COMMERCE DEPARTMENT

November 7, 2019

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. ET6,ET6132/RP-19-416

Dear Mr. Wolf:

Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department), in the following matter:

In the Matter of Minnkota Power Cooperative, Inc.'s and Northern Municipal Power Agency 2019 Resource Plan

The Petition was filed on June 28, 2019 by:

Jamie Overgaard
Rates, Load & Planning Manager
Minnkota Power Cooperative, Inc.
5301 32nd Ave S
Grand Forks, ND 58201

The Department recommends that the Minnesota Public Utilities Commission (Commission) **accept Minnkota Power Cooperative and Northern Municipal Power Agency's 2019 Resource Plan once they have submitted the evaluation of progress towards meeting Minnesota's greenhouse gas emission reduction goal, which is required in all resource plans**. The Department is available to answer any questions that the Commission may have in this matter.

Sincerely,

/s/ CHRISTOPHER T. DAVIS
Analyst Coordinator

CTD/ja
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. ET6,ET6132/RP-19-416

I. INTRODUCTION

A. BACKGROUND

Minnesota Rules parts 7843.0100 to 7843.0600 require electric utilities to file proposed integrated resource plans (IRPs) every two years. The Minnesota Public Utilities Commission (Commission) can vary those rules for good cause shown. Minnkota Power Cooperative, Inc. (Minnkota) and Northern Municipal Power Agency (NMPA) last filed a joint IRP on June 26, 2014 in Docket No. ET6,ET6132/RP-14-526.

On June 28, 2019, Minnkota and NMPA submitted their IRP for the period 2019 to 2033.

B. JOINT SYSTEM BACKGROUND

The Minnesota Department of Commerce, Division of Energy Resources (Department), refers to the municipal (NMPA)/cooperative (Minnkota) utility as the Joint System. Minnkota is a wholesale generation and transmission cooperative with eleven member/owner distribution cooperatives. Eight of the 11 member/owners are located in northwestern Minnesota and three are located in northeastern North Dakota. Minnkota is headquartered in Grand Forks, North Dakota.

In addition, Minnkota is associated with NMPA. NMPA consists of twelve member municipal utilities in the same region as Minnkota's distribution cooperatives. Ten of the members are located in northwestern Minnesota and two are located in northeastern North Dakota.

Minnkota and NMPA submitted their IRP as a Joint System since the electric generation resources and Western Area Power Administration (WAPA) allocations of NMPA and Minnkota are used collectively.

Minnkota and NMPA effectively form a Joint System because:

- They have operating agreements and joint ownership of transmission facilities;
- Minnkota's generation, NMPA's generation, Minnkota's Western Area Power Administration (WAPA) allocation, and the NMPA WAPA allocations are collectively used to serve the Joint System capacity and energy requirements; and
- Both the member systems of Minnkota and the member municipals of NMPA purchase their total electric capacity and energy requirements under similar wholesale power rate schedules.

Table 1 below shows the generating resources currently available to the Joint System.

Table 1: The Joint System's Available Generating Resources

Name	Type	Size	Owner	% Joint System	Available to Joint System[1]
Milton R. Young 1	Lignite Baseload	250 MW	Minnkota	100%	250 MW
Milton R. Young 2	Lignite Baseload	455 MW	Square Butte Co-op	78%	355 MW
Coyote	Coal Baseload	427 MW	NMPA	30%	128.1 MW
Langdon 1	Wind	171.7 MW	Minnkota PPA	58%	99 MW
Langdon 2	Wind	40.5 MW	Minnkota PPA	100%	40.5 MW
Ashtabula I	Wind	196.5 MW	Minnkota PPA	76%	148.5 MW
Ashtabula II	Wind	169.5 MW	Minnkota PPA	41%	69 MW
Oliver III	Wind	99.3 MW	Minnkota PPA	100%	97 MW
Infinity	Wind	1.8 MW	Minnkota	100%	1.8 MW
Thief River Falls	Hydro	0.5 MW	Thief River Falls	100%	0.5 MW
Cass County	Diesel	21.98 MW	Cass County Co-op	100%	21.98 MW
Fargo Landfill Gas	Landfill Gas	0.925 MW	Minnkota PPA	100%	0.925 MW
NMPA	Diesel	13.536 MW	Minnkota Lease	100%	13.536 MW
WAPA Minnkota	Hydro	76.632 MW	Minnkota Allocation	100%	72.632 MW
WAPA NMPA	Hydro	40.6 MW Winter/36.2 MW Summer	NMPA Allocation	100%	40.6 MW Winter/36.2 MW Summer

In addition, the Joint System currently has approximately 400 MW of interruptible load in the winter, and 100 MW in the summer. By the end of the planning period, the Joint System projects that its winter interruptible loads will grow to 465 MW and its summer interruptible loads to 125 MW.

C. JOINT SYSTEM PLANNING

The Joint System's planning process consisted of the following steps:

- Develop energy and peak demand forecasts, including high and low forecasts based on the effects of (1) harsh and (2) mild weather conditions; and
- Determine the Joint System's resource needs, both energy and capacity, over the planning period.

[1] Note that these are nameplate values. In the analysis section below the Department discusses the level of resources available to meet the Midcontinent Independent System Operator (MISO) resource adequacy requirements.

Based on a comparison of the projected energy requirements of the Joint System and the output of its generation resources, WAPA allocations, and wind purchased power agreements (PPAs), the Joint System determined that it did not need additional generation resources in the 2019-2033 period.

D. JOINT SYSTEM'S PROPOSED PLAN

The Joint System's proposed five-year action plan consists of the following:

- The completion of Load Forecast Studies in 2021 and 2023;
- Continued analysis of how to promote and enhance demand response activities;
- Continued analysis of the cost-effectiveness of integrating more demand-side-management programs and renewable energy resources into the Joint System's resource mix; and
- Continued completion of required IRPs.

II. DEPARTMENT ANALYSIS

A. OVERVIEW OF ANALYSIS

To review this IRP, the Department evaluated the Joint System's:

1. energy and demand forecasts,
2. resource needs projections,
3. demand-side resources,
4. progress towards meeting Minnesota's greenhouse gas emissions reduction goal and renewable energy standard, and
5. environmental issues.

Each component is discussed below. Overall, the Department's analysis indicates that:

1. The forecast has remained stable over time and thus the Department did not conduct an in-depth review. The Department recommends that the Commission accept the Agency's forecast for planning purposes.
2. The Joint System appears to have no resource needs during the planning period.
3. The Joint System IRP did not include an evaluation of its progress towards meeting Minnesota's greenhouse gas emissions reduction goal. The Joint System should discuss this evaluation, discussed below, in reply comments, which are due January 8, 2020, or before.

B. ENERGY AND DEMAND FORECAST

1. The Joint System's Forecast

The Joint System stated that its load forecast is comprised of the results of the Minnkota Load Forecast Study (LFS) and a load forecast of the 12 NMPA municipal systems.

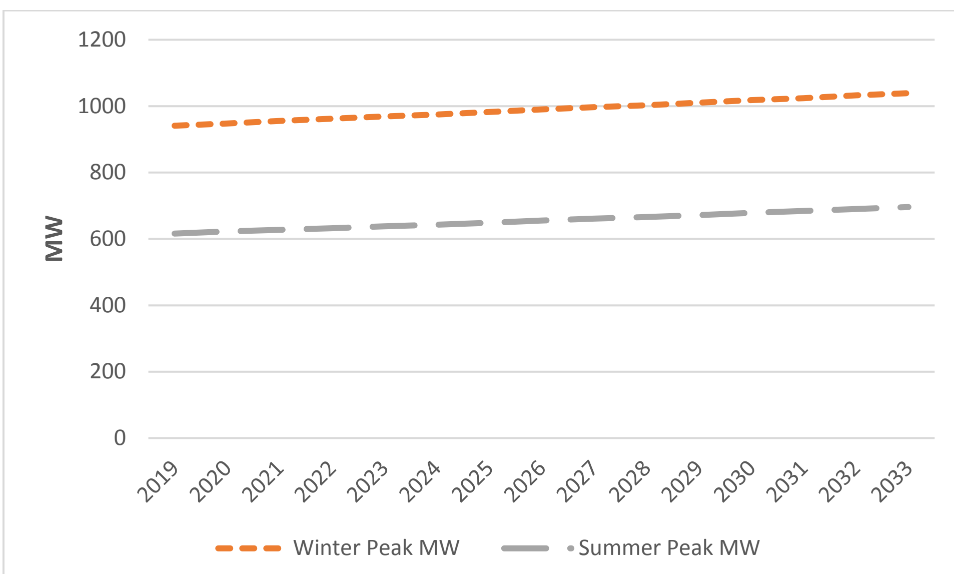
The member-owner distribution cooperatives and Minnkota are required to complete a Rural Utilities Service (RUS)-approved Load Forecast Study every other year. The latest LFSs were completed in 2017. Minnkota's LFS was developed in a bottom-up manner. The individual member system's energy and capacity requirements forecasts were summed to form Minnkota's base forecast. A forecast of Minnkota's transmission losses was also developed.

The municipal members of the NMPA are not required to complete an LFS. However, a load forecast using a linear regression analysis of the historical period 1999 through 2016 was completed for each of NMPA's members.

The forecast of the Joint System's energy requirements is the sum of the forecasts of Minnkota's energy requirements, NMPA energy requirements, and transmission losses. The Joint System stated that its winter and summer peak demand forecasts were based on historical trending.[2]

Figure 1 below shows the Joint System's projected median winter and summer peak demand forecasts.

Figure 1: Median Forecasts for the Joint System's
Winter and Summer Peak Demands (MW)



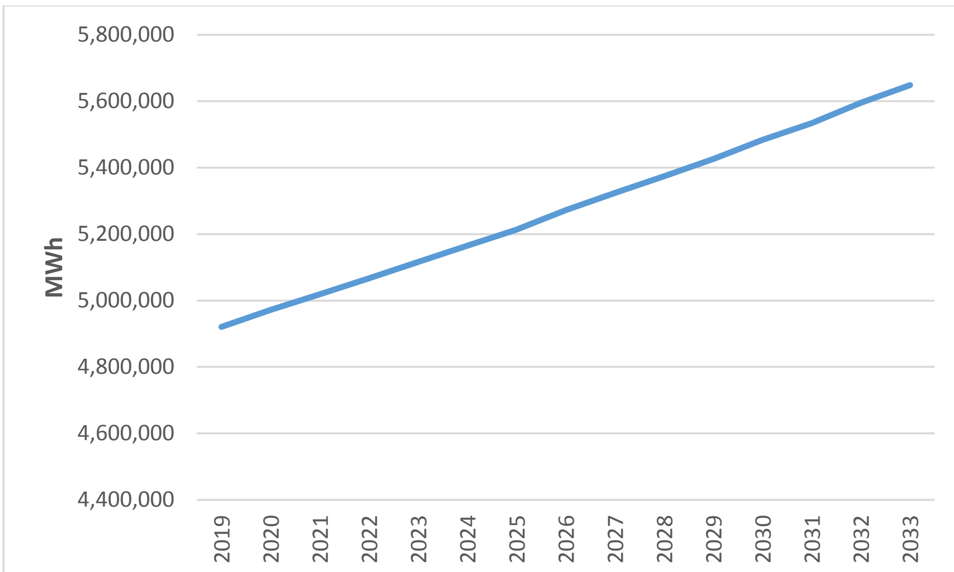
The Joint System projected that its winter peak demand will increase 1.0% per year and that its summer peak demand will increase 0.8% per year.[3]

[2] Meaning that the average increase from past years was calculated and used to project the winter and summer peak demand forecasts.

[3] Based on the 30-year projections from the 2017 Load Forecast Study.

Figure 2 below shows the Joint System's projected annual energy requirements.

Figure 2: Median Forecast of Joint System
Energy Requirements (MWh)



The Joint System projected that its annual energy requirements will increase 1.0% per year.

2. Department Analysis of Joint System Forecast

The Department conducted a historical analysis of the Joint System's demand and energy forecasts and found that since 2007, the Joint System's actual load has been significantly less than its forecasted demand and energy, as discussed below.

a. Forecasted demand

Table 2 below shows by how much the forecasted demand exceeded the actual demand. The few cases where demand was greater than forecasted are shown as negative percentages.

Table 2: Percentage by Which Forecasted Demand (MW) Exceeded Actual Demand (MW)

	Demand Forecast by Filing Year									
Forecast Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2008	-4.1%									
2009	2.2%	2.2%								
2010	15.5%	15.5%	14.7%							
2011	10.8%	10.8%	10.1%	10.1%						
2012	12.7%	12.7%	12.4%	12.4%	8.1%					
2013	2.3%	2.3%	2.5%	2.5%	-2.1%	-2.1%				
2014	8.5%	8.5%	8.9%	8.9%	3.2%	3.2%	3.3%			
2015	14.1%	14.1%	15.0%	15.0%	8.1%	8.1%	8.5%	8.5%		
2016	21.7%	21.7%	23.1%	23.1%	14.6%	14.6%	15.6%	15.6%	15.6%	
2017	20.6%	20.6%	22.8%	22.8%	13.4%	13.4%	14.7%	14.7%	14.7%	14.7%

As can be seen, the only time the Joint System's demand forecast was lower than actual demand was when the Joint System's:

- 2007 forecast under forecast demand for 2008,
- 2011 forecast under forecast demand for 2013, and when the
- 2012 forecast under forecast demand for 2013.

b. Forecasted energy

Table 3 below shows by how much the Joint System's forecasted energy requirements exceeded the actual energy requirements.

Table 3: Percentage by Which Forecasted Energy Requirements (MWh) Exceeded Actual Energy Sales (MW)

		Energy Forecast by Filing Year									
		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Forecast Year	2008	-1.3%									
	2009	1.6%	1.6%								
	2010	7.9%	7.9%	3.4%							
	2011	10.5%	10.5%	5.0%	5.0%						
	2012	14.3%	14.3%	8.0%	8.0%	3.9%					
	2013	5.6%	5.6%	-0.4%	-0.4%	-4.9%	-4.9%				
	2014	2.6%	2.6%	-3.4%	-3.4%	-8.1%	-8.1%	-7.9%			
	2015	16.2%	16.2%	9.0%	9.0%	2.7%	2.7%	3.6%	3.6%		
	2016	11.9%	11.9%	4.8%	4.8%	-2.1%	-2.1%	0.0%	0.0%	2.4%	
	2017	11.2%	11.2%	4.0%	4.0%	-3.8%	-3.8%	-0.9%	-0.9%	1.5%	1.5%

A review of Table 3 above indicates that, of the forecasts filed between 2007 and 2016, the Joint System's forecasted energy requirements were greater than actual energy sales 41 out of 55 times.
Given that the Joint System does not project any need for additional resources during the planning period, the Department's current constraint on forecasting resources, and the fact that the Joint System has historically over-forecasted demand and energy requirements, the Department opted not to conduct a detailed analysis of the Joint System forecast. The Department concludes that the Joint System's forecast is reasonable for planning purposes.

C. RESOURCE NEEDS

To estimate its resource needs, the Joint System subtracted its forecast from its available resources. The Joint System reported the results of its resource needs analysis in two figures on page 1 of its IRP. Based on its analysis, the Joint System concluded that it required no new resources during the planning period.

The Department's review revealed that in its analysis of capacity needs, the Joint System assumed a capacity factor for its wind resources (the total amount of energy the wind plant produced during a period of time divided by the amount of energy the plant would have produced at full capacity) rather than use the MISO capacity accreditation for the wind resource.[4] The Joint System provided the data used to create the updated table below, which shows the amount of resources that the Joint System had as of 2019 that would count towards its MISO resource adequacy requirements.

[4] The wind capacity factor assumed by the Joint System is approximately 42% while the MISO wind capacity accreditation for Minnkota's wind resources is approximately 21.5%.

Table 4: Current Minnkota Supply-Side Resources

Generation Plant	Energy Source	Nameplate MW	Unforced Capacity (UCAP)[5] MW
Young 1	Coal	250	240.4
Young 2	Coal	355	315.9
Coyote	Coal	128	108.6
Various Wind	Wind	459	99
Minnkota WAPA	Hydro	49	42.7
NMPA WAPA	Hydro	36	35.2
Municipal Diesels	Diesel	14	15.7
Cooperative Diesels	Diesel	20	20.7
Total		**1311**	**878.2**

As shown in Table 4 above, although the Joint System currently has 1,311 MW of installed capacity, it only has 878.2 MW of resources that count towards resource adequacy. Further, as shown in Table 5 below, the Joint System has some sales scheduled over the planning period, which reduce its available resources. Further, the Joint System is gradually increasing the percent of the Young 2 lignite coal plant that it receives, until 2026 when the Joint System will receive 100 percent of Young 2's output.

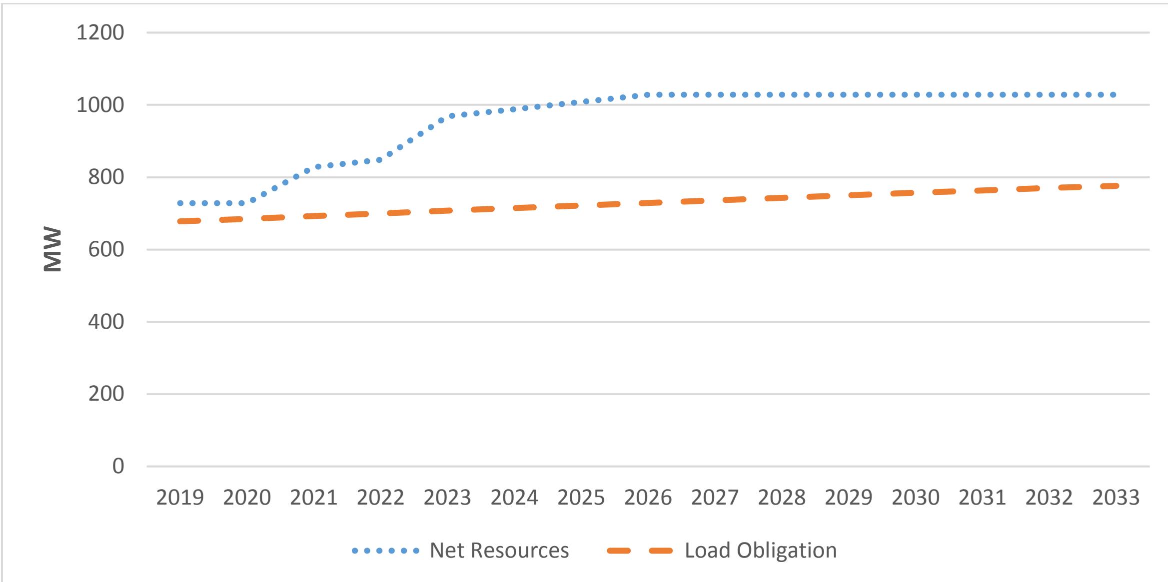
[5]The unforced capacity value is equal to the installed capacity of the unit multiplied by (1- unit's EFORd). Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.

Table 5: Joint System's Net Resources 2019-2033

	2019 Resources (MW)	Sales to Basin and Minnesota Power (MW)	Joint System Share of Young 2 Increasing from 78% to 100% by 2026 (MW)	Net Resources (MW)
2019	878.2	150		728.2
2020	878.2	150	0	728.2
2021	878.2	100	50	828.2
2022	878.2	100	20	848.2
2023	848.2		120	968.2
2024	968.2		20	988.2
2025	988.2		20	1008.2
2026	1008.2		20	1028.2
2027	1028.2		0	1028.2
2028	1028.2		0	1028.2
2029	1028.2		0	1028.2
2030	1028.2		0	1028.2
2031	1028.2		0	1028.2
2032	1028.2		0	1028.2
2033	1028.2		0	1028.2

Figure 3 below shows that the Joint System calculates that its net resources exceed its summer load obligations throughout the planning period.

Figure 3: Joint System's Resource Needs 2019-2033



As seen in Figure 3, even with reductions to its assumptions regarding available capacity from wind, the Joint System projects that it will have no resource needs over the planning period.

The Department notes that the future of the Coyote coal plant,[6] a significant source of the Joint System's resources, is uncertain. As explained in Otter Tail Power Company's request for an extension to when it files its next IRP (see Otter Tail's August 29, 2019 request in Docket No. E017/RP-16-386 for an extension to September 1, 2021 to file its next IRP, citing the need for more time to model the Regional Haze Rule), compliance with the Regional Haze Rule could lead to the decision to close Coyote due to high compliance costs. Otter Tail indicated that its future analysis will include the option of closing Coyote in 2028. The Department recommends that in its next IRP the Joint System discuss the future of Coyote and its impact on the Joint System's reliability, using updated information.

D DSM RESOURCES

Table 6 below shows the Joint System's actual energy savings for 2014-2018 and projected energy savings for the IRP planning period (2019-2033).

[6] The Coyote Plant is a 427 MW generating plant located southwest of Beulah, N.D., and operated by Otter Tail Power Company. NMPA owns a 30 percent share (128.1 MW) of this unit and has appointed Minnkota as its agent for scheduling capacity and energy from Coyote and for operational management responsibilities.

Table 6: Joint System's Actual Energy Savings (2014-2018) and Projected Energy Savings (2019-2033) as a Percent of Retail Sales

Year	Retail Sales	kWh Savings	Percentage
2014	1,718,746,166	27,209,892	1.58%
2015	1,748,260,864	27,678,829	1.58%
2016	1,794,803,833	31,584,595	1.76%
2017	1,467,985,277	27,628,406	1.88%
2018	1,261,946,444	21,538,490	1.71%
2019	1,222,912,595	18,343,689	1.50%
2020	1,235,141,721	18,527,126	1.50%
2021	1,247,493,138	18,712,397	1.50%
2022	1,259,968,070	18,899,521	1.50%
2023	1,272,567,750	19,088,516	1.50%
2024	1,285,293,428	19,279,401	1.50%
2025	1,298,146,362	19,472,195	1.50%
2026	1,311,127,826	19,666,917	1.50%
2027	1,324,239,104	19,863,587	1.50%
2028	1,337,481,495	20,062,222	1.50%
2029	1,350,856,310	20,262,845	1.50%
2030	1,364,364,873	20,465,473	1.50%
2031	1,378,008,522	20,670,128	1.50%
2032	1,391,788,607	20,876,829	1.50%
2033	1,405,706,493	21,085,597	1.50%

Even though the Joint System has an abundance of supply-side resources, it surpassed Minnesota's 1.5% energy savings goal each year from 2014 through 2018 and projects 1.5% energy savings throughout the planning period.

The Department concludes that the Joint System's commitment to energy savings is reasonable.

E. GREENHOUSE GAS REDUCTION GOAL, RENEWABLE ENERGY STANDARD AND SOLAR ENERGY STANDARD

1. Background

In 2013, the Minnesota Legislature passed amendments to Minnesota Statutes §216B.2422, subd. 4. The amended legislation now states (new language underlined):

> 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. <u>The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f</u>.

On August 5, 2013, the Commission issued a *Notice of Information in Future Resource Plan Filings* (Commission's Letter). The Commission's Letter states, in part:

> **PLEASE TAKE NOTICE** that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation of how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.

1. *Greenhouse gas reduction goals*

Minnesota Statutes section 216H.02, subdivision 1 states:

> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study.

Although the Joint System discusses carbon dioxide regulations beginning on page 37 of its IRP, the Company did not discuss how the resource plan helps the utility achieve the state's greenhouse gas reduction goals as required by the Commission's Letter of August 5, 2013. Without this analysis and discussion, the Joint System's IRP is incomplete. The Department recommends that the Joint System submit its required evaluation in Reply Comments or sooner.

2. *Renewable energy standard (RES)*

Minnesota Statutes section 216B.1691, subd. 2a states:

(a) Except as provided in paragraph (b), each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated:

(1)	2012	12 percent
(2)	2016	17 percent
(3)	2020	20 percent
(4)	2025	25 percent

The Joint System discussed its compliance with Minnesota's RES on pages 26-27 of its plan. Table 7 below compares the Joint System's renewable energy requirements to comply with the RES in each year of its IRP with the Joint System's projected wind energy production.

Table 7: The Joint System's Projected Compliance with Minnesota Renewable Energy Standard

Year	Joint System Minnesota Retail Sales (MWH)	% Renewables Required For MN RES	Renewable Energy Required for MN RES (MWH)	Langdon, Ashtabula and Oliver III Wind Energy Production (MWH)	Excess/(Undersupply) of Renewable Energy to Comply with MN RES (MWH)
2019	1,890,017	17	321,303	1,751,500	1,430,197
2020	1,908,538	20	381,708	1,751,500	1,369,792
2021	1,932,419	20	386,484	1,751,500	1,365,016
2022	1,963,070	20	392,614	1,751,500	1,358,886
2023	1,986,643	20	397,329	1,751,500	1,354,171
2024	2,010,661	20	402,132	1,751,500	1,349,368
2025	2,033,234	25	508,309	1,751,500	1,243,191
2026	2,053,306	25	513,326	1,751,500	1,238,174
2027	2,067,536	25	516,884	1,751,500	1,234,616
2028	2,080,540	25	520,135	1,751,500	1,231,365
2029	2,093,282	25	523,320	1,751,500	1,228,180
2030	2,107,670	25	526,917	1,751,500	1,224,583
2031	2,119,969	25	529,992	1,751,500	1,221,508
2032	2,134,801	25	533,700	1,751,500	1,217,800
2033	2,148,038	25	537,010	1,751,500	1,214,490

As shown in Table 7 above, the Joint System projected that it will surpass Minnesota's RES requirements every year.

3. Solar Energy Standard

Minnesota Statutes section 216B.1691, subd. 2f establishes a solar energy standard (SES) for public utilities. However, municipal and cooperative electric associations like NMPA and Minnkota are not considered public utilities and thus the SES does not apply to the Joint System.

F. ENVIRONMENTAL ISSUES

The Department reviews utility resource plans for compliance with pending state and national environmental legislation that affect the electric utility's operations. The Joint System discussed coal combustion residuals, waters of the United States, steam electric effluent limitation guidelines, regional haze, mercury & air toxics, and carbon dioxide regulations. Each of these is briefly discussed below.

1. Coal Combustion Residuals (CCR)

The final rule dealing with the disposal of CCR in landfills and surface impoundments became effective on October 19, 2015. The Joint System has been in full compliance since the rule's enactment and does not anticipate any significant challenges in continuing compliance with the CCR rule.

2. Waters of the United States (WOTUS)

A 2015 definition of WOTUS was stayed. As a result of Executive Order 13778, the Environmental Protection Agency (EPA) and the Army Corps of Engineers reviewed the 2015 WOTUS rule and proposed to rescind it and replace with a new WOTUS definition that was published in February 2019. The Joint System stated that it would continue to follow the rulemaking process. The Department notes that the Trump administration formally announced that the WOTUS rule had been repealed on September 12, 2019, with the repeal to take effect within weeks.

3. Steam Electric Effluent Limitation Guidelines (ELG)

The final ELG rule published in November 2015 provides regulatory standards for wastewater discharged to surface waters and municipal sewage treatment plants. For generating units greater than 50 MW, the ELG regulates six categories of wastewater. As currently written, the ELG requirement of zero liquid discharge of bottom ash transport water could affect operations at the Joint System's Milton R. Young plant. Currently, the EPA is reconsidering the rule. The Joint System anticipates that the rulemaking process will be completed in 2020 and anticipates that compliance will be required by December 2023.

4. Regional Haze Regulations (RHR)

To comply with the initial phase of RHR, the Joint System installed or implemented $425 million of changes in 2010-2011. In July 2016, the (EPA issued draft guidance for the RHR's second implementation period. State Implementation Plans are due in 2021. In January 2019, the Joint System submitted a Four-Factor Analysis to evaluate the cost, as well as other factors, for installation of additional NOx and SO2 controls at the Young plant.

The Four-Factor Analysis concluded that the following emissions control systems are technically feasible and have reasonable costs (as defined by North Dakota Department of Environmental Quality-provided guidance) for installation at the Young plant:

- NOx control – no change; continue operation of the existing SOFA + SNCR systems that achieve about 60% NOx reduction.
- SO_2 control – modification/upgrade of both Unit 1 and 2 WFGDs to increase SO_2 removal efficiency to 97.4% on Unit 1 and 97.7% on Unit 2. Current removal mandates are set at 95% on Unit 1 and 90% (or 0.15 lb/10^6 Btu) on Unit 2. If required for installation as part of the RHR, these modifications would result in combined annual SO_2 emissions reductions of about 1,250 tons based on baseline average annual emissions from 2016-2018.

The Joint System stated that it does not expect that any air pollution controls required at the Milton R Young plant as part of the RHR's second implementation period to present "a significant challenge in continuing to supply our member-owners with low-cost and reliable electricity."

5. Mercury and Air Toxics (MATS)

The MATS rule targets emissions reductions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases such as hydrochloric and hydrofluoric acids. Based on the MATS rule, Minnkota has installed mercury control equipment at the Young plant that includes coal additives and PAC injection systems on both units. The MATS rule became effective in 2015, and the Young plant has maintained compliance since that date.

6. Carbon Dioxide Regulations

On June 19, 2019, the EPA finalized a new rule – the Affordable Clean Energy (ACE) rule – that replaced the Clean Power Plan (CPP) final rule, which was published under section 111(d) of the Clean Air Act. Below is the Joint System's summary of its understanding of the ACE implementation requirements:

1. States will have three years from the date of the final rule publication to prepare and submit a SIP that establishes a standard of CO_2 emissions reductions performance:

i. Each affected facility will determine which "candidate technologies" can be applied to each of their sources
ii. The State must establish a standard of performance that reflects the emission limitation achievable at each affected source
iii. The State must take into account at each affected source, factors that are unique to that source, such as technology and practices already implemented, remaining useful life of the plant, etcetera.

2. Once the SIP is submitted, EPA will have 18 months to review and approve or disapprove the SIP. If needed, EPA will have two years to develop a Federal Implementation Plan (FIP).

3. Compliance with the determined emissions limitation standards will be required within two years of submittal of the SIP, but there is some discretion given to the States to extend this compliance schedule based on source-specific factors.

In regards to ACE, the Joint System stated it had previously investigated several heat-rate improvement projects that it could implement at the Young plant. Some of these projects may or not be possible means of complying with ACE. The Joint System stated that even with the uncertainty, it is well prepared to comply with the ACE requirement without unreasonably affecting its member owners and their consumers.

The Joint System also stated that it recognizes that stricter carbon regulations are possible in the future. As part of its response to this possibility, the Joint System stated that it is spearheading the feasibility review of Project Tundra, a project to capture CO_2 emissions from the largest lignite coal unit in its resource portfolio, Unit 2 of the Young plant. The Joint System's vision for Project Tundra is to retrofit Unit 2 with technology that could capture up to 95 percent of its CO_2 emissions. The captured CO_2 would then be sequestered in permanent geologic storage and/or utilized for enhanced oil recovery in the conventional oil fields of North Dakota. The Department notes that on September 17, 2019, Minnkota announced that it had received a United States Department of Energy (DOE) grant of $9.8 million, which then provided access to $15 million from the state of North Dakota's Lignite Research Fund. The funding will be used to conduct a Front-End Engineering Design (FEED) study on Project Tundra's proposed carbon capture system. The announcement stated that the sequestered CO_2 would then be permanently stored in a deep geologic formation more than a mile underground. In September and October 2019, a geophysical survey was to be completed near Center, N.D., to gather information about rock layers in the deep subsurface. Minnkota stated that it engaged with landowners, local leaders and received state permits prior to beginning this research.

The Joint System estimated that Project Tundra will cost approximately $1 billion. In its announcement, Minnkota stated that the project is currently seeking financial partners to help use existing 45Q federal tax credits,[7] which are currently $50 per ton of CO_2 that is captured and stored in a geologic formation deep underground.

7. Conclusions

The Department concludes that the Joint System is adequately tracking environmental regulations that might affect its operations.

III. CONCLUSION AND RECOMMENDATIONS

A. FORECAST

The Department recommends that the Commission accept the Joint System's forecast for planning purposes.

B. RESOURCE NEEDS

For its next IRP, the Department recommends that the Joint System update the Commission on the impact of the Regional Haze Rule on Coyote's operations and thus, on the Joint System's resource needs.

C. GREENHOUSE GAS EMISSIONS REDUCTION GOAL

In reply comments or before, the Department recommends that the Joint System comply with the Commission's August 5, 2013 letter regarding integrated resource plan requirements, and submit an evaluation of the Joint System's progress towards meeting Minnesota's greenhouse gas emissions reduction goal, including comparing its actual 2015 CO_2 emissions and projected 2025 emissions to the Joint System's actual 2005 CO_2 emissions.

/ja

[7] https://uscode.house.gov/view.xhtml?req=(title:26%20section:45Q%20edition:prelim)

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. ET6, ET6132/RP-19-416

Dated this **7th** day of **November 2019**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_19-416_RP-19-416
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_19-416_RP-19-416
Jamie	Overgaard	jovergaard@minnkota.com	Minnkota Power Cooperative, Inc.	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_19-416_RP-19-416
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_19-416_RP-19-416
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_19-416_RP-19-416