MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	January 4, 2024		**Agenda Item ***1**
Company	Otter Tail Power Company (OTP or the Company)		
Docket No.	E017/RP-21-339		
	In the Matter of Otter Tail Power Company's 2023-2037 Integrated Resource Plan		
Issues	Should the Commission approve, modify, or reject OTP's resource plan?		
Staff	Sean Stalpes	sean.stalpes@state.mn.us	651-201-2252

✓ **Relevant Documents**	**Date**
Otter Tail Power, Initial Filing (Public and Non-Public)	September 1, 2021
Otter Tail Power, Supplemental Filing (Public and Non-Public)	October 14, 2022
Otter Tail Power, Supplemental Comments (Public and Non-Public)	November 4, 2022
Department of Commerce, Comments (Public and Non-Public)	December 30, 2022
IUOE Local 49 and NCSRC of Carpenters, Comments	December 30, 2022
LIUNA Minnesota and North Dakota, Comments	December 30, 2022
Office of the Attorney General, Comments (Public and Non-Public)	December 30, 2022
Clean Energy Organizations, Reply Comments	February 1, 2023
Office of the Attorney General, Reply Comments	February 1, 2023
Otter Tail Power, Reply Comments	February 1, 2023
Otter Tail Power, Supplemental Letter	February 16, 2023
Otter Tail Power, Supplemental Resource Plan (Public and Non-Public)	March 31, 2023
Otter Tail Power, Appendices C, D, I, K	March 31, 2023

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ **Relevant Documents**	**Date**
Otter Tail Power, Appendix F	March 31, 2023
Otter Tail Power, Errata	April 25, 2023
Clean Energy Organizations, Comments (Public and Non-Public)	September 13, 2023
Clean Energy Organizations, Attachment 1 (Public and Non-Public)	September 13, 2023
Clean Energy Organizations, Attachment 2	September 13, 2023
Clean Energy Organizations, Attachment 3	September 13, 2023
IUOE Local 49 and NCSRC of Carpenters, Comments	September 13, 2023
Department of Commerce, Comments	September 13, 2023
Office of the Attorney General, Comments (Public and Non-Public)	September 13, 2023
Clean Energy Organizations, Corrected Attachment 1 (Public and Non-Public)	September 29, 2023
LIUNA, Reply Comments	October 30, 2023
Otter Tail Power, Reply Comments (Public and Non-Public)	October 30, 2023
Clean Energy Organizations, Reply Comments (Public and Non-Public)	October 30, 2023
Office of the Attorney General, Reply Comments	October 30, 2023

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PART 1: INTRODUCTION

The matter before the Commission is whether to approve, modify, or reject Otter Tail Power Company's 2023-2037 Integrated Resource Plan (2023 IRP). The Commission may also require next steps, such as resource acquisition and/or compliance filings, and establish requirements for OTP's next IRP, such as a filing deadline and analysis of specific topics of interest.

In this section, Staff will provide a brief summary of OTP's updated preferred plan as well as the only "alternative plan,"[1] which was proposed by the Clean Energy Organizations (CEOs).[2] Then, Staff will provide a procedural history, which dates back to the Company's September 1, 2021, Initial Filing. Notably, OTP removed its plan to withdraw from its 35% majority stake in the coal-fired Coyote Station located in North Dakota, and some parties prefer the early Coyote exit plan in the Initial Filing. Last, Staff will outline the major decisions the Commission will ultimately have to make.

I. OTP's Preferred Plan

Table 1 illustrates OTP's 15-year Preferred Plan compared to a base case (i.e., a model-optimized plan), with and without environmental externalities, and the resulting present value of revenue requirements (PVRR). OTP's "Preferred Plan" is occasionally referred to as the "Coyote 2040 Preferred Plan" because the term emphasizes the revision to retain Coyote Station through the remainder of the facility's economic life.

The green box outlines OTP's five-year action plan, which means the actionable steps OTP intends to take following IRP approval. This includes repowering some of OTP's existing wind facilities in North Dakota, adding onsite liquified natural gas (LNG) at Astoria Station in South Dakota, and acquiring new solar and wind in the 2027-'29 timeframe. OTP noted that it is not committing to specific actions that occur in the back half of the planning period, since OTP expects these actions will be revisited in the next IRP cycle.[3]

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[1] An alternative plan has a specific meaning under the Commission's IRP Rules. Under Minn. R. 7843,

[2] The CEOs include Fresh Energy, Clean Grid Alliance, Sierra Club, and the Minnesota Center for Environmental Advocacy. The CEOs' plan draws upon expert technical analysis by Anna Sommer and Chelsea Hotaling of Energy Futures Group (EFG); Tyler Comings of Applied Economics Clinic (AEC); and Elena Krieger, Karan Shetty, Yunus Kinkhabwala, and Kelsey Bilsback of Physicians, Scientists, and Engineers for Healthy Energy (PSE).

[3] While Hoot Lake Solar is included as a resource addition in the filings, Staff did not include it in Table 1 because the solar facility is now in-service, and there are no other actions in 2023-'24.

Table 1. OTP 2040 Preferred Plan Summary

	No Externalities		with Externalities	
	Base Case	Preferred Plan	Base Case	Preferred Plan
2025	Wind Repowers	Wind Repowers	Wind Repowers 400 MW Surplus Solar 100 MW Gen Wind	Wind Repowers
2026	Astoria Onsite Fuel	Astoria Onsite Fuel	Astoria Onsite Fuel 50 MW Gen Wind	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
2033-2037	OTP did not identify any specific actions in the 2033-2037 timeframe.			
PVRR	$2,714,497	$2,724,103	$3,152,731	$3,199,210

Note that Table 1 refers to "surplus" resources (see "100 MW Sur Solar" in 2027 of the Preferred Plan, for example) as well as "generic" resources (see "200 MW Gen Wind" in 2029, for example). "Surplus" and "generic" are differentiated by the location of the unit, how they interconnect to grid, and as a result, the interconnection cost. OTP stated:

> Surplus interconnection resources are built alongside an existing resource and share the interconnection rights while not exceeding the total output of the existing interconnection.[4]

A "generic" resource is the typical capacity expansion modeling unit that has no location and is assigned a network upgrade cost and assumed to go through the MISO queue process.

Table 2 below[5] shows the various types of solar units modeled in EnCompass.[6,7] As indicated, the amount of incremental accredited capacity for surplus resources will vary, and it will depend on the interconnection agreement at a specific site. However, because surplus resources are assumed to have no network upgrade cost, EnCompass selects surplus resources

[4] Updated IRP, p. 32.

[5] Updated IRP, Figure 3 of Appendix B.

[6] The table shows that EnCompass can also select a replacement resource, an example of which would be Hoot Lake Solar, which replaced the coal-fired Hoot Lake Plant and re-used the existing interconnection rights.

[7] Also note the "ITC Adjustment" column, which is the assumed benefit of the Inflation Reduction Act.

prior to generic resources—that is, to the extent they are available to the model.[8] Finally, all renewable resources account for the Inflation Reduction Act (IRA), and the IRA benefit is reflected in the "ITC adjustment" column.

Table 2: Base Case Solar Assumptions

Year available	ITC	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate	LCOE ($/MWh)	ITC adjustment	Interconn. adder	Base Case ($/MWh)
2025-2032	30%	Generic	25	Varies	$40	($8)	$7	$39
2025-2032	30%	Surplus	25	0%	$40	($8)	$0	$32
2025-2032	30%	Surplus + capacity	25	Varies	$40	($8)	$0	$32
After 2032	0%	Generic	25	Varies	$40	$0	$7	$47
After 2032	0%	Surplus	25	0%	$40	$0	$0	$40
After 2032	0%	Replacement	25	Varies	$40	$0	$0	$40

Two additional comments about Table 1, the Preferred Plan summary:

First, OTP modeled "Wind Repowers" as a fixed unit in all modeling runs, and they do not need any action or approval from the Minnesota Commission for the repowerings in this IRP. Also, repowered facilities, which include the Langdon, Ashtabula, Luverne and Ashtabula III wind farms in North Dakota, are assumed to improve the net capacity factor from roughly 40% to 50% at each wind farm, providing about 167 gigawatt-hours (GWh) of incremental wind output annually.

Second, OTP noted that its five-year action plan is not altered by any actions it may take at Coyote Station. However, if OTP withdraws from Coyote Station in a future resource planning proceeding, the Company would likely request authority to add 100 MW of solar and 150 MW of wind in the 2030/2031 timeframe (i.e., beyond this IRP's five-year action plan).

II. CEOs Alternative Plan

The CEOs proposed an alternative resource plan, which is summarized in Table 3 below. Notably, the CEOs' plan removes the Astoria LNG project and OTP's two remaining coal plants, Coyote Station and Big Stone. In place of these modifications, the CEOs' plan adds 100 MW of solar in 2027 and another 100 MW of solar in 2028. These solar additions are consistent with OTP's plan; however, the CEOs' plan adds 650 MW of wind in 2029 (through a combinations of replacement Coyote and generic wind), which is substantially more wind than OTP proposes. In addition, once Big Stone is removed in 2031, wind and battery units are added.

[8] Note that surplus and surplus/capacity solar is $32/MWh, which is $7 less per MWh than generic solar because it does not have network upgrade costs.

Table 3. CEOs Preferred Plan

Year	Additions	Subtractions
2025	Wind Repowers	
2026		Defer Astoria LNG Project to Next IRP
2027	100 MW Surplus+Capacity Solar	
2028	50 MW Surplus+Capacity Solar 50 MW Surplus Solar	Withdraw from Coyote (-150 MW)
2029	150 MW Replacement Wind - Coyote 500 MW Generic Wind	
2030	100 MW Surplus Solar	Withdraw from Big Stone (-256 MW)
2031	150 MW Generic Wind 100 MW Replacement Wind - Big Stone 150 MW Replacement Wind - Big Stone	
2032	25 MW Surplus Battery	

In summary, the major differences between the two plans include:

- The CEOs recommend the Astoria LNG Project be addressed in OTP's next IRP, while OTP addresses the urgency of mitigating risk by installing dual fuel capability at Astoria.
- OTP proposes to retain ownership in Coyote Station through its remaining life (2040), while the CEOs recommend that OTP withdraw from the plant by 2028.
- The CEOs also recommend that OTP withdraw from Big Stone in 2030; however, OTP responded that there has not been nearly enough analysis to support such a decision.
- Both the OTP and CEOs plans add 200 MW of solar in 2027-'28, and both plans add some wind in 2029, but the CEOs' plan adds much more wind and battery resources in 2029 and beyond.

Despite these differences, OTP noted that there is a fair amount of agreement between the OTP and CEOs near-term plans, which "should inform the Commission":

> Although we have fundamental disagreements with the CEOs' comments and priorities, there are areas of overlap that should inform the Commission. Specifically, the nature and amount of renewable generation to be added within approximately five years of the Commission's anticipated order in this docket is an area of general alignment with the CEOs.[9]

[9] OTP reply comments, p. 39.

What OTP is referring to in the excerpt above is that the OTP and CEOs plans both have the same amount of solar in 2027-'28, and both add wind in 2029. This is indicated by the highlighted text in Column 2 of Table 4 below (note that Column 3 means in addition to OTP's resources, so 200 MW wind (OTP/Column 2) + 450 MW wind (CEOs/Column 3) = 650 MW wind (CEOs total) in 2029).[10]

Table 4. Comparison of OTP and CEOs plans in 2027-2032

Column 1	Column2	Column3
Year	**Components of Otter Tail's and the CEOs' Preferred Plans that are identical**	**CEOs Preferred Plan's Additional Resources**
2027	100 MW Solar	
2028	100 MW Solar	
2029	200 MW Wind	450 MW Wind
2030		100 MW Solar
2031		250 MW Wind 150 MW Battery
2032	100 MW Solar 25 MW Battery	

What primarily drives the differences between the two near-term action plans is the disagreement between OTP and the CEOs on the future of Coyote Station. As background, OTP filed its IRP on September 1, 2021, and OTP filed an Updated IRP on March 31, 2023. According to OTP, the primary difference between the two plans concerns Coyote Station. In the Initial Filing, OTP stated:

> 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. Consequently, Otter Tail is proposing to commence the process of withdrawing from its ownership interest in Coyote Station upon approval of this Preferred Plan with the consummation of that process expected by the end of 2028.[11]

In the Updated IRP, OTP addressed this quote from the Initial Filing; the Company explained that while the EnCompass analysis informed this statement, OTP has since determined that Coyote Station will provide "a cost-effective hedge against market volatility, unresolved

[10] OTP reply comments, Table 5, p. 21.

[11] Petition, pp. 6-7.

accreditation questions, forecasting uncertainties and related risk of errors, and unforeseen developments."[12] Therefore, in light of current planning uncertainties, OTP seeks authority 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.[13]

In defining what "significant, non-routine capital investment" means, OTP referred to the Company's most recent Minnesota rate case, in which the Company "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."[14]

The CEOs argued that retaining ownership in either plant is not in the interest of OTP's ratepayers or the environment. Moreover, Coyote Station could require pollution controls to comply with the following U.S. Environmental Protection Agency's (EPA) rules:

1. Regional Haze, which requires compliance in 2028;
2. Greenhouse Gas (GHG) standard for existing plants (proposed), which could require compliance action by 2030 or retirement by the end of 2031; and/or
3. Mercury and Air Toxics Standard (MATS), which could require compliance by 2027 but possibly as early as 2025.[15]

III. Additional Party Comments

In addition to the CEOs' position summarized in the previous section, the following parties filed comments:

- Department of Commerce – Division of Energy Resources (Department);
- Office of the Attorney General – Residential Utilities Division (OAG);
- International Union of Operating Engineers Local 49 and North Central States Regional Council of Carpenters (IUOE Local 49/Carpenters); and
- LIUNA Minnesota and North Dakota (LIUNA)

The Department did not perform EnCompass modeling or make a recommendation on whether the Commission should approve, modify, or reject OTP's plan. However, the Department reviewed OTP's modeling and asked OTP to address certain issues in OTP's reply comments. The Department also determined that OTP's forecast was reasonable made a series of resource acquisition process recommendations. The Department also recommended that in OTP's next IRP, OTP base its planning reserve margin (PRM) on a loss of load expectation (LOLE) standard

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[12] Updated IRP, p. 13.

[13] Updated IRP, p. 11.

[14] Updated IRP, p. 38, footnote 31.

[15] CEOs initial comments, pp. 28-29.

of one day of load shed in ten years.[16]

The OAG argued that the Commission should modify OTP's updated preferred plan by removing the Astoria dual-fuel proposal and exit Coyote Station in 2028. According to the OAG, OTP has not proven that either its ownership stake in Coyote Station or on-site LNG at Astoria Station is in the public interest. In addition to its arguments for why OTP's plan subjects its ratepayers to excessive risk, the OAG calculated that the financial impact of removing these two components of the plan would result in a savings of $146 million.

IUOE Local 49/Carpenters,[17] who "work on a wide array of energy infrastructure construction," including the initial construction of large projects and ongoing maintenance at large coal plants, support OTP's Preferred Plan. IUOE Local 49/Carpenters believe the Astoria LNG project addresses the impacts of extreme weather events and the need to provide a hedge against high pricing events. The unions also agreed with OTP that Coyote Station is a cost-effective resource and supported OTP's proposed wind and solar resources.

LIUNA supported OTP's 2040 Preferred Plan and criticized the CEOs' planning assumptions. LIUNA's "specifically support[s] OTP's proposed dual-fuel upgrade, which [they] believe is necessary to ensure reliability."[18] LIUNA believes the CEOs' plan "relies heavily on optimistic assumptions about the future price and availability of renewable resources."

IV. OTP December 15, 2023, Bifurcated IRP Proposal

On Friday, December 15, 2023, OTP filed a letter with the Commission proposing to (1) use an Available Maximum Emergency (AME) resource designation at Coyote Station and (2) propose a bifurcated resource plan methodology that implements bifurcation using this new tool for Coyote Station. Because OTP's letter appeared in e-Dockets two days before these briefing papers were filed, Staff has not had time to weigh the merits of OTP's proposal, and no party has commented on it as of this writing. Staff anticipates filing decision options related to OTP's December 15 letter regarding procedural steps available to the Commission prior to the January 4, 2024, agenda meeting.

PART 2: BACKGROUND

I. Company Background

OTP stated in the Initial Filing:

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[16] Department comments, p. 36.

[17] IUOE Local 49 represents more than 12,000 Operating Engineers in Minnesota, North Dakota, and South Dakota. The Carpenters represents approximately 12,000 workers across Minnesota, Wisconsin, Iowa, Nebraska, North Dakota and South Dakota.

[18] LIUNA reply comments, p. 1.

> 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.[19]

The exact percentages of demand, energy, and customers are provided in the table below.

Table 5. Percentage of OTP Operations in Each State

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

OTP noted that the average population of the communities it serves is about 400 people.

According to the Department's comments, in 2020, OTP's 4.8 million MWh of energy sales were distributed as follows:

- Industrial—51.3%;
- Non-farm Residential—26.4%;
- Commercial—18.3%;
- Farm—2.3%;
- Other—1.2%; and
- Street and Highway Lighting—0.4%.

However, in 2022, OTP's energy sales grew to 5.6 million MWh, which is an increase of 16.5% since 2020.[20] This is consistent with OTP's adjusted load forecast in the Updated IRP.

A major theme across OTP's filings is that its IRP meets resource planning objectives in each of its jurisdictions. For instance, OTP stated that "a multi-jurisdictional utility like Otter Tail can only function effectively if all of its regulators endorse an outcome, or if one jurisdiction is willing to undertake its own, independent planning and resource selection."[21]

Further, OTP stated that it is already one of the smallest vertically integrated utilities in the country, and "splitting it into separate and even smaller utility systems would result in harmful inefficiencies and an increased cost of service."

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[19] Initial Filing, p. 27.

[20] This is according to EIA's early release of Form 861.

[21] OTP reply comments, pp. 4-5.

II. Existing Resources

The table below shows OTP's existing resource by fuel type and assumed seasonal capacity credit. Capacity ratings are based on MISO's ratings for the Planning Year June 1, 2023, through May 31, 2024. Note the impact of seasonal accreditation on wind and solar resources, which are highlighted with green-shaded cells.

Table 6. Owned Existing Resources[22]

Fuel Type	ICAP (MW)	SAC (Summer)	SAC (Fall)	SAC (Winter)	SAC (Spring)
Coal	406.8	414.2	402.8	406.4	410.9
Gas CT	292.1	283.3	295.5	300.8	321.5
Wind	350.4	75	92	188.1	98.3
Solar	49.9	Deferred	Deferred	2.5	25
Hydro	11.3	11.3	11.3	11.4	11.4
Oil	60.4	60.2	73.7	75.6	72.6
Load Control	Varies	125.5	139.1	248.7	153
Total Owned	***1,170.9***	***969.5***	***1,014.4***	***1,233.5***	***1,092.7***

The next table shows the same green-shaded cells to indicate total wind and solar, but this table breaks out the wind and solar by resource. Note that all of OTP's owned, large-scale wind is in North Dakota, and OTP's only owned, large-scale solar resource, the recently-completed Hoot Lake Solar project, is in Minnesota.

Table 7. Seasonal Accreditation for OTP's Owned Wind and Solar Resources

OTP Resources	ICAP (MW)	SAC (Summer)	SAC (Fall)	SAC (Winter)	SAC (Spring)
Wind					
Ashtabula (ND)	48	8.4	11.6	25.2	10.2
Ashtabula III (ND)	62.4	12.1	16.2	34.5	12.9
Langdon I (ND)	40.5	7	11.7	22.6	10.7
Luverne (ND)	49.5	10.1	15.6	27.8	11
Merricourt (ND)	150	37.4	36.9	78	53.5
Total Wind	***350.4***	***75***	***92***	***188.1***	***98.3***
Solar					
Hoot Lake Solar (MN)	49.9	Deferred	Deferred	2.5	25
Total Solar	***49.9***	***-***	***-***	***2.5***	***25***

OTP also purchase 44.8 MW of wind from the Edgeley, Langdon II, and customer-owned wind farms, which ranges from roughly 10-18 MW of accredited capacity depending on the season.

In total, OTP has about 450 MW of wind and solar (in installed capacity terms) on its system. An important issue for this proceeding, which may impact whether the Commission leans toward

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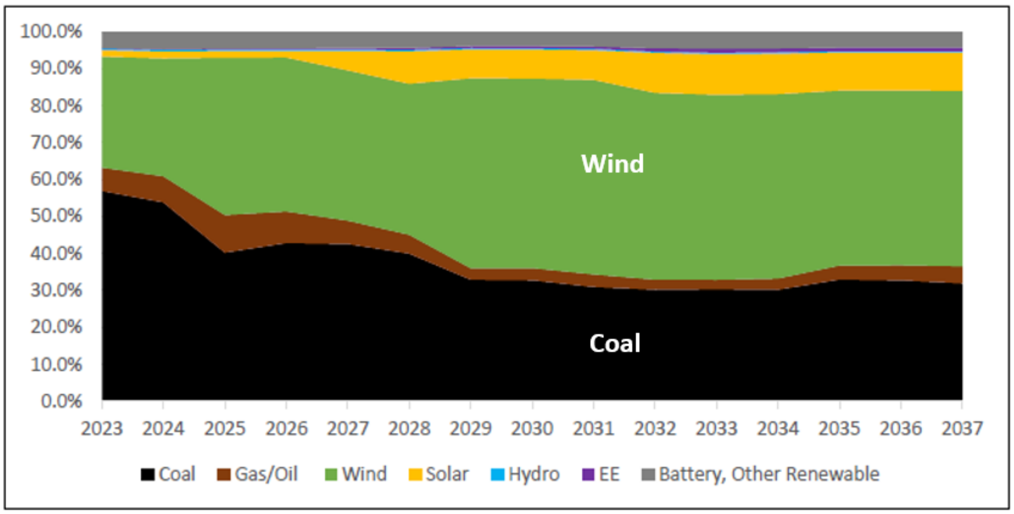
[22] Updated IRP, Appendix C: Existing Resources, Table 1-1, p. 1

OTP's or the CEOs' plan, is how much incremental renewables OTP can realistically add to its system by 2030.

The figure below shows the expected energy mix through 2037 under OTP's 2040 Preferred Plan. The data is based on Encompass outputs in runs without externalities. OTP's current fuel mix is roughly 55% coal, 30% wind, 5-10% natural gas/oil, with the rest made up of solar, hydro, and "other" renewables.

Figure 1: Fuel Mix Under OTP 2040 Preferred Plan, No Externalities



A. Baseload/Coal

OTP has two baseload power plants, which are both coal-fired:

Coyote Station is 427 MW lignite-mine mouth facility located near Beulah, North Dakota that is co-owned by:

- Otter Tail (35%);[23]
- Northern Minnesota Municipal Power Agency, who is represented by Minnkota (30%);
- Montana-Dakota Utilities Co. (25%); and
- Northwestern Energy (10%).

Coyote Station commenced service in 1981 and has a depreciable life that has been extended at various times during the life of the plant, the last time being in 2013 when the depreciable life was extended until 2041.

In 2016, the owners entered into a 25-year lignite supply agreement (LSA) with Coyote Creek Mining Company to supply Coyote Station with lignite from a new mine.

[23] OTP became the operating agent of Coyote Station in July 1998.

Big Stone is a 475 MW sub-bituminous coal-fired power plant located near Milbank, South Dakota. The plant is co-owned by:

- OTP (53.9%);
- Montana Dakota Utilities Co. (22.7%); and
- Northwestern Energy (23.4%).

In 2015, Big Stone was retrofitted with an Air Quality Control System (AQCS) for SO_2, NO_X, and mercury control.

The table below compares OTP's two coal plants and their EnCompass assumptions.

Table 8. Existing Baseload Unit Assumptions

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)	244.1	121.4
Heat Rate at Minimum (Btu/kWh)	11,770	12,786
Heat Rate at Maximum (Btu/kWh)	10,286	11,011
O&M Escalation	2%	2%
Fixed O&M (2022$/kW-yr)	$57.69	$70.52
Variable O&M (2022$/MWh)	$1.71	$1.51

According to OTP, Coyote and Big Stone have similar market operating complexities. For example, both plants can be dispatched by either MISO or SPP, and both have contractual obligations that require partners to take their minimum share of the plant whenever another owner calls for dispatch. Additionally, both plants are capable of being placed on economic commitment, and OTP explained that the co-owners meet periodically "to evaluate the market conditions and forecasts to evaluate the economic commitment (or not) in the future."[24]

Having said that, OTP noted four key differences between Coyote Station and Big Stone Plant:

1. "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."

2. "Big Stone's AQCS, with capital intensive state-of-the-art SO_2 and NO_X controls, is already in place."

3. "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)."

[24] Updated IRP, p. 35.

4. "Big Stone has recently been operated more frequently on economic dispatch, which reduces the hours it operates in a market below its production costs."[25]

In addition, Big Stone has an internal combustion emergency diesel unit, which operates only for extreme emergency or testing purposes, but can synchronize with the system and is submitted as a capacity resource.

B. Peaking Facilities

1. Astoria Station

Astoria Station is a natural gas-fired, simple cycle CT, with a summer rating of 245 MW and a winter capability 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. OTP noted that when selecting a CT for use at Astoria, it confirmed that any potential CT could be converted to dual fuel.

Astoria Station is located at the intersection of the Northern Border Pipeline and the new Big Stone South to Brookings transmission line. The map below, from the Office of the Attorney General's (OAG) December 30, 2022, comments, shows Astoria Station's position on the Northern Border Pipeline. OTP explained in the Initial Filing that "Astoria Station's location on the Norther Border Pipeline is advantageous," as it "is located between the Canadian and North Dakota supplier injection points and the higher load centers to the southeast."[26]

[25] Updated IRP, p. 35.

[26] Initial Filing, p. 57.

Astoria Station became operational in February 2021, and MISO has dispatched the plant regularly since April 30, 2021. The table below[27] lists OTP's thermal peaking plants along with the assumptions used in EnCompass. As shown below, Astoria is several times larger than OTP's other CTs and has the lowest variable O&M costs.[28]

[27] Initial Filing, Figure 20, Appendix F.

[28] For generic, H-Class CTs used in its EnCompass modeling, OTP used the same variable O&M as Astoria.

Table 9. Peaking Unit Assumptions

	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)	248	42.5	20.4	20.7	21.1
Firm Capacity(MW)	241.0	41.5	18.7	19.7	19.3
Heat Rate at Minimum (Btu/kwh)	11,513	14,023	27,156	25,135	25,339
Heat Rate at Maximum (Btu/kwh)	9,120	9,293	14,629	13,507	13,845
O&M Escalation	2%	2%	2%	2%	2%
Fixed O&M (2022$/kw-yr)	$3.56	$21.43	$3.35	$3.42	$3.35
Variable O&M (2022$/MWh)	$0.77	$3.68	$18.82	$24.18	$24.18

2. Solway

Solway is a dual-fuel CT that was brought online in 2003. The primary fuel is interruptible natural gas, and fuel oil serves as the back-up fuel supply. The combustion turbine also includes a clutch to allow synchronous condensing service to support the transmission system. Staff notes that Solway is the only unit in Table 9 that is located in Minnesota.

3. Jamestown 1 and 2, Lake Preston

OTP has two fuel oil-fired CTs located at Jamestown, North Dakota that were installed in 1976 and 1978. The Jamestown units operate a very limited number of hours during the year, usually only for emergency, peaking, and testing situations.

Lake Preston, located at Lake Preston, South Dakota, is identical to the Jamestown units and also installed in 1978. This unit is also fired with fuel oil and has limited operation.

C. Renewable Resources

1. Wind and Solar

As mentioned previously, OTP has roughly 350 MW of owned wind and 50 MW of owned solar (which is Hoot Lake Solar) on its system. Additionally, OTP purchases about 55 MW of wind and solar generation.

2. Hydro

OTP has 6 hydroelectric facilities located at five dams on the Otter Tail River near Fergus Falls, Minnesota. These hydro units were constructed in the early 1900s and have a total capability of about 3.7 MW. The hydro units are under FERC jurisdiction and were licensed for the first time in 1991. All of the units were built prior to licensing requirements.

III. 2016 IRP

OTP's most recently-approved IRP was filed in September 2016 and approved in the Commission's April 26, 2017, Order (2017 IRP Order). That IRP's five-year action plan retired the 150 MW, coal-fired Hoot Lake Plant in 2021 and proposed to acquire the following generic units:

- a 250 MW simple-cycle natural gas combustion turbine (CT) in 2021;
- 100 MW of wind in 2018 and another 100 MW of wind in 2020; and
- 30 MW of solar by 2020 to comply with Minnesota's Solar Energy Standard (SES).

As shown in Table 5, OTP implemented its IRP through the development of the 245 MW, natural gas-fired Astoria Station CT, the 150 MW Merricourt Wind Project, and the 49.9 MW Hoot Lake Solar Project. The table below summarizes OTP's implementation of its 2016 IRP:[29]

Table 10. Execution of 2016 IRP Order[30]

April 2017 IRP Order	Execution of 2016 IRP
Acquire 200 MW of wind in the 2018-2020 timeframe.	The 150 MW Merricourt Wind Farm became commercially operational in December 2020.
Acquire 30 MW of solar in about 2020.	Received MPUC approval to construct the 49.9 MW Hoot Lake Solar Project beginning in 2021.
Add up to 250 MW of peaking capacity in 2021.	The 245 MW Astoria Station was completed and became operational during Q1 2021.
Achieve average annual energy savings of 46.8 GWh (1.6% of sales).	Average annual energy savings of 1.86%.

The Commission's 2016 IRP Order established a June 3, 2019, filing date for the Company's next IRP. However, in advance of this deadline, OTP requested a one-year extension, to June 1, 2020, to file its next IRP. OTP cited environmental regulations and the transition from the Strategist capacity expansion model to EnCompass as reasons why a delay is warranted. The Commission approved OTP's request.

OTP later requested a second extension to delay the next IRP, to September 1, 2021. OTP again stated that more information was needed to evaluate compliance with the Regional Haze Rule. The Commission approved OTP's second extension request, but given the length of time since the 2017 IRP Order, the Commission required OTP to make compliance filings related to (1) how OTP intended meet the SES and (2) modeling scenarios that examined Regional Haze

[29] Excerpt of Table 2-1 of the Initial Filing.

[30] Initial Filing, Table 2-1, p.

compliance and Coyote Station retirement using Minnesota environmental externalities and carbon regulatory costs.[31]

IV. 2023 IRP – Procedural Background

This section will briefly summarize the five main Company-filings in this proceeding:

1. Initial Filing – September 2021
2. Letter Requesting Amended Procedural Schedule – October 14, 2022
3. Revised Astoria Proposal – November 4, 2022
4. Filing Addressing 100 Percent Carbon-Free Standard – February 16, 2023
5. Updated IRP – March 31, 2023

A. Initial Filing – September 2021

OTP made its Initial Filing on September 1, 2021. However, the comment period was extended several times, and during these extension periods, several developments led OTP to ultimately update its plan. Table 6 compares the Initial Filing action plan to a redline version of the Initial Filing plan, which reflects the current proposal. Note that there are more solar and wind resources, but they are added later in the planning period. Staff understands this is largely due to OTP's significantly-increased load forecast.

Table 11. OTP Initial Filing Preferred Plan, Action Plan

	Initial Filing Action Plan (9/1/21)	Updated IRP (3/31/23)
2023	Hoot Lake Solar COD	Hoot Lake Solar COD
2024	Provide five-year advance notice of termination of Coyote Station Plant Ownership Agreement by January 1, 2024	~~Provide five-year advance notice of termination of Coyote Station Plant Ownership Agreement by January 1, 2024~~
2025	150 MW Solar	~~150 MW Solar~~
2026	Onsite Fuel oil at Astoria	Onsite ~~Fuel oil~~ LNG at Astoria
2027	100 MW Wind	~~100 MW Wind~~ 100 MW Solar
2028	Withdrawal from Coyote Station (-149 MW)	~~Withdrawal from Coyote Station (-149 MW)~~ 100 MW Solar
2029		200 MW Wind

B. Letter Requesting Amended Procedural Schedule – October 14, 2022

On October 14, 2022, OTP filed a request to amend the procedural schedule of the IRP (October 2022 Letter). In the October 2022 Letter, OTP discussed recent developments, specifically MISO's seasonal resource adequacy construct and non-thermal capacity accreditation and the

[31] Compliance filings for OTP's solar acquisition plan were due in April 2020 and July 2020, and the compliance filing for the EnCompass modeling was due in December 2020.

passage of the Inflation Reduction Act (IRA), that necessitated supplemental modeling.

However, OTP stressed the urgency for adding dual fuel at Astoria Station, so OTP proposed leaving the comment period unchanged for dual fuel at Astoria and delay the remainder of the IRP. The Commission issued a notice granting OTP's request on November 1, 2022.

The October 2022 Letter also noted that the secondary fuel source will change from fuel oil to LNG,[32] and OTP provided an updated cost estimate, which was higher than the estimate in the Initial Filing. OTP explained that LNG was preferable because LNG will have a lower initial capital cost, lower O&M costs, lower fuel costs, and lower emissions than fuel oil.[33]

C. Revised Astoria Proposal – November 4, 2022

On November 4, 2022, OTP filed a Revised Astoria Proposal, which updated various tables, figures, and analysis from the Initial Filing. This included an analysis of market exposure during an extreme, Winter Storm Uri-like event; OTP used historical LMP data to compare what the financial benefit would have been if Astoria had dual fuel capability during Uri. Supplemental Table 3-12[34] attempted to back cast the net benefit of having dual fuel available at Astoria during Uri. While the benefits of dual fuel varied significantly based on any given sensitivity – for instance, the net benefit calculation was very sensitive to the amount of timely gas nominations and the assumed LMP – the net benefit of dual fuel capability ranged from $4.7 million to $23.7 million. (Staff notes that the OAG argued this calculation makes several unreasonable assumptions.)

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[32] OTP explained that Astoria will utilize an LNG storage tank and the required pumps and vaporizers to convert the liquid to a gas. The vaporized gas will be delivered to the turbine via the same onsite route as pipeline natural gas. Since vaporized LNG is like pipeline natural gas, combustion turbine modifications will not be required and combustion turbine operation will remain the same. OTP evaluated onsite liquefaction but could not justify the added cost. This is mainly due to the frequency at which Otter Tail assumed LNG would be used. LNG will be trucked to site and will be procured under a long-term agreement that will be competitively bid.

[33] OTP retained Sargent & Lundy to develop the fuel oil design and cost estimate and to complete the economic analysis between fuel oil and LNG. For LNG, Otter Tail retained HDR, Inc., to develop the design and cost estimate. HDR, Inc., has experience in estimating and supporting recent LNG projects. After the conceptual designs and cost estimates were completed a net present value comparison was used to determine which fuel source would have the lowest cost over a 30-year life.

[34] Supplemental Table 3-12 is an update of Table 3-12 of the Initial Filing. Updates include updating the output of Astoria Station from 245 MW to 285 MW, and it allows for unit commitment in the real-time energy market. Assuming 285 MW of output, a five-day supply of on-site fuel would allow for generation output of five days, or 34,200 MWh (5 days x 24 hours x 285 MWs = 34,200 MWh) from the stored dual fuel resource.

Table 12. OTP's Financial Analysis of Astoria LNG (from its November 2022 Filing)

				Gas Only		LNG Dual Fuel Integration (5 Day Invty)			Net Benefit Delta	
LMP Pricing Scenario	Timely Gas Purchase: % of Daily Capacity	Timely MMBtu Purchase (MMBTu)	Intraday Purchase (MMBTu)	Net Benefit: Average Gas Case	Net Benefit: Worst Gas Case	LNG Dispatch (MWh)	Net Benefit: Average Gas Case	Net Benefit: Worst Gas Case	Net Benefit: Average Gas Case	Net Benefit: Worst Gas Case
Historical Astoria LMPs	0%	0	70,950	($840,795)	($5,346,120)	31,350	$3,862,028	$3,826,553	$4,702,823	$9,172,673
	10%	74,923	(3,973)	($2,313,096)	($6,226,902)	31,350	$3,962,974	$3,892,932	$6,276,069	$10,119,834
	15%	112,385	(41,435)	($3,102,458)	($7,240,915)	31,350	$4,013,447	$3,926,121	$7,115,905	$11,167,036
	25%	187,308	(116,358)	($4,943,698)	($12,246,128)	31,350	$4,100,203	$3,953,336	$9,043,901	$16,199,464
	50%	374,616	(303,666)	($9,678,766)	($25,815,180)	31,350	$4,256,076	$3,860,743	$13,934,842	$29,675,922
	100%	749,232	(678,282)	($19,194,308)	($53,047,505)	31,350	$4,522,414	$3,581,333	$23,716,723	$56,628,838
Historical Astoria LMPs X2	0%	0	337,722	($3,727,217)	($28,119,827)	34,200	$10,403,895	$10,276,185	$14,131,112	$38,396,012
	25%	187,308	150,414	($6,957,434)	($25,620,066)	34,200	$11,075,987	$10,990,847	$18,033,421	$36,610,913
MISO LMP Price Cap $3,500/MWh	0%	0	749,232	$208,816,344	$127,252,224	34,200	$245,272,001	$245,101,721	$36,455,656	$117,849,497
	25%	187,308	561,924	$207,466,301	$146,293,211	34,200	$247,740,255	$247,612,545	$40,273,954	$101,319,334
Historical SPP Big Stone LMPs	0%	0	533,544	($9,688,416)	($9,688,416)	34,200	$71,788,382	$71,639,387	$26,114,513	$81,327,803
	25%	187,308	346,236	$43,969,076	$4,875,626	34,200	$72,460,473	$72,354,048	$28,491,398	$67,478,423

D. Filing Addressing 100 Percent Carbon-Free Standard – February 16, 2023

On February 2, 2023, the procedural schedule for OTP's IRP was brought before the Commission as a Discussion Item, and at that agenda meeting, the Commission inquired about the Company's plans to comply with the imminent passage of the Carbon-Free Standard (CFS).[35] After the CFS was passed into law, OTP made a supplemental filing with a preliminary analysis of how the CFS may impact its IRP, specifically the Astoria LNG project. The filing stated in part:

> Otter Tail forecasts our owned renewable generation will allow us to comply with this legislation, and it is therefore not expected to materially alter our preferred plan (to be submitted by March 31, 2023.)
>
> . . .
>
> [S]pecifically applicable to our request for authority to add onsite fuel inventory at Astoria Station, the Minnesota Clean Energy Law does not affect our request. It does not affect our request because: (1) it will not change Otter Tail's total electric sales to retail customers in Minnesota, and (2) it will not reduce the amount of electricity we will generate from carbon-free energy technologies from which we will provide electricity to those customers. The analysis supporting onsite fuel inventory at Astoria Station is not, therefore, affected by the Minnesota Clean Energy Law.
>
> Effectively, the Minnesota Clean Energy Law requires retirement of renewable energy credits (REC) for each kWh sold to Otter Tail's Minnesota customers. The new law does not require any specific disposition of existing fossil fuel generation plants, nor does it forbid investment in fossil fuel plants. Even more importantly, it 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

[35] Minnesota Session Law 2023, Chapter 7 was signed by the Governor on February 7, 2023.

resource plans are to be evaluated.[36]

E. Updated IRP – March 31, 2023

On March 31, 2023, OTP filed its *Application for Supplemental Resource Plan Approval 2023-2037* filing (Updated IRP), According to OTP, the primary difference between the two plans concerns Coyote Station. Whereas in the Initial Filing OTP withdrew from Coyote Station by 2028, the Updated IRP retains ownership in Coyote "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." OTP stated:

> 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. <u>These scenarios include a high renewable energy cost scenario and a low renewable accreditation scenario</u>.

OTP continued that, while the EnCompass analysis indicates that withdrawing from Coyote Station has an economic benefit, "this must be evaluated against uncertainty, risk, and the nature of irreversible choices in a rapidly changing environment."[37] OTP clarified that:

> 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 <u>is not altered by any actions we may take concerning Coyote Station</u>.[38]

OTP noted several changes that have occurred since the Initial Filing that required supplemental modeling and that drove OTP to revisit its proposed plan. Some of those factors described in this section include: MISO's seasonal resource adequacy construct (SAC) and non-thermal capacity accreditation; changes to OTP's load forecast; the Inflation Reduction Act (IRA); natural gas and energy market price volatility; and the Carbon-Free Standard (CFS). These developments are briefly summarized below:

- ***MISO's seasonal resource adequacy construct and non-thermal capacity accreditation methodology.***

MISO's shift to a seasonal planning reserve margin requirement (PRMR) will increase OTP's planning reserve margins (PRMs) above what was included in the Initial Filing. For example, in the Initial Filing, OTP assumed an annual 9.4% MISO PRM to calculate its total obligation

[36] Supplemental Letter Addressing the MN Carbon-Free Standard, February 16, 2023, p. 2.

[37] Updated IRP, p. 6.

[38] OTP Updated IRP, p. 6.

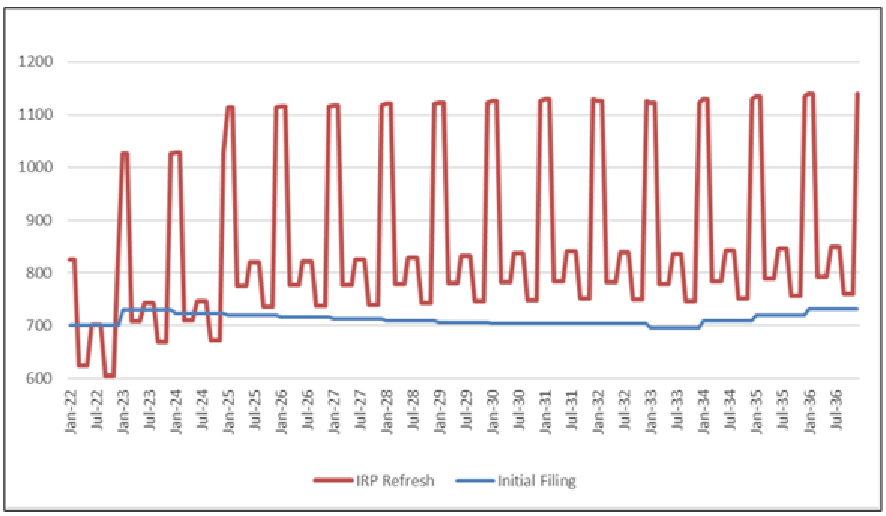
resource need.[39] OTP stated in its Updated IRP that its PRM percentage for the winter season would be 25.5%.[40] This is an especially important change because OTP is a winter-peaking utility.

Table 13. MISO Seasonal Planning Reserve Margin

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

Illustrated another way, Figure 2 below compares the modeled PRMR (in MW) of the Updated IRP (red line, seasonal) to the Initial Filing (blue line, annual).

Figure 2. Initial Filing vs. Updated IRP PRMR



OTP also needed to adjust its non-thermal capacity accreditation and apply the capacity credit for each season. While OTP noted that the exact accreditation values were "unknown at the time of input development" for its Updated IRP, OTP "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."[41]

- ***MISO capacity shortfalls and Winter season market exposure***

[39] See OTP Initial Filing, Table 3-2, p. 17.

[40] Updated IRP, p. 20.

[41] Updated IRP, p. 21.

In addition to OTP's own capacity position under the SAC, OTP noted that MISO has shifted from capacity surplus to capacity shortfall, and MISO modeling indicates near-term capacity risk. OTP cited MISO's 2022 Regional Resource Assessment (RRA), which found that Local Resource Zone 1 (LRZ 1), where OTP is almost entirely located, may have a capacity shortfall as early as 2023.

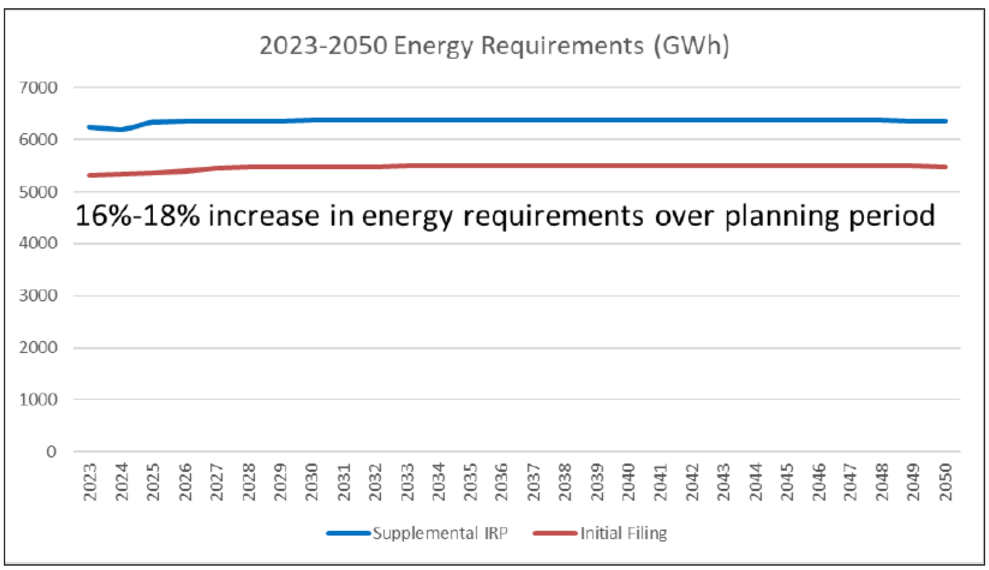
- ***Inflation Reduction Act (IRA)***

The IRA provides renewed and new incentives for wind, solar, clean energy storage, and clean energy manufacturing projects, and OTP incorporated these incentives into its supplemental modeling.[42]

- ***Changes to OTP's load forecasts***

The Initial Filing sales and demand forecasts were completed in early-2021 using actual sales data through December 2020. Since then, OTP has added new large load customers, and the Company expects to add other large load customers within the next two years. Compared to the Initial Filing, the energy requirements in EnCompass was increased by 16%-18% over the planning period.[43] OTP also noted that some of these loads are typical agricultural processing facilities, while others, such as data processing customers, are atypical relative to other OTP customers.

Figure 3. Sales Forecast Comparison



[42] Specifically, OTP's wind price assumptions through 2032 assume projects qualify for 100% of the production tax credit (PTC). Similarly, solar energy price assumptions for 2025 through 2032 include a 30% investment tax credit (ITC). Battery storage prices also include a 30% ITC.

[43] OTP Updated IRP, p. 30.

OTP stated that "the prudence of Otter Tail's withdrawal from Coyote Station is premised on the load forecasting that forms the basis of this IRP. However, as the future is uncertain, changes to Otter Tail's capacity needs could impact the prudence of a withdrawal from Coyote Station."[44] In other words, according to OTP, the fact that OTP's load forecast has increased makes the capacity and energy provide by Coyote more valuable.

- ***Natural Gas and Energy Market Price Volatility***

Since the Initial Filing, factors such as extreme weather events and geopolitical instability have resulted in natural gas price volatility. Consequently, natural gas prices have been more than doubled, on average, than the assumptions in the Initial Filing. The two figures below illustrate OTP's natural gas and energy market price assumptions used in the Initial Filing compared to the Updated IRP. Note that beyond the first few years, OTP assumes a return-to-normal scenario that aligns with the assumptions in the Initial Filing.

- ***Carbon-Free Standard***

On February 7, 2023, Governor Tim Walz signed the CFS into law, which establishes percentages of electric utilities' total retail sales in Minnesota provided from carbon-free resources 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."[45]

In summary, OTP's five-year action plan, consists of the following actions:

- Repowering existing wind facilities in North Dakota
- Installing onsite LNG fuel storage at Astoria Station in 2026.
- 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.
- Withdrawing from OTP's 35% ownership interest in Coyote Station in the event OTP is required to make a major, non-routine capital investment in the plant.

The CEOs recommend the Commission adopt the CEOs Preferred Plan, or approve an action plan consisting of the following modification to OTP's plan:

- Withdraw from Coyote Station by no later than 2028, and
- Find that Otter Tail has demonstrated a need for:
    - planned wind repowers in 2025,
    - 200 MW of surplus solar in the 2027-2028 timeframe,

[44] Updated IRP, p. 50.

[45] Minn. Stat. §216B.1691 Subd. 2g.

- 350 MW of wind resources in the 2029- 2031 timeframe,
- an additional 200 MW of surplus solar in the 2030-2032 timeframe, and
- 50 MW of surplus battery resources by no later than 2032.

- Withdraw from Big Stone Plant by no later than 2030, and
- Find that there is an additional need for:
  - 550 MW of wind resources in the 2029-2031 timeframe and
  - 125 MW of battery resources by 2031.
- Defer a decision on Otter Tail's Astoria LNG proposal until the Company's next IRP.

Staff notes that the list above includes the CEOs' expansion plan-related recommendations; it is not a complete list of their recommendations.

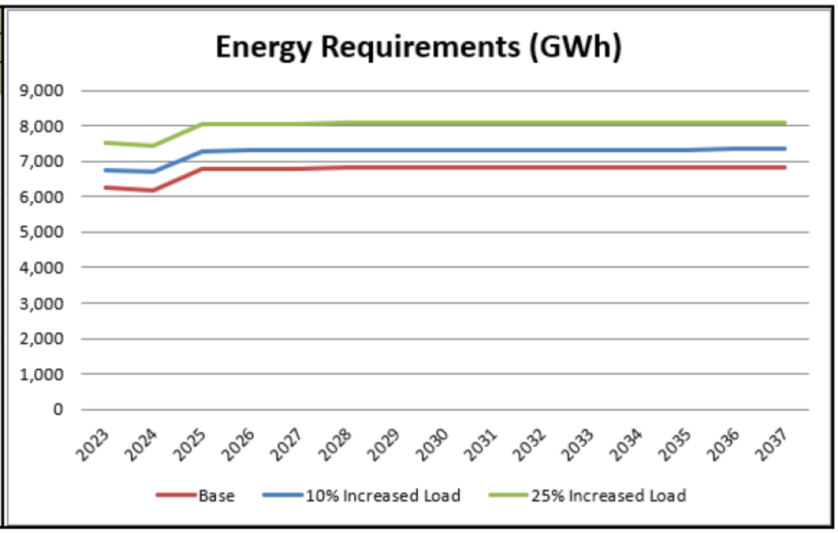
PART 3: DEVELOPMENT OF PLAN AND ECONOMIC MODELING

I. Resource Needs/Forecasting

OTP completed its forecasts "in-early 2021 using actual sales data through December 2020."[46] Since the Initial Filing, new load additions are expected to increase OTP's energy requirements by 16-18%, which was incorporated into the supplemental modeling. The figure below shows the base energy requirements and +10% and +25% increased load sensitivities.

Figure 4. OTP Energy Requirements under Base, +10%, and +25% Load

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



The Department reviewed OTP's resource needs and concluded that "with no further actions, OTP will first encounter very small capacity surpluses or deficits in the early 2030s. Therefore, near term actions would be taken to address energy issues rather than capacity issues."[47]

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[46] Updated IRP, p. 30.

[47] Department comments, p. 4.

Additionally, the Department determined that "winter and summer seasons clearly will be the driving force in OTP's resource planning, at least for capacity purposes."

The Department did not review the technical details of OTP's forecasts, nor did the Department test OTP's previous or current statistical models, but the Department reviewed past forecasts for accuracy in order to determine the potential for bias. Based on this review the Department concluded that "the demand forecast errors do not exhibit a clear bias," and any forecast errors are "too small to be meaningful." The Department observed that OTP's energy forecasts tend to be too high but concluded that, due to the addition of large, energy-intensive loads, no forecast adjustment is warranted. Overall, the Department's conclusion of OTP's forecasts is that "OTP's demand and energy forecast processes have very little systematic bias."

The CEOs used OTP's demand and energy forecasts for modeling purposes. However, OTP's EnCompass analysis considered sensitivities in which load increased by 10-25%, and generally speaking, the higher-load sensitivities were the few sensitivities which found that extending Coyote Station was economic. On pages 22-23 of the CEOs' initial comments, CEOs explained why load increases of this magnitude are predicated on very speculative arguments.

II. Modeling Assumptions

A. Renewable Energy Prices

Appendix F of the Updated IRP describes OTP's EnCompass modeling assumptions. As noted, OTP's renewable price assumptions incorporated the benefits of the IRA. OTP noted that it did not forecast a low-cost wind sensitivity analysis because of the assumed maximum possible benefit from the IRA.

The CEOs' modeling expert, EFG, modified OTP's assumptions as it relates to the IRA. OTP assumed that the IRA would be available for projects that began operation by 2032, but EFG explained that the tax credits could be available for projects that qualify for safe harbor provisions until 2035.

The main difference, however, between the CEOs' and OTP's renewable price assumptions relate to the long-term price trend. The important takeaway here is that the CEOs' used OTP's high-cost assumption in the short-term – to reflect current supply chain challenges and transmission congestion – but assumed that renewable energy prices would stabilize in the long-term. The CEOs argued that the following developments will help bring prices down over the long-term:

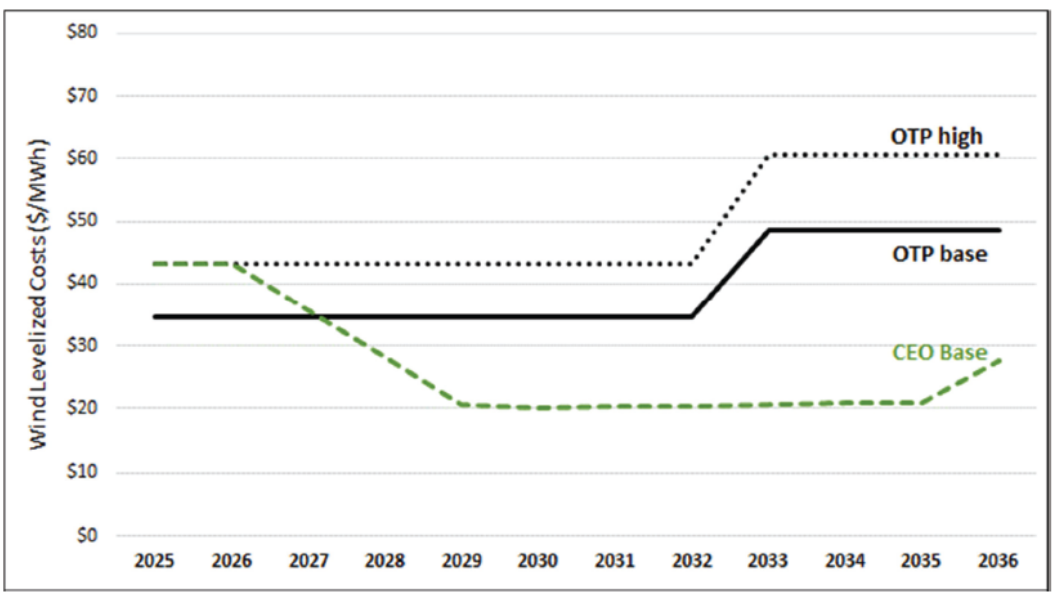
1. The first tranche of projects under MISO's Long Range Transmission Planning (LRTP) initiative includes 18 transmission lines with expected commercial operation dates between 2028-2030. Three lines are located wholly or partially within Minnesota and improve connections between Minnesota and neighboring states.

2. FERC Order 2023 will improve the interconnection process nationwide, and following FERC's issuance of Order 2023, MISO initiated its own interconnection reform effort.

3. The IRA initiated a massive federal effort to increase domestic clean energy manufacturing, which will boost supply and improve stability during trade disruptions. EFG's report stated: "In the first nine months since the passage of the IRA, more than 100 new clean energy manufacturing facilities or expansions were announced in the U.S., including new wind, solar, and battery manufacturing plants. While some of these facilities will not begin production until 2025 or later, a majority have announced production dates by the end of 2024. It is reasonable to assume this activity will continue and contribute to reduced supply chain constraints by the end of the decade, if not before."[48]

The two figures below illustrate the differences between OTP's and CEOs' wind price assumptions. The first figure shows the wind prices assumed under the OTP high, OTP base, and CEOs base case. Note that the CEO base wind price is much lower than the OTP base. Also, the uptick in wind prices in the later years depict assumptions of how far into the future wind projects may qualify for IRA-related PTCs.

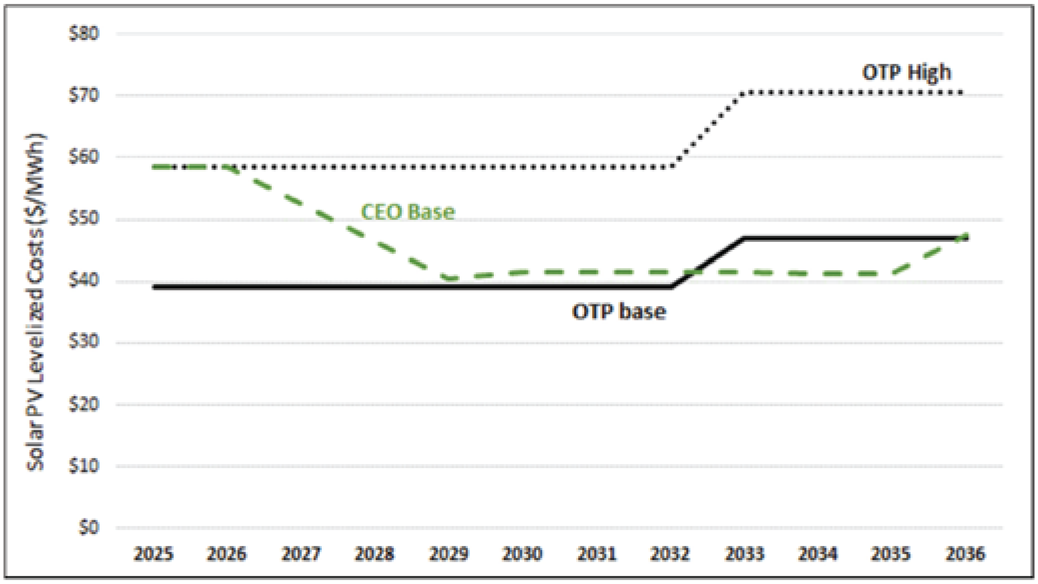
Figure 5. New Wind Costs: OTP high, OTP base, and CEO base



The next figure shows the same three cases but for solar price assumptions. In the case of solar, the CEO base is much more aligned with the OTP base.

[48] CEOs initial comments, Attachment 1 – EFG report, p. 6.

Figure 6. New Solar Costs: OTP high, OTP base, and CEO base



The Department presented the "most recent pricing data for new capacity available to the Department," which was from Xcel Energy's 2022 Solar RFP proceeding.[49] Xcel's petition showed "substantial increases in new unit prices in most markets over the past three years." The Department recommended that "OTP review the data on new unit pricing (or more recent data if it is available to OTP) and re-set the price for new units so that it is more reflective of the current environment."[50]

LIUNA stated that the CEOs' renewable price assumptions are "optimistic" and "unrealistic," arguing that:

> while there is reason to believe that proposed transmission expansion might help to stabilize prices, there is no indication that transmission expansion will outpace demand enough to significantly lower transmission interconnection costs. While significant transmission expansions have been approved and more are in the pipeline, growth in demand for renewable energy continues to outstrip supply. Most practitioners that we talk to from utilities and independent power producers expect that new transmission capacity will be used as fast as we can build it. Similarly, domestic manufacturing will help ensure that Americans see greater benefit from clean energy investments in their communities, but it is not clear that onshoring will significantly change the availability of components for clean generation and transmission.
>
> Further, transmission congestion and supply-chain disruptions are just two of

[49] Docket No. E002/M-22-403, Xcel's May 5, 2023 petition.

[50] Department comments, p. 24.

> many cost drivers for renewables. Developers face increasing costs across many fronts, from the terms of land leases to the permitting and engineering work needed to accommodate sites that keep getting closer to environmental resources and/or human activity as the acreage of wind and solar generation grows. Given the demand pressures from across the Midwest and the nation, which have only been exacerbated by beneficial Federal investment, we can expect other components of project cost to rise even if the cost of the underlying technology falls.[51]

B. Renewable Resource Accreditation

OTP explained its approach for renewable resource accreditation as follows:

> 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.[52]

The next three tables show the values that were used for wind, solar, and battery accreditation within OTP's Updated IRP modeling. The first table[53] includes OTP's wind accreditation assumptions by season and as a percentage of a wind resource's installed capacity (ICAP) in the current year, 2031, and 2041. For each benchmark year, Staff highlighted the season with the highest percent accreditation in green and the season with the lowest percent accreditation in red.

Table 14. Seasonal WIND Accreditation (% of ICAP) in 2023, 2031, 2041

Season	2023	2031	2041
Summer	18%	18%	16%
Fall	23%	21%	21%
Winter	40%	37%	26%
Spring	23%	12%	12%

Moving on to solar, OTP (again, relying on MISO assumptions) assumed very little accredited capacity from solar in the winter; moreover, solar accreditation declines significantly over time during the summer due to the increased penetration of solar in the region.

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51 LIUNA comments, p. 2.

52 Updated IRP, p. 21.

53 Updated IRP, excerpt of Table 4-3, pp. 21-22.

Table 15. Seasonal SOLAR Accreditation (% of ICAP) in 2023, 2031, 2041

Season	2023	2031	2041
Summer	45%	23%	18%
Fall	25%	18%	20%
Winter	6%	1%	11%
Spring	15%	17%	11%

Battery accreditation tells a slightly different story. As a percentage of ICAP, batteries' accreditation remains higher than wind and solar, and it is highest in the winter and summer.

Table 16. Seasonal BATTERY Accreditation (% of ICAP) in 2023, 2031, 2041

Season	2023	2031	2041
Summer	82	82	100
Fall	68	68	100
Winter	82	82	97
Spring	76	76	64

Again, these values are OTP's base assumptions. OTP also ran high and low accreditation sensitivities, and the low accreditation scenario found that retaining ownership of Coyote Station through 2040 is least-cost. The CEOs recognized the risk associated with renewable accreditation assumptions in future years but argued that "there are problems with the way Otter Tail modeled [the low accreditation] sensitivity:"[54]

> While Otter Tail reduces resource accreditations for wind, solar, and batteries by **[Trade Secret Data Removed]** in the "low accreditation" scenario, it does not adjust the thermal units' accreditation nor the Company's seasonal planning reserve margin requirements (PRMR). This is a critical point: the changes MISO is contemplating to non-thermal resource accreditation will also impact the PRMR, utility capacity obligations, and thermal resource accreditation.
> . . .
> by reducing non-thermal accreditation values without corresponding adjustments to other factors, Otter Tail's low accreditation scenario paints a one-sided and incomplete picture. Additionally, cutting accreditation values for all three clean energy resources (wind, solar and batteries) in all four seasons by a flat **[Trade Secret Data Removed]** is arbitrary.

[54] CEOs initial comments, p. 24.

C. MISO Assumptions

1. Spot Market Sales

Both the Department and the CEOs commented on OTP's spot market energy limit. The Department explained, "OTP's EnCompass outputs show the Company does not sell into the energy spot market but is a substantial purchaser . . . in order to provide a broader and more realistic view of how OTP's generation units will likely operate within the MISO energy market, the Department recommends OTP re-configure EnCompass so that it has the ability to buy from and sell to the energy spot market."[55]

The CEOs Preferred Plan was developed after allowing the model to engage in sales; however, the CEOs ran a sensitivity with energy sales turned off in order to show that the CEOs Preferred Plan was less expensive than OTP's regardless of the treatment of market sales.

In reply comments, OTP responded:

> Otter Tail's base modeling assumption is that any excess generation on our system will receive no value from the MISO market. On its face, this may seem unduly conservative, but it is not uncommon for excess generation to be worth less than zero dollars because additional monetary production incentives (such as renewable energy credits or production tax credits) enable negative bids for renewable energy.[56]

2. PRM

The Department recommends that the Commission:

> Order Otter Tail to comply with a planning reserve margin based on a LOLE standard of one day of load shed in ten years, calculated considering the power pool to which Otter Tail belongs, which currently is MISO. This recommendation applies only to the next IRP filed by Otter Tail and should be re-visited during the next IRP.

As Staff understands the Department's recommendation, this would require OTP to continue to use the same methodology as it does currently (although the Department and OTP can verify this at the agenda meeting). The Department stated that the "primary purpose of this recommendation is to enable the Commission and Otter Tail to observe the results of MISO's experiment with a [downward-sloped demand curve, or DSDC], if it is approved by FERC, before implementing it in Minnesota."[57] OTP did not respond to this issue in reply comments.

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[55] Department comments, p. 20.

[56] OTP reply comments, p. 18.

[57] Department comments, p. 14.

D. Expansion Units

The table below shows the five resource types available to EnCompass:

Table 17. Resource Alternatives Available in EnCompass

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.

The Department commented that OTP made too much capacity available to the model too early in the planning period. Specifically, OTP "made available at least 400 MW of new capacity as soon as 2025," and the Department argued that it "may be difficult for OTP to add a large quantity of new capacity that soon."

The CEOs took the opposite view. As EFG stated in Attachment 1 to the CEOs comments:

> we adjusted a number of the assumptions OTP made regarding the availability and level of new resources to ensure that the EnCompass inputs reflected the full suite of actually available options so that constraints imposed in the model would not limit resource selection. The changes that we made for the CEO modeling include:
>
> {1) Raising the solar generic constraint to 1000 MW on a cumulative basis throughout the entire planning period;
> (2) Allowing the model to add up to 1000 MW of generic wind per year and on a cumulative basis throughout the entire planning period;
>
> (3) Revising the annual generic battery storage constraint to 500 MW annually and 1000 MW on a cumulative basis throughout the entire planning period;
>
> (4) Placing a global constraint on replacement resources to allow the model to optimize the selection of up to 150 MW of replacement wind, solar, and battery storage resources between 2033-2041, rather than being limited to 50 MW of each resource.
>
> (5) Adjusting the replacement resource options available to the model, to demonstrate the potential for a resource plan that both exits and retires the coal

plants and utilizes the valuable interconnection rights at both plants.[58]

E. CO_2 Regulatory Costs and Environmental Externalities

Both the Department and the CEOs criticized OTP's modeling of CO2 regulatory cost and externality runs because they did not reflect the most recent Commission-ordered environmental and regulatory cost contingencies using EnCompass.

OTP responded:

> By way of background, Otter Tail provided the full range of Commission ordered environmental and cost contingencies in our Initial Filing. In our Supplemental Filing, we modeled only the mid-range for Environmental and Cost Contingencies. This was done to reduce the number of modeling runs because we were under a compressed timeline. The additional sensitivities that were included in our Initial Filing provided insights, but nothing that ultimately resulted in adjustments to our Preferred Plan. Although our Supplemental Filing model had some significant changes, the outcome that was to be expected from this full range was already understood from our Initial Filing's modeling runs that considered various ranges of carbon costs. However, <u>Otter Tail provides [Attachment 3] at the request of the Department. These modeling results were as expected and do not change our Supplemental Preferred Plan</u>.[59]

Another issue involves the units to which OTP applied regulatory/externality costs. The CEOs argued that OTP inappropriately included "only a fraction of externalities" in its modeling. This is because "when Otter Tail modeled externality costs, it <u>excluded all CO_2 costs resulting from generators located outside of Minnesota</u> (i.e., all thermal units except Solway) <u>and excluded criteria emission externality costs from any units more than 200 miles from Minnesota</u> (Coyote), even though those generators are fundamental to Otter Tail delivering retail sales in Minnesota."[60] The modeling used "a uniform treatment of externality costs across all units."

PART 4: ACTION PLAN

I. EnCompass Summary

A. OTP

The figure below shows a grid of OTP's sensitivities, each of which was modeled under 2040 <u>and</u> 2028 Coyote exit scenarios:

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[58] CEOs initial comments, Attachment 1, pp. 11-12.

[59] OTP reply comments, p. 51.

[60] CEOs initial comments, p. 45.

Figure 7. OTP EnCompass Sensitivities (Appendix I)

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

Zero Externalities

Externality Values Applied

Appendix I includes the "IRP Sensitivity Summary," which compares the PVRR of all sensitivities. Below are two excerpts of the summary, which show the Base Case and Preferred Plan with and without externalities under the Coyote 2028 and 2040 scenarios. Note that the PVRR of the Base Case and Preferred Plan are <u>lower under the 2028 Coyote exit</u> than the 2040 exit.

Table 18. PVRR 2040 and 2028 Coyote Withdrawal – No Externalities

	2023 Base Case PVRR ($000)	Preferred Plan PVRR ($000)
Withdraw from Coyote 12/31/2040	$2,742,670	$2,764,110
Withdraw from Coyote 12/31/2028	$2,714,497	$2,724,103
2028 Difference from 2040 Exit	-$28,173	-$40,007

Table 19. PVRR 2040 and 2028 Coyote Withdrawal – Externalities Included

	2023 Base Case PVRR ($000)	Preferred Plan PVRR ($000)
Withdraw from Coyote 12/31/2040	$3,257,885	$3,312,474
Withdraw from Coyote 12/31/2028	$3,152,731	$3,199,210
2028 Difference from 2040 Exit	$105,154	-$113,264

B. CEOs

As described above, the CEOs modeling expert, EFG, made changes to OTP's wind, solar, and battery storage cost assumptions, certain MISO-related assumptions, and resource constraints. With these changes, EFG tested three different plans—OTP's 2028 Preferred Plan; OTP's Preferred Plan, and the CEOs Preferred Plan, which is an "all renewable and battery storage expansion plan." The CEOs found their plan to be least-cost, which is shown by the table below (in $ and % terms). The CEOs estimate that their plan is about $626 million less expensive than OTP's 2028 plan and $816 million less expensive than OTP's 2040 plan.

Table 20. Savings of CEOs Plan Compared to OTP Plans ($000)

	PVRR	Cost / (Savings) of CEOs Plan	% Cost / (Savings) of CEOs Plan
CEOs Preferred Plan	$2,196,616	-	-
Revised OTP 2028 Plan	$2,822,359	$(625,743)	(22%)
Revised OTP Preferred 2040 Plan	$3,012,835	$(816,219)	(27%)

The CEOs tested different types of renewable resources based on their ability to share or replace existing interconnection rights (i.e., surplus or replacement resources) or go through the MISO queue process (i.e., generic resources). The CEOs noted that "even if replacement interconnection was not available at either Coyote or Big Stone and those resource additions in CEOs Plan were made through generic wind and battery procurements instead, the CEOs Preferred Plan would still cost $716 million less (23% less) for Otter Tail customers than the Revised OTP Preferred 2040 Plan, and $525 million less (18.6% less) than the Revised OTP 2028 Plan."[61]

As noted above, OTP did not allow sales into the MISO market, and therefore any possible sales revenue was not considered. While the CEOs did allow spot market energy sales, the CEOs experimented with turning energy sales off in the model. Doing so reduced the cost savings of the CEOs Preferred Plan, but the CEOs Preferred Plan was still $407 million cheaper than OTP's 2040 Coyote Plan.

II. Resource Adequacy, Energy Availability, and Fuel Assurance

A. OTP

According to OTP, in addition to the EnCompass modeling, "dispatchability, fuel supply and deliverability, price assurance, and other attributes that contribute to the resilience of the resource portfolio" are important attributes of a reasonable plan. These attributes were highlighted during the 2014 Polar Vortex, Winter Storm Uri in 2022, and Winter Storm Elliot in 2022. During these events, "renewable generation was at times not available, natural gas

[61] CEOs initial comments, p. 51.

availability was at times limited, and electricity market prices and natural gas prices were at times extremely high."[62]

OTP stated that "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."[63]

Additionally, Winter Storm Elliot "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."[64]

The Updated IRP expressed concern about the possibility that these extreme events may be occurring more frequently. OTP stated: "It is noteworthy that two extreme weather events causing market disruptions and volatility (Winter Storms Uri and Elliot) occurred within a 22-month period."[65]

In the Initial Filing, OTP discussed the concept of "resilient" generation, while the Updated IRP discussed the same concepts but were referred to as "fuel-assured resources." As Staff understands it, "resilient" and "fuel-assured" are basically the same idea; for instance, OTP stated in response to the OAG's comments that "[t]he OAG Comments also suggest there is a significant distinction between fuel assurance and resilience. There is not."

The following table shows the current resilient/fuel-assured resources on OTP's system. OTP uses the amount of resilient generation to calculate its exposure to the spot market. Note that zero MW are given to Astoria as OTP does not consider Astoria to be resilient without dual-fuel capability.[66] The green-shaded column shows 720 MW of winter season resilient/fuel assured generation, and Astoria is currently <u>not</u> assumed to be a resilient/fuel-assured resource

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[62] Updated IRP, p. 16.

[63] Updated IRP, p. 28.

[64] Updated IRP, p. 29.

[65] Updated IRP, p. 29.

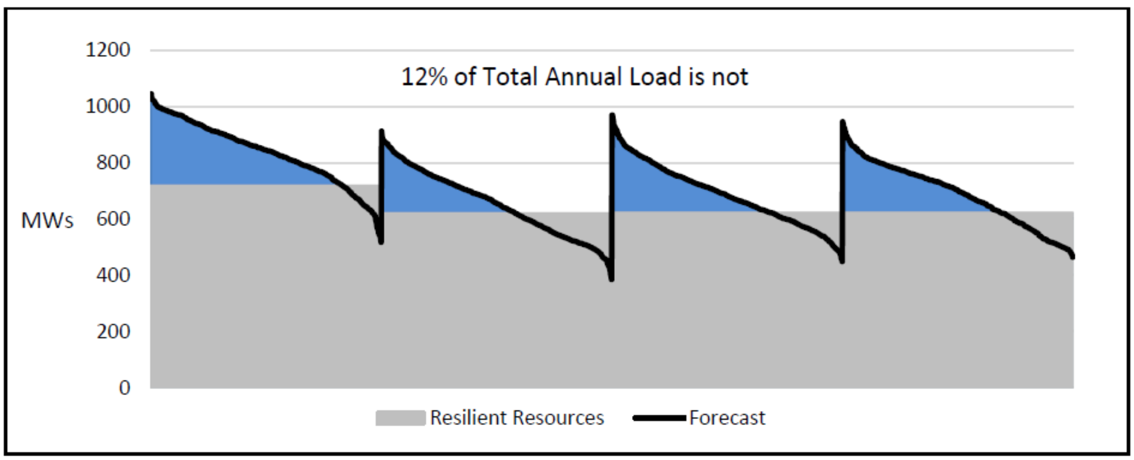
[66] Updated IRP, Supplemental Table 4-1, p. 17.

Table 21. Resilient Generation (in Installed Capacity)

	2023			
	Summer	**Fall**	**Winter**	**Spring**
Big Stone	256	256	256	256
Coyote Station	149	149	149	149
Astoria (no LNG)	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***

OTP's seasonal load duration curves below compare total resilient generation capabilities to forecasted hourly load to assess market exposure. In 2023, OTP calculated that 12% of its total annual load will not be covered by resilient/fuel assured generation. Note that market exposure assumes that "variable resources were not generating at the time load exceeded the resilient generation capabilities."[67] The four areas reflect different seasons, and the gray-shaded areas shows OTP's resilient/fuel assured resources. In the winter, OTP has 720 MW of resilient, fuel-assured resources, but the peak hourly load is approximately 1,000 MW.

Figure 8. 2023 Forecasted Load Relationship with Resilient Generation[68]

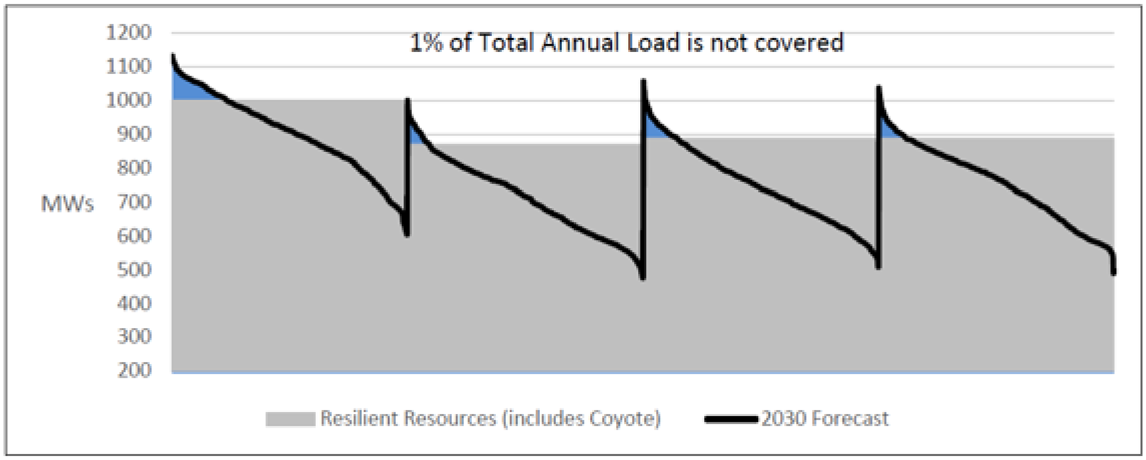


The next figure shows resilient generation in 2030 with the Astoria LNG project. Here, winter resilient generation increases to 1,000 MW (720 MW + 280 MW from Astoria = 1,000). Here OTP is able to almost completely cover its load with resilient/fuel assured resources.

[67] Updated IRP, p. 18.

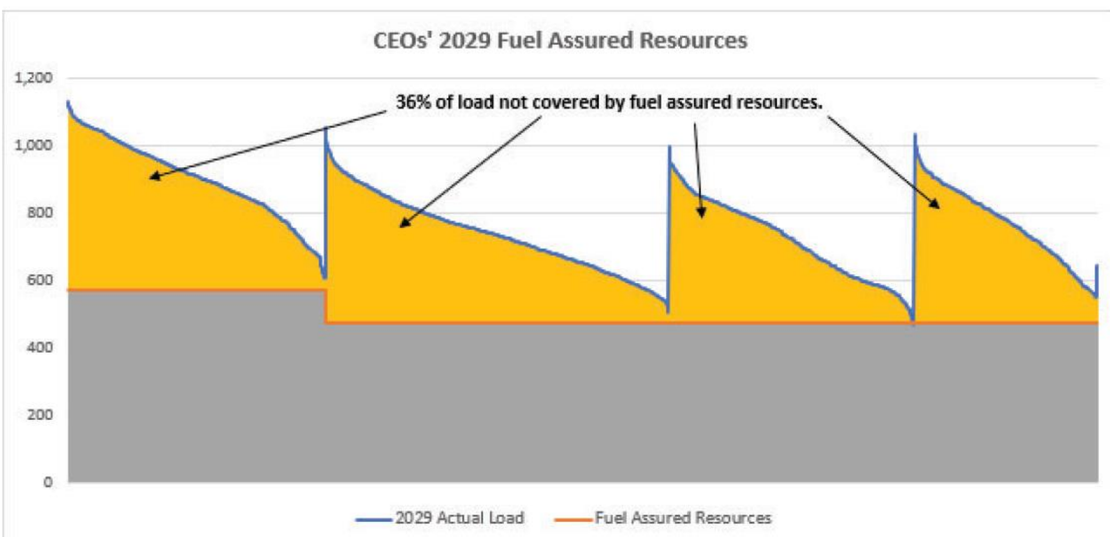
[68] Staff believes OTP's table is supposed to read "12% of Total Annual Load is not covered by resilient resources."

Figure 9. 2030 Forecasted Load Relationship with Resilient Generation (including Coyote Station)



In OTP's reply comments, the Company performed a similar analysis of the CEOs Preferred Plan. OTP calculated the percent of load exposed to the market in 2029 and 2031—the years following withdrawal from Coyote and Big Stone, respectively. Without Coyote Station or the Astoria LNG Project, OTP calculated that 36% of the Company's load would not be covered by fuel-assured resources in 2029 under the CEOs' Preferred Plan:[69]

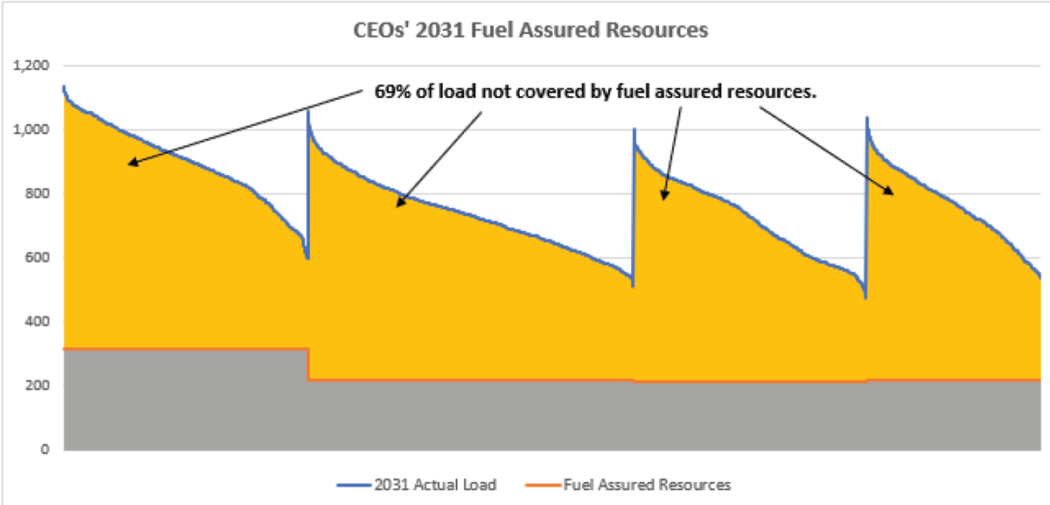
Figure 10. CEOs' 2029 Fuel Assured Resources



In 2031, without the Astoria LNG project, Coyote Station, or Big Stone, OTP calculated that 69% of OTP's load would not be covered by fuel-assured resources under the CEOs plan:

[69] OTP reply comments, Figure 1, pp. 14-15.

Figure 11. CEOs' 2031 Fuel Assured Resources



OTP then stated how the Commission should interpret these findings:

> As demonstrated above, the CEOs' plan would have Otter Tail rely entirely on MISO to serve the Company's customers by allowing for significant deficits in fuel assured generation. The CEOs propose that Otter Tail's customers be exposed to significant levels of energy market purchases at inopportune times, which is not prudent utility planning and exposes customers to significant financial risk.[70]

B. CEOs

To assess the energy adequacy of the CEOs Preferred Plan under winter peak conditions, EFG reviewed hourly detailed output of OTP's system on two winter peak days in 2029. Winter peaks days in 2029 were chosen in order to perform the hourly analysis with Coyote Station offline but with Big Stone still available.[71,72] The CEOs explained:

> On the first peak winter day we evaluated in 2029 when Big Stone is still available, <u>CEOs' resource portfolio is able to export energy to MISO in nearly every hour and has surplus capacity</u>. Otter Tail has an additional 350 MW of peaking units and approximately 130 MW of winter demand response resources which are not called on.
>
> . . .

[70] OTP reply comments, p 15.

[71] CEOs initial comments, Attachment 1 – EFG Report, p. 33.

[72] Note that EFG had to change some of OTP's assumptions because in many hours the model was choosing MISO market purchases over the dispatch of some of OTP's existing resources for economic purposes. Therefore, EFG (1) increased market prices to ensure existing resources would be dispatched first and (2) allowed OTP's demand response resources to be called. The representative days are shown in Figures 4 and 5 of the CEOs initial comments and will be summarized in the Staff Discussion where Staff returns to this issue.

> The second day we investigated was both a peak day and had low wind output, especially for the new wind resources added by CEOs' plan. On this day, EFG adjusted the market price forecast upwards to ensure that Otter Tail's resources were dispatched before the model turned to market purchases in order to better reflect a "worst case" high priced winter day. This led to additional contributions from peaking units and demand response compared to the first winter peak day. Market purchases on this day account for on average 2% of Otter Tail's hourly demand.[73]

EFG ran the same type of analysis in 2031—i.e., without Coyote or Big Stone:

> In 2031, after both coal units are removed from Otter Tail's fleet, CEOs Preferred Plan is still able to provide energy availability during winter peak and low wind generation days. Even on a low wind availability day, we see significant energy contribution from Otter Tail's growing wind fleet, as well as solar and batteries ... On these two days, market purchases on average account for 21% and 17%, respectively, of Otter Tail's hourly demand.[74]

III. Coyote Station

A. OTP

1. Factors to Consider

OTP emphasized that any discussion regarding withdrawal from Coyote Station must consider, at a minimum, the following factors:

- **Capacity needs:** OTP must have sufficient generation to provide reliable service to its customers.
- **Regulatory approvals:** Any withdrawal plan "is premised and conditioned on the support of the Company's regulators, particularly the state commissions regulating Otter Tail's rates . . . [and] 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."[75]
- **Environmental Compliance:** The base modeling assumption reflects the North Dakota Department of Environmental Quality (ND DEQ) proposed State Implementation Plan (SIP) that Coyote Station does require any emissions controls—in other words, $0 for

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[73] CEOs initial comments, pp. 55-56.

[74] CEOs comments, p. 56.

[75] OTP Supplement, p. 42.

any potential compliance with EPA rules. However, OTP modeled Regional Haze sensitivities.

- **Operational Matters:** While OTP stated that it is open to conceptual ideas about solar or natural gas at Coyote Station, "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."[76]

- **Community impacts:** OTP stated that "Coyote Station is important both to the adjacent mine and the local community," and withdrawal/retirement plans will be "determined through consultation with community members and elected officials." This will include a transition plan for the Company's workforce currently operating the plant.

2. Price Stability

From a system perspective, OTP emphasized the benefit of price stability. The table below shows the net system cost of energy paid by OTP's customers since 2013 and illustrates the benefits of OTP's "consistent and cost-effective portfolio of resources over that period."[77]

Table 22. Net Cost of Energy Paid by OTP Customers since 2013

Calendar Year	Net System Cost of Energy ($/MWh)[78]
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

Specific to Coyote Station, Figure 5-1 of the Updated IRP – which is not included in the briefing papers because it was marked trade secret – provides a year-over-year comparison for Coyote revenues and total costs (fixed and variable) from 2017-2022. According to OTP, this figure

[76] OTP Supplement, p. 44.

[77] Updated IRP, p. 36.

[78] 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.

illustrates that Coyote Station's cost stability over time, even as markets have fluctuated, demonstrates the limitations of a production cost analysis:

> 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).[79]

3. Complexities of Co-ownership

OTP urges the Commission to consider the complexities of withdrawing from contractual agreements with other co-owners. For instance, OTP stated that:

> 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 [like Big Stone] that affect any withdrawal analysis.[80]

A Coyote Station retirement and/or withdrawal analysis should also recognize the complexity of changes to transmission rights among co-owners. OTP explained:

> The Coyote Station co-owners are parties to a 1978 transmission facilities agreement (TFA) [81] that predates the formation of Regional Transmission Organizations (RTO's). FERC has deemed the TFA as a grandfathered agreement (GFA).
>
> . . .
>
> Otter Tail's withdrawal from Coyote Station or the plant's early retirement would likely require the co-owners to negotiate ownership and transmission service rights currently addressed by the TFA and any such arrangements would require FERC review and approval, while considering MISO tariff provisions. The nature of those negotiated changes could affect the TFA's status as a FERC grandfathered agreement. If FERC were to remove the TFA's grandfathered designation, there could be significant financial and operational implications for Otter Tail, including

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[79] Updated IRP, p. 38.

[80] Updated IRP, p. 13.

[81] OTP stated, "The primary purpose of the TFA was to facilitate the coordinated and efficient construction of transmission facilities needed to deliver the Coyote Station's electricity. The co-owners share in maintenance costs for commonly-owned assets and do not do so for discretely-owned assets."

> changes in Otter Tail's transmission service rights and FTR rights and revenues, the nature and scope of which cannot be estimated or predicted at this time.[82]

In reply comments, OTP clarified that "Otter Tail has no unilateral right to withdraw from Coyote Station. Instead, each Coyote Station co-owner, including Otter Tail, has a right to terminate the Coyote Station Plant Ownership Agreement upon not less than five years advance notice, with the earliest termination date possible being December 31, 2021.[83]

In summary, to withdraw from its ownership interest in Coyote Station, OTP must either:

1. divest its ownership shares to another co-owner or third-party and secure releases from those obligations; or

2. terminate the co-tenancy in the plant under the ownership agreement.

OTP noted that "termination of the Plant Ownership Agreement does not cause the automatic termination of the Lignite Sales Agreement (LSA)."

In the event of a 2028 buy-out, OTP projected it would be obligated to pay approximately $21.7 million. However, 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. This $21.7 million estimate will be discussed further in the next section.

4. Costs of Withdrawing from Coyote Station

OTP explained that there are two general cost categories to withdrawal: (1) undepreciated net book value, and (2) early termination costs under the LSA. OTP's economic analysis developed for the Initial Filing assumed a "conservative estimate" of $68.5 million to withdraw from Coyote Station at the end of 2028.[84] The table below shows that this amount is the sum of undepreciated book value, which is based on Coyote Station's remaining depreciable life that currently extends to 2041, plus costs for decommissioning and early termination of the lignite supply agreement (LSA).

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[82] OTP reply comments, p. 36.

[83] "If not sooner terminated pursuant to §22.1, this Agreement shall terminate on December 31, 2021, or at any time thereafter, upon request made by any Owner to the other Owners not less than five years prior to the termination date (which the requesting Owner shall specify in its request for termination). In the event such request for termination is made, the Plant Property shall be sold in the manner and upon the terms approved by the Coordination Committee during the last year of the term of this Agreement, and the net proceeds realized from such sale shall be divided among the Owners according to their Ownership Shares." Coyote Station Plant Ownership Agreement Section 22.2."

[84] 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.

Table 23. OTP Share of Coyote Station Estimated Foreseeable Withdrawal Costs

	Forecast (in $millions)	
Coyote Station	**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**	**68.5**

* Project Book Balances in 2023: March 31, 2023: $58.31M, YE 2023: $55.21M
**This is the Coyote End of Life book value collected and accumulated in the current depreciation rates for the decommissioning of the plant.

Again, OTP clarified that the Company is requesting authority to withdraw from Coyote if a "large, non-routine capital investment is required," which OTP emphasized "should be distinguished from routine capital investments necessary for the plant to operate safely, reliably, and in compliance with current regulations."[85]

B. CEOs

While OTP characterized its decision to retain ownership in Coyote as a "cautious and measured approach" in light of the uncertain planning environment, the CEOs responded that:

> Hanging onto Coyote until a major new cost is forced upon the plant is an unduly risky approach that results in higher customer costs and does not meet the standards that Minn. Stat. § 216B.2422 and the Commission's planning rule require.[86]

The CEOs cited the following risks associated with continuing to operate Coyote Station:

- OTP's Initial Filing showed that withdrawing from Coyote in 2026 yielded even greater savings than withdrawing from it in 2028.
- In the self-commit docket, OTP also provided ample evidence of the financial risks faced at Coyote due to having a co-owner that could force OTP to run the plant at a market loss.
- OTP has been discussing regulatory risks attached to Coyote Station's carbon and criteria emissions, including the cost of Regional Haze Rule compliance, since its last IRP.

The CEOs summarize its position on Coyote as follows:

> In summary, in the large majority of Otter Tail's sensitivities, withdrawal from Coyote in 2028 is a clearly superior course of action. The few scenarios that show the opposite are underpinned by extreme and unlikely scenarios: energy market

[85] Updated IRP, p. 38.

[86] CEOs initial comments, p. 15.

> and natural gas prices doubling over the (relatively high) base forecast; load increasing by 25% over the base forecast; resource accreditations for wind, solar, and storage being cut in half; and renewable energy prices remaining at recent highs for the full planning period. Of course, these runs also fail to reflect the impact of EPA's proposed GHG rule, which would only provide further support for the 2028 retirement date. CEOs' re-runs of these scenarios show that even under the most extreme assumptions about the future, it only appears financially advantageous to delay withdrawal from Coyote if one ignores any potential future regional haze compliance and any carbon regulatory costs. It is clear then that delaying withdrawal from Coyote until 2040 is simply not reasonable.[87]

1. EnCompass Modeling

Table 1 of the CEOs' initial comments provide a summary of OTP's sensitivity results, which compare the cost or savings (in PVRR) resulting from a 2028 Coyote exit compared to a 2040 Coyote exit. All sensitivities with environmental externalities support early exit. Most of the sensitivities which did not consider environmental externalities still showed early exit to be least-cost, and the 2040 Coyote exit was least-cost only under those scenarios which the CEOs' believe to have used "extreme assumptions." Staff also notes that early exit was less expensive under every scenario which considered Regional Haze compliance costs, which Staff highlighted in green.

[87] CEOs initial comments, p. 28.

Table 24. OTP Sensitivities A-U, PVRR Comparisons of 2028 vs. 2040 Plans

		Cost (Savings) of 2028 Coyote withdrawal Compared to 2040 withdrawal ($000)	
	Scenario Name	**No Externalities Included**	**Externalities Included**
A	2023 Base Case	($28,173)	($105,154)
A.1	Preferred Plan	($40,007)	($113,264)
B	Natural Gas & Energy Markets (NGEM) +50%	($27,223)	($80,510)
C	NGEM +100%	$230	($54,033)
D	NGEM -50%	($41,494)	($106,873)
E	Regional Haze (RH) Mid Cost	($83,982)	($155,499)
F	RH Mid Cost NGEM +100%	($53,899)	($1,096,581)
G	RH High Cost	($103,845)	($179,189)
H	RH High Cost NGEM +100%	($72,677)	($1,115,381)
I	10% Increased Load	($13,950)	($104,668)
J	10% Increased Load NGEM +100%	$6,503	($64,565)
K	25% Increased Load	$33,386	($97,300)
L	25% Increased Load NGEM +100%	$18,516	($45,720)
M	High Renewable Accreditation	($51,225)	($114,143)
N	Low Accreditation	$37,082	($26,297)
O	Carbon Tax	($134,913)	
P	Renewable High Cost	$37,531	($85,272)
Q	Renewable High Cost NGEM +100%	$42,196	($24,053)
R	Solar and Battery Low Cost (40% ITC)	($32,992)	($113,658)
S	Low Accreditation RH High	($39,099)	($93,888)
T	25% Increased Load RH High	($39,845)	($164,207)
U	Renew High Cost RH High	($39,166)	($158,931)

The table shows that 7 out of the 22 futures in the No Externalities case show it is least-cost to operate Coyote through 2040. These 7 futures include combinations of (1) a 100% increase in both gas prices and energy market prices; (2) a 10-25% increase in load; (3) high renewable energy costs; and (4) low resource accreditations. Staff isolated these 7 futures from Table 24 into Table 25 below:

Table 25. OTP Sensitivities C, J, K, L, N, P, and Q
PVRR Comparisons of 2028 vs. 2040 Plans

		Cost (Savings) of 2028 Coyote withdrawal Compared to 2040 withdrawal ($000)	
	Scenario Name	**No Externalities Included**	**Externalities Included**
C	NGEM +100%	$230	($54,033)
J	10% Increased Load NGEM +100%	$6,503	($64,565)
K	25% Increased Load	$33,386	($97,300)
L	25% Increased Load NGEM +100%	$18,516	($45,720)
N	Low Accreditation	$37,082	($26,297)
P	Renewable High Cost	$37,531	($85,272)
Q	Renewable High Cost NGEM +100%	$42,196	($24,053)

CEOs' responses to these 7 futures explained why they believe the assumptions are unreasonable:

- **Scenario C** assumes natural gas and energy market (NGEM) prices are twice as expensive as the base assumption. First, the CEOs stated that the Commission should consider not just one data point in the range but the complete range of NGEM prices. As shown in the table below, the three other NGEM sensitivities all show the 2028 Coyote exit to be least-cost (notably, these are from the No Externalities runs). Additionally, the magnitude of savings from early exit under these three other NGEM runs are much greater than the small net cost of early exit under the NGEM +100% run.

Table 26. Cost (Savings) under NGEM Sensitivities

	2023 Base Case	**Nat. Gas & Energy Market (NGEM) +50%**	**NGEM +100%**	**NGEM -50%**
Cost (Savings) from 2028 exit vs 2040 exit (PVRR)	($28,173,000)	($27,223,000)	$230,000	($41,494,000)

- **Scenarios J, K, and L** rely on assuming a 10% or 25% increased load forecast over the planning period. First, the CEOs noted that OTP's IRP forecast understates by one-third the actual energy conservation OTP plans to achieve over the next three years. Second, the CEOs argued that the higher load sensitivities incorporated "new large agricultural processing customers and what CEOs understand to be crypto-currency mining customers." According to the CEOs, these loads are uncertain, they could be curtailable loads, and the agricultural and crypto companies have pledged to be net-zero, so it would be antithetical to reference these customers to justify continued operations of a coal plant.

- **Scenario N** assumes low capacity accreditation for renewable resources. As discussed previously, the CEOs believe OTP unreasonably cut accreditation values for wind, solar, and battery in each season by in the "low accreditation" scenario, while not adjusting accreditation for its thermal units or its seasonal PRMR. Therefore, OTP's low accreditation scenario "paints a one-sided and incomplete picture" in a way that is "more pessimistic for clean energy resources than is reasonable."

- **Scenarios P and Q** assume high costs for renewable resources will persist in the long term. The CEOs argued that OTP's base renewable price assumptions are already unreasonably high, as they understate the tax credits available under the IRA and fail to account for supply chain and transmission availability benefits that will likely be realized by domestic clean energy manufacturing initiatives, LRTP, and interconnection reform.

2. Environmental Compliance/Regulatory Costs

The CEOs do not believe it is plausible that Coyote will not undergo any pollution control through 2040, as OTP assumed. In part, this is due to the high emissions rates of Coyote even relative to other coal plant, and it is because EPA already warned North Dakota before it submitted the SIP that "the state should reassess its determination that SO_2 and NO_X controls are not warranted for Coyote."[88,89]

Not only do the CEOs argued that Regional Haze compliance costs are likely, but costs may be much higher than OTP estimated in its sensitivity analysis. Based on comments from the ND DEQ SIP proceeding, the CEOs asserted that OTP may be "seriously understating the compliance cost risks." For context, Staff provides the following excerpt from the CEOs comments:

> In June 2022, the National Parks Conservation Association, Sierra Club, and Badlands Conservation Alliance (collectively, "Conservation Organizations") submitted comments on the North Dakota Department of Environmental Quality's ("DEQ's") proposed SIP, identifying serious problems with it. Those comments found that North Dakota DEQ's proposal impermissibly exempted Coyote from technically feasible, cost-effective controls. Specifically, in order to comply with the regional haze provisions of the Clean Air Act, the Conservation Organizations noted Coyote should be required to install selective catalytic reduction ("SCR") controls to reduce its NOx emissions, and that the plant should be required to install a dry scrubber system to control SO_2 emissions.
> . . .
> [T]he Conservation Organizations' expert recommended that EPA require both SCR technology and a dry scrubber at Coyote. His detailed analysis estimated that a new SCR would cost $185 million and that a dry scrubber replacement would

[88] CEOs initial comments, p. 30.

[89] EPA Comments on the North Dakota State Implementation Plan for Regional Haze (RH SIP) - Draft for Federal Land Manager Review, June 1, 2022, p. 6. These comments are included as an embedded attachment in the North Dakota Regional Haze SIP, App. D.6-583, available at https://deq.nd.gov/aq/ planning/RegHaze.aspx.

> cost $193 million, for a total of $378 million. Otter Tail's share of that cost would be $132 million. Even Otter Tail's own compliance cost analysis, performed by Sargent & Lundy, estimated Otter Tail's share of compliance costs would be between $51.1-93.5 million (assuming a NOx control technology far less effective than SCR and depending on the level of scrubber replacement). Otter Tail thus appears to be seriously understating the compliance cost risks for this regulation in the sensitivities where it considers them.[90]

Regardless, according to the CEOs, while the ND DEQ proceeding indicates higher compliance costs than the IRP assumptions, OTP's IRP modeling still shows the 2028 Coyote exit to be approximately $84-104 million less expensive on a PVRR basis than the 2040 Coyote exit.

In addition to the regulatory compliance risks posed by the Regional Haze Rule, the CEOs argued that Coyote Station also faces regulatory risk under both the EPA's proposed GHG rule for existing plants and EPA's proposed Mercury and Air Toxics Standard (MATS). According to the CEOs, neither the OTP Preferred 2040 Plan nor the OTP 2028 Plan would comply with either of these regulations.

The CEOs acknowledged that the rules are still in their proposed form, but "none of the [IRP] futures include any cost to comply with the EPA's proposed GHG rule."[91] This is particularly troubling considering the MATS rule "focuses particularly on bringing mercury emissions from lignite-fired coal plants like Coyote down to the level of other coal plants." The CEOs noted that Coyote Station has one of the highest mercury emissions rates in the nation, and in 2022, Coyote emitted mercury "at a rate approximately three to five times higher than any other coal plant in Minnesota and South Dakota."[92]

3. Climate and Public Health Considerations

The CEOs calculated that under the OTP Preferred 2040 Plan, CO_2 emissions "largely plateau in the 2030s and show a rise by the end of the decade." Under the OTP 2028 Plan, CO_2 emissions decline until 2032, then begin to climb again until the mid-2040s.[93]

The CEOs quantified the societal impact of OTP's plans using the full range of EPA's social cost estimates, which was required under the amendments to Minn. Stat. § 216B.2422, subd. 3[94] and recently adopted by the Commission. The CEOs' modeling showed:

- The OTP Preferred 2040 Plan would result in between $2.5 and $7.7 billion in climate

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[90] CEOs initial comments, pp. 30-31.

[91] CEOs initial comments, p. 19.

[92] CEOs initial comments, p. 35.

[93] CEOs initial comments, p. 79.

[94] Laws of Minnesota 2023, chapter 7, section 18.

damage using the full range of EPA cost estimates, with a central estimate of $4.3 billion in damage.

- The OTP 2028 Plan would cause between $1.9 and $6.0 billion in climate damage, with a central estimate of $3.3 billion in damage.

Note that these estimates reflect only the costs of CO_2 emissions associated with Minnesota's share of OTP's energy sales.

The CEOs retained Physicians, Scientists, and Engineers for Healthy Energy (PSE) to provide expert analysis of health and equity issues, and PSE's report is Attachment 2 of the CEOs' initial comments. The report describes the "considerable harm to human health that results from continuing to run the Coyote and Big Stone plants, and the extent to which these harms fall disproportionately on vulnerable populations, especially Native communities."[95]

PSE used 2020 emissions data from the National Emissions Inventory (NEI) and 2020 electricity generation from the Energy Information Administration (EIA) to establish each plant's historical emissions and to calculate emission factors for each facility. The emissions rate for Coyote Station compared to Big Stone is shown in the table below. Note that while Coyote Station and Big Stone have similar carbon intensities, Coyote has a significantly higher emissions rate for NO_X, SO_2, and $PM_{2.5}$.

Table 27. PSE Report: 2020 annual coal power plant emissions and electricity generation

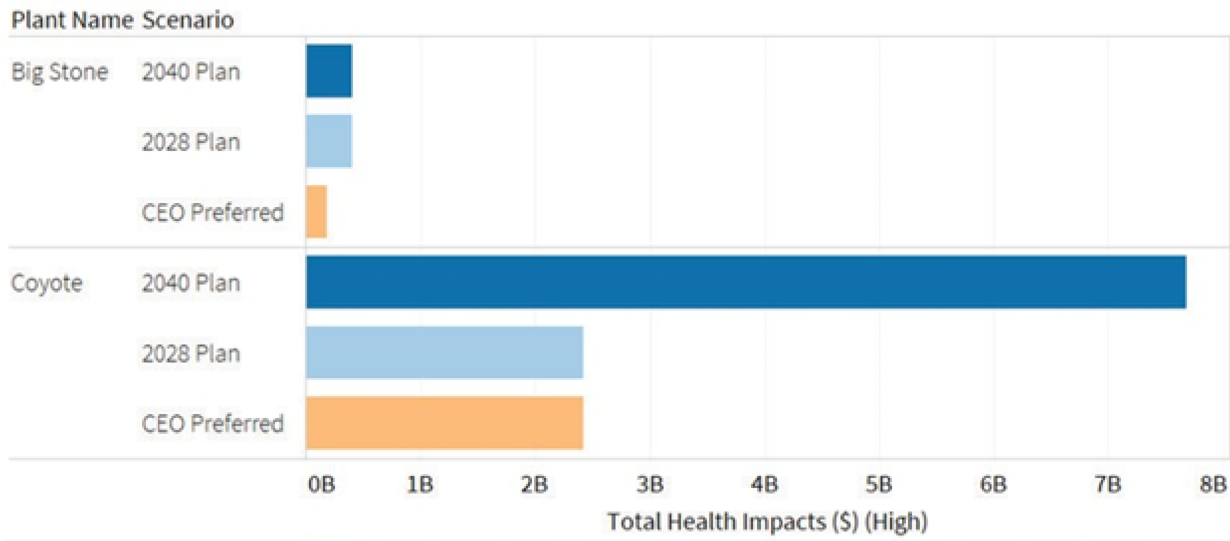
Plant Name	Generation *MWh*	Carbon Dioxide (CO_2) *Tons/MWh*	Nitrogen Oxides (NO_x) *Lbs/MWh*	Sulfur Dioxide (SO_2) *Lbs/MWh*	Particulate Matter ($PM_{2.5}$) *Lbs/MWh*	Volatile Organic Compounds (VOCs) *Lbs/MWh*
Coyote	2,380,100	1.22	4.94	10.06	0.38	0.06
Big Stone	1,648,200	1.26	0.95	0.81	0.03	0.08

The magnitude of these health savings are shown in the figure below, which are represented in dollar savings.[96]

[95] CEOs initial comments, p. 4.

[96] CEOs initial comments, Attachment 2, p. 17.

Figure 12. PSE Report: Total Health Impacts by Power Plant



a. OTP Reply

OTP stated that the Company "identified significant errors and missing context in the PSE Report that that undermine its conclusions," including inaccurate statements about OTP rates and that PSC "gives little, if any consideration to the regional socioeconomic benefits provided by Coyote Station and Big Stone Plant." OTP stated the report "also fails to acknowledge that Coyote Station and Big Stone Plant have strong track records of environmental compliance and sustainability." OTP noted that the similar to PSE's report in Minnesota Power's most recent IRP docket,[97] which contained similar flaws.

4. MISO Y-2 Study

The CEOs believe there is a "reasonable possibility Coyote will cease operations in or around 2028 due to the costs of environmental compliance and/or due to a request from Otter Tail to terminate the operating agreement." Therefore, the CEOs recommend the Commission require OTP to request an Attachment Y-2 study "to identify the types and scale of reliability challenges a potential retirement could pose, and if any such issues are identified, to begin work to define mitigations to those issues."[98]

a. OTP reply

OTP did not object to the CEOs' recommendation to submit <u>a non-binding Y- 2 study request to MISO</u> to determine Coyote Station retirement impacts, but OTP noted that "<u>the Commission should recognize the limited value of a Y-2 study</u>." OTP stated that MISO would assess issue "at or near the time of the request," which in this instance could presumably be years in advance of

[97] Docket No. 21- 33

[98] CEOs initial comments, p. 40.

a potential Coyote Station withdrawal or retirement." Moreover, a Y-2 study could not account for the co-ownership issues, including transmission rights under a withdrawal scenario, as well as the fact that OTP's co-owners "have not signaled a present intention to retire the plant."

b. Staff Comment

Like OTP, Staff questions the value of a Y-2 study for Coyote Station, given the co-ownership complexities and jurisdictional issues at play. First, at the present time, it does not appear the plant will retire in the event of OTP divests from Coyote in 2028. Second, the Commission cannot legally require that a power plant in another state be shut down.

On the other hand, throughout the filings, OTP has maintained that (a) Coyote Station has critical reliability attributes, but (b) in the event the plant may need to install pollution controls, the co-owners may decide to close it down. Assuming (a) is true and (b) is possible, it could be instructive to the Commission's decision for the next IRP to have an accompanying Y-2 study. After all, even though OTP does not propose the 2028 exit plan at this juncture, OTP did state that "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."[99] Thus, a Y-2 study could be a useful "for the next IRP" Commission requirement, which OTP stated it does not oppose.

Staff notes that in Xcel Energy's 2015 IRP, the Commission required that Xcel shall, for its next IRP, "describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island testing combinations of baseload retirement scenarios."[100] As part of its 2019 initial filing, Xcel provided seven Attachment Y-2 studies by MISO, along with a more traditional NERC-based analysis of its fleet by an external consultant. While Staff is not suggesting such a wide-scoping level of analysis here, Staff believes that requiring a Y-2 study to accompany OTP's baseload analysis in the next IRP would be consistent with past practice.

C. OAG

Like the CEOs, the OAG pointed to OTP's own modeling, which showed early withdrawal from Coyote Station to be the most cost-effective course of action, regardless of whether major upgrades were needed to comply with the Regional Haze Rule. In the Initial Filing, retaining ownership in Coyote was economic in only two sensitivities. In the Updated IRP, even when environmental externalities were excluded, withdrawing from Coyote by 2028 was least-cost. Therefore, the OAG recommends the Commission direct OTP to withdraw from Coyote Station by 2028 as originally proposed in the Company's Initial Filing:

> According to Otter Tail's modeling, exiting Coyote Station in 2028 would save $113

[99] Updated IRP, p. 39.

[100] Docket No. 15-21, Commission Order (January 11, 2017), Order Point 14.a.

> million when counting externality values. Because early withdrawal would minimize both customer costs and environmental costs, Otter Tail has not demonstrated that its supplemental preferred plan is in the public interest, and the Commission should direct the Company to instead pursue withdrawing from Coyote Station by 2028 as it originally proposed.[101]

The OAG also noted that "all of the scenarios Otter Tail analyzed assume full rate recovery of early termination fees under the LSA and a return on the remaining undepreciated plant balance," which the OAG believes are unreasonable assumptions. OTP assumes that $21.7 million in LSA early termination costs and a return on Coyote Station's remaining book value will be recovered by ratepayers and assumed as part of the PVRR. However, the OAG does not believe these costs should be included in the PVRR, and without them, "the case for early withdrawal becomes even stronger."[102] Having said that, whether these two costs are present in the model does not tip the scales one way or another—the model shows early exit to be economic regardless.

For additional context, the OAG highlighted Coyote Station's production cost losses OTP's last rate case[40] as well as the Commission's investigation into self-commitment and self-scheduling.[41] According to the OAG, the LSA OTP signed in 2012 has caused Coyote Station to incur millions more in production costs than it received in offsetting market revenues. The OAG maintains that ratepayers should not have to pay the exit fees from a contract the Commission never approved and which has already cost ratepayers millions. Additionally, the OAG argued that ratepayers should not pay for a return on a coal plant that is no longer serving them.

The OAG also expressed frustration that, following the Commission's 2017 IRP Order, OTP twice requested and received extensions on the filing of its next IRP, "ostensibly for the purpose of gaining certainty about federal environmental-compliance costs." According to the OAG, "[t]he resulting delay postponed Commission scrutiny of Coyote Station's economics but, ultimately, yielded no certainty about the plant's environmental-compliance costs." When North Dakota finally issued its SIP in August 2022, it did not call for any new pollution controls to be added to Coyote Station. However, the OAG noted that this "does not mean that Coyote Station will incur no compliance costs, because the EPA has the final word on the adequacy of North Dakota's proposed SIP." And while the "EPA's final decision is impossible to predict," the EPA stated that "North Dakota should reassess its determination that emissions controls are not warranted for Coyote Station."[103]

D. OTP Reply

OTP responded to the CEOs' and OAG's assertions that Coyote Station is uneconomic by stating that the plant has, through its operational life, provided customers with price stability and a

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[101] OAG initial comments, p. 16.

[102] OAG comments, p. 9.

[103] OAG comments, p. 8.

cost-effective hedge against market volatility. According to OTP, the CEOs and OAG rely on a production cost analysis to support their position, but a production-cost comparison to market prices is not a measure of cost effectiveness. OTP explained that comparisons of production costs to MISO revenues are inadequate the following reasons:

- "Unavoidable fixed costs are not considered in the production cost losses analysis. These are costs that Otter Tail would pay even if it relied entirely on the spot market.

- A generation plant's capacity function necessary to meet resource adequacy requirements is not considered in the production cost losses analysis; any assessment of the cost effectiveness must necessarily consider replacement energy and capacity costs. By only comparing the energy production costs and MISO energy market revenues, the production cost analysis ignores a generation plant's capacity function within a resource portfolio.

- A production cost analysis is based on an incorrect premise that a utility would simply rely upon the spot market to serve its customers in the absence of the generation plant in question. In reality, a utility would secure a replacement resource or resources to provide capacity and energy benefits to provide certainty to its resource mix rather than relying on day ahead energy markets and exposing customer to fluctuating prices."[104]

In response to the OAG's discussion of its analysis in the self-commit docket, OTP stated that in the self-commit docket, OTP performed the same production-cost analysis for its most recent major wind PPA, Ashtabula III. The results showed proportionally greater production cost losses for the Ashtabula III PPA than for Coyote Station, but this does not mean that OTP's wind PPAs are not cost-effective; rather, it means they are not able to flexibly respond to market prices.

IV. Big Stone

A. CEOs

One of the CEOs' criticisms of OTP's modeling is that the Company did not examine any early retirement dates for Big Stone. The CEOs conducted EnCompass modeling which showed that OTP's plan to retain an ownership stake in Big Stone until 2046 is not in the public interest. CEOs' EnCompass modeling shows that exiting Big Stone in 2030 (in addition to exiting Coyote in 2028) and adding more wind and battery storage will cost less, reduce regulatory risk, and greatly reduce externalities compared to Otter Tail's plan to depend on Big Stone until 2046.

The CEOs' No-Big Stone scenario considered up to 250 MW of replacement resources, although 150 MW of a four-hour battery was a fixed resource. EnCompass was then allowed to optimize the remaining 100 MW by choosing between replacement solar, wind, and/or additional battery storage resources, and EnCompass selected 100 MW of wind.

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[104] OTP reply comments, p. 42.

1. OTP Reply

OTP responded that the record is not sufficiently developed to take any action on Big Stone, and any changes to current operations at Big Stone would be very significant. OTP stated that the following issues, none of which were examined by the CEOs, require consideration before assessing withdrawal from Big Stone:

1. the support of state commissions in the Company's three-state footprint;

2. an analysis of alternatives and options with our co-owners;

3. consideration of the impact on the host communities of Big Stone City, South Dakota (and adjacent Ortonville, Minnesota);

4. replacing the reliability attributes of the plant, and in a cost-effective manner; and

5. a rate impacts analysis resulting from necessary changes to the plant's depreciation schedule, especially in light of the capital investment for the AQCS project.

OTP explained that while Big Stone and Coyote Station have many similar co-ownership and operating complexities, there are important differences the Commission must consider. In particular, the Commission should consider that Big Stone is a much larger plant than Coyote, and it was recently retrofitted with a $364 million AQCS project.

V. Astoria LNG Project

A. OTP

OTP argued that the record supports adding onsite LNG fuel storage at Astoria Station by 2026 because dual fuel capability will:

- Provide reliability benefits by ensuring that fuel will be available even during extreme events;
- Provide rate stability for customers; and,
- Protect against price spikes.

OTP stressed that given the risks posed by Winter Storm Uri and Winter Storm Elliott – with Winter Storm Elliott being particularly challenging due to OTP's inability to procure fuel – the Commission should approve dual fuel capability <u>in this IRP cycle</u>. Deferring action until OTP's next IRP "increases the risk of another extreme event testing reliability and markets."

A. CEOs

CEOs recommend the Commission defer a decision on dual fuel at Astoria until OTP's next IRP. CEOs submit that "there is no imminent need for this addition while Otter Tail is still operating two large dispatchable resources." CEOs recognize that OTP may have a need for firm dispatchable capacity and fuel assurance once it no longer includes multiple large dispatchable generators, but this type of "insurance policy" is currently premature.[105]

In response to OTP's claims that "fuel assurance" is a MISO-identified reliability attribute, the CEOs stated:

> it is well known that MISO's reliability attributes discussion is still in early stages of development, and there is significant work to be done before any requirements, guidelines, or market products are established. Additionally, many of MISO's reliability attributes are meant to be looked at on a larger, system-wide scale, not utility by utility, in recognition of the regional nature of the wholesale power market and many reliability functions.[106]

The CEOs also noted that OTP's argument that their LNG proposal is necessary to avoid excessive exposure to market risk, OTP "previously used this same justification when asking the Commission to approve the Astoria gas plant in the first place in its last IRP." The CEOs characterized OTP's solution to market risk as "a moving target, leading to new (and costly) fossil fuel investment proposals with each of OTP's last two IRPs."[107]

B. OAG

According to the OAG, OTP's dual-fuel proposal would increase ratepayer costs while "doing little or nothing to increase Astoria Station's capacity accreditation or improve system reliability." The OAG stated"

> Perhaps the biggest flaw in Otter Tail's case is its mistaken assumption that adding fuel assurance to one 245 MW generator would materially improve grid reliability. Otter Tail's system is part of a much larger, regional grid; a single utility, acting alone, cannot meaningfully improve the reliability of the MISO system, which has a peak load of more than 100 gigawatts. Neither MISO nor FERC has incentivized, much less required, onsite fuel storage for gas-fired units. Otter Tail acknowledges that MISO has not even defined "fuel assurance."[108] Yet the Company's dual- fuel proposal would preempt definitive action by MISO and FERC, the organizations responsible for deciding how to make the grid resistant to extreme weather. The Company's ratepayers should not be responsible for shoring up the reliability of the regional grid absent any requirements or incentives to do so.[109]

The OAG further argued that the Company's economic analysis "greatly overstates the

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[105] CEOs initial comments, p. 91.

[106] CEOs initial comments, p. 91.

[107] CEOs initial comments, p. 92.

[108] OTP, June 23, 2023 Supplemental Comments, p. 3.

[109] OAG initial comments, pp. 18-19.

proposal's benefits as a hedge against high market prices," which is aligned with the Department's December 30, 2022, comments. The Department concluded that "refurbishing Astoria is not justified solely based on the economic benefits as calculated by OTP."

1. OTP Reply

OTP stated that the OAG's analysis is flawed because the OAG:

- gives little consideration to the price protection and hedge value against intra-day pricing risk afforded by fuel storage
- assigns far less value to fuel assurance as a key MISO reliability attribute than MISO itself.
- overlooks the fact that fuel-assured dispatchable resources are essential to the transition to carbon- free resources.
- Inaccurately states that because other natural gas plants in the region were able to secure fuel, the Commission should discount Otter Tail's claims that it could not.
- focuses on whether plants were operating during Winter Storm Elliott without any information on when gas was procured, which renders the OAG's analysis superficial and speculative.

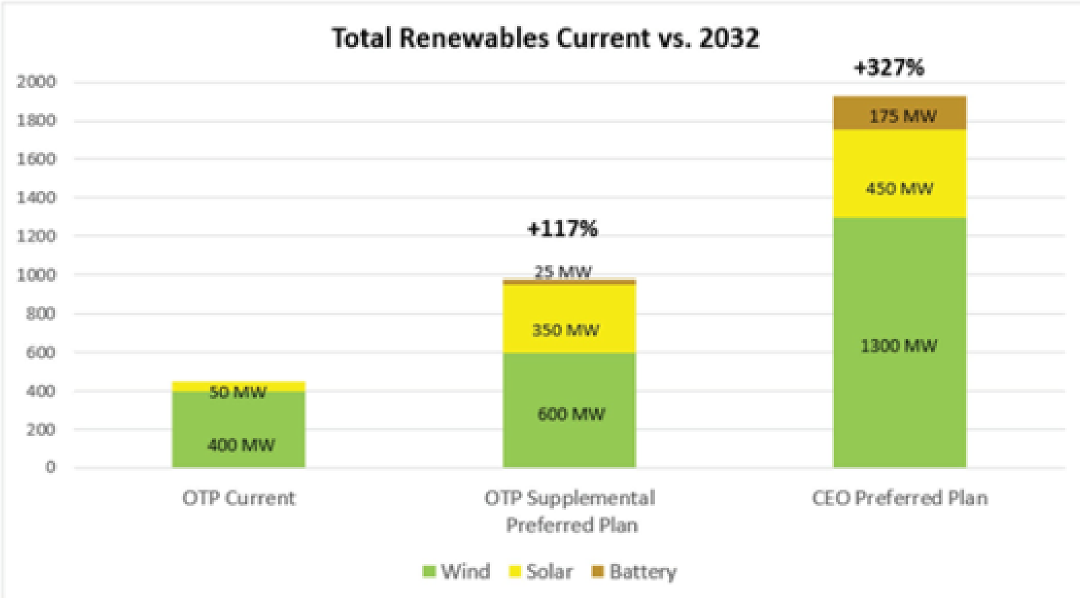
VI. Renewable Energy Acquisitions

OTP currently has about 400 MW of wind on its system, through a combination of ownership and purchased output, and about 50 MW of solar, through the recent completion of Hoot Lake Solar. Thus, OTP's five-year action plan will increase the total amount of renewables on OTP's system from about 450 MW to about 850 MW, which is an increase of roughly 90%.

OTP intends to further add about 100 MW of solar and 25 MW of battery in 2032. As shown by the figure below, this represents a roughly 117% increase relative to OTP's current system. The CEOs Preferred Plan, OTP argued, increases OTP's renewables by 327% by 2032.[110]

[110] OTP reply comments, p. 9.

Figure 13. Percent Increase in Total Renewables by 2032



OTP argued that the CEOs' recommended amount of renewables is excessive considering the size of OTP's system and would result in "significant rate pressure" for its customers:

> would create significant rate pressure for our customers through the Company's early withdrawal from Coyote Station (2028) and Big Stone Plant (2030), coupled with a massive amount of new wind resource additions and a substantial premature investment in battery storage before anticipated technological advancements have been realized.
>
> . . .
>
> Starting in 2029, the CEOs would have Otter Tail acquire 450 MW of wind resources above and beyond the 200 MW of wind resources called for by our Supplemental Preferred Plan. That is equivalent to adding *three* 150 MW Merricourt Wind Projects. Merricourt, Otter Tail's most recent wind project, was its largest ever. Indeed, it was the largest capital expenditure in the Company's history. By way of reference, Merricourt went into service in 2020 at a total cost of $258 million, before recent inflationary pressure presented itself.

VII. CFS, RES, and SES

A. OTP

As mentioned previously, OTP's IRP procedural schedule was discussed at the Commission's February 2, 2023, agenda meeting as a Discussion Item. And on February 16, 2023, OTP filed a Supplemental Letter stating, among other things, that the CFS will not impact the Astoria LNG proposal because (1) it will not change OTP's total electric sales to retail customers in Minnesota, and (2) it will not reduce the amount of electricity generated from carbon-free resources.[111]

In the Updated IRP, OTP stated that the Company is well-positioned to comply with the CFS, as the law allows utilities to comply through the retirement of RECs. In fact, with the addition of Hoot Lake Solar, OTP can cover 57% of energy sales to Minnesota customers. OTP's wind repowering plan will increase that percentage to 65% (assuming RECs from any jurisdiction can be retired to comply with the CFS).

B. Department

The Department deferred comments on CFS compliance to the Commission's *Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon Free Standard under Minn. Stat. § 216B.1691* (Docket No. 23-151):

> the Commission has opened a generic docket and has indicated it will be exploring how utilities will comply with the Carbon-free standard. The Commission's generic docket will provide additional clarity on compliance and OTP's current information should not be taken as evidence of its ability to comply or not comply with the new standard. The Department will defer further comment on the carbon-free energy standard until the Commission's investigation provides more detailed guidance.[112]

C. CEOs

The CEOs argued that OTP's compliance plan "depends on an interpretation of Minnesota's Carbon Free Standard that <u>renders the law meaningless for Otter Tail</u>." The CEOs stated that, on a system-wide basis, OTP is currently generating or procuring carbon-free generation amounting to only about 28% of its sales. By 2030, its carbon-free generation would amount to only 54-57% of retail sales. The CEOs recognized that the statute allows utilities to retire RECs, but the Commission has the authority to establish criteria for demonstrating compliance:

> While CEOs recognize that the CFS applies only to Minnesota retail sales and allows for the use of RECs for compliance, the law requires the Commission to establish the specific criteria for demonstrating compliance with the CFS. In its implementation of the CFS the Commission must, among other things, take all reasonable actions within its authority to maximize the net benefits of the law to all Minnesota citizens, including by ensuring that statewide air emissions are reduced.[113]

Additionally, the CEOs do not agree that OTP's plan is in ratepayers' best interest. Since OTP's

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[111] Supplemental Letter Addressing the MN Carbon-Free Standard, February 16, 2023, p. 2.

[112] Department comments, p. 28.

[113] CEOs initial comments, p. 12.

plan relies on "unbundled" RECs, which have value, OTP could sell unbundled RECs and acquire cost-effective renewable resources, rather than continuing to operate uneconomic coal plants and retire RECs for CFS compliance.

1. OTP Reply to CEOs

OTP responded to the CEOs comments by calling it a "flawed analysis." OTP argued that "[t]he plain language of Minn. Stat. § 216B.1691, subd. 2 and subd. 4 authorize the use of RECs as an alternative means to satisfy the CFS." While a credit may generally be used only once, OTP noted that:

> a credit may be used to satisfy both the carbon-free energy standard obligation under subdivision 2g and either the renewable energy standard obligation under subdivision 2a or the solar energy standard obligation under subdivision 2f, if the credit meets the requirements of each subdivision.[114]

OTP also stated that the CEOs' reference to OTP's <u>total system-wide retail sales</u> indicates that the CEOs apply the CFS to retail energy sales outside of Minnesota, which does not adhere to the statute.

2. Staff comment

Staff agrees with OTP on this issue. This is not to say the Commission cannot establish its own criteria, as the Department and the CEOs recommend, but that OTP appears to have demonstrated an ability to comply with the compliance targets for planning purposes.

The CEOs point solely to OTP's continued operation of its coal plants as evidence that OTP is not reasonably complying with the CFS. Staff notes that OTP's five-year action plan includes adding nearly as much wind and solar between 2025-2029 (400 MW) as currently exists on its system (roughly 450 MW), which will substantially increase its amount of available RECs. Admittedly, Staff does not fully understand the CEOs' argument which challenges OTP's approach to use new RECs to comply, so the CEOs can better explain their position. But the statute clearly mentions (1) allowing RECs to comply and (2) decarbonizing at levels equal to retail sales to Minnesota customers.

Staff further notes that OTP calculated CFS compliance under three different scenarios, which assume different compliance levels depending on how RECs could be allocated across jurisdictions. The Company's calculations are summarized in the table below. The top row of the table assumes only Minnesota RECs can be retired to comply with the CFS, the second assumes South Dakota keeps RECs for its own renewable compliance standard (i.e., OTP can retire Minnesota- and North Dakota-generated RECs only), and the third assumes OTP can retire RECs generated from any jurisdiction for the purposes of CFS compliance. Note that by 2030, OTP will be able to cover 100% of its compliance position, except under the MN-only

[114] See Minn. Stat. § 216B.1691, subd. 4 (as amended by the Minnesota Clean Energy Law).

scenario. (Also, note: HLS means "Hoot Lake Solar.") The green-shaded cell (57% compliance) indicates OTP's current position, assuming that OTP can use RECs from any jurisdiction.

Table 28. CFS Compliance under Preferred 2040 Plan[115]

MN REC Forecast	Current: No HLS, No Repowers	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%

When considering (1) the investments OTP proposes to make in wind and solar in its five-year action plan and (2) the statutory language allowing RECs to be used to comply with the CFS, Staff believes OTP is making reasonable progress toward CFS compliance.

VIII. Resource Acquisition

A. Department

The Department recommends the Commission approve a bidding process for OTP's future resource acquisitions as follows:

1. OTP should use a bidding process for supply-side acquisitions of 100 MW or more lasting longer than five years;
2. ensure that the RFP is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing unless changed circumstances dictate otherwise;
3. ensure that the RFP includes the option for both PPA and BT proposals unless the Company can demonstrate why either a PPA or BT proposal is not feasible;
4. provide the Department and other stakeholders with notice of RFP issuances;
5. notify the Department and other stakeholders of material deviations from initial timelines;
6. update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;

[115] Updated IRP, Table 4-6: Minnesota Clean Energy Law Compliance Breakdown (Coyote 2040), p. 28.

7. where OTP or an affiliate proposes a project:

    a. require OTP to create separate teams for the Company's project and for evaluation of the bids received;

    b. engage an independent auditor to oversee the bid process and provide a report for the Commission;

8. include in the RFP a plan to address the impact of material delays or changes of circumstances on the bid process;

9. cap any Right of First Offer (ROFO) made by OTP at net book value; and

10. ensure that any RFP documents for peaking resources issued are technology neutral.

B. Clean Energy Organizations

CEOs agree with the Department's recommendations regarding a future competitive resource acquisition process, with one modification. The CEOs recommend the minimum size to trigger an RFP be lowered to 25 MW (rather than 100 MW) to recognize the relatively smaller size for battery storage. The CEOs believe their recommendation would be consistent with Xcel Energy's and Minnesota Power's most recent IRPs.

With the CEOs modification (below in red brackets), Step 1 of the Department's process would be:

1. OTP should use a bidding process for supply-side acquisitions of 100 MW or more [or for energy storage resources, acquisitions of 2S MW or more] lasting longer than five years;

C. OAG

The OAG supports the Department's competitive bidding recommendation. According to the OAG, three conditions of the Department's proposal are particularly important to protect ratepayers:

- accepting both PPA and build–transfer proposals, which will ensure the best possible price;
- using a separate team and an independent auditor when an OTP bid is involved, which will avoid a conflict of interest; and
- capping the price of any offer Otter Tail makes under a right of first offer at net book value, which will protect ratepayers from misaligned incentives.

D. OTP Reply

OTP described how the flexibility of its current process was able to secure the Hoot Lake Solar

Project. In approving Hoot Lake Solar, the Commission declined to adopt the Department's recommendation to deny OTP's petition, which was based in large part on the Department's perceived deficiencies in OTP's resource acquisition process.

OTP stated that while the Company "[s]hares the Department's goal of securing the most cost-effective projects for our customers, OTP believes its customers "are better served by the flexible and cost-effective approach" used in prior projects, such as the Merricourt Wind and Hoot Lake Solar projects.

STAFF DISCUSSION

I. Commission Review of Resource Plans

OTP's IRP was filed pursuant to Minn. Stat. § 216B.2422 and Chapter 7843 of Minnesota Rules. Minn. R. 7843.0500, subp. 2 states that "[i]f the commission concludes that a set of resource options would be optimal, considering the desirable attributes listed in subpart 3, it may identify that set of resource options as a preferred resource plan." Subpart 3 states that resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;
B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. minimize adverse socioeconomic effects and adverse effects upon the environment;
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

While the Commission is required to consider these five factors, the rule does not direct that any one criterion has priority over another. In determining whether the plan is in the public interest, the Commission may assign different weights to one or more factors. A summary of the OTP and CEOs plans in the context of the Commission's criteria is provided below:

1) ***Reliability:*** OTP emphasized how its Supplemental Preferred Plan aims to provide long-duration energy and fuel assurance, which are part of MISO's six proposed reliability attributes. OTP's analysis included forecasted load in relation to resilient generation on its system, which, according to OTP, demonstrated a need to address market exposure, especially during stressed conditions. A key component of the CEOs' plan was its production cost modeling showing that OTP's system needs and resource capabilities could be met across every hour of every day, including during peak load winter days with normal and low wind output.

2) ***Rates and Bills:*** In IRPs, rate impact estimates require several assumptions with a high degree of uncertainty regarding capital expenditures and O&M costs for all areas of a utility's business. This is why IRP generally focuses on only the generation-related

portion of a utility's business. Therefore, "least-cost planning" typically employs capacity expansion modeling to assess the generation-related costs and risks across a broad range of outcomes for load growth, fuel prices, capital costs, and so on. Of course, this is not to suggest that rate impact analyses are unimportant or should be disregarded. In this case, for instance, Staff believes OTP raised important rate impact considerations related to potential changes to a plant's depreciation schedule, market exposure, and reasonably-sized resource acquisitions.

3) ***Environmental and Socioeconomic Impacts:*** Socioeconomic impacts cover a broad range of issues, such as the affordability of electricity, impacts to host communities, equity considerations, workforce planning, and so on. OTP stated that withdrawing from Coyote may result in "adverse socioeconomic impacts for employees working at Coyote Station, the adjacent mine, and the community in and around Beulah, North Dakota." The CEOs stressed the urgency of addressing climate change, the human health impacts of OTP's coal plants, and equity concerns.

4) ***Flexibility:*** The ability to adapt to financial, social, and technological factors outside of a utility's control is generally discussed in terms of flexibility and risk. OTP stated that developments since the Initial Filing have shown how quickly key planning assumptions can change, and in light of current planning uncertainties, OTP believes a withdrawal from Coyote now would be a "premature and irretrievable" decision. According to OTP, "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."[116] The CEOs countered that Coyote Station is "an old and especially polluting coal plant subject to unique contractual entanglements and obvious regulatory and market risk," and clean replacement resources "will provide Otter Tail with far more flexibility."[117]

5) ***Risk:*** OTP identified numerous risks that are contributing to a highly uncertain planning environment, including but not limited to: natural gas prices and availability; energy market risks; and MISO-related risks. OTP believes dual fuel capability at Astoria Station will help mitigate these risks. The CEOs argued that reliance on coal presents cost and environmental regulation risks.

The table below intends to provide the Commission with a few examples of the benefits of each plan, which the Commission can use to support its motion:

[116] Updated IRP, p. 13.

[117] CEOs initial comments, p. 37.

Table 29. Five Factors to Consider

	OTP	CEOs
Reliability	Onsite LNG at Astoria provides fuel assurance, and Coyote enhances system resiliency and reliability.	The CEOs' plan meets OTP's capacity and energy needs in all hours of every year.
Rates & Bills	Coyote Station provides price stability.	The CEOs Plan is less expensive than both OTP's 2028 and 2040 Coyote plans.
Envir. & Socioec. Impacts	Coyote and Big Stone provide regional socioeconomic benefits.	OTP's coal plants present climate and human health damages.
Flexibility	Coyote is a cost-effective hedge against planning uncertainties.	Coyote is "subject to contractual entanglements and obvious regulatory and market risk."[118]
Risk	OTP's plan addresses natural gas price and availability, energy market, and MISO-related risks.	OTP's plan presents cost, environmental regulation, and co-ownership risks.

I. Five-Year Action Plan

Minn. R. 7843.0400, subp. 3(c) requires utilities to outline their five-year action plan, which consists of the resources a utility plans to acquire and the regulatory filings a utility intends to make over the next five years. Given the passage of time since the Initial Filing, the Commission can think of OTP's five-year plan as generally including the planning years 2025-2029 (although there is nothing which prohibits the Commission from extending the action plan). The main issues the Commission will need to address in this timeframe include:

- The Astoria LNG Project;
- Coyote Station (although the CEOs recommend OTP withdraw from Big Stone by 2031); and
- Renewable resource acquisition, as well as the process for acquiring resources.

OTP recognized in its reply comments that while the Company and the CEOs disagree on many of these issues:

> there are areas of overlap that should inform the Commission. Specifically, the nature and amount of renewable generation to be added within approximately five years of the Commission's anticipated order in this docket is an area of general

[118] CEOs initial comments, p. 37.

alignment with the CEOs.[119]

The five-year resource additions are shown below.[120] Note that Coyote Station is not included as an addition because OTP proposes to continue operating it as an existing resource. Also, 2024 is not included because no resources are proposed in either plan for that year.

Table 30. Resource additions 2025-2029 (Installed Capacity, MW)

Year	OTP	CEOs
2025	Wind Repowers	Wind Repowers
2026	Astoria LNG Project	-
2027	100 MW Surplus Solar	100 MW Surplus Solar
2028	100 MW Surplus Solar	100 MW Surplus Solar
2029	200 MW Generic Wind	150 MW Replacement Wind-Coyote 500 MW Generic Wind

The Commission can adopt either one of these action plans outright, or, given various uncertainties, the Commission can authorize OTP to acquire amounts with a specified range. **Decision Option 1** includes, among other items, the areas of agreement between OTP and CEOs reflected in the table above as follows:

1. The Commission approves OTP's five-year action plan and authorizes OTP to:
   A. Repower existing wind facilities in 2025;
   B. Acquire 200 MW of solar resources in 2027-2028; and
   C. Acquire at least 200 MW of wind resources by 2029.

The next section will discuss whether OTP's proposal to install onsite fuel at Astoria should be part of the list above.

II. Astoria LNG Project

As shown in the table above, OTP also asks that the Commission approve the Astoria Station LNG Project as part of the Company's five-year action plan. The CEOs do not support this and recommend that onsite fuel at Astoria be considered in the Company's next IRP. The OAG recommends denying the proposal altogether. The Department recommended approving OTP's Astoria proposal in its November 2022 comments, but since these comments pre-dated OTP's Updated IRP, the Commission may wish to ask the Department if they maintain that position.

Staff does not have a strong position on whether the Commission should approve onsite fuel at

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[119] OTP reply comments, p. 39.

[120] The plans both include 150 MW of "Surplus + Capacity Solar" and 50 MW of "Surplus Solar." For simplicity, Staff refers to both types of solar as "Surplus Solar."

Astoria, but the threshold issue seems to be (a) balancing OTP's reasons for seeking dual fuel capability at Astoria, which are valid, with (b) the significant cost associated with the project.

On the one hand, Staff agrees with OTP that having backup fuel will protect against natural gas price volatility and availability, and events such as the 2014 Polar Vortex and Winter Storms Uri and Elliot revealed potentially significant adverse consequences that may arise during such events.

Further, Staff shares OTP's concern regarding seasonal resource adequacy under the SAC, and onsite dual fuel capability at Astoria may greatly improve the likelihood of the plant receiving a high, stable capacity value. In a changing environment in which OTP has seen recent increases to its winter and spring PRMR, the need for accredited capacity in those seasons is incredibly valuable. And, as explained in OTP's February 1, 2023, reply comments on the dual fuel proposal, during Winter Storm Elliot, Astoria Station was placed on forced outage due to pipeline limitations, which put the unit's capacity value at risk:

> Because of this occurrence, we expect to see a decrease in the unit's accreditation under the new Resource Adequacy accreditation methodology per Schedule 53 of MISO's Seasonal Accreditation Construct. This risk of reduced accreditation further demonstrates that adding onsite fuel inventory is necessary and prudent.[121]

Staff believes this "risk of reduced accreditation" is one reasonable justification to approve onsite LNG at Astoria.

On the other hand, the OAG highlighted important ratepayer considerations associated with the retrofit, essentially arguing that OTP cannot receive a blank check to mitigate risk. The OAG highlighted Astoria's short history consisting of: 1) coming online in early-2021; 2) OTP requesting in its September 2021 IRP that it needs to add fuel oil; and 3) OTP announcing a year later that the costs will be much higher than previously expected. The OAG's comments express great discomfort with such significant investments in a brand-new fossil fuel resource. While OTP strongly refuted the OAG's comments, Staff agrees with the OAG that the Commission should be mindful of the magnitude of OTP's cost estimate.

Either way, Staff believes the record is sufficiently developed for the Commission to make a decision <u>in this proceeding</u>, and furthermore, a Commission decision one way or another is probably helpful in that it enables OTP to move forward with regulatory certainty. Additionally, the cost-benefit considerations of dual fuel capability at Astoria do not seem to depend on the path forward at Coyote; OTP stated in its Initial Filing that the Company's analysis "supports dual fuel at Astoria Station regardless of the course of action on Coyote Station."[122]

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[121] OTP February 1, 2023, reply comments, p. 3.

[122] Initial Filing, p. 8.

For these reasons, Staff does not support the CEOs' position to delay a decision on Astoria until the next IRP.

Overall, Staff believes OTP provided a reasonable proposal to address several present-day risks – both financial and safety-related – that support approving LNG at Astoria; however, the Commission can reasonably decide that the costs are excessive, deny the proposal without prejudice, and require that OTP continue to explore other, less-expensive options to address those risks.

Finally, Staff does not believe there are any apparent conflicts with either the Minnesota Renewable Preference Statute or greenhouse gas (GHG) emissions goal. LNG will be a backup fuel source to be used under extreme conditions and for a very specific purpose; further, when LNG is dispatched, it may offset other natural gas plants that may otherwise dispatch in MISO, thus producing minimal net GHG emissions.

III. Resource Adequacy and Energy Availability

Staff believes two areas of the record that could be particularly instructive to the Commission's decision involve:

1. seasonal resource adequacy, specifically OTP's winter PRMR and seasonal resource accreditation, and

2. the CEOs' production cost modeling/hourly analysis and OTP's response.

In the next two sections, Staff will discuss how the Commission may view the OTP and CEOs plans in the context of these issues.

A. Seasonal Resource Adequacy

OTP and the CEOs argue about the seasonal PRMR and non-thermal capacity resource accreditation. Staff notes that when the Updated IRP was filed, exact seasonal accreditation values for wind and solar were unknown, so OTP "used values from MISO's loss of load expectation (LOLE) study for years 2023 through 2030."[123] (These assumptions are shown on pages 15 and 16 of these briefing papers.) For an additional data point, the table below compares OTP's wind and solar accreditation assumptions (non-italicized) to MISO's Final Planning Year 2024-'25 LOLE Results, which were presented on November 7, 2023 (bold, italicized). Note that the PY 2024-'25 winter PRM is slightly higher (at 27.4%) than what OTP assumed for the Updated IRP (25.5%), and the spring PRM for PY 2024-'25 is also slightly higher (at 26.7%) than the Updated IRP, which supports OTP's concerns over "significant winter and spring reserve planning margins."[124]

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[123] Updated IRP, p. 21.

[124] Updated IRP, p. 5.

Table 31. MISO Seasonal Planning Reserve Margin

Season	OTP Updated IRP, PRM %	PY 2024-'25 LOLE Study Results, PRM %:
Summer	7.4%	***9.0%***
Fall	14.9%	***14.2%***
Winter	25.5%	***27.7%***
Spring	24.5%	***26.7%***

The next table compares the Updated IRP's wind and solar seasonal accreditation values (non-italicized) to MISO's PY 2024-'25 values (bold, italicized). Note that wind was valued at 53.1% in the winter for PY 2024-'25, which is higher than the Updated IRP assumptions, and solar was valued at 12.8% in the summer, also much higher than the Updated IRP assumptions.

Table 32. Seasonal Wind and Solar Accreditation (% of ICAP)

Resource/Season	Current	2031	PY 2024-'25
Wind			
Summer	18%	18%	***18.1%***
Fall	23%	21%	***15.6%***
Winter	40%	37%	***53.1%***
Spring	23%	12%	***18.0%***
Solar			
Summer	45%	23%	***46.4%***
Fall	25%	18%	***37.6%***
Winter	6%	1%	***12.8%***
Spring	15%	17%	***33.8%***

To be clear, Staff presents this information to provide one additional data point, not to, by itself, verify or discredit any party's arguments. Rather, Staff's takeaway of the Updated IRP assumptions, when considered alongside MISO's 2024-'25 values, is that the Commission can expect some volatility in these values over time in both directions. While OTP has reason to be concerned about its obligations during the winter and spring – as supported by even higher PRM percentages in the spring and winter than originally assumed – Staff agrees with CEOs that OTP provides a somewhat-pessimistic view of future renewable accreditation, and higher contributions to the PRM from wind and solar appear quite possible.

As an example of how this information can be applied to the record here, recall that the CEOs compared 2029 and 2031 winter capacity accreditation (the years after removing each coal plant) to assess seasonal resource adequacy under various plans. The CEOs argued that the CEOs Preferred Plan actually provides the most accredited winter capacity in 2029. However, in 2031, OTP's 2040 Preferred Plan provides the most accredited winter capacity. The plans with the most accredited winter capacity are indicated by the green-shaded cells.

Table 33. Total Accredited Capacity in 2029 and 2031 by Plan

	CEOs Preferred Plan	Revised OTP 2040 Plan	Revised OTP 2028 Plan
2029	1,251	1,212	1,070
2031	1,172	1,185	1,099

The discussion above intends to explain why, when considering how wind and solar accreditation could be used in decision-making, there is little to no reason to believe that the low accreditation scenario should be given any more weight than the base or high renewable accreditation sensitivities.

What this means in terms of OTP's EnCompass analysis, which included three sensitivities for renewable accreditation (base/high/low), is that only one sensitivity – low accreditation and no externalities – showed continued operation of Coyote Station until 2040 to be economic. In other words, 5 of 6 sensitivities assuming various levels of renewable accreditation showed that exiting Coyote by 2028 is least-cost. The Preferred Plan (base), High, and Low Accreditation sensitivities with and without externalities are shown in the table below.

Table 34. PVRR Comparison in Renewable Accreditation Sensitivities

		Cost (Savings) of 2028 Coyote withdrawal Compared to 2040 withdrawal ($000)	
	Scenario Name	**No Externalities**	**Externalities Included**
A.1	Preferred Plan	($40,007)	($113,264)
M	High Renewable Accreditation	($51,225)	($114,143)
N	Low Accreditation	$37,082	($26,297)

B. CEOs Hourly Analysis and OTP's Response

1. Production Cost Modeling and CEOs' 2029 Hourly Analysis

Importantly, the CEOs claim that its plan "meets Otter Tail's own modeled capacity and energy needs for all hours of the year throughout the planning period."[125] This section will examine that statement.

To consider whether the CEOs plan could ensure energy availability under a Winter Storm Uri-like event, EFG "evaluated hourly dispatch of the CEO plan during several peak winter days in the years after exiting Coyote and Big Stone."[126] As Staff understands EFG's report, OTP did not

[125] CEOs initial comments, p. 3.

[126] CEOs initial comments, p. 54.

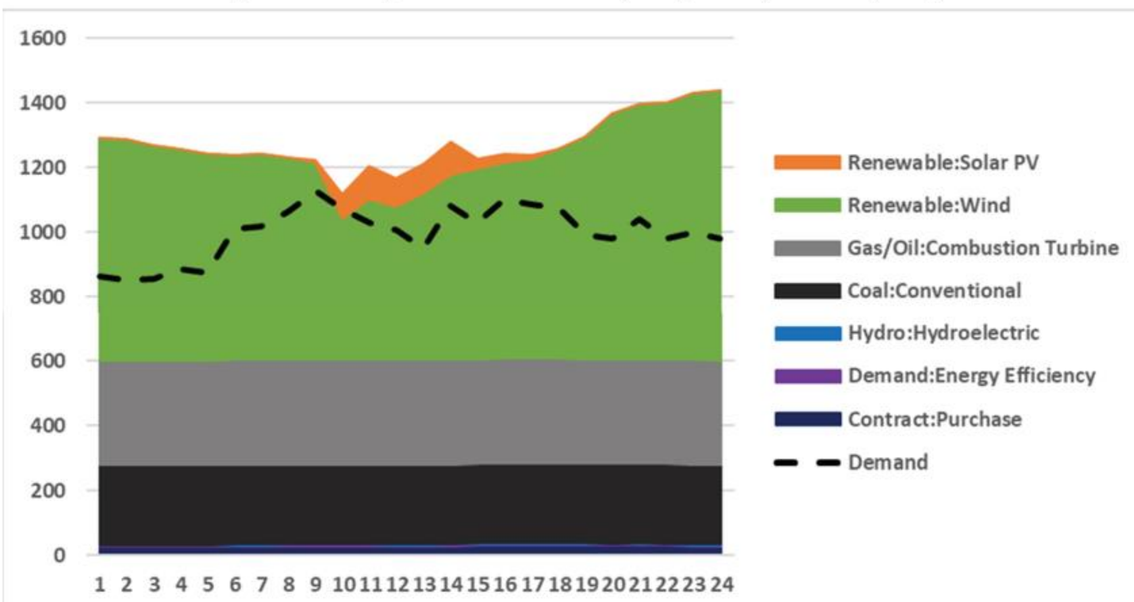
run the same granular level of analysis for its own or the CEOs' plan because OTP did not run production cost modeling. According to EFG, this means:

> EnCompass performs the capacity expansion step with simplified dispatch using time sampling and then maps the results onto the entirety of each year. Portfolios are then typically put through the production cost modeling step where the resource portfolio is fixed and dispatched under more granular unit commitment and dispatch across all 8760 hours in each year of the planning period.[127]

EFG performed production cost modeling on two winter peak days in 2029. The first day assumed peak load and a typical wind production profile, and the second day assumed peak load and low wind output. These are represented by two figures below.[128]

The first figure simulates Day 1, January 5, 2029, which includes the CEOs Preferred Plan (i.e., renewables and no Coyote Station) along with the rest of OTP's resources, including Big Stone and Astoria. The CEOs explained that in almost every hour, OTP's system has a capacity surplus and is an exporter to MISO. Also note the significant contribution from wind in green:

Figure 4. Example Winter Peak Day on January 5, 2029 (MW)



The next figure, Day 2, is a winter peak day with low wind output. Importantly, on this day, market purchases account for 2% of OTP's hourly demand on average.

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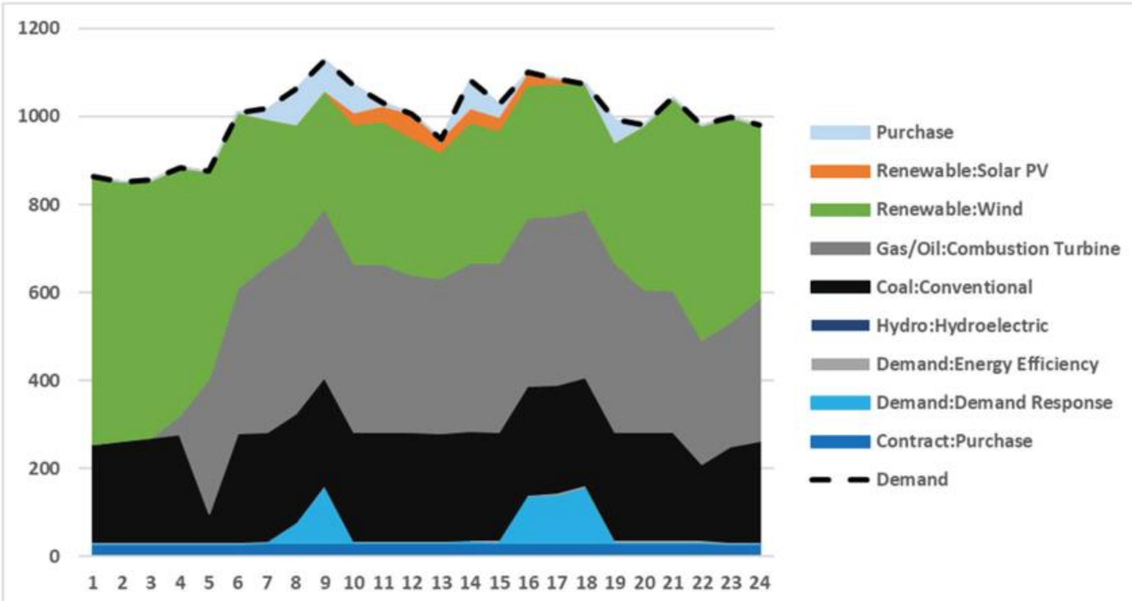
[127] CEOs initial comments, Attachment 1 – EFG Report, p. 18.

[128] The figures below were designated as trade secret in the CEOs' comments, but because they are helpful representations of what is occurring in the model, Staff reached out to OTP and CEOs, who both allowed Staff to use the figures in these public briefing papers.

Figure 5. Example Winter Peak Day with Low Wind Output on January 26, 2029 (MW)



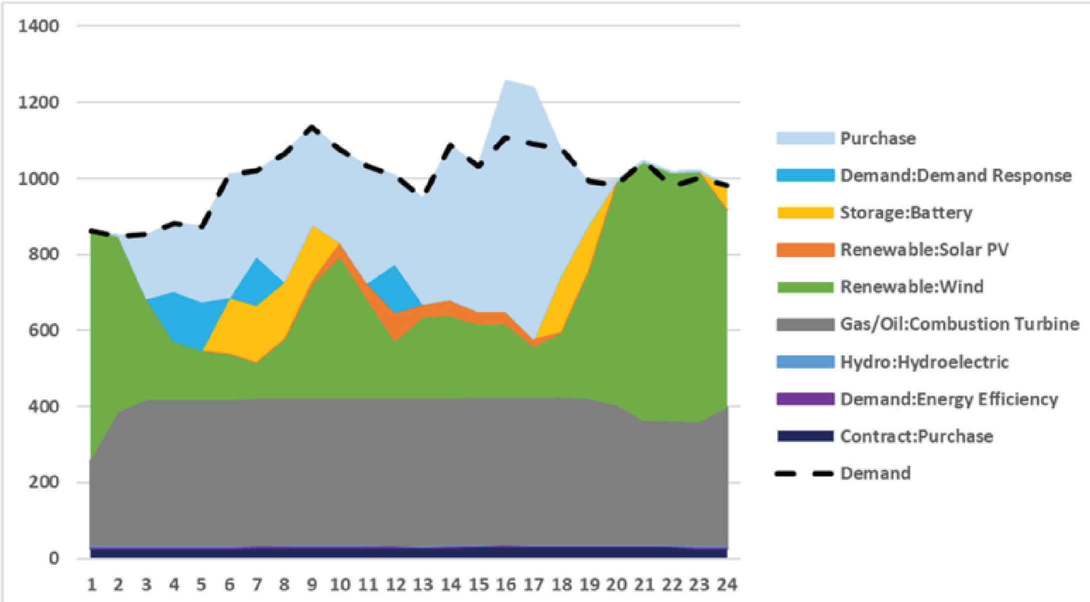
Staff does not believe there is one, correct way to interpret the two figures above. On the one hand, Staff believes the CEOs' hourly analysis supports it claims that (1) the CEOs Preferred Plan can meet OTP's capacity and energy needs for all hours of the year, and (2) that it can do so even under the extreme conditions.

On the other hand, since the model appears to rely on market purchases during peak times, it could also be interpreted that the hourly analysis validates OTP's concerns about market exposure and the need for resilient/fuel assured generation.

2. 2031 Hourly Analysis (No Coyote or Big Stone)

EFG performed the same type of analysis in 2031, after both coal units are removed from OTP's system. Again, the CEOs claimed their plan is still able to provide energy availability during winter peak and low wind generation days. The figure below shows a winter peak day in 2031 with typical wind output.

Figure 6. Example Winter Peak Day on January 31, 2031 (MW)



Staff's takeaway from the hourly analysis of the 2031 winter peak day is that the CEOs plan appears to show significant and possibly excessive market exposure. Anticipating this conclusion, the CEOs argued that:

> On these two days [in 2031], market purchases on average account for 21% and 17%, respectively, of Otter Tail's hourly demand. In recent years OTP, has purchased between 22-40% of its annual energy requirements from the MISO market. CEOs Preferred Plan caps such purchases at 25% of annual energy requirements. The purchases seen on these days, while possibly expensive, are reasonable in scale-and part of the optimized, least-cost resource plan.

Staff does not agree that historical annual averages is an apples-to-apples comparison to average market purchases during extreme conditions. Without the presence of Coyote Station or Big Stone, Staff does not agree that the CEOs plan provides reasonable energy adequacy during winter peak days.

3. OTP Reply

OTP raised several concerns in response to the CEOs' hourly analysis:

- Market and reliability risks of the CEOs' plan are evident during expected unserved energy (EUE) events, which "results in significant market exposure at the worst possible times. OTP would be almost entirely reliant on the market in the hours of the day which coincided with the hours that MISO identifies as having the greatest risk for EUE."[129]

[129] OTP reply comments, p. 16.

- CEOs' hourly analysis assumes Astoria Station's maximum output for a majority of the day and the availability of pipeline-delivered fuel supply, which OTP did not have during Winter Storm Elliot.

- The CEOs' plan raises safety concerns because it does not provide dependable electricity. Importantly, their simulation occurs in the coldest time of the year, and many of OTP's rely on electricity as a primary heat source.

For these reasons, OTP disagrees that the CEOs plan can serve OTP's customers in every hour of the high stress periods. According to OTP, the CEOs' claim "can only be true if market purchases are considered a reasonable and viable option during MISO-defined loss-of-load hours, which is not the case."[130]

IV. Big Stone Plant

If OTP were to withdraw from one of its coal plants, that coal plant would clearly be Coyote Station, and Staff believes the record shows that withdrawing from Coyote Station <u>and</u> Big Stone would fail to meet several of the Commission's IRP evaluation criteria. Therefore, Staff agrees with OTP that the Commission should not require any operational changes to Big Stone as part of this proceeding, and at least three areas of the record support this conclusion:

1. As discussed in the previous section, CEOs' 2031 hourly analysis found that on winter peak days with Coyote Station and Big Stone removed from the plan, market purchases accounted for 17%-21% of OTP's hourly demand on average, which in Staff's view fails to provide sufficient energy availability and proper risk management.

2. Staff is concerned about seasonal capacity risk in the event that neither Coyote nor Big Stone is part of OTP's generation portfolio. As noted previously, OTP's Planning Year 2023-'24 winter PRM was 25.5%, and its winter PRMR was 1,117 MW. Together, Coyote Station and Big Stone amount to slightly over 400 MW of accredited winter capacity, or roughly one-third of winter accredited capacity. While Staff does not challenge the CEOs' renewable accreditation assumptions, as a practical matter, Staff questions the assumption that one-third of any utility's accredited capacity can be seamlessly replaced within 7 years.

3. In 2015, the Commission approved a $364 million AQCS project at Big Stone, and Staff shares OTP's concerns over the rate impacts of adding replacement energy and capacity at Big Stone on top of the remaining value of the AQCS.

Having said that, Staff believes a variation of the CEOs' recommendation to examine Big Stone more thoroughly in the next IRP would be a useful exercise. OTP has been required to do this in past IRPs and compliance filings, which evaluated retirement scenarios for Hoot Lake Plant and Coyote Station.

[130] OTP reply comments, p. 18.

The CEOs recommend:

> In the alternative to [the CEOs' recommendation to withdraw from Big Stone], require Otter Tail to begin planning now for a Big Stone withdrawal by no later than 2030 and to present a plan in its next Minnesota IRP that withdraws from Big Stone by no later than the end of 2030. The plan should demonstrate that Otter Tail is taking proactive steps to keep a 2030 exit on the table and is exploring the economic value of retiring the plant, including consulting with co-owners on the issue.

While Staff supports this analysis conceptually, the way this decision option is currently written implies that Big Stone is not in the public interest, and Staff does not believe this record supports this conclusion and therefore should not frame the scope of future analysis. However, OTP stated in its response to this recommendation that, in order to consider withdrawing from Big Stone, certain factors must be considered. That list is provided below, and Staff believes some combination of the CEOs' recommendation and OTP's list below would be helpful analysis for the next IRP. OTP cited the need for:

- the support of state commissions in the Company's three-state footprint;
- an analysis of alternatives and options with our co-owners;
- consideration of the impact on the host communities of Big Stone City, South Dakota (and adjacent Ortonville, Minnesota);
- replacing the reliability attributes of the plant, and in a cost-effective manner; and
- a rate impacts analysis resulting from necessary changes to the plant's depreciation schedule, especially in light of the capital investment for the AQCS project.

Re-worded below, these topics seem to fall under four general categories:

- Multi-jurisdictional and co-ownership complexities;
- A resource planning analysis (i.e., EnCompass modeling, reliability impacts, etc.);
- Rate impacts; and
- Host community and other socioeconomic impacts.

Staff developed Decision Option 13 to create a more balanced scope to the analysis, which the Commission can discuss with parties.

V. Coyote Station

Staff believes the following conclusions can be drawn based on the record:

- The economic case for continuing to operate Coyote Station is not persuasive. In both the No Externalities and Externalities Included modeling runs, and in both the Initial Filing and the Updated IRP, the majority of sensitivities indicate that exiting Coyote sooner rather than later is least-cost.

- The risk of environmental compliance costs at Coyote Station is very high, and under no scenario does investing in environmental controls appear to be cost-effective.

- Even though Coyote Station is located in North Dakota, public health concerns apply to Minnesota.

- However, OTP demonstrated that it faces a capacity risk under the SAC to meet its winter and spring PRMR. Additionally, Staff believes OTP raised important considerations regarding OTP's share of the foreseeable withdrawal costs at Coyote Station, which include undepreciated net book value and early termination costs under the LSA.

Below, Staff provides additional discussion of some of these issues.

1. Excessive financial risk for Minnesota ratepayers

Minn. R. 7843.0500, subp. 1 (Commission Review of Resource Plans) states in part:

> **Subpart 1. Decision.**
>
> Based upon the record, which is the information filed with the commission in the resource plan proceeding of a utility, including responses to information requests, the commission shall issue a decision <u>consisting of findings of fact and conclusions</u> on the utility's proposed resource plan and the alternative resource plans . . .

Next, Minn. R. 7843.0600, subp. 2 (Relationship to Other Commission Processes) states:

> **Subp. 2. Resource plan findings of fact and conclusions.**
>
> The findings of fact and conclusions from the commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related commission proceedings, including, for example, rate reviews, conservation improvement program appeals, depreciation certifications, security issuances, property transfer requests, cogeneration and small power production filings, and certificate of need cases. In those proceedings, <u>the commission's resource plan decision constitutes *prima facie* evidence of the facts stated in the decision</u>. This subpart does not prevent an interested person from submitting substantial evidence to rebut the findings and conclusions in another proceeding.

One fact that is clear from the proceeding is that all scenarios and sensitivities which quantify either emissions controls or the societal impacts of pollution show that continued operation of Coyote Station beyond 2028 is not in the public interest. Therefore, if OTP requests cost recovery for emissions controls in any future proceeding, this record would indicate that investing in emissions controls rather than withdrawing from Coyote would be imprudent.

A second fact is that when OTP considered the Commission's CO_2 regulatory cost values, which "must be used in all electricity generation resource acquisition proceedings," pursuant to Minn. Stat. § 216H.06, exiting Coyote by 2028 was less-expensive than exit by 2040.

A third fact is that OTP's EnCompass analysis of its Preferred Plan showed that the 2028 Coyote exit was less expensive than the 2040 exit by $40 million without externalities included. When externalities were included, the 2028 Coyote exit was less expensive than the 2040 Coyote exit by $113.3 million.

If the Commission believes it will be helpful for future proceedings, the Commission may memorialize these and other facts in its order.

2. Exceedingly High Environmental Regulatory Compliance Risk

OTP's base assumption was that Regional Haze compliance costs would be zero. However, OTP acknowledged that the Company and other co-owner may develop a plan for winding down operations at Coyote Station if regulatory costs are required. OTP's EnCompass analysis certainly supports this path; the Company quantified Regional Haze and CO_2 regulatory costs, and under every scenario, with and without externalities, withdrawing from Coyote by 2028 was least-range, and savings ranged from roughly $84-$179 million.

Table 35. Environmental Compliance Sensitivities Comparing 2028 Coyote Exit to 2040 Coyote Exit

		Cost (Savings) of 2028 Coyote withdrawal Compared to 2040 withdrawal ($000)	
	Scenario Name	**No Externalities Included**	**Externalities Included**
A.1	Preferred Plan	($40,007)	($113,264)
E	Regional Haze (RH) Mid Cost	($83,982)	($155,499)
G	RH High Cost	($103,845)	($179,189)
O	Carbon Tax	($134,913)	

Moreover, OTP did not include any scenarios which considered costs for the GHG Power Plant Rule or the MATS rule. While these are not finalized rules, Staff believes the CEOs raised a valid concern that OTP did not consider any future under which proposed rules could result in potential costs. According to the CEOs:

- In 2021, Coyote Station emitted SO_2 at a rate at least eight times higher than any coal plant in Minnesota or South Dakota.
- In 2021, Coyote Station emitted NO_X at a rate at least three and a half times higher than any coal plant in Minnesota or South Dakota.[131]
- In 2022, Coyote Station emitted mercury at a rate approximately three to five times higher than any other coal plant in Minnesota and South Dakota.

[131] CEOs initial comments, p. 32.

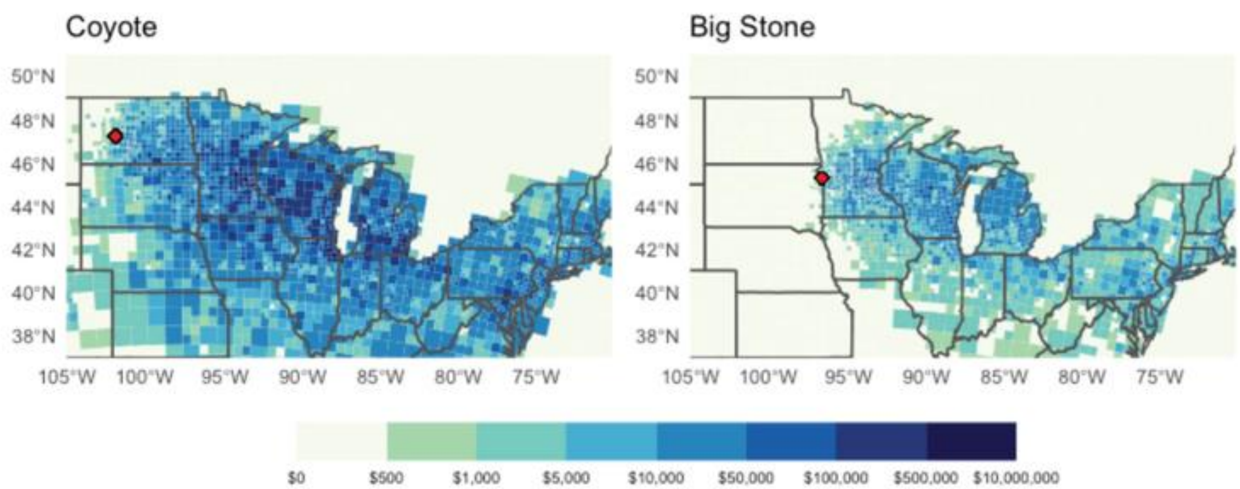
- The EPA proposes reducing allowable mercury emissions from lignite-fired plants to 1.2 lb/TBtu, which is well-below Coyote's 2022 emission rate of 2.28 lb/TBtu.[132,133]

While OTP proposes a wait-and-see approach, the fact remains that OTP's proposal includes continued operation at Coyote until 2040 with zero regulatory compliance costs, which seems unrealistic.

3. Public health impacts

Attachment 2 to CEOs' initial comments is the PSE health and equity report (PSE Report), which describes the human health impacts from continuing to operate Coyote Station and Big Stone. According to the CEOs, PSE found that Coyote Station emits significantly more NO_X, SO_2, and $PM_{2.5}$ than Big Stone – in fact, twenty times more SO_2 and $PM_{2.5}$.[134,135] PSE also found that public health impacts from both plants extend across multiple states. As shown below, "it is clear that although neither coal plant is located in Minnesota, Minnesotans are unquestionably bearing the adverse health consequences of the continued operation of these plants."[136]

Figure 14. Annual total $PM_{2.5}$ public health impacts of Coyote Station and Big Stone



In reply comments, OTP responded to the PSE Report, citing several errors and flaws in the analysis. As it relates to public health, OTP noted that the PSE Report "fails to acknowledge that

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[132] CEOs initial comments, p. 35.

[133] 88 Fed. Reg. 24,857.

[134] This is because Coyote burns lignite coal, which is the lowest grade of coal, and requires more coal to be burned to generate the same amount of electricity as hard coal like bituminous or subbituminous (Big Stone utilizes subbituminous). Lignite also tends to have higher amounts of sulfur and ash content.

[135] CEOs initial comments, p. 86.

[136] CEOs initial comments, p. 89.

Coyote Station and Big Stone Plant have strong track records of environmental compliance and sustainability."[137]

OTP also stated that, because Coyote Station is located outside of Minnesota, "the PSE Report's implications for Coyote Station appears to be beyond the bounds of this proceeding."[138] Staff disagrees on this point. OTP's arguments may provide reasons why the Commission should give less weight to the PSE Report, but they are not a reason to ignore it entirely. If the Commission is persuaded that the PSE Report contains relevant information, the Commission could evaluate the impact the Report has on a reasonable resource mix for the Company as an integrated, multi-jurisdictional utility.

4. Possible Commission Actions

In the Hoot Lake Solar proceeding, OTP requested authorization to recovery 100% of the costs from Minnesota customers. While OTP recognized that Hoot Lake Solar was a cost-effective system resource, full allocation of costs to Minnesota would provide "a reasonable resolution of the policy differences across the states in which Otter Tail provides retail electric service."[139]

Similarly here, the Commission can find that while Coyote can remain in OTP's plan for now, it would be unreasonable for Minnesota ratepayers to pay for future environmental compliance costs for the benefit of maintaining the regional socioeconomic benefits associated with Coyote Station. Then, in future rate recovery proceedings, OTP can develop an allocation proposal similar to what OTP did in the Hoot Lake Solar docket.

Otherwise, the Commission can either accept OTP's or the CEOs' proposal, which are:

- **OTP**: Authorize OTP to withdrawal from its 35% ownership interest in Coyote Station in the event OTP is required to make a major, non-routine capital investment in the plant.

- **CEOs**: Find that it is not prudent and not in the public interest for Otter Tail to retain its share of Coyote beyond 2028 and that Otter Tail should therefore withdraw from Coyote as soon as reasonably possible, but by no later than 2028.

VI. Renewable Resources

As discussed in the Five-Year Action Plan section, Staff believes a reasonable Commission finding – which would reflect consensus between OTP and the CEOs – would include repowered wind facilities, 200 MW of solar by 2028, and at least 200 MW of wind by 2029. Modifying the plan to include higher amounts of renewables will depend on decisions regarding Coyote Station and Big Stone, as well as rate impact considerations.

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[137] OTP reply comments, p. 27.

[138] OTP reply comments, p. 26.

[139] Docket No. 20-844, OTP Hoot Lake Solar Petition, p. 16.

In response to LIUNA's comments, which criticized the CEOs' planning assumptions for being overly optimistic, first, the CEOs actually agree with LIUNA and OTP in the near-term by adopting OTP's high renewables cost assumptions over the next few years. Where the CEOs differ from OTP is that the CEOs assume there will be a "re-balancing" by 2029, which will make wind in particular a cost-effective replacement for Coyote.

Second, Staff does not agree that the CEOs' assumption is not based on arbitrary, optimistic assumptions; the CEOs adopted the medium- to long-term forecast from the National Renewable Energy Laboratory {NREL) Annual Technology Baseline {ATB) from 2022, which is the same data source Xcel Energy used in their most recent IRP.

Third, even OTP's modeling also showed that withdrawing from Coyote Station in 2028 was least-cost. OTP's PVRR comparisons of the 2028 and 2040 exit scenarios support a plan that is largely aligned with the CEOs' plan through 2029.

Finally, Staff notes that the CEOs' EnCompass analysis did not test scenarios with and without onsite LNG at Astoria, so it should be understood that LIUNA's comments about the CEOs' modeling assumptions seem to pertain to the amount of renewable energy beyond what OTP has proposed that were selected in place of coal plant exits in 2028 and 2030.

Having said that, LIUNA, like the Department and OTP, raised concerns over the amount of renewables that can realistically be added by 2029, which is a separate issue to the price inputs. Staff shares this concern, and the size of OTP's system as well as the amount of renewables that will be needed to satisfy OTP's PRMR are important considerations.

Next, it is worth noting that EnCompass is not selecting wind, solar, or battery storage units solely as a result of environmental externalities or for policy reasons. The table below includes OTP's sensitivities (A-U) under the No Externalities, Coyote 2040 runs, and Staff denotes the years in which EnCompass selected a solar ("S"), wind ("W), or battery ("B") resource.[140] The purpose of the table is to show that in nearly every sensitivity OTP considered – again, without externalities and with Coyote operating until 2040 – the five-year action plan includes renewable resource additions. Also, note that under many sensitivities add renewable resources sooner than what OTP has proposed.

[140] Note that a major limitation of this table is that it does not indicate the size of each addition, so while all selections may appear as equivalent as they are presented, they are not.

Table 36. Years with Renewable Energy Additions under No Externalities, Coyote 2040 Plan Modeling Runs

Sensitivity	2025	2026	2027	2028	2029
A					
A.1			S	S	W
B	S		W		
C	S, W				
D					
E					
F	S, W				
G					
H	S, W				
I	S, W	S			
J	S, W			W	
K	S, W	S, W, B	W		B
L	S, W, B	W			W
M					
N			S	B	
O		S	B		
P					
Q	S, W		S	W	
R			S	S	
S		B	S	B	
T	S, W	W, B	W, B		S
U					
Total	***S = 10 W = 9 B = 1***	***S = 3 W = 3 B = 3***	***S = 5 W = 3 B = 2***	***S = 2 W = 2 B = 2***	***S = 1 W = 2 B = 1***

Lastly, one modeling input that could be important to renewable resource additions may actually involve Astoria Station, although Staff defers to the modelers to discuss this point. EFG noted in its report that they placed a capacity factor limit on Astoria because the facility was dispatching an unusually high amount. EFG explained:

> In some of the early years in the planning period, the model was opting to operate the Astoria unit at a high capacity factor. In order to manage the model's reliance on the Astoria unit and reflect more typical combustion turbine operations, we added an annual capacity factor limit of 25% in our modeling runs.[141]

According to OTP's 2023 Annual Forecast Report in Docket No. 23-11, OTP reported that Astoria operated at an 8.07% capacity factor. The previous year, in OTP's 2022 Annual Forecast Report filed in Docket No. 22-11, the Company reported that Astoria operated at a 17.6% capacity factor. To the extent Astoria was operating at unrealistically high levels in OTP's model, the modeling parties can clarify how the Commission should consider this result.

[141] CEOs, initial comments, p. 15.

VII. Resource Acquisition

OTP's Preferred Plan includes the acquisition of the following incremental (i.e., not repowered) renewable additions by year:

- 2027: 100 MW solar
- 2028: 100 MW solar
- 2029: 200 MW wind
- 2030: 100 MW solar
- 2031: 150 MW wind
- 2032: 100 MW solar

The Commission may wish to clarify both the resource acquisition process that shall be used and the size, type of timing of resources that must be acquired. The Commission has broad flexibility on this: The Commission could require OTP to acquire only the solar by 2028, the solar and the wind by 2029, or some other combination.

As discussed previously, the Department recommended the Commission approve a competitive bidding process similar to the resource acquisition process the Commission approved in Minnesota Power's 2021 IRP. That proposed process is outlined on page 36 of the Department's September 13, 2023, comments and on pages 60-61 of these briefing papers. The OAG supported the Department, as did the CEOs, but with one modification: to reduce the minimum size of storage acquisitions that would trigger a competitive bidding process (since storage resources are typically smaller in size than other resources).

In reply comments, OTP opposed the Department's recommendation to initiate a competitive bidding process largely by citing the Commission's order in the Hoot Lake Solar docket, in which the Commission stated:

> While the Commission appreciates the Department's close scrutiny of Otter Tail's acquisition process, the Commission concurs with Otter Tail that its competitive bidding process and the evaluation of the proposals it received were reasonable and prudent, consistent with the Commission's directives, and resulted in the least-cost solar resource available.[142,143]

Staff believes this excerpt from the Commission's order and citation in OTP's reply comments requires additional context because OTP did not mention the five years leading up to this order.

To start, the Commission's 2017 IRP Order required that OTP procure 30 MW of solar by about 2020. OTP was also required to file its next IRP by June 3, 2019. In OTP's ensuing extension

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142 Order Approving Petition, Authorizing Allocation of Output & Costs, Authorizing Cost Recovery, and Requiring Compliance Filings, April 29, 2021, *In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar Project* Docket No. E-017/M-20-844.

143 OTP reply comments, pp. 52-53.

requests, the Company reported little progress in its ability to acquire a physical solar asset, and the Company repeated its intention to purchase S-RECs until a cost-effective solar project emerged. That was until the Commission's second IRP extension request, in which the Commission expressed some frustration with OTP's lack of a solar acquisition coupled with its request for another year to file an IRP. The Commission's December 30, 2019, IRP extension order stated:

> while Otter Tail's filing stated that it had procured enough solar renewable energy credits to satisfy the Minnesota Solar Energy Standard for 2020 and 2021, it also stated that its intention was to use SRECS until a solar energy project can be shown to be part of a least cost resource plan. <u>The Commission finds that Otter Tail needs to be more proactive in its approach to compliance</u> . . . <u>The Commission will require the Company to, by June 1, 2020, have completed a competitive-bidding process</u> to procure the approximately 30 MW or more of installed solar capacity needed to satisfy its resource plan.[144]

The Hoot Lake Solar petition was filed on November 25, 2020, about 6 months after the deadline for OTP to complete a competitive bidding process.

When considering the complete history of the events which led to Hoot Lake Solar, which was approved nearly four years after the Commission's 2017 IRP Order, the events leading up to Hoot Lake Solar was not as seamless as the Company makes it appear. Moreover, just because Hoot Lake Solar is a cost-effective resource does not, by itself, prove that the Department's recommendation would be bad for OTP customers. OTP repeated why Hoot Lake Solar is a good project, but the Company did not directly explain why Hoot Lake Solar could not have been bid into a process like the one the Department recommends.

[144] Docket No. 16-386, OTP 2016 IRP, Commission Order (December 30, 2019), pp. 4-5.

DECISION OPTIONS

Approval

1. Approve Otter Tail Power Company's 2023–2037 Supplemental Preferred Plan. *(Otter Tail. Staff note: For clarity, "Supplemental Preferred Plan" is used interchangeably with "2040 Preferred Plan.")*

OR

2. Approve the Clean Energy Organizations' Preferred Plan as an alternative to OTP's Supplemental Preferred Plan. *(CEOs)*

3. Find that OTP's demand and energy forecasts are reasonable for planning purposes. *(Department)*

4. Approve OTP's proposal to carry out the following in the next five years:[145]
    a. The addition of onsite liquified natural gas (LNG) fuel storage at Astoria Station in 2026.
    b. Adding approximately 200 MW of solar generation in the 2027-2028 timeframe.
    c. Taking the initial steps necessary to add approximately 200 MW of wind generation in the 2029 timeframe.
    d. Withdrawal from OTP's 35% ownership interest in Coyote Station in the event OTP is required to make a major, non-routine capital investment in the plant.

5. Approve the bidding process for OTP's future resource acquisitions as outlined on page 36 of the Department's September 13, 2023, comments. **AND**
    a. Modify Step 1 of the Department's proposed process to state: "1. OTP should use a bidding process for supply-side acquisitions of 100 MW or more or for energy storage resources, acquisitions of 2S MW or more lasting longer than five years." (CEOs modification to Step 1)

CEOs Modifications (as an alternative to Decision Option 2)

6. Find that it is not prudent and not in the public interest for Otter Tail to retain its share of Coyote beyond 2028 and that Otter Tail should therefore withdraw from Coyote as soon as reasonably possible, but by no later than 2028.

7. Authorize Otter Tail to give contractual notice of its intent to withdraw to co-owners while declining to explicitly find at this time that Otter Tail required Commission authorization to give this notice or that it was prudent not to give notice of withdrawal earlier. *(Staff note: The Commission may consider ending this option after "to co-*

[145] The language in 5.A.-5.D. is from page 2 of the Updated IRP.

owners." Staff is unclear if the language beginning with "while declining" is rationale or a Commission finding.)

8. Modify Otter Tail's Preferred 2040 Plan to:
    a. Include withdrawing from Coyote by no later than 2028.
    b. Find that Otter Tail has demonstrated a need for: planned wind repowers in 2025, 200 MW of surplus solar in the 2027-2028 timeframe, 350 MW of wind resources in the 2029- 2031 timeframe, an additional 200 MW of surplus solar in the 2030-2032 timeframe, and 50 MW of surplus battery resources by no later than 2032.
    c. Require Otter Tail to request an Attachment Y-2 study with MISO, and perform any transmission and reliability analysis that may be needed to evaluate the impacts of a potential Coyote retirement and any potential mitigations that may be needed. The Y- 2 study shall be filed in this docket and with the Company's next Minnesota IRP, or by March 1, 2026 at the latest.
    d. Conduct an assessment of the value of reusing the Company's interconnection rights at Coyote, and file that assessment in this docket within 12 months of this order.

9. Find that it is not prudent and not in the public interest for Otter Tail to retain its interest in Big Stone beyond 2030 and that Otter Tail should therefore withdraw from Big Stone as soon as reasonably possible, but by no later than 2030.

10. Find that it is prudent and in the public interest for Otter Tail to accelerate its acquisition of wind power and battery storage at a scale and pace consistent with the resources listed in this order.

11. Further modify Otter Tail's Preferred 2040 Plan to include:
    a. Withdrawing from Big Stone by no later than 2030;
    b. Finding there is a need for and approving the following resources, additional to those in Decision Option 9.b: 550 MW of wind resources in the 2029-2031 timeframe and 125 MW of battery resources by 2031.
    c. Requiring Otter Tail to request an Attachment Y-2 Study from MISO for the Big Stone Plant and to perform any transmission and reliability analysis that may be needed to evaluate the impacts of a potential Big Stone retirement and identify any mitigations that may be needed. The Y-2 study should be filed in this docket and with the Company's next Minnesota IRP, or by March 1, 2026 at the latest.
    d. Requiring Otter Tail to conduct an assessment of the transmission congestion present in the Big Stone area, the impact of LRTP lines and other transmission infrastructure, and the future local transmission outlook. The results of this evaluation shall be filed with the Company's next Minnesota IRP.
    e. Requiring Otter Tail to conduct an assessment of the value of reusing the Company's interconnection rights at Big Stone, and to submit that assessment in this docket with the Company's next Minnesota IRP, or by March 1, 2026 at the latest.

f. Requiring Otter Tail to issue a Request for Information 6-12 months prior to filing its next IRP, seeking information from developers on projects under development in proximity to Big Stone or in proximity to potential paths for a generation-tie line. The results of the RFI should be filed with OTP's next IRP.

12. Require Otter Tail to begin planning now for a Big Stone withdrawal by no later than 2030 and to present a plan in its next Minnesota IRP that withdraws from Big Stone by no later than the end of 2030. The plan should demonstrate that Otter Tail is taking proactive steps to keep a 2030 exit on the table and is exploring the economic value of retiring the plant, including consulting with co-owners on the issue.

OR

13. Require Otter Tail to prepare an analysis considering the withdrawal from or continued operation of Big Stone to file in its next Minnesota IRP. The analysis must include a resource planning analysis, a rate impact analysis, and address multi-jurisdictional, co-ownership, socioeconomic, and environmental issues. *(Staff variation of Decision Option 12, which is discussed on pages 73-74 of the briefing papers.)*

14. Find that it may be economic for Otter Tail to add the wind, solar and/or battery storage resources listed above before the dates specified, and therefore the company should actively assess market conditions and project availability to bring forward economic resources when feasible, and by no later than the dates listed above.

15. Defer a decision on Otter Tail's Astoria LNG proposal until the Company's next IRP.

Requirements for the Next IRP

16. Require Otter Tail to submit its next IRP by two years from the date of this order. *(CEOs. Staff note: Staff has no problem with the length of time the CEOs propose, but the Commission may want to add a specific date.)*

17. Direct Otter Tail in its next IRP to:
    a. Include an analysis of the costs of its preferred plan and its comparative plans under the full range of regulatory and externality costs specified by the Commission in its forthcoming order in docket 22-236. This analysis should include emissions both inside and outside Minnesota to the extent they are associated with generation used to serve Minnesota customers.
    b. Present modeling runs that allow a reasonable amount of both market purchases and sales.
    c. Conduct production cost modeling to obtain more detailed information to develop the portfolio PVRRs and to evaluate the dispatch of resources during specific periods of time, including during periods of challenging system conditions.

d. Include an analysis of the health and equity impacts of its preferred plan.
e. Include an assessment of energy efficiency, demand flexibility, and energy storage options, especially in comparison with the addition of on-site fuel storage at its Astoria facility.
f. Order Otter Tail to comply with a planning reserve margin based on a LOLE standard of one day of load shed in ten years, calculated considering the power pool to which Otter Tail belongs, which currently is MISO. (Department)