MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	December 5, 2019	Agenda Item **3
Company	Otter Tail Power Company (OTP or the Company)	
Docket No.	**E017/RP-16-386** **In the Matter of Otter Tail Power Company's 2017-2031 Resource Plan**	
Issues	1. Should the Commission grant OTP's requested extension for its next Integrated Resource Plan (IRP) from June 1, 2020 to September 1, 2021? 2. If so, should the Commission require OTP to file any supplemental information by June 1, 2020?	
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✓ **Relevant Documents**	**Date**
Commission Order Approving Plan with Modifications	April 26, 2017
Otter Tail Power, *Extension Request*	August 29, 2019
Department of Commerce, *Comments*	September 25, 2019
Otter Tail Power, *Response to PUC IRs 3-7*	September 25, 2019
Otter Tail Power, *Response to PUC IR 8 (Public and Non-Public)*	October 30, 2019
Otter Tail Power, *Response to PUC IR 9*	October 30, 2019
Otter Tail Power, *Response to PUC IR 10*	October 30, 2019

I. Statement of the Issues

Should the Commission grant Otter Tail Power Company's (OTP or the Company) request to delay filing its next Integrated Resource Plan (IRP) from June 1, 2020 to September 1, 2021?

If so, should the Commission require OTP to file any supplemental information by June 1, 2020?

II. Background

On June 1, 2016, OTP filed its IRP covering the 2017-2031 planning period.

On April 26, 2017, the Commission issued its *Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan*. The Commission approved a five-year action plan that included the addition of:

- 200 megawatts (MW) of wind in the 2018-2020 timeframe;
- 30 MW of solar in about 2020, sized to meet OTP's requirements under the Minnesota Solar Energy Standard (SES);
- Up to 250 MW of peaking capacity in 2021; and
- Average annual energy savings of 46.8 gigawatt-hours (GWh), or 1.6% of retail sales.

The Commission also modified OTP's expansion plan to include 100-200 MW of new wind (in addition to the 200 MW in the five-year action plan) in 2022-2023.

The Commission required OTP to file its next IRP by June 3, 2019. Among other things, the Commission required the Company to examine how higher levels of new wind could impact reliability of service (with the wind in the five-year action plan, about 25-30% of OTP's total retail energy will be served by wind). In addition, the Commission required OTP to evaluate new demand response (DR) for capacity savings (almost all of OTP's DR is for the winter, which does not receive accredited capacity to meet MISO's planning reserve margin requirements).

Note that OTP's request to delay filing its next IRP is the Company's second such request. On August 23, 2018, OTP requested a one-year extension, from June 3, 2019 to June 1, 2020, to file its next IRP. The reasons why OTP claimed it needed more time were essentially the same as those provided in OTP's instant extension request; OTP cited EPA rules, including the Regional Haze Rule, and the new capacity expansion model the Company will be using, the "EnCompass" model, as reasons why a delay would be prudent. OTP explained in 2018:

> Waiting one year to gain additional certainty around the Regional Haze Rule and the Clean Power Plan Replacement Rule will provide all parties with a more informed resource plan.

> Granting the extension will also afford the Company and the Department additional time to become familiar with the new capacity expansion model. It would also spread out the workload for parties to this proceeding. More accurate pricing of solar energy could also be included.[1]

On December 13, 2018, the Commission approved OTP's extension request and established a new IRP filing date of June 1, 2020.

On August 29, 2019, OTP requested another roughly one-year extension (15 months to be precise), from June 1, 2020 to September 1, 2021, to file its next IRP. As noted above, OTP basically repeated (almost verbatim) what it had stated in its 2018 extension request:

> Waiting one year to gain additional certainty around the Regional Haze Rule will provide all parties with a more useful and informed resource plan. In addition, granting the extension will also afford the Company and the Department additional time to become familiar with the new capacity expansion model. It would also spread out the workload for parties to this proceeding. More accurate pricing of solar energy could also be included.[2]

III. Otter Tail's Extension Request

OTP's extension request largely addresses the progress it has made in implementing the four main components of the Company's approved five-year action plan listed above. OTP believes its request is reasonable because it has sufficient resources to meet its capacity obligations, and more time will allow further examination of environmental regulations. These issues are discussed in greater detail in the following sections.

A. Five-Year Action Plan

As noted above, the four key components of OTP's five-year action plan include a wind unit, enough solar to comply with the SES, a peaking unit, and a 1.6% energy savings level. In the table below, staff provides a summary of the approved, generic resources compared to the current status of OTP's implementation of the five-year action plan:

[1] Otter Tail 2018 extension request, at 1.

[2] Otter Tail 2019 extension request, at 9.

Generic Resource	Status
200 MW of wind in the 2018-2020 timeframe	The 150 MW Merricourt Wind Energy Center is currently under construction. The project is expected to be operational in 2020.[3]
30 MW of solar in about 2020	OTP is still working with various developers to identify a cost-effective solar project that would produce enough solar to meet Minnesota's SES requirement. OTP projects a 25 MW solar project would meet the SES.
Up to 250 MW of peaking capacity in 2021	Astoria Station, a simple-cycle natural gas combustion turbine project located near Astoria, South Dakota, is in development. The commercial operation date for Astoria Station is March 2021. OTP noted it is "on time and on budget," and all major permits have been obtained.
Average annual energy savings of 46.8 GWh (1.6% of retail sales)	OTP achieved annual energy savings of 4.03% in 2018 and is expecting to achieve over 2% in 2019. Both far exceed the 1.6% goal from the IRP.

B. *Projected Load & Capability*

OTP argues that a 15-month extension is not problematic because it has plenty of resources to cover its resource adequacy obligation. The table below (from page 6 of OTP's extension request) shows the Company's MISO Planning Reserve Margin Requirement (PRMR) through 2029. It further shows that OTP does not have a capacity need for the next decade. There is a small deficit projected in 2020, which staff believes OTP is covering through bilateral contracts, but with the completion of the 248 MW Astoria Station natural gas plant and the 150 MW Merricourt Wind project, OTP will be able to cover its resource need thereafter:

[3] OTP addressed the potential concern that Merricourt Wind is 50 MW less than the wind approved in the five-year action plan. OTP explained that since Merricourt has a uniquely high capacity factor (~50%), the total amount of energy generated by the 150 MW Merricourt Wind project and 200 MW of generic wind from the IRP, which had lower capacity factor assumptions, is roughly the same.

II. PROJECTED LOAD & CAPACITY

Load

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Forecasted Load	788.4	824.0	830.7	834.5	838.3	842.1	845.9	849.7	853.5	857.3
Net EE Reduction	2.7	6.6	10.9	15.4	20.1	25.0	29.8	34.7	39.6	44.5
Summer Peak	785.8	817.4	819.8	819.1	818.2	817.1	816.0	815.0	813.9	812.8
Coincident Peak	715.0	743.8	746.0	745.4	744.5	743.5	742.6	741.6	740.6	739.7
PRMR	**772.2**	**803.3**	**805.7**	**805.0**	**804.1**	**803.0**	**802.0**	**800.9**	**799.9**	**798.8**

Capability

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Coal	506	370	370	370	370	370	370	370	370	370
Natural Gas/Oil	101	344	344	344	344	344	344	344	344	344
Wind	59	82	82	82	82	82	82	82	82	82
Solar	0	0	0	0	0	0	0	0	0	0
Hydro	3	3	3	3	3	3	3	3	3	3
Purchased	60	10	10	10	10	10	10	10	10	10
Load Management	19	19	21	21	21	21	21	21	21	21
Total	**747**	**827**	**829**	**829**	**829**	**829**	**829**	**829**	**829**	**829**

Net Position	**(25.1)**	**23.3**	**22.9**	**23.6**	**24.5**	**25.6**	**26.6**	**27.6**	**28.7**	**29.8**

C. *Regional Haze*

1. Rule Requirements

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program, the Regional Haze Rule, for Federal Class I areas. These areas include national parks, memorial parks, and wilderness areas over a certain size. The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Federal Class I areas.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address visibility. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states. (Minnesota is a member of the Central Regional Air Planning Association, or CenRAP.)

The CAA and the Regional Haze Rule mandate that certain older polluting facilities, like power plants, adopt emissions control technology that is determined to be the "Best Available Retrofit Technology" (BART). For the first implementation period, which covered the 2008-2018 timeframe, BART-eligible sources included coal units that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. This meant that OTP was required to reduce emissions by applying BART at the Big Stone Plant in South Dakota, but not Coyote Station, which commenced operations in 1981.

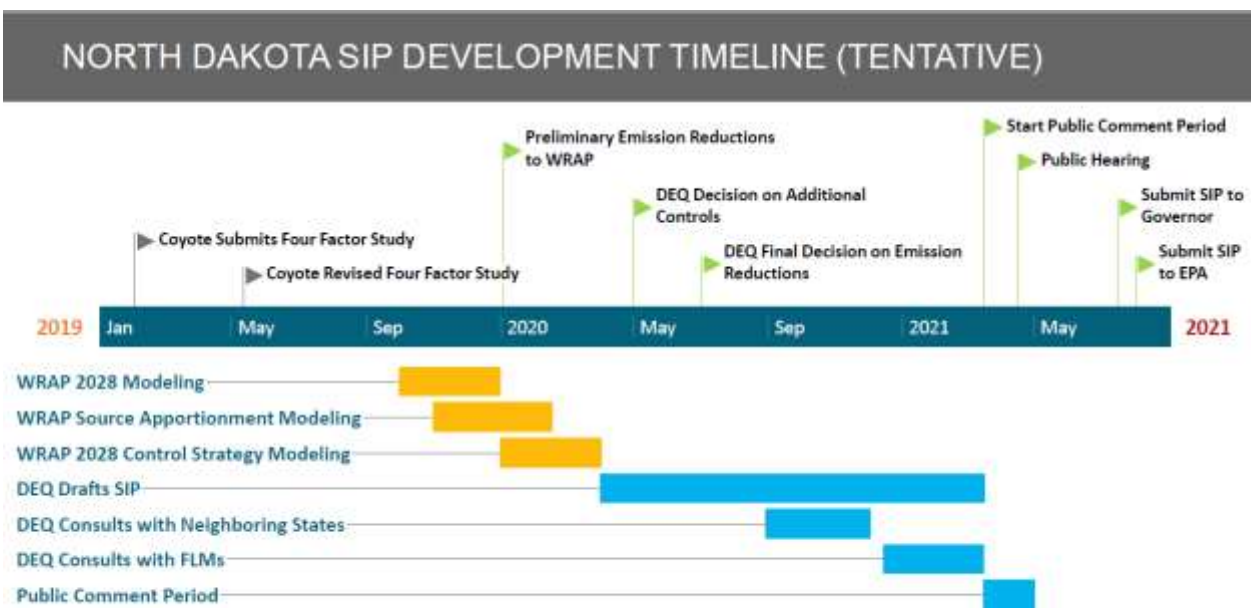
Coyote Station is likely to be a focal point of North Dakota's second implementation period. First, it currently has very minor air quality controls. Second, according to EPA's Clean Air Markets data, Coyote Station has among the highest sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions rates (on a lb/MMBtu basis) of all coal plants in the nation,[4] thus making it quite important for North Dakota's next SIP to address Regional Haze.

2. SIP Timeline and the Sargent & Lundy Report

a. Second Implementation Period Summary

As noted, the Regional Haze Rule divides the process into ten-year planning periods. The second implementation period begins in 2021 and ends in 2028.[5] The Regional Haze Rule does not explicitly address individual facilities, but each affected state must develop its own SIP that will apply emission limitations to individual facilities to make reasonable progress for the implementation period.

OTP noted that Coyote Station is the Company's only North Dakota facility expected to be affected by North Dakota's SIP. Regional Haze SIPs for the second planning period must be submitted to EPA for review by **July 31, 2021**. On page 9 of OTP's extension request, the Company provided a tentative timeline for the second planning period (DEQ refers to the North Dakota Department of Environmental Quality):



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[4] Table of Emissions, Emission Rates, Heat Input: 2018 vs. 2019, https://www.epa.gov/airmarkets/power-plant-data-highlights#Quarterly

[5] On April 25, 2016, EPA announced several revisions to the Regional Haze Rule. One revision extended the SIP submittal deadline for the second regional haze planning period by three years, from July 31, 2018 to July 31, 2021.

b. Sargent & Lundy Report

As part of North Dakota's SIP development for the second implementation period, the North Dakota DEQ requested that each addressed power plant submit a "four-factor analysis" by January 31, 2019. OTP, along with the three other Coyote Station owners, retained Sargent & Lundy to develop this four-factor analysis. OTP received minor comments from the State on the initial submittal, and a revised analysis was submitted May 10, 2019. The report is available at https://deq.nd.gov/AQ/planning/RegHaze.aspx.

The Sargent & Lundy report evaluates technically feasible SO_2 and NO_X emissions reduction measures by applying the four factors listed below:

- Factor 1: The cost of compliance;
- Factor 2: The time necessary to achieve compliance;
- Factor 3: The energy and non-air quality environmental impact of compliance; and
- Factor 4: The remaining useful life of any existing source subject to such requirements.[6]

Staff will discuss a few of the details discussed in the Sargent & Lundy report in later sections of the briefing paper. This way the Commission can review, with staff comments, certain aspects of the report within the context of OTP's request for additional time to file its next IRP.

IV. Department Comments on the Requested Extension

On September 26, 2019, the Department filed comments stating it "does not oppose" OTP's request for a 15-month extension. It was the only party to provide comments on the procedural schedule. The Department explained:

> Given that the Company does not have any capacity needs in the foreseeable future, the July 2021 finalization of North Dakota's Regional Haze SIP will provide more information concerning costs of complying with the Regional Haze Rule, the requested delay in filing Otter Tail's IRP will not impair the Commission's ability to make determinations regarding the Coyote plant, and the Company is proceeding with implementing its 5-year action plan, the Department does not oppose Otter Tail's Extension Request.[7]

[6] Sargent & Lundy noted that the Coyote Station owners did not identify dates for the remaining useful life of the unit "before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1." Thus, Sargent & Lundy assumed a 20-year equipment life of the control measures to calculate emission reductions, amortized costs, and cost-effectiveness.

[7] Department comments, at 4.

Recall that one reason OTP stated an extension is reasonable is so OTP and the Department can become more familiar with the new capacity expansion model. Staff notes that the Department did not address one way or another whether an extension is beneficial for this reason. The Commission can ask the Department what its plan is for securing a new model, but at this time staff is unaware whether the Department needs more time to become more familiar with a new capacity expansion model. Staff would note that the Department will be evaluating Xcel Energy's, Minnesota Power's, and Great River Energy's (who is also using EnCompass) IRPs in 2020-2021, so the unfortunate reality is that the Department will probably have to dive into the deep end of new modeling software regardless of OTP's IRP schedule.

V. Staff Discussion of OTP's Extension Request

A. *Issues Other Than Capacity Needs Could Warrant a Fresh IRP*

While staff does not necessarily oppose OTP's request to delay the IRP, at the same time, careful consideration must be given to the possible downside risks of doing so. The Commission's task is to weigh the benefit of waiting and accruing more information from the North Dakota SIP process against any concerns the Commission might have with leaving several other aspects of resource planning unaddressed.

Generally speaking, staff does not share the Company's view that the Regional Haze Rule is particularly problematic from an IRP modeling perspective, and staff does not agree that OTP's net capacity surplus is, by itself, an adequate reason to delay the next IRP process. In isolation the uncertainty surrounding the Regional Haze Rule could be a reasonable cause for delay, but staff would urge the Commission to consider other factors.

For one, compliance with the Regional Haze Rule was already a reason OTP was previously granted a one-year extension out to 2020, and OTP did not indicate at the time that another 15 months on top of that would be required. Moreover, uncertainty regarding future investments in emissions control technology at Coyote Station will still remain once the North Dakota SIP is submitted to EPA in July 2021. The EPA will still need to approve North Dakota's SIP, and it is not hard to imagine OTP asking for a third extension, citing uncertainty regarding EPA's decision as the reason for more time. OTP discussed the post-SIP submittal process in response to Staff Information Request No. 3:

> If requirements for Coyote Station are proposed in North Dakota's July 2021 State Implementation Plan (SIP), it is anticipated that the SIP will identify enforceable emission limitations based on the installation of specific control technology. However, at that point the SIP is still subject to EPA review, and subsequent proposed approval or disapproval (disapproval would be in the form of a Federal Implementation Plan). EPA's proposed action will be published for public comment, and ultimately EPA will take those public comments into account when issuing a final determination.[8]

[8] OTP response to PUC Information Request No. 3.

As the Commission well-knows, resource planning is an iterative process that aims to take a fresh look at a utility's planning efforts every two years. Extending OTP's next IRP yet another 15 months would leave a more than five-year gap in-between resource plan filings, which is not a minor issue. OTP's last IRP was filed on June 1, 2016, and the Commission approved the plan with modifications on April 26, 2017. This means that more than three years have already passed since OTP has filed an IRP, and approving OTP's 15-month extension would mean the Commission will likely not review another OTP resource plan until late-2022/early-2023.

OTP downplays the risk of granting additional time by referring to its currently-projected net capacity surplus; however, staff has three main concerns with using the Company's net capacity position projection as the measuring stick for risk.

1. OTP's Capacity Surplus is Small and Relies on MISO Adjustments

OTP's net capacity surplus is fairly small, at roughly 20 MW, and the reason a surplus exists at all is partially due to the assumptions OTP makes for its MISO-coincident load and MISO planning reserve margin, both of which can change annually. OTP assumes that its peak is 91% coincident with MISO's peak, which reduces the accredited capacity OTP is obligated to have on its system. The Company also assumes an 8% reserve margin, in unforced capacity (UCAP) terms, but over the long-term this number will change for reasons completely outside of OTP's control; in fact, MISO currently estimates it will need an 8.9% UCAP planning reserve margin for the 2020/21 planning year, a full percentage point above the current level.[9]

OTP shows a Load and Capability table on page 6 of its extension request, which is also presented on page 4 of the briefing paper. By isolating two rows—the forecasted load and the total capability—the Commission will see that OTP's total resource capability is actually *less* than its forecasted load in all years but one:

Otter Tail Projected Load and Capability

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Forecasted Load (MW)	788.4	824.0	830.7	834.5	838.3	842.1	845.9	849.7	857.3
Total Capability (MW)	747	827	829	829	829	829	829	829	829

It is also worth noting that OTP is a winter-peaking utility, and as shown in the table below, OTP's winter peak is about 175 MW higher than its summer peak:

[9] MISO, "Planning Year 2020/21 Loss of Load Expectation Study Results," https://cdn.misoenergy.org/20191106%20RASC%20Item%2003a%20PY%202020-21%20LOLE%20study%20results397078.pdf

Year	Winter Peak (MW)
2020	959
2021	1,004
2022	1,011
2023	1,015
2024	1,019
2025	1,022
2026	1,026
2027	1,030
2028	1,034
2029	1,038

Of note, OTP has about 100 MW more winter DR than summer DR, which means that the total capability row in the table above would be higher if looking at a winter net capacity position. But as this is only emergency DR, winter emergency DR would not be able to meet OTP's higher energy needs or hedge against market price risk during these months. OTP may therefore need to rely excessively on the spot market or its most expensive generators.

To be clear, staff is not arguing that OTP's MISO-related resource adequacy assumptions are unreasonable; most if not all utilities who are MISO members make these adjustments in their IRPs. The point is there is risk in relying on MISO-adjusted values over a long-term time horizon, especially since coincidence factors and reserve margins are applied on an annual basis. Moreover, resource planning dockets have often stressed that utilities should not use MISO as a "crutch," as doing so could expose ratepayers to excessive market risk. Third, it is unclear from OTP's Load and Capability table how prepared it might be for a seasonal resource adequacy construct, which is an issue other Minnesota IOUs are beginning to emphasize in their resource plans.

What is also important is the fact that it has been several years since OTP's forecast has been reviewed, so neither staff nor the Department can confirm whether OTP's roughly 20 MW capacity surplus is even accurate. In fact, OTP's projected obligation in its extension request appears to be substantially less than in its 2016 IRP Petition. The difference between the two filings is shown in the table below (for space, staff includes comparisons only from 2020-2027).

Obligation (in MW) by Filing	2020	2021	2022	2023	2024	2025	2026	2027
2016 IRP Petition[10]	840.7	848.2	855.0	861.8	878.5	895.3	902.4	909.6
2019 Extension	772.2	803.3	805.7	805.0	804.1	803.0	802.0	800.9
Difference	68.5	44.9	49.3	56.8	74.4	92.3	100.4	108.7

Staff notes that if the total capability shown in the 2019 extension request is compared to the obligation shown in the 2016 IRP Petition, OTP would have a capacity deficit in all years.

[10] OTP Petition, Table 2-2: Summer 2017-2031 Base Case Projected Load and Capability.

2. A Utility's Net Capacity Position is Only One Element of Resource Planning

a. The Commission's "Five Factors to Consider"

Whether OTP has enough resources to cover its MISO planning reserve requirements for the near-term is only one of several factors the Commission considers in resource planning. Even if OTP is long on capacity for the next decade, this does not mean that adding no resources will be the least-cost plan.

According to Minn. R. 7843.0500, subp. 3, the Commission must evaluate resource options and resource plans 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.

OTP discusses these factors in its extension request, but the Company approached them in a different way than staff. OTP explained that gaining additional certainty around the Regional Haze Rule will help meet the objectives of Minn. R. 7843.0500, subp. 3 by addressing "regulatory constraints" and OTP's ability to respond "to continuing changes in other financial, social, and technological factors affecting OTP's operations."[11]

This is true, but staff has other concerns, including: whether OTP's forecasted demand shown in its extension request is reasonable; whether OTP is appropriately managing its energy costs; whether OTP is adequately limiting market risk; and whether OTP is minimizing adverse effect upon the environment. A new IRP proceeding would address all of these factors, and the Commission would decide which expansion plan is reasonable under both the revenue requirement and societal cost tests. The Load and Capability table OTP presents in its extension request is not an adequate substitute for a least-cost plan.

b. Market Risk

A common measure of utilities' exposure to market risk is their amount of energy needs met by spot market purchases. In OTP's 2016 IRP Petition, OTP projected that 22% of its 2017 energy

[11] OTP extension request, at 10.

requirements were served by market purchases,[12] which, arguably, already reflects a relatively high exposure to the spot market. (By comparison, in Minnesota Power's Nemadji Trail Energy Center (NTEC) docket, MP's energy market exposure was 11%, and MP argued that with NTEC, it could reduce its spot market exposure to 3%.[13])

In response to Staff Information Request No. 10, OTP explained that the actual amount of its retail load served by market energy purchases in 2017-2018 was even higher than what the Company projected in the IRP:

> In 2017, 35% of our retail load was served with energy purchases. In 2018 it was 27% (not including our wind PPAs). Market prices have been lower than forecasted in our 2016 IRP which is why market purchases have been higher than anticipated.[14]

Of course, lowering system costs by taking advantage of depressed market energy prices is not unreasonable. However, it could be that OTP's amount of retail load served by market purchases is indicative of something else, perhaps that OTP's existing generators are expensive to operate, or that it needs additional resources to cost-effectively operate for many hours of the year (i.e. an intermediate need). As staff will discuss in the next section, the Commission's April 26, 2017 IRP Order modified OTP's plan to add 100-200 MW additional wind in 2022-2023 in part for this reason, as the record showed that more wind would be cost-effective and mitigate OTP's exposure to market risk.[15] However, it does not appear OTP is on track to implement the resource plan the Commission approved.

3. The Commission Modified OTP's IRP to Include New Wind

a. OTP's energy need

Notably, OTP's extension request only discusses resources approved in its five-year action plan. While the Commission's April 26, 2017 Order did not use the word "require" in reference to resources outside of OTP's five-year action, this does not mean the Commission did not address later years of the IRP, nor that the record did not identify an energy need in these years. In fact, the Department recommended two additional wind units (of 100 MW each) in the 2022 and 2023, which, according to the Department's October 5, 2016 initial comments, was consistent with OTP's own modeling results:

> **the Company's modeling outputs**, summarized in the Petition's Appendix I, demonstrate that in every case except OTP's preferred plan, Strategist selected an additional 100 MW of wind in 2022 and 2023. This result indicates that additional

[12] OTP IRP Petition, Figure 2-4: 2017 Energy by Fuel Source.

[13] Docket No. 17-568, In the Matter of the Application of Minnesota Power's Petition for Approval of the Energy*Forward* Resource Package. See Figure 7 on page 2-14 of MP's Petition and Figure 21 on p. 53 of Palmer Direct Testimony.

[14] OTP response to PUC IR 10 (October 30, 2019).

[15] See, for example, the Department's October 5, 2016 comments, at 27.

wind would be a cost effective tool for mitigating spot market exposure.[16] *(Emphasis added by staff.)*

In other words, the record showed that (a) OTP has a significant energy need (200 MW of wind is a lot of energy for a utility of OTP's size) and (b) wind was the most cost-effective resource to meet that need. This result was consistent in both the Department's and OTP's modeling. Also note that OTP's modeling took into account the phasing-out of the wind PTC, and the Strategist model still selected wind resources at prices double than what they are now. Figure 2 of OTP's Petition shows its wind energy assumptions:

Figure 2: Wind Energy Assumptions

Strategist Name	Construction Start	COD by end of	First Full Year of Operations	PTC	Fixed Price ($/MWh) Low	Fixed Price ($/MWh) Base	Fixed Price ($/MWh) High	NCF	Nameplate Capacity (MW)	Accredited Capacity (15.6% of Nameplate) (MW)	Year that one Superflous unit available
W16	2016	2020	2021	100%	$25.00	$30.00	$35.00	40%	100	15.60	2018, 2020
W17	2017	2021	2022	80%	$29.00	$34.00	$39.00	40%	100	15.60	2022
W18	2018	2022	2023	60%	$34.00	$39.00	$44.00	40%	100	15.60	2023
W19	2019	2023	2024	40%	$39.00	$44.00	$49.00	40%	100	15.60	
W20	2020	2024	2025	0%	$48.00	$53.00	$58.00	40%	100	15.60	2025
W23	2023	2027	2028	0%	$51.24	$56.24	$61.24	40%	100	15.60	2027
W26	2026	2030	2031	0%	$54.69	$59.69	$64.69	40%	100	15.60	

b. OTP's Compliance with the Commission's Order

OTP's initial proposed plan did not include additional wind beyond the five-year action plan. After comments from parties, OTP filed a "Revised Preferred Plan," which included an additional 100 MW wind unit in 2022. The Commission's April 26, 2017 Order modified OTP's IRP to incorporate both OTP's Revised Preferred Plan and the Department Plan (which added 100 MW of wind in both 2022 and 2023); the Commission allowed a range of 100-200 MW of new wind beyond the five-year action plan:

> 5. The Commission hereby modifies Otter Tail's integrated resource plan to include 100 MW to 200 MW of wind in the 2022 to 2023 timeframe. This does not preclude additional wind during the five-year action plan period.[17]

In the Department's comments to OTP's extension request, the Department correctly observed that OTP "ignored Order Point 5 from the Commission's April 26, 2017 IRP Order."[18] The Department then summarized its conversations with OTP about this issue:

> The Department discussed the 100 MW to 200 MW of wind procurement requirement with Otter Tail, which stated that it did not address Order Point 5 because the wind resources were slated for procurement outside of its 5-year

[16] Department comments, at 27 (October 5, 2016).

[17] Commission ordering paragraph 5 (April 26, 2017).

[18] Department comments, at 2.

> action plan and because the Company's recent capacity expansion modeling indicated that solar, and not wind, may be the next most cost-effective resource.[19]

However, despite the fact that OTP ignored the Commission's modification to OTP's plan, the Department was not concerned about OTP's compliance with the Commission's Order:

> [G]iven that the Company proposed to submit its next IRP by September 1, 2021, the Department concludes that the Company can propose the most cost-effective resource at that time and still procure the resource in a timely manner.

Staff is concerned the Department may have reached its conclusion based on evidence that is not in the record, and staff does not agree with the Department that OTP can procure the resource in a timely manner, at least not in a way that can comply with the Commission's modified IRP.

First, what is most troubling about OTP's response to the Department is that the Company cites new capacity expansion modeling that the Department acknowledges it cannot confirm to be credible. The Department explicitly stated that it "has not viewed the Company's new capacity expansion modeling and thus cannot comment on whether additional wind is no longer a cost-effective resource for 2022-2023."[20] OTP's new modeling has not been incorporated as part of the record, and to staff's knowledge no party has reviewed it, so staff would urge the Commission to disregard new claims from the Company about what its results indicate.

Second, while it is true that the new wind was selected in years 6 and 7 of the planning period (i.e. outside of the five-year action plan), if the Commission knew at the time that OTP would not file another resource plan until late-2021, its language might have been more instructive and instead required OTP to secure the energy. But the Commission's April 26, 2017 Order required OTP to file its next IRP "no later than June 3, 2019," more than two years earlier than what OTP now proposes. If OTP had filed a new IRP on June 3, 2019, then staff would agree OTP would have sufficient time to secure its energy need in a timely manner, but now the ability to do so is far less certain.

Third, according to OTP's wind energy assumptions from its IRP, shown in Figure 2 above, for a wind project with a COD (commercial operation date) of 2022, OTP assumed the construction date would need to begin in 2018. For a wind project with a COD of 2023, OTP assumed the construction date would need to begin in 2019. Obviously neither construction date can now be accomplished. So, either OTP's wind assumptions used for this IRP are wrong, or the Company will not be able to meet the Commission's timeline.

Fourth, neither OTP nor the Department explain how OTP plans to secure the energy. If OTP will propose a generic resource as part of its next IRP process—and the Department states Ordering Paragraph 5 can be addressed "at that time," meaning September 1, 2021—then

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[19] Department comments, at 2.

[20] Department September 26, 2019 comments, at 3.

there is no way possible to reevaluate the 2022 and 2023 wind units and still meet a 2022 energy need. Regardless, it is difficult to accept that OTP can implement or even has any intention to implement the Commission's modified plan when OTP's current position is: (1) solar is now more cost-effective than wind, but (2) OTP will continue to buy solar renewable energy credits (SRECs) for SES compliance because North and South Dakota regulators will not approve projects that are not part of the least-cost mix.

Fifth, wind and solar facilities have completely different generation profiles, and the total energy generated from 200 MW of wind and 30 MW of solar would not reflect comparable resource plans. Again, what OTP neglected to answer in its response to the Department was how OTP plans to meet the energy need that was identified. Instead, OTP responded that the next most cost-effective resource, according to its new EnCompass modeling that is not part of the record, has changed in type.

Staff will repeat that the Department stated in its October 5, 2016 comments in this proceeding, "in every case except OTP's preferred plan, Strategist selected an additional 100 MW of wind in 2022 and 2023. This result indicates that additional wind would be a cost effective tool for mitigating spot market exposure."[21] It is not clear what has changed, but what is known is that under OTP's proposed schedule, 2022 would be the first year of the new planning period. There is simply not enough time to go through an entire IRP process to revisit the question of whether wind in 2022 is still needed or cost-effective, and nowhere in the extension request did OTP mention they would propose a new wind unit in the meantime. In fact, OTP suggested the opposite by stating that solar—which it will not propose until North and South Dakota are on board—is more cost-effective.

The bottom line is that the Commission obviously felt years 6 and 7 of the planning period were important enough to modify the size, type, and timing of OTP's resource plan accordingly in its Order. For OTP to argue that because these resources were outside of the five-year action plan they do not need to be addressed is only acceptable for a procedural schedule that envisioned a new IRP filed by June 2019. And as an aside, it is odd that OTP has already drawn conclusions about the most cost-effective resources determined by its EnCompass modeling, since OTP also argues that it needs until September 2021 to become more familiar with the new model.

B. OTP's Solar Acquisition Plan

This section will discuss OTP's solar acquisition plan in the context of OTP's request for additional time to file its IRP. Overall, this issue might simply boil down to how much direction the Commission wishes to give the Company on SES compliance and solar acquisition generally.

As discussed previously, OTP plans to comply with the SES in the short-term by procuring enough SRECs to meet its obligations for 2020 and "a significant portion of 2021."[22] OTP stated

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[21] Department's October 5, 2016 comments, at 27.

[22] OTP extension request, at 6.

it will continue to do so "until a cost-effective solar energy project (or projects) can be shown to be part of a least cost resource plan portfolio."[23]

One concern the Commission might have with this approach is the lack of record development since the Commission's April 2017 Order—during which time the price of solar has dropped substantially—coupled with the fact that there has been no competitive bidding process to verify OTP's claim that solar is not currently cost-effective. Staff notes that OTP is the only investor-owned utility in Minnesota that has not issued a solar RFP as part of a docketed proceeding, and furthermore, when MP[24] and Xcel[25] issued theirs, they found that bid prices were lower than the generic solar price assumptions used in their respective IRPs. (For Xcel Energy, staff is referring to Xcel's Minnesota solar RFP in 2014; Xcel's December 2017 all-source RFP in Colorado attracted far lower solar prices than expected, and the historically low solar bids in that case is an outcome Xcel characterized as "unprecedented."[26])

A possible decision option is to require OTP to issue a solar RFP, and the Commission could even outline the parameters of what a solar RFP might look like. This would actually be the action most consistent with OTP's five-year action plan, in which, as illustrated in Table 2-5 of OTP's IRP below, the Company proposed to "construct or obtain [a] PPA for an approximate 30 MW solar installation by 2019:"

Table 2-5: Five-Year Action Plan Activities

Year	Activity
2016	June 1 Triennial CIP filing for 2017, 2018, 2019 MISO interconnection process for CT Preparation for permitting effort for CT
2017	Permitting and approvals for 248 MW CT MISO interconnection process for CT Begin construction on 100 MW wind project
2018	Commercial operation of 100 MW wind project Permitting and approvals for 248 MW CT MISO interconnection process for CT Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020
2019	June 1 Triennial CIP filing for 2020, 2021, 2022 Engineering and procurement for 248 MW CT Begin construction on 100 MW wind project Construct or obtain PPA for an approximate 30 MW solar installation
2020	Construction of 248 MW CT File MISO Attachment Y for retirement of Hoot Lake Plant Commercial operation of 100 MW wind project Commercial operation of 30 MW solar project
2021	Start-up and commercial operation of 248 MW CT Retirement of Hoot Lake Plant

OTP noted in its extension request that its "EnCompass modeling still does not choose solar as part of a least cost energy."[27] OTP did not provide the assumptions that led to this conclusion,

[23] *Id*.

[24] Docket No. 15-690.

[25] Docket No. 14-162.

[26] https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/

[27] OTP extension request, at 5-6.

but it did note, "Regulators in both North Dakota and South Dakota have been unwilling to allow resources that are not part of a least-cost resource mix to be charged to customers in their states."[28] It is fair to characterize solar as a cost-prohibitive resource because that is indeed what the record has shown up to this point. The problem is this record only includes assumptions that are now three years old and were not derived from a competitive bidding process. (Again, staff recommends the Commission either disregard or take with a grain of salt modeling that is not part of the record or has been reviewed by parties.)

OTP claims in its extension request (like it did in its 2018 extension request) that in another year it could have more accurate information on solar prices. But if OTP issued a solar RFP, it could have accurate, market-based solar prices available to it within a few months. The core problem, it seems, is not the "accuracy" of solar prices; as OTP laid out in response to Staff Information Request No. 6, OTP's hope is that solar prices continue to fall to the point where its North and South Dakota jurisdictions will allow cost recovery. In staff's view, there is no reason to suppose any greater likelihood of multi-jurisdictional allowance of solar costs by September 2021.

C. *Coyote Station*

This section will return to the issue that underlies OTP's request to have additional time to file its next IRP—Coyote Station and compliance with the Regional Haze Rule. First, staff will provide some characteristics of the power plant. Then, staff will discuss Regional Haze compliance generally, as well as some of the cost of compliance analysis conducted thus far. Finally, staff will discuss the interrelationship of the North Dakota and Minnesota regulatory process. Staff notes that this section is mostly intended to provide the Commission with more information and context regarding Coyote Station and its role as the predominant reason for the requested extension.

1. Plant Characteristics

Coyote Station, located near Beulah, North Dakota, is a 427 MW lignite-fired mine mouth facility,[29] which became operational in 1981. (Coyote Station is OTP's only plant still burning lignite coal.) OTP is one of four co-owners, and OTP's 35% ownership share (the largest share among the co-owners) amounts to roughly 150 MW.

In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement with Coyote Creek Mining Company to deliver the annual coal supply needs of Coyote Station for 25 years beginning in May 2016 through 2040. OTP's 2016 IRP and 2018 Depreciation Study both assume a June 2041 retirement date for the facility.

Additional details are provided in the table below:

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[28] OTP extension request, at 6.

[29] A "mine mouth" facility is a coal-fired power plant built near a coal mine.

Age	On line since 1981	
Employees	Approximately 80	
Capacity	427 megawatts	
Air Quality Controls	• Dry Scrubber/Fabric Filter for SO_2 and PM Control (original to plant) • Overfire Air for NO_x control (Installed in 2016 for Regional Haze Round 1) • Activated Carbon Injection for Hg Control (MATS Rule)	
Ownership	Otter Tail Power Company	35%
	Northern Municipal Power Agency	30%
	Montana-Dakota Utilities Co.	25%
	NorthWestern Energy	10%

2. Regional Haze Rule Compliance

In its extension request, OTP identified a wide range of potential costs to reduce SO_2 and NO_X:

> SO_2 controls capital costs are estimated to be in a range of \$0.5M - \$325M. Examples of the control options evaluated for Coyote Station include upgrades to existing equipment, adding new technology in combination with existing equipment, and installing a new scrubber. Annual operation and maintenance costs are estimated to be between \$2M - \$22M depending on the control option.
>
> NOx controls capital costs are estimated to be in a range of \$20M - \$25M. Only two post-combustion control options are found to be technically feasible. Annual operation and maintenance costs are estimated to be between \$3M - \$7M.[30]

Below, staff will provide a few tables from the Sargent & Lundy report in order to provide the Commission with a fuller picture of OTP's discussion of the range of compliance costs.

First, Table 4-1 of the Sargent & Lundy report provides a baseline emissions summary of SO_2 and NO_X at Coyote Station:[31]

[30] OTP extension letter, at 8.

[31] Baseline annual SO_2 and NO_X emissions were determined based on data obtained from the Coyote Unit 1 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline heat inputs.

Table 4-1. Coyote Unit 1 Baseline Emissions

Pollutant	Baseline Controls	Emissions		Heat Input	Notes
		lb/MMBtu	tons/yr	MMBtu/yr	
SO_2	DFGD/FF	0.85	12,994	30,562,287	SO_2 emissions based on annual average tpy for period January 2013-June 2018 (excluding 2015)
NO_X	SOFA	0.46	7,363	32,301,802	NOx emissions based on annual average tpy for period July 2016 to June 2018 (post-SOFA upgrades)

SO_2 Control

Table 6-1 of the Sargent & Lundy report identifies technically feasible emissions control options for SO_2 and their respective costs. Total capital investments range from $0.5 million to $325 million, with annual operating costs in the $2 million to $22 million range. (It is these estimates that informed the excerpt above from OTP's extension request.) Since Coyote Station already has some pollution control,[32] investments at the low end involve improvements to existing controls. Investments at the high end of the cost range would involve new retrofits:

Table 6-1. SO_2 Control Cost Summary ($2018)

SO_2 Control Option	Total Capital Investment $	Annualized Capital Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
DSI + Existing FGD	$23,765,000	$1,948,000	$10,423,000	$12,371,000
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$526,000	$43,000	$2,042,000	$2,085,000
DSI + FGD Operational Improvements	$24,292,000	$1,991,000	$12,465,000	$14,456,000
FGD Upgrades - Replacing Existing Absorbers with New Absorber	$127,823,000	$10,475,000	$6,332,000	$22,197,000 (Note 1)
Dry FGD (CDS) + Existing FF	$242,647,000	$19,885,000	$20,610,000	$40,495,000
Wet FGD	$324,742,000	$26,613,000	$22,481,000	$49,094,000

Note 1. Total annual cost for "FGD Upgrades - Replacing Existing Absorbers with New Absorber" option includes annualized lost revenue due to extended outage and replacement power required for installation ($5,390,000).

The costs for SO_2 control shown in the table above correspond to how much Coyote Station must reduce its emissions, which will be a subject for the SIP process—basically, higher SO_2 reductions results in higher compliance costs. Table 5-8 of the Sargent & Lundy report, below,

[32] According to the Sargent & Lundy report, "Coyote Unit 1 commenced operation in 1981, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the North Dakota Department of Environmental Quality (NDDEQ) evaluated emissions from the Coyote Station as a reasonable progress source. The reasonable progress analysis prepared by NDDEQ concluded that no additional controls would be required on Coyote Unit 1 during the initial planning period; however, NDDEQ and Otter Tail reached an agreement whereby Otter Tail committed to install SOFA equipment to reduce NO_X emissions. In the initial planning period SIP NDDEQ noted that additional SO_2 and NO_X controls for Coyote Unit 1 would be reevaluated during future planning periods to determine if additional emissions reductions would be required."

shows that Coyote Station's baseline SO_2 emissions rate is 0.85 lb/MMBtu, and the options considered in the analysis would reduce SO_2 by 32%-93%:

Table 5-8. Evaluate Technically Feasible SO_2 Control Options for Effectiveness

Control Option	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	0.85	-
New Retrofit WFGD	0.06	92.9%
New Retrofit DFGD (CDS/FF)	0.09	89.4%
New Retrofit DFGD (SDA/FF)	0.16	81.1%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	0.29	65.9%
DSI + FGD Operational Improvements	0.33	61.2%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.50	41.2%
DSI + Existing FGD	0.58	31.8%

Note 1. Emission rates shown in Table 5-8 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

NO_X control

Table 6-3 of the report, below, shows the NO_X control cost summary. This table illustrates the $20-25 million range in capital investment and $3-7 million range in annual O&M that OTP referenced in its extension request:

Table 6-3. NO_X Control Cost Summary ($2018)

NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Combustion Optimization	$0	$0	$0	$0
SNCR + Combustion Optimization	$19,840,000	$1,626,000	$3,128,000	$4,754,000
SNCR + RRI + Combustion Optimization	$25,895,000	$2,122,000	$6,495,000	$8,617,000

3. Relationship of North Dakota SIP and Minnesota IRP Timelines

OTP explained that one reason for the extension was because it expects the ranges will narrow during SIP development, and "[a]ccurate information on the cost of compliance will be very important for OTP to submit a useful and instructive resource plan."[33] Staff does not disagree with OTP, but in this instance, it is not necessarily problematic if the cost of compliance range is fairly wide, especially if there are other resource planning concerns the Commission has.

One reason is because, as OTP noted in its September 10, 2019 response to the *Notice Seeking*

[33] OTP extension letter, at 9.

Comments, the Company claimed it will actually not be committing to an investment in emissions controls in the near-term:

> Just to clarify, the Regional Haze Rule requires compliance by December 31, 2028. There would likely be no investment made prior to 2025. So, even with a September 1, 2021 IRP filing date, there would be ample time to develop an IRP record prior to any investment in pollution control equipment and construction. In fact, it is probable that Otter Tail will file two IRP's prior to any investment being made.[34]

Staff has four responses to OTP's comment:

First, if no investment will be made in the next five years, and if OTP could even file two IRPs prior to any investment being made, then why is more accuracy so critical at this juncture given that there is already an analysis of compliance costs? The Sargent & Lundy initial and revised four-factor analyses evaluated a number of retrofit options, which it then used to derive cost of compliance estimates. In a scenario analysis, OTP could consider all options, or use a few data points (a low-, mid-, and high cost of compliance), which could then be compared to a plant closure option for Regional Haze compliance. With no analysis provided in the record up to this point, one cannot say how many data points are needed to maximize value in the decision-making process, but it is possible trends could be revealed even with a wide range.

Second, it might be the case that long-term operation of the plant is uneconomic even without emissions controls. It could be that running the plant does not generate enough revenue in the market, or that any additional environmental costs make the plant uneconomic. Staff notes that, from a modeling perspective, emissions control costs are not be the only type of environmental costs applied; OTP must also model environmental externalities (societal) costs. What emissions control cost would do is increase the fixed and variable costs associated with operating the power plant. However, in a scenario of minimal emission controls, there will be higher environmental externalities costs (because there will be more pollution as a result).

In other words, environmental costs will be attributed to Coyote Station no matter what: if there are minimal control costs, this means there is less pollution reduction, which in turn means there will be high externalities costs. If a more expensive retrofit is needed for compliance, this would mean there is less pollution, which in turn means lower environmental externalities costs. A new IRP proceeding will determine the interplay of emissions controls and environmental externalities. The point here is that environmental costs will be attributed to Coyote Station from both a regulatory and societal perspective; the emissions control technology will simply result in different proportions of costs that come from environmental externalities versus regulatory costs, which is not to say it will yield the same costs in the end.

Third, according to the Sargent & Lundy report, OTP might need 3-5 years to install emissions control equipment, depending on the selected technology, which could require OTP to make investments by 2023 to meet a July 2028 compliance deadline. Tables 7-1 and 7-2 of the

[34] OTP comments, at 1 (September 10, 2019).

Sargent & Lundy report display SO_2 and NO_X implementation schedules (staff included a red box to illustrate technologies with longer implementation periods):

Table 7-1. SO_2 Emissions Control System Implementation Schedule

SO_2 Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table 7-2. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22

Finally, as a general matter, staff is unconvinced that OTP will not have to invest in emissions control technology before 2025, or at least have a regulatory commitment (in the form of emissions controls) to implement the SIP that the EPA approves. Obviously OTP is far more aware of its own timeline for environmental compliance than staff, so perhaps OTP needs to clarify or elaborate on its comments about timing. But in addition to the issue discussed above about the length of time for certain retrofit options, as staff understands the Regional Haze Rule, North Dakota must file a compliance report to EPA by January 31, 2025 to show it is on a path to complying with the approved SIP.[35] This would suggest that, if Coyote Station will be critical to North Dakota's SIP, it might not be acceptable to OTP's North Dakota regulators, Coyote Station's co-owners, or even the EPA, to have either no financial commitment or remaining planning uncertainty for Coyote Station by January 2025.

[35] EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

This might be important because it is likely that OTP's next IRP process would closely scrutinize the reasonableness of not just continuing to operate, but further investing in, a 40-year old coal-fired power plant. According to OTP's response to Staff Information Request No. 5, OTP outlined how its next IRP would consider the retrofit versus retirement options:

> Otter Tail Power would likely evaluate multiple emission control options in our next IRP **if uncertainty around the ultimate compliance option remains**. In the 2013 Baseload Diversification Study (RP-13-961), each emission control option under consideration was evaluated as a separate sensitivity in our capacity expansion modeling. There will also be an additional sensitivity where no emission control option is added, and Coyote is retired in 2028.[36] *(Emphasis added by staff.)*

It is unclear when the "uncertainty around the ultimate compliance option" will be resolved, but presumably, the further OTP's next IRP gets pushed out, the more likely it is that plant closure will fade as a possible compliance option. The benefit of building a record in an IRP process is not necessarily to gather evidence to require OTP to shut down Coyote Station—the Minnesota Commission has limited authority in this regard—but to examine the retirement option in a way that the North Dakota SIP process might not. This could be important information to have in the event of a future request for cost recovery from Minnesota ratepayers for OTP's investment in pollution controls. The way staff is looking at it is: How can an IRP record insulate Minnesota ratepayers from any excessive costs, as well as address the environmental priorities of the State of Minnesota, and how does the timing of OTP's next IRP address this question?

4. Renewable Preference Statute

One final note staff would make on Coyote Station is that some might argue that the application of BART would qualify the power plant as a "refurbished nonrenewable energy facility." According to Minn. Stat. §216B.2422, subd. 4:

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, **nor shall the commission allow rate recovery** pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. *(Emphasis added by staff.)*

As discussed, OTP's next IRP will include a range of estimates for Regional Haze compliance. However, in doing so, OTP must also accompany this cost of compliance analysis with a demonstration that renewable energy is not more cost-effective than retrofitting the plant. Staff did not include OTP's requirement to do so in the decision options, as OTP is surely aware of the statute. But if the Commission believes it will be helpful for guiding OTP's next IRP, it could explicitly refer to Minn. Stat. §216B.2422, subd. 4 in a way that would clearly and formally

[36] OTP Response to PUC IR No. 5.

establish the expectation that the renewable preference statute must be accounted for in modeling its next IRP.

D. *Staff Proposed Decision Options*

In this section staff raises a couple options for the Commission to consider if it is both inclined to approve a delay, but is at the same time concerned about some of the issues staff has discussed thus far.

1. If the Extension is Granted, Should Supplemental Information be Required?

Overall, staff believes five years in-between IRP filings is simply too long, especially given that the Commission modified OTP's IRP to include up to 200 MW of wind in years 2022 and 2023. This length of time, in staff's opinion at least, presents a risk that OTP is (a) not minimizing its energy costs and/or market exposure and (b) neglecting issues the Commission ordered OTP to examine in its next IRP. Staff also has general concerns about OTP continuing to put off its solar acquisition due to jurisdictional issues it foresees. Thus, if the Commission delays the filing date for OTP's next IRP to September 1, 2021, staff proposes a supplemental filing by June 1, 2020, the contents of which will be up to the Commission.

Such a filing could include, at the very least, supplemental information limited to its new EnCompass modeling along with a discussion of OTP's resource needs and activities it plans for the next five years. What staff has in mind is a filing resembling the nontechnical summary required by Minn. R. 7843.0400 subp. 4 accompanied by OTP's modeling results. Throughout its extension request OTP refers to new modeling runs from which it has drawn conclusions about its next most cost-effective resource additions, so staff does not believe this filing would be too challenging for the Company to complete. While it would not consist of a full list of items required by Minn. R. 7843.0400 (Contents of Resource Plan Filings) and Minn. Stat. § 216B.2422, the Commission could provide direction requesting a specified set of scenarios for OTP to evaluate and issues to address.

The Commission's motion under this plan, as staff has drafted it, would be Decision Options 2 and 2.a.:

- Decision Option 2: Approve Otter Tail Power Company's request to delay the filing date for its next Integrated Resource Plan from June 1, 2020 to September 1, 2021. **AND**

- Decision Option 2.a: Require Otter Tail Power Company to make a supplemental filing by June 1, 2020, which shall include a Base Case with low, mid, and high scenarios for Regional Haze compliance options, as well as a Coyote Station 2028 retirement scenario. The Company shall also run a reasonable number of sensitivities for each scenario, including Minnesota environmental externality and carbon regulatory costs. The compliance filing will be limited to Otter Tail's EnCompass modeling results and is not subject to all items required by Minn. R. 7843.0400 and Minn. Stat. § 216B.2422.

Whether this supplemental filing will come back to the Commission for review, or how stakeholders may submit comments, can be handled by staff at a later date.

Of course, the Commission does not need to restrict the supplemental filing to modeling results, as there might be additional areas the Commission wishes to explore. While staff did not include additional topics as part of the proposed decision options, a June 2020 supplemental filing could revisit issues the Commission require OTP to address in its next IRP. These were outlined in ordering paragraph 7 of the Commission's April 26, 2017 Order:

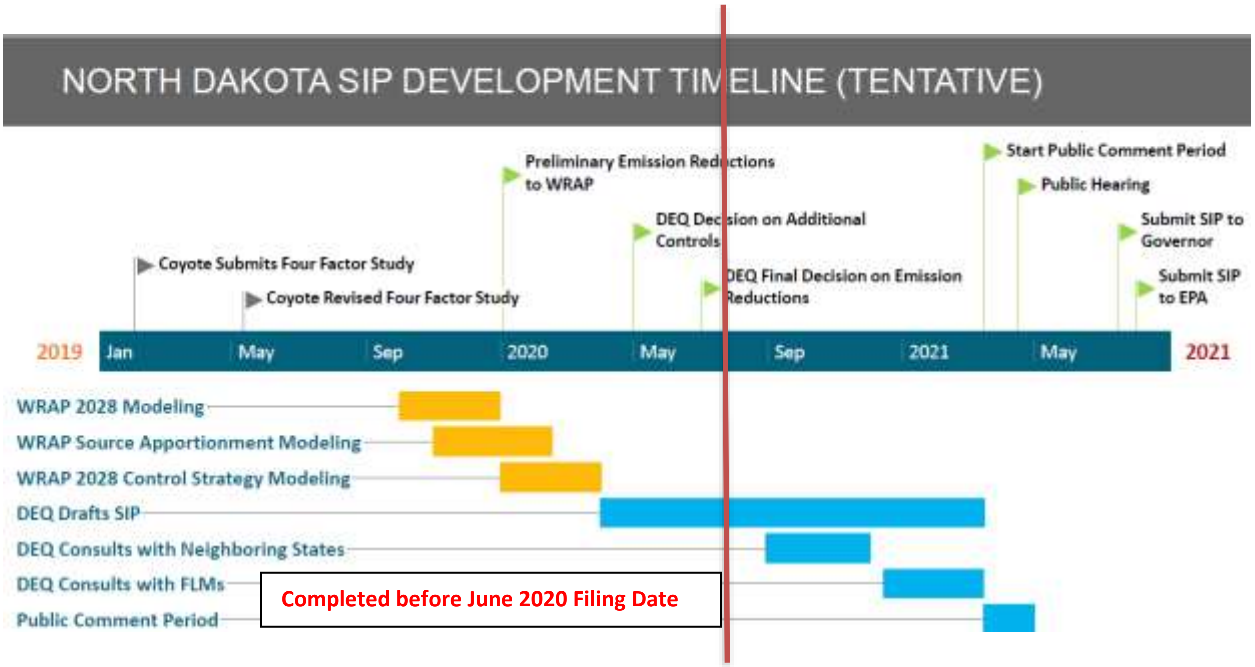
> 7. Otter Tail must include in its next resource plan filing:
>
> a. a transparent methodology to reflect forecasted load associated with pipelines or pipeline replacements.
>
> b. a discussion of how incremental levels of new wind could be reasonably procured and worked into the system while maintaining reliability of service.
>
> c. an evaluation of capacity savings the Company could achieve via demand-response programs, including more from its existing direct load control programs. The Company must also study reliability, price, and technology-based demand-response products.
>
> d. a detailed discussion of how the identified technical and economic potential for direct load control programs can be integrated into its supply-side and demand-side resource mix. The Company must also provide its strategies to improve on its installed kilowatts as a percentage of technical potential and include any overall and specific program benchmarks.
>
> e. an analysis of the cost-effectiveness of its oil peaker plants (at Jamestown, North Dakota, Units 1 and 2; and Lake Preston, South Dakota) relative to other supply and demand-side alternatives as it relates to transmission constraints.
>
> f. the status of Clean Power Plan compliance plans in the states included in Otter Tail's service territory.

Some of these topics are probably less relevant today than they were at the time of the Order. However, if staff had to pick two, ordering paragraphs 7.b. (new wind) and 7.c (demand response) might be the most urgent, since the record has shown OTP has a significant energy need and a small capacity surplus (or even a deficit depending on the filing).

2. Is a Shorter Delay More Reasonable?

If the Commission is leaning toward delaying OTP's IRP filing date, staff suggests the Commission also consider a shorter delay as an alternative to merely supplementing the record next June. If the core issue is really that, in OTP's words, the ranges of costs for complying with the Regional Haze Rule "are expected to narrow during SIP development,"[37] then there will probably be a point well-before September 2021 where the compliance cost estimates are not likely to change too significantly. This is because most of the technical analysis and modeling will already be complete in 2020. As shown by the figure below, which is also on page 5 of the briefing papers, even if the current IRP deadline is left as is (June 2020), the current timeline will roughly coincide with the North Dakota DEQ's final decision on emission reductions.

Staff put a vertical red bar and a red text box on the figure to illustrate what information OTP would have at its disposal by the time it files its IRP under the current schedule. The available information includes: the initial and revised Coyote Station four-factor studies (which are already complete); the WRAP control strategy modeling; the DEQ decision on additional controls; and the DEQ final decision on emissions controls:



Of course, timelines can change, and OTP may need time to incorporate the DEQ final decision into its analysis, so one option staff proposes is to delay OTP's plan by six (6) months instead of fifteen (15). This would delay OTP's IRP filing until December 1, 2020. Staff understands that moving the date to December 2020 would place the IRP filing date in the middle of the DEQ SIP-drafting stage, as indicated by the blue horizontal bar. However, in light of staff's previously discussed concerns about the five-year gap in-between IRP filings, staff believes a compromise is reasonable.

Also, note the distinction between the yellow bars and blue bars. It appears from the figure above that the yellow bars indicate modeling and other technical analysis, while the blue bars indicate a decision-making process (although staff welcomes OTP to clarify that inference). If OTP files its IRP by December 1, 2020, this would seemingly provide plenty of time after the

[37] OTP extension letter, at 9.

processes indicated by the yellow bars (i.e. the technical analysis and modeling) are complete. This should be able to provide a reasonable range of compliance cost estimates. After all, the purpose of these processes are to allow the North Dakota DEQ to make an informed decision by mid-2020, even though the SIP drafting phase will be ongoing.

VI. Decision Options

1. Deny Otter Tail Power Company's request to delay the filing date for its next Integrated Resource Plan from June 1, 2020 to September 1, 2021. **OR**

2. Approve Otter Tail Power Company's request to delay the filing date for its next Integrated Resource Plan from June 1, 2020 to September 1, 2021. **AND**

   2.a. Require Otter Tail Power Company to make a supplemental filing by June 1, 2020, which shall include a Base Case with low, mid, and high scenarios for Regional Haze compliance options, as well as a Coyote Station 2028 retirement scenario. The Company shall also run a reasonable number of sensitivities for each scenario, including Minnesota environmental externality and carbon regulatory costs. The compliance filing will be limited to Otter Tail's EnCompass modeling results and is not subject to all items required by Minn. R. 7843.0400 and Minn. Stat. § 216B.2422. **OR**

3. Delay the filing date for Otter Tail Power Company's next Integrated Resource Plan from June 1, 2020 to December 1, 2020.

4. By the end of 2020, Otter Tail Power Company shall initiate a competitive-bidding process to procure approximately 30 MW of installed solar capacity. *(Staff note: The Commission can require a solar RFP regardless of whether it adopts Option 1 or 2.)*