The amount of detail required to model this type of accreditation methodology would require a much more in-depth data release from MISO. We are closely monitoring the proposed accreditation methodology. Because the proposed methodology has not been finalized, we have used accreditation values mentioned in Section 4.2.2.

Furthermore, MISO's states in its presentation entitled *Identification of Sufficient Reliability Attributes* that "[i]n 2023 MISO will explore attributes to define quantitative metrics, enhance visibility and develop a roadmap to assist members in resource planning and prioritization of appropriate market mechanisms."[20] The attributes that MISO is exploring (availability; long duration energy at high output; fuel assurance; rapid start-up; ramp-up capability; and voltage stability) have always been considered within Otter Tail's planning process in a qualitative manner. Otter Tail is generally supportive of MISO's efforts to explore these attributes in a quantitative manner and subsequently applying value to each. Otter Tail will continue to provide feedback and any support necessary to assist MISO in this matter.

4.3 Inflation Reduction Act (IRA) 2022

President Biden signed the IRA into law on August 16, 2022. The IRA provides approximately $369 billion toward wind, solar, clean energy storage, and clean energy manufacturing projects. Notably the IRA extends tax incentives for wind and solar facilities that were set to expire. The impact of this legislation is included throughout this Supplemental Filing and specifically addressed in terms of impacts on resource costs in Appendix F and potential new resources in Appendix D.

4.3.1 IRA & Wind Energy Facility Equipment Upgrades

The IRA provides for full production tax credits for repowered wind facilities. Our Langdon, Luverne, Ashtabula, and Ashtabula III wind energy facilities qualify for repowering. Repowering of these facilities will lead to increased energy output of 167 GWh which is approximately equivalent to the energy output of a 40 MW wind facility with a 50 percent capacity factor. Table 4-4 below provides the expected annual energy increase at the four facilities.

Table 4-4: Wind Energy Facility Equipment Upgrade

Line No.	Wind Energy Facility	Name Plate (MW)	Current NCF	Repower NCF	Current GWh	Repower GWh	Increase GWh
1	Ashtabula	48.0	40%	50%	168	210	42
2	Langdon	40.5	40%	50%	142	178	36
3	Luverne	49.5	42%	50%	182	217	35
4	Ashtabula III	62.4	40%	50%	219	274	55
	Total				**711**	**878**	**167**

[20] *Identification of Sufficient System Reliability Attributes*, Resource Adequacy Subcommittee, January 18, 2023.

Development and siting work continues on these projects that are expected to be in service in 2024 and 2025. These projects are projected to cost **[PROTECTED DATA BEGINS**… **…PROTECTED DATA ENDS]** and generate more than $230 million in production tax credits.

4.4 Minnesota Clean Energy Law

On February 6, 2023, Minnesota Governor Tim Walz signed into law the 100 percent Clean Energy Law (Minnesota Clean Energy Law.) The law requires a transition to 100 percent carbon-free energy for all Minnesota electric customers by 2040.

Minn. Stat. §216B.1691 Subd. 2g (as amended by the Clean Energy Law) reads:

> *Subd. 2g.* ***Carbon-free standard.*** *In addition to the requirements under subdivisions 2a and 2f, each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:*
>
> | | | |
> |---|---|---|
> | *(1)* | *2030* | *80 percent for public utilities; 60 percent for other electric utilities* |
> | *(2)* | *2035* | *90 percent for all electric utilities* |
> | *(3)* | *2040* | *100 percent for all electric utilities.* |

Minn. Stat. §216B.1691, Subd. 4 (as amended by the Minnesota Clean Energy Law) explains that renewable energy credits may be utilized to comply with the carbon-free requirements:

> *. . . (b) In lieu of generating or procuring energy directly to satisfy a standard obligation under subdivision 2a, 2f, or 2g, an electric utility may utilize renewable energy credits allowed under the program to satisfy the standard.*

Otter Tail is uniquely (and well) positioned to comply with the Minnesota Clean Energy Law's 100 percent carbon-free obligation. Compliance can be achieved if the energy delivered to Minnesota customers is accompanied by a corresponding quantity of RECs

that can be retired on their behalf.[21]

We have significant renewable generation already in our fleet relative to the quantity of energy we deliver to our Minnesota customers. Right now, with our current generation fleet, we have enough renewable generation to cover approximately 54 percent of our energy sales to Minnesota customers, which will increase to 57 percent when our Hoot Lake Solar project (now under construction) comes on-line later in 2023. Our Supplemental Preferred Plan builds on this foundation, adding significant renewable generation before 2030.

We forecast that our owned and contracted renewable generation will allow us to comply with this legislation. Table 4-5 and Table 4-6 provide a summary of how we will satisfy the Clean Energy Law's standards in the prescribed timeframe. Table 4-5 assume for analysis that we withdraw from Coyote Station by 2030. Table 4-6 assumes for analysis that we remain in Coyote Station for the balance of its remaining life.

Table 4-5: Minnesota Clean Energy Law Compliance Breakdown (Withdrawal from Coyote pre-2030)

MN REC Forecast	Current No Hoot Lake Solar (HLS) No Wind Repower	2023 w/HLS	2025 w/HLS & Repowers	2030 Preferred Plan*	2035 Preferred Plan*	2040 Preferred Plan*
MN covered by MN RECs	25%	28%	31%	54%	69%	69%
MN covered by MN/ND RECs	50%	53%	59%	106%	137%	137%
MN covered by MN/ND/SD RECs	54%	57%	65%	116%	151%	151%

[21] Otter Tail's 2023 forecasted Minnesota sales are about 2,700 GWh. The Minnesota Clean Energy Law effectively requires retirement of renewable energy credits (REC) for each kWh sold to Otter Tail's Minnesota customers. The new law does mandate any specific disposition of existing fossil fuel generation plants. Importantly the new law does not alter a utility's obligation to reliably deliver electricity to Minnesota customers, and it does not alter the several factors under which integrated resource plans are to be evaluated. The factors of reliability and flexibility are of utmost importance, especially considering the ambition of the new law, the success (or failure) of which will largely depend on whether utilities, the MPUC and other stakeholders are able to achieve compliance without disruptions to reliability.

Table 4-6: Minnesota Clean Energy Law Compliance Breakdown (Coyote 2040)

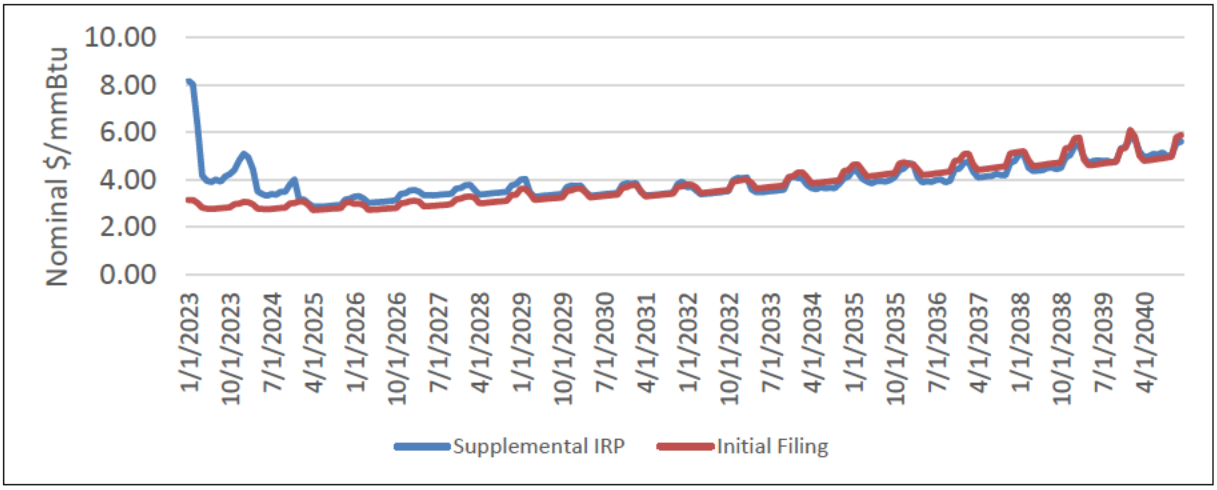
MN REC Forecast	Current No Hoot Lake Solar (HLS) No Wind Repower	2023 w/HLS	2025 w/HLS & Repowers	2030 Preferred Plan	2035 Preferred Plan	2040 Preferred Plan
MN covered by MN RECs	25%	28%	31%	51%	55%	55%
MN covered by MN/ND RECs	50%	53%	59%	100%	109%	109%
MN covered by MN/ND/SD RECs	54%	57%	65%	110%	120%	120%

4.5 Natural Gas and Energy Market Volatile Conditions

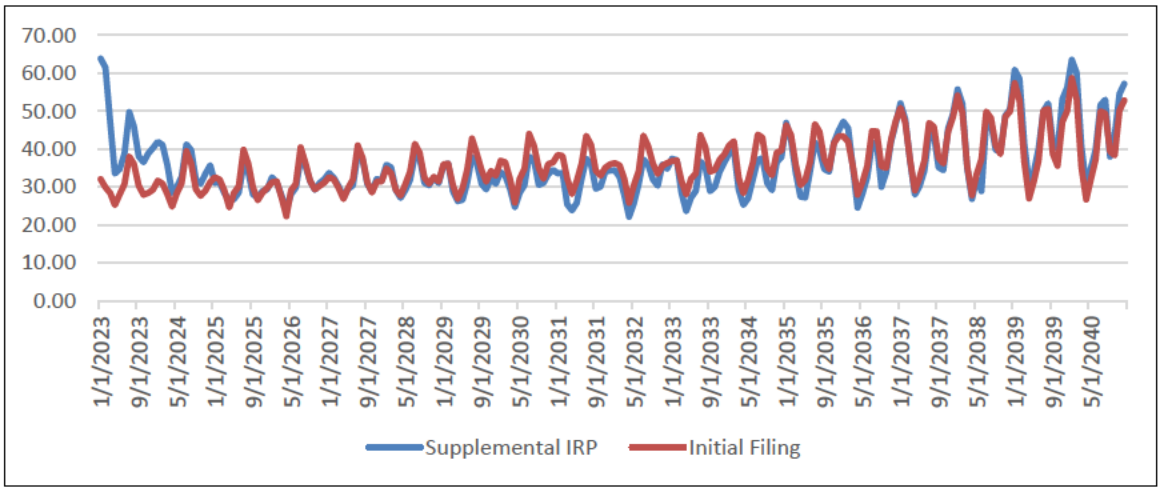
The natural gas transmission lines where the Otter Tail natural gas peakers are located are reliable. Notwithstanding this reliability, the extraordinary pricing variability during Winter Storm Uri in 2021 compelled us to review the intra-day pricing variability exposure of a natural gas generator without a secondary fuel source backup.

Since our Initial Filing, a combination of factors including extreme weather events and geopolitical instability (such as Ukraine war) have caused volatility in the gas markets, causing gas prices to more than double, on average, in the near term compared to those forecasted in our Initial Filing. Graphs 4-4 – 4-6 show the differences in natural gas and energy market pricing used in our Initial Filing compared to our Supplemental Filing.

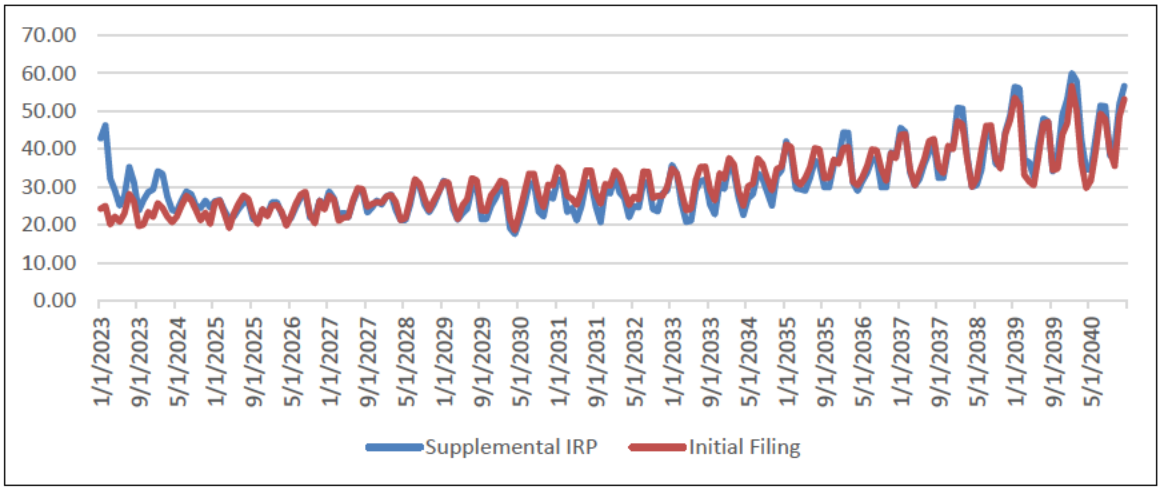
Graph 4-4 Natural Gas Forecast, Initial Filing vs Supplemental



Graph 4-5 Peak Energy Forecast, Initial Filing vs Supplemental



Graph 4-6 Off-Peak Energy Forecast, Initial Filing vs Supplemental



In addition to these events we recently experienced Winter Storm Elliot in December 2022.[22] This event was marked by significant volatility in natural gas markets including a period of time in which natural gas was not available at any price because of increased demand and production facility freeze offs.[23] It is noteworthy that two extreme weather events causing market disruptions and volatility (Winter Storms Uri and Elliot) occurred within a 22-month period. This is consistent with The North American Electric

[22] Winter Storm Elliot Winter was deemed a bomb cyclone, bringing extreme cold temperatures to the eastern two-thirds of the Lower 48, with blizzard conditions occurring in several states. See https://www.wunderground.com/article/storms/winter/news/2022-12-23-winter-storm-elliott-bomb-cyclone-midwest-northeast-winds-snow.

[23] Otter Tail's experience with Winter Storm Elliot is detailed in the Company's February 1, 2023 Reply Comments concerning onsite fuel storage at Astoria Station in MPUC Docket No. E017/RP-21-339 and in our February 8, 2023 Application to the ND PSC for an advance determination of prudence in Case No. PU-23-066.

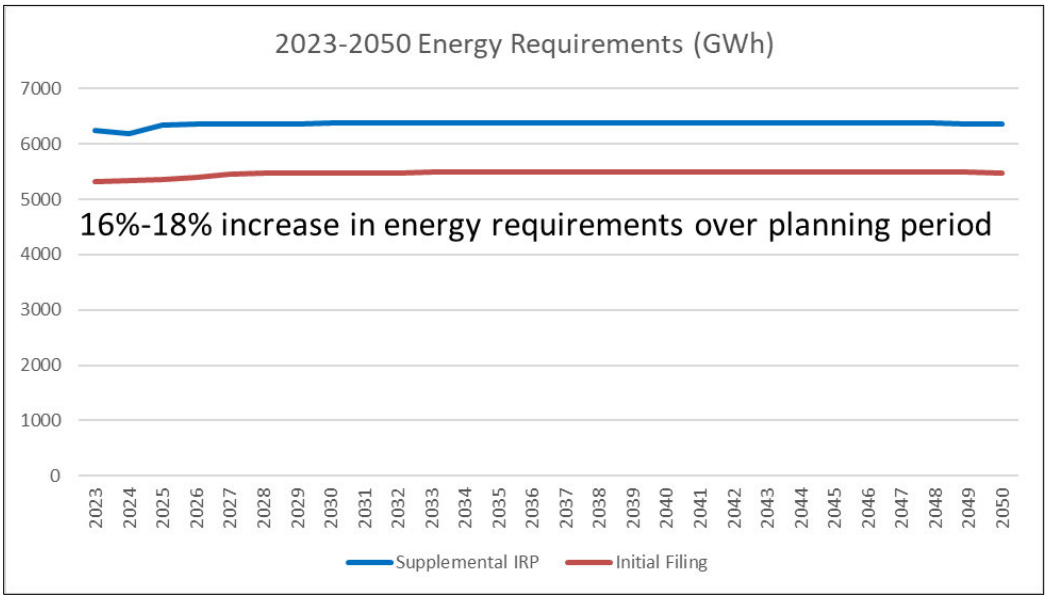
Reliability Corporation's (NERC) 2022-2023 Winter Reliability Assessment, which highlights the increased risks of extreme events.[24]

Given this history, we applied greater scrutiny to the sensitivities regarding natural gas and energy markets in developing our Supplemental Preferred Plan. Although we have the most confidence in our base case scenario, the adjusted natural gas and energy market sensitivities inform our Supplemental Preferred Plan.

4.6 Load Forecast – New Large Loads

As detailed in Otter Tail's August 2, 2021, Prefiling, the Initial Filing sales and demand forecasts were completed in early 2021 using actual sales data through December 2020. Since then, we have added new large load customers with the addition of other large load customers expected within the next 24 months. These new large loads are included in the sales and demand forecast inputs to our EnCompass expansion capacity modeling and were considered in developing the Supplemental Preferred Plan. From an energy perspective, the impact of new customers on the sales forecast is a 16 percent to 18 percent increase in energy requirements over the planning period as compared to the Initial Filing. This increase to forecasted energy sales is depicted in Figure 4-4 below.

Figure 4-4: Sales Forecast Comparison



[24] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

As noted above, the new loads and expected new loads are in some respects atypical for Otter Tail, both in size and the nature of the loads. While unusual, we are seeing increased interest from customers for such loads.

4.7 Plan Development

The software model we use for resource plan modeling is EnCompass, which replaced the Strategist model used for our 2016 Plan.[25] Otter Tail's long-range peak demand and energy forecasts were incorporated into the EnCompass database, along with the supply-side and demand-side resources available to the Company over the course of the study period. EnCompass was then used to develop a series of least-cost resource plans. We defined the objective function as minimizing total utility costs (i.e., a zero-externality scenario) and, for Minnesota, minimizing total societal costs (i.e., an externality value scenario).

The EnCompass software develops an optimized resource plan for each scenario for the time period 2022 through 2036. Scenarios were developed, including evaluation of sensitivities that varied load growth, altered natural gas and energy market prices, adjusted MISO accreditation percentages, and applied externalities.[26]

4.8 New Resource Alternatives

Otter Tail considers both demand-side and supply-side resources in long-term planning analysis. Appendix D to this filing provides a more detailed discussion of the new resources we evaluated. Table 4-7 provides a list of the alternatives evaluated within the EnCompass model:

[25] Otter Tail first used the EnCompass software in previous Minnesota proceedings that were approved by the MPUC including its forecasted 2021 Energy Adjustment Rider rates in Docket No. E017/AA-20-462.

[26] The externality values reflected in our Supplemental Filing are the most recent figures available from the MPUC. These values were established pursuant Minn. Stat. § 216H.06 in the MPUC's September 30, 2020 Order in Dockets E-999/CI-07-1199 and E-999/DI-19-406. These values may change in the future; the Minnesota Clean Energy Law directs the Commission "to provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, released in September 2022, including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate. The commission shall adopt the estimates contained in the final version of the external review draft report when it becomes available."

Table 4-7: List of Resource Alternatives Included in the EnCompass Model

Resource Alternative Model	Description
49 MW Firm Dispatchable Unit	Generic 49 MW nameplate capacity, closely resemble aeroderivative type simple cycle
248 MW Firm Dispatchable Unit	Generic 248 MW nameplate capacity, closely resemble CT within model
Wind	50 MW nameplate capacity utility scale wind resource. Generic, surplus and replacement options all available to the model.
Solar	25 MW nameplate capacity utility-scale solar resource. Generic, surplus and replacement options all available to the model
Standalone Battery	25 MW nameplate capacity utility-scale battery resource. Generic, surplus, and replacement options all available to the model.

4.8.1 Cost Assumptions

Otter Tail used a blend of the 2022 National Renewable Energy Laboratory Annual Technology Baseline and Level 10 cost data as the main source for new resource cost assumptions. Adjustments were made to account for investment and production tax credits, interconnection costs, and congestion when appropriate. Detailed resource costs can be found in Appendix D.

4.8.2 Interconnection queue status and costs

Due to the large number 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. Surplus interconnection and replacement interconnection 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.

4.8.3 Long-range transmission plan impacts

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. The inclusion of long-range transmission plan (LRTP) projects in the MISO interconnection study process will likely impact the total number of requests in the queue and real-time congestion experienced by existing generators, but the total impact is unknown. For this reason, the LRTP projects did not impact our modeling assumptions. Our Supplemental Preferred Plan, however, accounts for LRTP projects by deferring some wind projects until LTRP projects are complete.

5 Additional Factors Considered in Our Supplemental Filing Analysis

5.1 Multi-State Jurisdictional Complexity

As we indicated in our Initial Filing, Otter Tail faces unique challenges given its small size and multi-jurisdictional service area. Otter Tail is very small, serving just 137,000 customers in its three states. The percentage of Otter Tail's utility service delivered to each state varies depending on whether demand, energy or the number of customers is measured. Overall our service is approximately 50 percent Minnesota, 40 percent North Dakota and 10 percent South Dakota. Supplemental Table 5-1 (updated from our Initial Filing) provides approximate 2022 figures for of demand, energy, and customer count in each state.

Supplemental Table 5-1: Percentage of Otter Tail operations in each of its three states

	Minnesota	North Dakota	South Dakota
Demand	51%	39%	10%
Energy	50%	41%	9%
Customer count	47%	44%	9%

In all three states Otter Tail serves very small rural towns—the average population of our communities in the three-state region is approximately 400 people. Continuing to operate as a single, cost-effective multi-state utility is important for our customers and these small communities. Otter Tail is already one of the smallest vertically integrated utilities in the country. To give some perspective, Xcel Energy's NSP Minnesota subsidiary, through which Xcel serves Minnesota, North Dakota, and South Dakota, is approximately 10 times the size of Otter Tail. Because of this already very small size,

splitting Otter Tail into separate and even smaller utility systems would result in harmful inefficiencies and an increased cost of service.

The Supplemental Preferred Plan presented in this filing meets resource planning objectives in each of our jurisdictions, and we feel it can be supported in all the states we serve, and it has the additional benefit of providing a path for Otter Tail to continue operating with a single integrated system.

5.2 Multiple ISOs (SPP & MISO)

As noted in our Initial Filing Otter Tail faces challenges stemming from the fact that Big Stone Plant and Coyote Station are both co-owned and they each operate in two Independent System Operators (ISOs): Southwest Power Pool and MISO. The challenges we face with respect to these issues remains the same as detailed in our Initial Filing. The following is a brief recap of each co-owned facility as referenced in our Initial Filing:

Coyote Station

Coyote Station is 427 MW lignite-mine mouth facility located near Beulah, North Dakota that is co-owned by Otter Tail (35 percent), Northern Minnesota Municipal Power Agency (represented by Minnkota Power Cooperative) (30 percent), Montana-Dakota Utilities Co. (MDU) (25 percent), and Northwestern Energy (10 percent). Coyote Station commenced service in 1981 and it had a depreciable life that assumed retirement in 2016.[27] The depreciable life was extended at various times during the life of the plant, the last time being in 2013, when the depreciable life was extended by nine years, from 2032 to 2041.[28]

Otter Tail, Minnkota, and MDU operate within the MISO market; Northwestern Energy operates within the SPP market. The SPP and MISO markets do not have mechanisms for inter-ISO coordination of commitment status of jointly owned units that partially operate in each ISO. Furthermore, both markets model partial shares of jointly owned units as individual, separate, and distinct generators. If each partner share of the unit were to be offered on an economic commitment basis, in many hours only a portion of the entire unit would be dispatched. From a practical standpoint, however, since the plant is one physical generator, dispatch of a single owner's share of the plant will result in the dispatch of all

[27] *See* MPUC MN Docket E017/D-83-2.
[28] *In the Matter of Otter Tail Power Company's Request for Approval of its Five Year Depreciation Study*, MPUC Docket No. E017/D-13-795, Order (Apr. 7, 2014).

owners' shares of the plant. Furthermore, from a co-owner contractual standpoint, if one owner calls on its share of the plant, all owners are required to take their share of the total minimum output.

Big Stone Plant

Big Stone is co-owned by Otter Tail (53.9 percent), Montana Dakota Utilities Co. (22.7 percent), and Northwestern Energy (23.4 percent). Big Stone Plant, located near Milbank, South Dakota, is a 475 MW coal plant burning sub-bituminous coal from the Powder River Basin. It was retrofitted with an Air Quality Control System (AQCS) in 2015. The AQCS is comprised of state-of-the-art controls for SO2, NOx, and mercury. Big Stone has similar market operating complexities as Coyote. Big Stone straddles both the MISO and SPP wholesale energy markets and can be dispatched by either ISO. Big Stone contractual obligations require partners to take their minimum share of the plant whenever another owner calls for dispatch.

Both Big Stone and Coyote Station are currently capable of being placed on economic commitment. The Big Stone and Coyote co-owners meet periodically to determine if Big Stone or Coyote should be placed into economic commitment or must-run status based on market conditions. Our intention is to continue to evaluate the market conditions and forecasts to evaluate the economic commitment (or not) in the future. The EnCompass sensitivities included in this IRP generally have the Big Stone capacity factor from around 20 percent to 60 percent depending on the sensitivity. This range is far below the 85-90 percent capacity factor of traditional baseload coal plants.

There are several differences between Coyote Station and Big Stone Plant. Big Stone is a delivered fuel plant where we only pay for coal that we take—as contrasted with Coyote where we have a fixed component in the fuel cost. Big Stone's AQCS, with capital intensive state-of-the-art SO2 and NOx controls, is already in place. While the Company would have sufficient capacity resources after withdrawal from Coyote Station, replacing Otter Tail's interest in Big Stone would require the addition of another large dispatchable resource (likely a gas Combustion Turbine). Also, Big Stone has recently been operated more frequently on economic dispatch, which reduces the hours it operates in a market below its production costs.

5.3 Coyote Station – Price Stability & Cost Effectiveness

In addition to being a resilient resource Coyote Station has provided Otter Tail customers with price stability and a cost-effective hedge against market volatility. These features of Coyote Station should not be undervalued in the current planning environment where uncertainty is prevalent. Various stakeholders have in other dockets argued that Coyote Station is not cost effective based on a production cost analysis which compares Coyote's production costs against market revenues. As we have noted in other proceedings this production-cost comparison to market-price is useful in assessing the flexibility of a plant, but it is not a measure of cost effectiveness. [29] There are many cost-effective plants that have limited operational flexibility and would show "production cost losses" including most non-dispatchable renewable resources and many base load generators.

The goal of a utility's resource planning is to manage a portfolio of resources in a way that meets cost, risk, and other objectives. If we were to focus on cost alone as a resource planning objective, we would focus on the performance of the portfolio of resources under a variety of circumstances over time. Table 5-2 below reflects the actual cost of energy paid by Otter Tail's customers since 2013. It shows that Otter Tail's customers have benefitted from Otter Tail's consistent and cost-effective portfolio of resources over that period.

[29] See *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesot*a, E-017/GR-20-719, Gerhardson Rebuttal at 16-22; *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities,* Docket No. E999/CI-19-704, Otter Tail Power Company Response Comments, June 15, 2021.

Table 5-2: Net Cost of Energy Paid by Otter Tail Customers since 2013

Calendar Year	Net System Cost of Energy ($/MWh)
2013	23.48
2014	25.15
2015	24.73
2016	23.06
2017	23.78
2018	24.14
2019	23.93
2020	20.30
2021	21.68
2022	25.89[30]

Coyote Station's costs have remained stable over time even as markets have fluctuated. Figure 5-1 provides a year-over-year comparison for Coyote revenues and total costs (fixed and variable) from 2017-2022.

Figure 5-1: Coyote Revenue and Fuel Cost

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

[30] Calculation includes proposed return of Planning Resource Auction revenues from 2022, as proposed in Otter Tail's FCA true-up filing being submitted March 1, 2023, in MPUC Docket No. E017/AA-21-311.

Figure 5-1 shows that Coyote's costs of operations have remained stable over the period and that markets have turned higher following lows in 2020. Figure 5-1 demonstrates that the perceived "net benefit/costs" of Coyote Station have largely been driven by the prices available in the energy markets (which have been highly variable) not by the production costs of the plant (which have been very stable). These characteristics of Coyote Station combined with the risks outlined in this Supplemental Filing inform our views about remaining in Coyote Station until and unless there is a need for a large, non-routine capital investment necessary to comply with regulatory mandates or to keep the plant operational.

5.4 Coyote Station – Withdrawal Process & Key Considerations

Otter Tail is requesting authority to withdraw from its ownership interest in Coyote Station when a large, non-routine capital investment is required. As noted above, this type of capital investment should be distinguished from routine capital investments necessary for the plant to operate safely, reliably, and in compliance with current regulations. In basic terms, a large capital investment that could cause us to withdraw from Coyote Station would differ qualitatively and quantitively from routine capital investments the co-owners have made in Coyote Station in the past and which are projected to be made in the future to operate the plant safely, reliably and in compliance with current law. Each year the Coyote Station co-owners develop a ten-year routine capital plan with contingencies that would serve as a baseline in our analysis. These type of routine capital investments would need to be made even if Coyote Station's operating life were significantly reduced to maintain the plant's safety, reliability, and compliance up to the final day of operations. [31]

We cannot predict when (and if) a capital investment that may compel us to withdraw from Coyote Station will arise. That being said, in this Supplemental Filing and our Initial Filing we have discussed developments in the implementation of the Regional Haze Rule, which has an anticipated compliance deadline of 2028 (year end).

By withdrawal of its ownership interest, the Company means that it is seeking to end its

[31] In Otter Tail's most recent Minnesota rate case we drew distinctions between (a) routine capital investments necessary to maintain safety, reliability, and compliance with current regulations and (b) major, non-routine capital investments, such as may be required to comply with Regional Haze regulations. Those distinctions remain valid. See *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, E-017/GR-20-719, Gerhardson Rebuttal at 13-15.

ownership and role in operating the facility in a manner that is both least-cost to Otter Tail's customers and least-impactful to other plant stakeholders, including the co-owners. As noted in our Initial Filing withdrawing from Coyote Station will be complex.

The process for withdrawal from Coyote Station and key considerations remain largely unchanged from our Initial Filing. As noted in the Initial Filing, to withdraw from our ownership interest in the plant we must either (1) divest its ownership shares in the plant to another co-owner or third-party who will take on Otter Tail's current obligations, and secure releases from those obligations as necessary in favor of the acquiring party; or (2) terminate the co-tenancy in the plant under the ownership agreement and any contractual obligations that survive the termination of that co-tenancy. Neither option is without risk or potential cost to Otter Tail and its customers. In addition to these options there is the possibility of the co-owners mutually agreeing to terminate the Plant Ownership Agreement and provide for an orderly wind-down of plant operations and disposition of plant if a large capital investment is required for regulatory compliance or operational purposes.

Should a major, non-routine capital investment in Coyote Station be necessary, Otter Tail will assess whether a consensus exists among the co-owners to terminate the Plant Ownership Agreement. Absent a consensus, Otter Tail would seek divestment through the sale or transfer of its ownership interest. If there were no qualified buyers for Otter Tail's ownership interest, we could unilaterally initiate termination of the Plant Ownership Agreement upon five years advance notice. The timing and sequencing of our engagement with our co-owners on an exit from Coyote Station would depend on many factors. These discussions are likely to be complex and fluid. Our intent would be to secure an exit from Coyote Station in the least disruptive and most expeditious manner as is reasonably possible.

Otter Tail's termination of the Plant Ownership Agreement would depend on several factors the status of which is subject to future developments. Such unilateral termination could impact the other co-owners, given post closure obligations of the parties to each other, the community, and the state of North Dakota along with the potential that the co-owners may choose to continue to rely on the plant for their own load serving needs. It is important to underscore the irrevocable nature of unilateral termination of the Plant Ownership Agreement. There is no mechanism for a provisional notice of termination

that can later be withdrawn. Once given, notice of termination sets in motion events intended to lead to closure of Coyote Station. These matters are fraught with commercial and political matters beyond Otter Tail's control or ability to unilaterally influence. Without an orderly process for implementing termination of Otter Tail's participation in the plant, there is some potential for disputes amongst the co-owners to arise. Otter Tail is hopeful that a mutually agreeable path can be found, but if it is not, Otter Tail would need sufficient assurances that it could recover any prudently incurred costs of terminating the Plant Ownership Agreement.

As we noted in our Initial Filing, termination of the Plant Ownership Agreement does not cause the automatic termination of the Lignite Sales Agreement (LSA). The LSA and applicable law contain provisions allowing for early termination under certain conditions. If the LSA is terminated early, the agreement provides for the co-owners to buy the membership interests in the mine entity (Coyote Creek Mining Company, L.L.C.) and thereby assume certain of its obligations. Otter Tail projected that in the event of a 2028 buy-out, it would be obligated to pay approximately **$**21.7 million. That figure was used in the Company's modeling, and is a forecast based on current assumptions. That figure remains unchanged in this Supplemental Filing; it was used in the Company's modeling. Any actual buy-out amount would be calculated in the future based on the actual termination date of the LSA and would depend on conditions at the time. As with any contractual termination, there is always the potential for disputes.[32] These costs would need to be recoverable should Otter Tail move forward with a withdrawal.

Cost Impacts of Withdrawal from Coyote Station

The economic analysis that we developed in our Initial Filing provided a conservative estimate of the reasonably foreseeable costs of withdrawing from Coyote Station at the end of 2028 of $68.5 million. That figure remains largely the same, estimated as follows:

[32] As is the case in any situation involving the early termination of a contract there is a risk of litigation. Otter Tail has not included the costs of potential litigation in its modeling.

Supplemental Table 5-3: Coyote Station Estimated Foreseeable Withdrawal Costs

OTP Share	**Forecast (in millions)**	
Coyote Station [33]	**YE 2040**	**YE 2028**
Book Value (non-land accts 311-316)	(13.4)	$33.4
2041 Decommissioning/Salvage*	$13.4	$13.4
LSA Early Termination Costs	$0	$21.7
Total For Withdrawal	**$0.0**	**$68.5**
*This is the Coyote End of Life book value collected and accumulated in our current depreciation rates for the decommissioning of the plant. Note: Does not include any: (1) ancillary costs of withdrawal such as loss of plant-related transmission rights or other operational matters; (2) any potential costs of disputes; (3) any unforeseen liabilities.		
Project Book Balances in 2023: March 31, 2023: $58.31M YE 2023: $55.21M		

The $68.5 million figure does not consider: (1) ancillary impacts to Otter Tail's costs due to withdrawal; (2) any costs related to disputes between the co-owners and Otter Tail or between North American Coal or Otter Tail; and (3) any unforeseen or retained liabilities other than undepreciated net book value of the plant. If Otter Tail commences the process of withdrawing from Coyote Station, we expect to obtain more clarity on these costs and refine our economic assessment as part of the process of withdrawal. There are two general cost categories to Otter Tail's withdrawal: (1) undepreciated net book value, and (2) early termination costs under the LSA. The undepreciated net book value is based on Coyote Station's remaining depreciable life which currently extends to 2041.[34]

As noted above, Otter Tail's remaining net plant balance of approximately $55 million is being depreciated over the current remaining life of the plant. Any withdrawal from Coyote Station requires consideration of how (and when) to recover the undepreciated balance. In addition to the undepreciated plant balance there are LSA early termination costs to consider. As noted in our Initial Filing, Otter Tail proposes that LSA termination costs and the undepreciated plant balance be placed within a regulatory asset account,

[33] The year 2028 is provided for the purpose of analysis. It reflects the anticipated deadline for Reginal Haze Rule compliance.
[34] As noted earlier, the original depreciable life of Coyote Station assumed retirement in 2016. The depreciable life was extended at various times during the life of the plant, the last time being in 2013, when the depreciable life was extended by nine years, from 2032 to 2041.

which can serve as a vehicle for recovery. The cost impact to customers would then depend on the amortization schedule by which these expenses are recovered over time. One option is a schedule that aligns with Coyote Station's current retirement date of 2041. This option would have the least impact on ratepayers and would be the Company's preferred option. A similar mechanism was used by the MPUC for the abandonment of Xcel Energy's Prairie Island nuclear facility EPU project. The second option would be to accelerate recovery of the regulatory asset account balance to match the early exit date, which would have greater customer impacts. Additional options would fall on a date between these bookends. The paramount issue is that our Commissions authorize recovery, including a return on the undepreciated regulatory asset.

Other Factors that Could Impact Withdrawal

In addition to the contractual issues discussed above, there are additional factors that could influence the ultimate process and form of any withdrawal from Coyote Station. These variables are dynamic and difficult to predict, especially in combination and we cannot rule out the possibility that some combination of factors, including developments that are not currently contemplated, could produce different results in the future. As we noted in our Initial Filing, regulatory approvals will be a precondition to Otter Tail's withdrawal from Coyote Station. Additionally, the ancillary impacts of withdrawal on Otter Tail's transmission rights will need to be further studied.[35]

Regulatory Approvals

Otter Tail's plan to withdraw from Coyote Station should a large capital investment become necessary is premised and conditioned on the support of the Company's regulators, particularly the state commissions regulating Otter Tail's rates. Regardless of whether a formal framework for review and approval of an IRP exists, it is essential that the Commissions in Minnesota, North Dakota, and South Dakota each support withdrawal and allow Otter Tail to recover the resulting costs in rates. Each state has a different regulatory construct and Otter Tail will work to obtain appropriate guidance from each Commission at the appropriate time.

Environmental Compliance

In 1999, the U.S. Environmental Protection Agency (EPA) published regulations

[35] Upon withdrawal, Otter Tail may need to have alternative transmission arrangements in place, the cost of which are difficult to predict. Our resource planning model does not account for these costs.

implementing Section 169A of the Clean Air Act (CCA) establishing the Regional Haze Rule as the comprehensive visibility protection program for Federal Class I areas.[36] States are required to submit Regional Haze Rule state implementation plans (SIPs) that evaluate reasonable progress in approximately 10-year increments. The first Regional Haze planning period covered the years 2008-2018, while the second planning period covers the timeframe ending in 2028. The EPA has designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address visibility. North Dakota is a member of the Western Regional Air Partnership, which serves as the RPO in 15 western states.[37]

The North Dakota Department of Environmental Quality (North Dakota DEQ) submitted a proposed Regional Haze SIP to EPA on August 10, 2022. Within the SIP, the North Dakota DEQ determined that additional emissions reductions measures are not reasonable to apply at Coyote Station for the second planning period. On August 23, 2022, EPA determined that North Dakota's SIP revision was complete; however, this completeness determination does not constitute a finding on the merits of the submission.

The base assumption in Otter Tail's IRP modeling analysis reflects the fact that North Dakota DEQ does not propose a SIP requiring additional controls on Coyote Station. However, Otter Tail recognizes there is a risk that the EPA may not accept that approach;[38] therefore, Otter Tail also included sensitivities in its modeling for the possibility that the Coyote Station owners will be required to make significant upgrades. If significant upgrades are required, the work of making those upgrades will likely need to begin well before 2028 so that they can be operational by the time of the anticipated compliance deadline of December 2028.

[36] These areas include national parks, memorial parks, and wilderness areas over a certain size. The Regional Haze Rule did not mandate specific milestones or rates of progress, but instead called for states to establish goals that provide for reasonable progress towards achieving natural visibility conditions by the year 2064.
[37] Minnesota is a member of the Central Regional Air Planning Association.
[38] In May 2022 public comments on the North Dakota SIP the EPA stated that North Dakota should reassess the determination that additional controls are not necessary. Otter Tail is not quantifying the risk the EPA will not accept North Dakota's approach, nor is it taking a position in this filing as to what action the EPA should or should not take.

Otter Tail Capacity Needs
The future is uncertain and changes to Otter Tail's capacity needs could require adjustments to its Supplemental Preferred Plan. Otter Tail will continue to monitor its needs to ensure it has sufficient generation to meet its obligation of reliable service to its customers.

Operational Matters
As we noted in our Initial Filing if Coyote Station is closed, there are other potential uses for the site. Solar or natural gas generation (two natural gas pipelines are in the vicinity) are two possibilities given the existing transmission interconnection. However, while Otter Tail is open to the concept, there is no agreement among the Coyote Station owners regarding re-use of the site, and such consensus would be necessary for any such development. In addition, state and local preferences and policies would need to be considered. Accordingly, our Supplemental Preferred Plan does not incorporate any predictions or assumptions regarding re-development, and the Company is simply noting the possibility here as it may be relevant to stakeholders and Commissions.

Mitigation of Impacts on the Community
The Company understands the importance of Coyote Station and the adjacent mine to the local community. If there is a withdrawal, we will endeavor to mitigate its impacts. We anticipate that any plans for mitigation will be determined through consultation with community members and elected officials. Included in these impacts will be Otter Tail's need to appropriately transition our workforce currently operating the plant. The transition will depend on the path for withdrawal that would ultimately be chosen. Consequently, we are not able to present any concrete plans in this regard currently.

5.5 Astoria Onsite Fuel Inventory

As noted above in Section 2 "Procedural Background" that portion of our Initial Filing addressing onsite fuel inventory at Astoria Station is more fully addressed in filings made apart from this Supplemental Filing. In Minnesota, Astoria Station onsite fuel storage has been addressed in the current IRP docket with a comment period separate from this Supplemental Filing.[39] In North Dakota, Otter Tail has applied for an Advance

[39] We explained the basis for this bifurcation in an October 4, MPUC 2023 letter filing stating that "[w]e believe it is appropriate to address dual fuel at Astoria Station without delay to strengthen the resilience and availability of the unit during extreme conditions. We believe this is necessary to protect our customers from extreme events and related market volatility. Our preferred plan anticipates 2026 commercial

Determination of Prudence from the ND PSC for an onsite fuel inventory system at Astoria Station. As noted in those filings Astoria Station was constructed to replace the capacity and dispatchable attributes of Otter Tail's Hoot Lake coal-fired generating plant, retired in 2021. Astoria Station functions very well to replace the capacity lost at Hoot Lake, but its dependency on just-in-time delivered fuel limits its ability to serve as a dispatchable hedge against energy market disruptions. Adding the capability for onsite fuel inventory at Astoria Station will provide an important dispatchable-market-hedge attribute that was lost when Hoot Lake was retired.

6 Conclusion

6.1 Supplemental Preferred Plan is in the Public Interest

The Company remains committed to operating its generation facilities as efficiently as practicable while minimizing adverse effects on the environment. The new resources identified in our Supplemental Preferred Plan will meet the Company's needs while maintaining flexibility and limiting the risk of exposure to changes in financial, social and technological factors beyond its control. The Supplemental Preferred Plan maintains flexibility during a period of much uncertainty.

The Supplemental Preferred Plan maintains and enhances system resiliency and corresponding reliability, the importance of which has been demonstrated by events such as the recent Winter Storm Uri and Winter Storm Elliot.

The Supplemental Preferred Plan satisfies the legal and regulatory requirements in the multi-state service territory and allows Otter Tail and its customers to realize the benefits of operating as a single system while recognizing the differing state requirements. The Supplemental Preferred Plan, which includes (a) average annual energy savings of 1.86 percent, (b) 100 MW of surplus interconnection solar in 2027 and 2028, (c) 200 MW of surplus interconnection wind in 2029 time frame, and (d) the authority to withdrawal from Coyote Station if a large capital investment in the plant becomes necessary, satisfies all rules and requirements of each our state jurisdictions and provides a clear concise report to interested parties of what Otter Tail intends to do to satisfy customer needs in

operation of dual fuel at Astoria Station and we are currently engaged in development activities with that target date in mind. Current supply chain issues and inflationary pressures are sufficiently complex that delays on this particular element of our IRP filing would expose our customers to cost increases and would not be in the public interest."

the near term, and identifies the resources the Company is considering for viable options for the long term.

6.2 Socio-Economic Impacts of the Supplemental Preferred Plan

The Supplemental Preferred Plan is a least cost/least-risk plan that meets all statutory and regulatory requirements while providing reliable and affordable electricity to customers. The Supplemental Preferred Plan provides for resilient generation and protects customers from market volatility. The Supplemental Preferred Plan is a reasonable and prudent approach in an increasingly uncertain planning environment.

The Supplemental Preferred Plan supports economic development in the states we do business by keeping costs low and reliability high for commercial and industrial customers so that those customers can invest in greater productivity and growth. Likewise, Otter Tail keeps costs low and reliability high for the residential consumer, recognizing that electricity is a fundamental input to the overall health, welfare, and productivity of society.

The resource additions in the Supplemental Preferred Plan will create construction jobs. We acknowledge that should we withdrawal from ownership in Coyote Station as outlined in this Supplemental Filing there is potential for adverse socio-economic impacts for employees working at Coyote Station, the adjacent mine, and the community in and around Beulah, North Dakota. As the future of the plant becomes clearer, we anticipate that any plans for mitigation will be determined through consultation with community members and elected officials and labor representatives. Included in these impacts will be Otter Tail's need to appropriately transition our workforce currently operating the plant. The transition will depend on the path for withdrawal that will ultimately be chosen.

The Supplemental Preferred Plan will allow us to continue fostering greater awareness and participation in energy efficiency in the homes and businesses the Company serves, helping to meet future energy needs, and avoiding the addition of more expensive generation alternatives. Under this plan the Company will continue to develop an effective demand-side management portfolio, a successful collaboration among Otter Tail and residential, commercial, and industrial customers. These programs provide customers

with economic rates that allow them to be more productive and invest in the regional economy while providing load shifting or shedding capability in times of emergency.

In summary, in terms of socio-economic impact the Supplemental Preferred Plan provides cost-effective, reliable electricity to all classes of customers, preserves and creates jobs in the utility industry, and reduces emissions, all while being responsive to the varied concerns of our stakeholders. Greater detail regarding impacts of specific projects within the plan will be addressed as those projects are developed.

6.3 Five-Year Action Plan

The Supplemental Preferred Plan will require considerable activity within the next five years to bring about the resources previously approved and those selected in the plan. Table 6-1 identifies some of the more major activities and the approximate timelines for those activities. Some of these activities are already underway. There are many other related activities that will be taking place to support the major items identified in the table that will involve many stakeholders, regulatory agencies, and interested parties.

Table 6-1 -Five Year Action Plan

Year	Activity
2023	Commercial operation of Hoot Lake Solar
2024	Continue to monitor need for large capital investment in Coyote Station and commence withdrawal if such investment becomes necessary
2025	- MISO interconnection process for first 100 MW solar project. Engineering and procurement for Astoria onsite fuel project. - Continue to monitor need for large capital investment in Coyote Station and commence withdrawal if such investment becomes necessary
2026	- Engineering and procurement for first 100 MW solar project. - MISO interconnection process for second 100 MW solar project. - Construction and commercial operation of Astoria onsite fuel project - Continue to monitor need for large capital investment in Coyote Station and commence withdrawal if such investment becomes necessary
2027	- Construction and commercial operation of first 100 MW solar project. - Engineering and procurement for second 100 MW solar project. - MISO interconnection process for 200 MW wind project. - Continue to monitor need for large capital investment in Coyote Station and commence process of withdrawal if such investment becomes necessary
2028	- Construction and commercial operation of second 100 MW solar project. - Engineering and procurement for 200 MW wind project. - Continue to monitor need for large capital investment in Coyote Station and commence process of withdrawal if such investment becomes necessary

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

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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

			A	A.1	B	C	D	E	F	G	H	I	J
	NPVRR Comparison												
	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		$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		$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		-$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		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
4	2024											
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			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		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			25 MW Sur Solar		50 MW Gen Wind		
8	2028							25 MW Sur Solar	25 MW Gen Solar 50 MW Gen Wind			
9	2029	25 MW Sur Battery										
10	2030									50 MW Gen Wind		
11	2031	100 MW Gen Wind	25 MW Sur Battery 50 MW Gen Wind		25 MW Sur Battery					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		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											
14	2034	25 MW Rep Battery									25 MW Rep Battery	
15	2035		50 MW Sur Wind							50 MW Rep Wind		
16	2036				50 MW Rep Wind						50 MW Rep Wind	
17	2037											

	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		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
19	2024											
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		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		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			25 MW Sur Solar		50 MW Gen Wind		
23	2028		25 MW Gen Solar	50 MW Gen Wind				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		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											
26	2031	50 MW Gen Battery 50 MW Gen Wind	50 MW Gen Battery 25 MW Sur Battery				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			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											
29	2034											
30	2035				50 MW Rep Wind					50 MW Rep Wind		
31	2036											
32	2037								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.

Appendix F: EnCompass Modeling Assumptions

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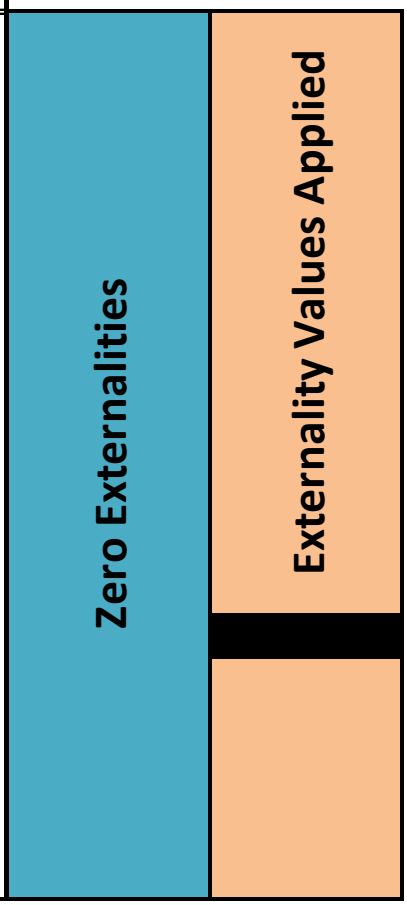
1 Sensitivities Evaluated

Figure 1 shows a grid of sensitivities evaluated in this resource plan. As further described in the petition, for each sensitivity, this filing includes EnCompass modeling runs to provide insight into the impacts of Otter Tail continuing with its interest in Coyote Station through 2040 and 2028. Otter Tail includes all modeling runs with and without externalities in Appendix I.

Figure 1: Sensitivities Evaluated

Sensitivity	Description
A	2023 Base Case
A.1	Preferred Plan
B	NG & Energy Markets +50%
C	NG & Energy Markets +100%
D	NG & Energy Markets -50%
E	Regional Haze Mid Cost
F	Regional Haze Mid Cost NGEM +100%
G	Regional Haze High Cost
H	Regional Haze High Cost NGEM +100%
I	10% Increased Load
J	10% Increased Load NGEM +100%
K	25% Increased Load
L	25% Increased Load NGEM +100%
M	High Renewable Accreditation
N	Low Renewable Accreditation
O	Carbon Tax
P	Renewables High Cost
Q	Renewables High Cost NGEM +100%
R	Solar and Battery Low Cost (40% ITC)
S	Low Accreditation Regional Haze High
T	25% Increased Load Regional Haze High
U	Renewables High Cost Regional Haze High



2 Wind Energy Assumptions

Figure 2 shows the wind energy assumptions used in the resource plan. Otter Tail evaluated wind energy resource alternatives as purchased power agreements (PPA) with a 35-year term and fixed pricing over that term. Wind integration costs are included in the fixed price assumptions.

The wind energy price assumptions through 2032 include the impacts of the August 2022 Inflation Reduction Act which provides for 100 percent production tax credit

(PTC) for projects that meet certain criteria. The wind energy price assumptions after 2032 do not include PTCs.

Wind project sizes are assumed to be 50 MW in size with a 50 percent net capacity factor. Accredited capacity varies by season. Otter Tail models wind projects as purchased power agreements with a fixed levelized cost of energy.

Otter Tail includes three categories for these wind projects: (1) Generic wind resources require a new generation site, (2) Surplus interconnection wind may be added alongside an existing generating facility where the generation of both resources does not exceed the existing interconnection amount of the original facility, and (3) Replacement interconnection wind resources reuse the existing interconnection rights of an existing resource that is retiring. Otter Tail includes Figure 2 below with the wind project alternatives included in the base model.

Figure 2: Base Wind Energy Assumptions

				Base Case $/MWh				
Year available	Wind Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	PTC adjustment	Inconnection adder assuming $500/kW	Congestion adder	Base Case ($/MWh)
2025-2032	Generic - 100% PTC	50	Varies	$36.00	($15.00)	$10.00	$3.50	$34.50
After 2032	Generic	50	Varies	$35.00	$0.00	$10.00	$3.50	$48.50
After 2032	Surplus Interconnection	50	0%	$35.00	$0.00	$0.00	$0.00	$35.00
After 2032	Replacement Interconnection	50	Varies	$35.00	$0.00	$0.00	$0.00	$35.00

Otter Tail does not forecast a low cost sensitivity for wind generation. The Inflation Reduction act provides for additional PTCs for domestic content and energy communities but these are considered on a project by project basis.

3 Solar Energy Assumptions

Otter Tail evaluated solar energy resource alternatives as purchased power agreements (PPA) with a 35-year term and fixed pricing over that term. Solar integration costs are included in the fixed price assumptions.

Similar to wind, the solar energy price assumptions for 2025 through 2032 include the impacts of the Inflation Reduction Act which provides for a 30 percent investment tax credit (ITC) for projects that meet certain criteria. The solar energy price assumptions after 2032 do not include ITCs.

Solar project sizes are assumed to be 25 MW in size with 24 percent net capacity factor and an accredited capacity of 25 percent. Otter Tail includes Figure 3 below with the solar project alternatives included in the base model.

Figure 3: Base Case Solar Energy Assumptions

					Base Case $/MWh				
Year available	ITC	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	ITC adjustment	Inconnection adder assuming $200/kW	Congestion adder	Base Case ($/MWh)
2025-2032	30%	Generic	25	Varies	$40.00	($8 00)	$7.00	$0.00	$39.00
2025-2032	30%	Surplus Interconnection	25	0%	$40.00	($8 00)	$0.00	$0.00	$32.00
2025-2032	30%	Surplus Interconnection w/ Capacity	25	Varies	$40.00	($8 00)	$0.00	$0.00	$32.00
After 2032	0%	Generic	25	Varies	$40.00	$0.00	$7.00	$0.00	$47.00
After 2032	0%	Surplus Interconnection	25	0%	$40.00	$0.00	$0.00	$0.00	$40.00
After 2032	0%	Replacement Interconnection	25	Varies	$40.00	$0.00	$0.00	$0.00	$40.00

Similar to wind, Otter Tail includes three categories for solar projects: (1) Generic solar resources require a new generation site, (2) Surplus interconnection solar may be added alongside an existing generating facility where the generation of both resources does not exceed the existing interconnection amount of the original facility, and (3) Replacement interconnection solar resources reuse the existing interconnection rights of an existing resource that is retiring. Figure 4 provides the assumptions included in the Low Sensitivity solar energy assumptions.

Otter Tail's low solar price is included in the *Solar and Battery Low Cost (40% ITC)* sensitivity in Appendix I.

Figure 4: Low Sensitivity Solar Energy Assumptions

					40% ITC Low Cost Case $/MWh				
Year available	ITC	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	ITC adjustment	Inconnection adder assuming $200/kW	Congestion adder	Base Case ($/MWh)
2025-2032	40%	Generic	25	Varies	$40.00	($11.00)	$7.00	$0.00	$36.00
2025-2032	40%	Surplus Interconnection	25	0%	$40.00	($11.00)	$0.00	$0.00	$29.00
2025-2032	40%	Surplus Interconnection w/ Capacity	25	Varies	$40.00	($11.00)	$0.00	$0.00	$29.00
After 2032	0%	Generic	25	Varies	$40.00	$0.00	$7.00	$0.00	$47.00
After 2032	0%	Surplus Interconnection	25	0%	$40.00	$0.00	$0.00	$0.00	$40.00
After 2032	0%	Replacement Interconnection	25	Varies	$40.00	$0.00	$0.00	$0.00	$40.00

4 Battery Storage Assumptions

Otter Tail evaluated battery storage resource alternatives as purchased power agreements (PPA) with a 30-year term and fixed pricing over that term. Battery storage costs are included in the fixed price assumptions.

The battery storage price assumptions included below are based on Otter Tail's industry knowledge and estimates specific to Otter Tail and include impacts of the Inflation Reduction Act which includes a 30 percent ITC for projects that meet certain criteria. The low price storage costs include a 25 percent reduction from the base assumptions which is the equivalent of an increase in the ITC from 30 percent to 40 percent. The results of this low cost battery sensitivity are included in the *Solar and Battery Low Cost (40% ITC)* sensitivity in Appendix I.

Figure 6: Battery Storage Assumptions

Year available	Battery Storage Alternative	Size (MW)	Accredited capacity (% of Nameplate)	Base Cost Fixed Cost ($/Year)	Low Cost Fixed Costs ($/Year)
2025-2032	25 MW Surplus Battery	25	Varies	$3,000,000	$2,250,000
2025-2032	25 MW Battery	25	Varies	$3,300,000	$2,500,000
After 2032	25 MW Replacement Battery	25	Varies	$3,300,000	$2,500,000
After 2032	25 MW Battery	25	Varies	$4,300,000	$3,200,000

5 Natural Gas Fuel Price Assumptions

Figure 7 shows the forecasted monthly natural gas fuel prices used in the 2021 resource plan. Otter Tail used the Wood Mackenzie July 2022 North American Power Service for determining the natural gas fuel prices used in the resource plan. Otter Tail evaluated natural gas prices at +/- 50 percent of the base case and at +100 percent of the base case. The natural gas price sensitivities are included in Appendix I.

Figure 7: Natural Gas Fuel Price Assumptions

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

6 Coal Price Assumptions

Otter Tail's coal price forecasts for its two coal-fired thermal units are developed using existing coal and freight contracts. For modeling purposes in this resource plan coal fuel prices are broken into two portions: fixed fuel costs and variable fuel costs. The 2022 fixed fuel costs modeled for Big Stone reflect the rail car lease costs of **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** (OTP portion) annually. The 2022 fixed fuel costs modeled for Coyote station are modeled at **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** (OTP portion) annually and represent the non-variable portion of the fuel supply agreement.

The variable cost portion of fuel costs are shown in Figure 8 (Big Stone Plant) and Figure 9 (Coyote Station.)

Figure 8: Big Stone Plant Variable Portion Coal Price Assumptions

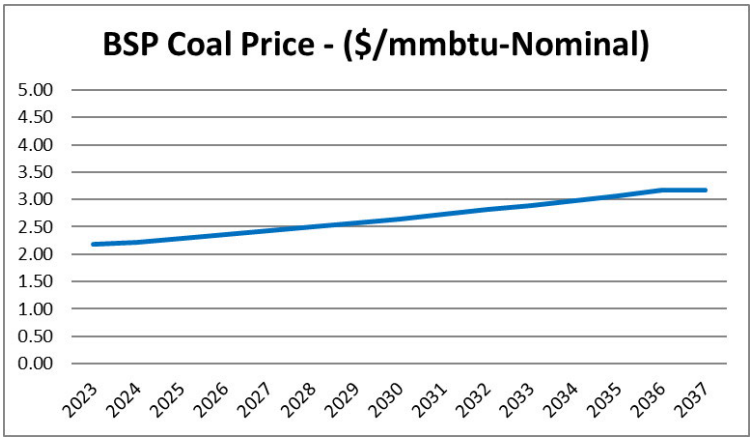
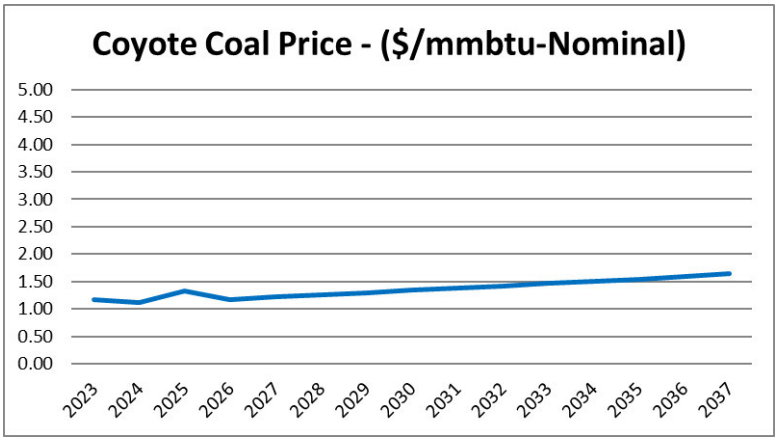


Figure 9: Coyote Station Variable Portion Coal Price Assumptions

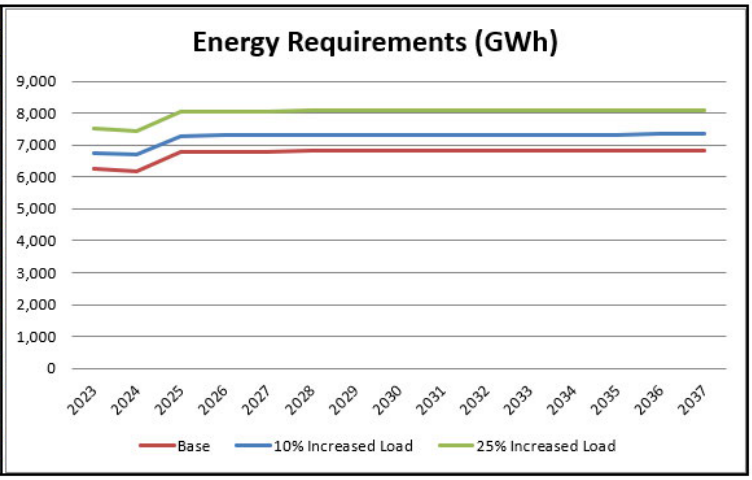


7 Increased Load Assumptions

Figure 10 shows the energy requirement assumptions used in the resource plan. The increased load sensitivities are provided in Appendix I.

Figure 10: Increased Load Assumptions

Year	Base	10% Increased Load	25% Increased Load
2023	6,257	6,764	7,525
2024	6,192	6,693	7,444
2025	6,792	7,293	8,044
2026	6,800	7,302	8,054
2027	6,803	7,305	8,058
2028	6,813	7,315	8,069
2029	6,813	7,316	8,070
2030	6,820	7,323	8,079
2031	6,821	7,325	8,080
2032	6,824	7,327	8,083
2033	6,823	7,327	8,082
2034	6,824	7,328	8,083
2035	6,830	7,334	8,091
2036	6,832	7,336	8,093
2037	6,831	7,335	8,092

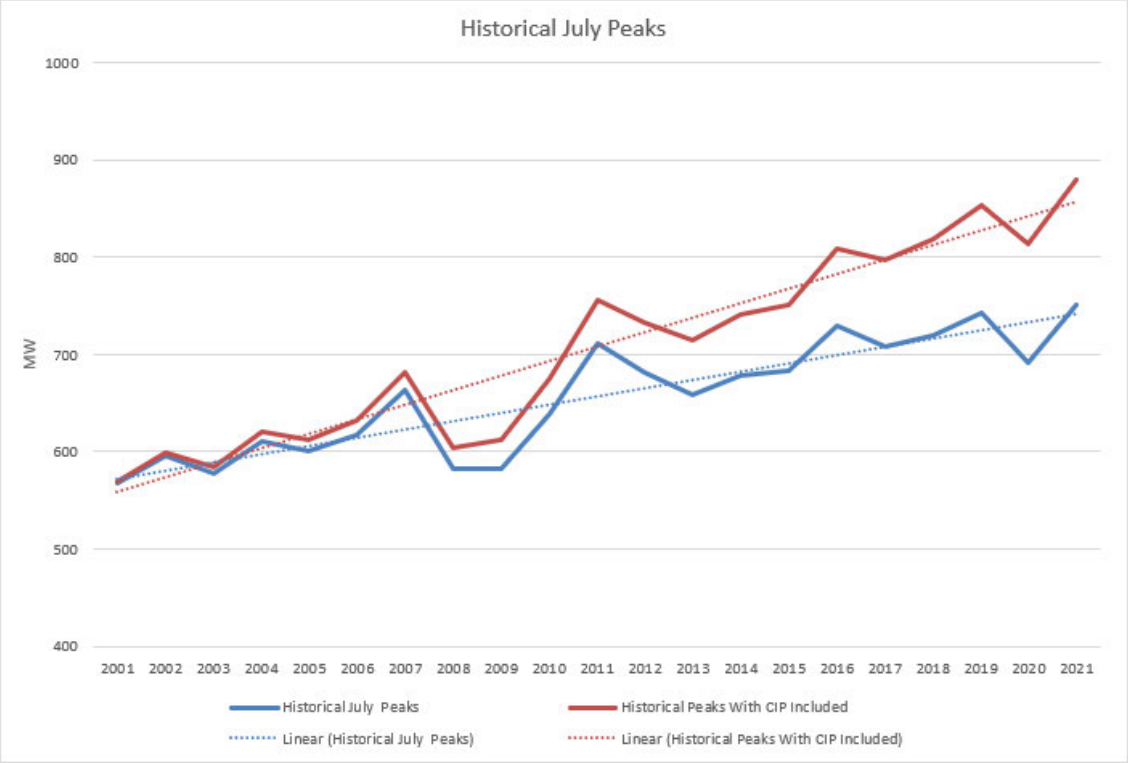


8 Energy Efficiency Assumed in Forecast

Otter Tail has been actively incorporating energy efficiency and Demand Side Management (DSM) programs since 1992. As time goes on and energy efficiency programs grow, a portion of future energy efficiency is included in the energy and demand forecasts. This conclusion was reached based on the fact that our historical load growth has been incrementally lowered by the existing energy efficiency programs which will translate to a lower future load growth through the forecasting process. In other words, the forecast assumes additional new energy efficiency to maintain the reduced load growth rates caused by the historical energy efficiency programs.

Figure 11 shows the historical DSM for 2001 through 2021 where the solid blue line provides the actual historical July peaks, and the solid orange line provides the historical July peak had Otter Tail not had any demand reductions. The dotted blue line provides the actual historical slope of 8.51 compared to the orange dotted line slope of 14.94 if Otter Tail had not had any demand reductions.

Figure 11: DSM Assumptions



The values for each year are listed in Figure 12, along with the three other seasons' data that were analyzed for the resource plan.

Figure 12: Built-In DSM/EE

12-Year Cumulative Total				Summer		Fall		Winter		Spring	
Summer	Fall	Winter	Spring	Historical July Peaks	Historical Peaks With CIP Included	Historical November Peaks	Historical Peaks With CIP Included	Historical January Peaks	Historical Peaks With CIP Included	Historical March Peaks	Historical Peaks With CIP Included
2.0	2.0	1.9	2.0	567	569.0	594	596.0	618	619.9	569	571.0
3.7	7.4	11.0	14.7	596	599.7	594	601.4	635	646.0	621	635.7
6.5	12.9	19.1	25.6	578	584.5	610	622.9	668	687.1	666	691.6
9.8	19.7	29.1	39.0	610	619.8	610	629.7	686	715.1	616	655.0
12.4	24.7	36.5	48.9	600	612.4	644	668.7	656	692.5	606	654.9
15.3	30.6	45.2	60.6	617	632.3	669	699.6	652	697.2	617	677.6
18.2	36.5	53.9	72.2	663	681.2	676	712.5	697	750.9	647	719.2
22.2	44.4	65.6	87.9	582	604.2	692	736.4	688	753.6	677	764.9
30.2	60.5	89.4	119.8	582	612.2	640	700.5	800	889.4	752	871.8
36.5	73.0	108.0	144.6	638	674.5	729	802.0	817	925.0	698	842.6
43.2	86.4	127.7	171.0	712	755.2	668	754.4	811	938.7	768	939.0
50.5	101.0	149.3	199.9	682	732.5	708	809.0	824	973.3	665	864.9
56.1	56.1	53.7	56.3	659	715.1	752	808.1	797	850.7	739	795.3
62.1	62.2	59.5	62.3	679	741.1	783	845.2	874	933.5	834	896.3
68.4	68.5	65.5	68.7	683	751.4	733	801.5	897	962.5	805	873.7
79.0	79.1	75.6	79.3	730	809.0	723	802.1	876	951.6	765	844.3
88.7	88.8	84.9	89.0	708	796.7	800	888.8	894	978.9	832	921.0
99.5	99.6	95.2	99.8	719	818.5	834	933.6	912	1007.2	763	862.8
111.7	111.8	106.9	112.1	742	853.7	795	906.8	924	1030.9	819	931.1
121.9	122.0	116.6	122.3	691	812.9	714	836.0	845	961.6	759	881.3
128.6	128.7	123.1	129.1	751	879.6	767	895.7	830	953.1	780	909.1
			SLOPE	8.51	14.95	10.09	15.90	15.00	19.89	11.36	15.94

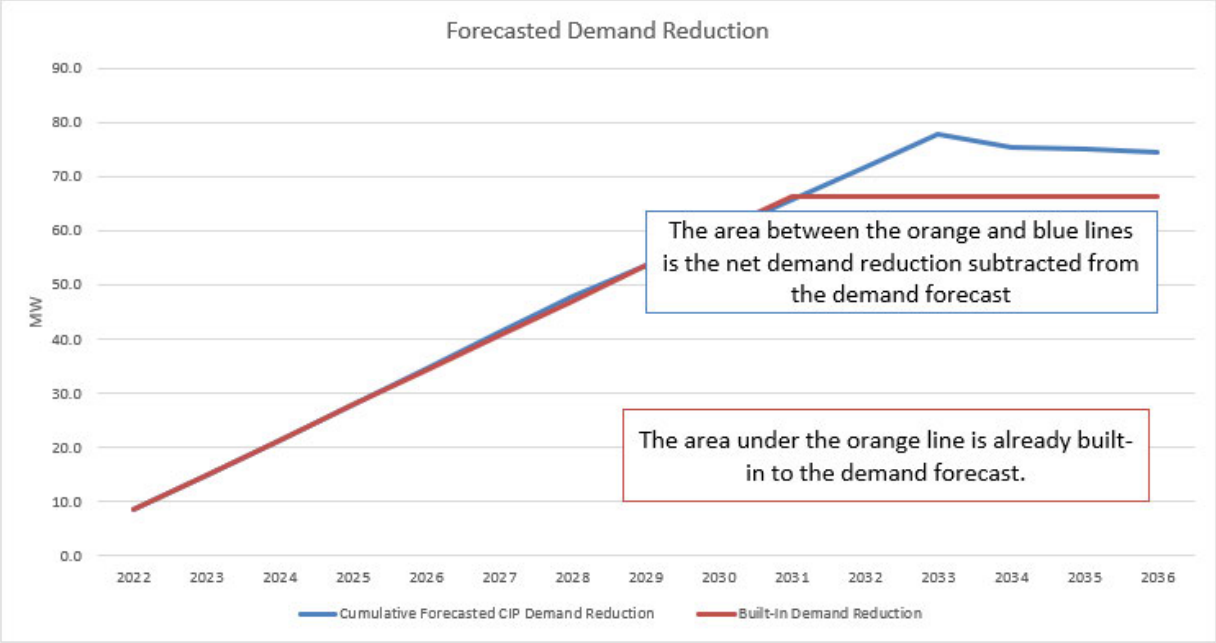
Otter Tail forecasts expected demand reductions for the resource planning period. Figure 13 below provides those forecasted demand reductions and utilizes the historical data provided above to determine the amount of those forecasted demand reductions already built-in to the forecast. This amount assumed to already be part of the forecast is removed from the annual forecasted demand reduction to arrive at the Net Demand Reduction that Otter Tail includes in the forecast for CIP demand reduction. This was completed on a seasonal basis

Figure 13: Net CIP Demand Reduction to Forecast

Cumulative Forecasted CIP Demand Reduction				Built-In Demand Reduction				Net CIP Demand Reduction			
Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	**Summer**	**Fall**	**Winter**	**Spring**
8.3	8.2	8.3	8.3	8.3	8.2	8.3	8.3	**0.0**	**0.0**	**0.0**	**0.0**
14.7	14.6	14.7	14.6	14.8	14.1	13.2	12.8	**-0.1**	**0.5**	**1.5**	**1.7**
21.1	20.9	21.0	20.9	21.2	19.9	18.1	17.4	**-0.1**	**1.0**	**2.9**	**3.5**
27.8	27.5	27.7	27.6	27.7	25.7	23.0	22.0	**0.1**	**1.8**	**4.7**	**5.6**
34.5	34.1	34.4	34.2	34.1	31.5	27.9	26.6	**0.4**	**2.7**	**6.5**	**7.6**
41.3	40.8	41.1	40.9	40.6	37.3	32.8	31.2	**0.7**	**3.5**	**8.3**	**9.7**
47.7	47.2	47.5	47.3	47.0	43.1	37.7	35.8	**0.7**	**4.0**	**9.8**	**11.5**
53.7	53.1	53.5	53.2	53.5	48.9	42.6	40.3	**0.3**	**4.2**	**10.9**	**12.9**
59.7	59.0	59.5	59.2	59.9	54.7	47.5	44.9	**-0.2**	**4.3**	**12.0**	**14.3**
65.7	65.0	65.4	65.1	66.3	60.6	52.4	49.5	**-0.6**	**4.4**	**13.1**	**15.6**
71.7	70.9	71.4	71.1	66.3	60.6	52.4	49.5	**5.4**	**10.3**	**19.0**	**21.6**
77.7	76.8	77.4	77.0	66.3	60.6	52.4	49.5	**11.4**	**16.3**	**25.0**	**27.5**
75.4	74.5	75.0	74.7	66.3	60.6	52.4	49.5	**9.0**	**14.0**	**22.7**	**25.2**
75.0	74.1	74.6	74.3	66.3	60.6	52.4	49.5	**8.6**	**13.6**	**22.3**	**24.8**
74.6	73.7	74.2	73.9	66.3	60.6	52.4	49.5	**8.2**	**13.2**	**21.9**	**24.4**

Figure 14 below shows the growth of these demand reductions included in Otter Tail's forecast for the summer season using the data above.

Figure 14: Forecast Demand Reduction



9 Market Energy Price Assumptions

Otter Tail used the Wood Mackenzie July 2022 North American Power Service as the basis for the market energy prices used in this resource plan. Otter Tail applied the Wood Mackenzie forecasted monthly on-peak and off-peak energy prices to an hourly profile to reflect the hourly variability/volatility of the energy market. Otter Tail

evaluated market energy at +/- 50 percent and +100 percent of the base case. Figure 15 shows the market energy price basis for the assumptions used in the resource plan. The market energy price sensitivities are provided in Appendix I.

Figure 15: Market Energy Price Assumptions

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10 Externality Price Assumptions

Otter Tail includes all modeling runs with and without externalities in Appendix I. For the modeling runs with externalities Figure 16 provides the application of the externalities for Otter Tail Generating Resources.

Figure 16: Application of Externalities for Otter Tail Generating Resources

	Regulatory Cost of Carbon	CO2 Externality Values	Criteria Values
Big Stone	X		X
Coyote	X		
Astoria	X		X
Solway	X	X	X

As identified in Appendix A, in compliance with Minnesota Docket Nos. CI-07-1199, CI-14-643, and DI-19-406, Otter Tail includes externality sensitivities. For these sensitivities, Otter Tail includes the criteria values for PM2.5, NOX, and SO2 defined in Minnesota Docket No. CI-14-643 and the CO2, for 2020-2024, and Regulatory Cost of Carbon values determined in Minnesota Docket Nos CI-07-1199 and DI-19-406. These values are provided in Figure 17 below.

Figure 17: Externality Values

CO2 Externality Values (2020-2024)

	Low	Median	High
2020	$9.05	$25.76	$42.46
2021	$9.25	$26.31	$43.36
2022	$9.46	$26.86	$44.26
2023	$9.66	$27.41	$45.16
2024	$9.87	$27.97	$46.06

Regulatory Cost of Carbon (2025-2050)

	Low	Median	High
2025+	$5.00	$15.00	$25.00

Criteria Values (2020-2050)

	Low	Median	High
PM2.5	$3,437	$6,220	$8,441
NOX	$1,985	$4,762	$6,370
SO2	$3,427	$6,159	$8,352

11 New Firm Dispatchable Alternative Assumptions

Figure 18 shows key assumptions used for new dispatchable alternatives in the resource plan. For the purposes of this resources plan Otter Tail utilized thermal resource alternatives as guidelines for project costs and expects that developing technologies may provide different firm dispatchable options in the future.

Figure 18: New Firm Dispatchable Alternatives

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12 Existing Unit Input Assumptions

Figure 19 shows key input assumptions used for existing baseload units.

Figure 19: Existing Baseload Unit Assumptions

Existing Baseload Units		
Name	**Big Stone Plant**	**Coyote Station**
Coal Type	sub-bituminous	lignite
Retirement Date	2046	2041
Nameplate Capacity (MW)	255.8	149.8
Firm Capacity (MW) Summer	253.242	142.31
Firm Capacity (MW) Fall	243.01	142.31
Firm Capacity (MW) Winter	253.242	142.31
Firm Capacity (MW) Spring	253.242	134.82
Heat Rate at Minimum (Btu/kwh)	12,669	12,786
Heat Rate at Maximum (Btu/kwh)	10,032	11,011
O&M Escalation	2%	2%
Fixed O&M (2022$/kw-yr)	$44.50	$99.50
Variable O&M (2022$/MWh)	$3.42	$3.15

Figure 20 shows key input assumptions used for existing peaking units.

Figure 20: Existing Peaking Unit Assumptions

Existing Peaking Units					
Name	**Astoria Station**	**Solway**	**Lake Preston**	**Jamestown 1**	**Jamestown 2**
Fuel	natural gas	natural gas	fuel oil	fuel oil	fuel oil
Retirement Date	2056	2038	2033	2033	2033
Nameplate Capacity(MW)	242 to 288	42.5	20.4	20.7	21.1
Firm Capacity (MW) Summer	235.9	41.4	18.7	19.7	19.3
Firm Capacity (MW) Fall	244.5	41.4	18.7	19.7	19.3
Firm Capacity (MW) Winter	280.6	41.4	18.7	19.7	19.3
Firm Capacity (MW) Spring	256.6	41.4	18.7	19.7	19.3
Heat Rate at Minimum (Btu/kwh)	13,509	13,853	26,961	25,082	25,338
Heat Rate at Maximum (Btu/kwh)	10,022	9,637	16,567	15,300	15,519
O&M Escalation	2%	2%	2%	2%	2%
Fixed O&M (2022$/kw-yr)	$2.54	$4.49	$4.50	$2.74	$2.74
Variable O&M (2022$/MWh)	$0.47	$3.61	$8.73	$4.91	$5.31

Figure 21 shows key input assumptions used for existing wind purchased power agreements.

Figure 21: Existing Wind Energy Purchases

Existing Wind Purchased Power Transactions		
Name	ND Wind II (Edgeley)	Langdon PPA
Transaction End Date	Nov-2028	Nov-2032
Nameplate Capacity(MW)	21	19.5
Firm Capacity (MW) Summer	3.8	3.5
Firm Capacity (MW) Fall	4.9	4.5
Firm Capacity (MW) Winter	8.5	7.9
Firm Capacity (MW) Spring	4.8	4.5
Net Capacity Factor	26%	41%

Figure 22 shows key input assumptions used for Otter Tail owned wind facilities.

Figure 22: Existing Otter Tail-Owned Wind Facilities

Existing Otter Tail-Owned Wind					
Name	Langdon	Ashtabula	Luverne	Merricourt	Ashtabula III
End of Life Date	Dec-2042	Dec-2043	Dec-2044	Dec-2055	Sep-2038
Nameplate Capacity(MW)	40.5	48	49.5	150	62.4
Firm Capacity (MW) Summer	7.3	8.7	9.0	27.2	11.3
Firm Capacity (MW) Fall	9.4	11.1	11.4	34.7	14.4
Firm Capacity (MW) Winter	16.3	19.3	19.9	60.5	25.1
Firm Capacity (MW) Spring	9.3	11.0	11.4	34.5	14.4
Net Capacity Factor	40%	36%	41%	50%	39%

Figure 23 shows key input assumptions used for Otter Tail's owned Hoot Lake Solar facility which is expected to be in commercial operation in 2023.

Figure 23: Existing Otter Tail-Owned Solar Facility

Existing Otter Tail Owned Solar	
Name	Hoot Lake Solar
Expected Commission Date	Jan-2023
Nameplate Capacity(MW)	49
Firm Capacity (MW) Summer	22.2
Firm Capacity (MW) Fall	12.4
Firm Capacity (MW) Winter	3.1
Firm Capacity (MW) Spring	7.4
Net Capacity Factor	24%

13 Other Assumptions

General Inflation Rate – 2%
Capital Cost Escalation Rate – 1%
Debt Rate – 4.77%
Discount Rate – 7.34%
Composite Tax Rate – 26.26%
Debt Ratio – 47.50%