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March 31, 2021

Steve Kahl  
Executive Secretary  
ND Public Service Commission  
600 East Boulevard Avenue  
Bismarck, ND 58505-0480

**RE: Otter Tail Power Company – Electric – Extreme Cold Weather Event Investigation  
Case No. PU-21-106  
Date Request Response**

Dear Mr. Kahl:

Enclosed please find Otter Tail Power Company's Data Response to ND-PSC-001.

Please feel free to contact me at (218) 739-8279 or [stommerdahl@otpc.com](mailto:stommerdahl@otpc.com) if you have any questions.

Sincerely,

*/s/ STUART TOMMERDAHL*  
Stuart Tommerdahl  
Manager, Regulatory Administration

cjh  
Enclosures

OTTER TAIL POWER COMPANY  
Case No: PU-21-106

Response to: ND Public Service Commission

Analyst: Victor Schock

Date Received: March 08, 2021

Date Due: March 22, 2021

Date of Response: March 31, 2021

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

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Data Request:

- 1.1 Please provide forecasted February 2021 electric usage and cost estimates by customer class used to derive the Feb 2021 Fuel and Purchased Power (FCR) rate.
- 1.2 Please provide the actual February 2021 electric usage and cost actuals by customer class.
- 1.3 What is the total North Dakota difference between the forecast and actual electric cost/revenues for February 2021?
- 1.4 What amount of gas was forecasted to be used from storage for power generation during February? What actual amount of gas was used from storage for power generation?
- 1.5 What amount of gas is procured using contract prices versus spot pricing for power generation? Is the contracted percentage the same year to year?
- 1.6 How much of the electric usage during the events was used by customers on an interruptible rate?
- 1.7 How much interruptible customer electric usage was curtailed?
- 1.8 How much interruptible customer electric usage could have been curtailed during the events?
- 1.9 What does your tariff or policy dictate regarding interruptible customers when electric supply is available, but the electric price is extreme?
- 1.10 What mechanism would normally be used to recoup the under collection of electric costs from question 1.3?
- 1.11 What timeframe would the under collection normally be spread over? What return amount does the company earn on the under collected balance?

1.12 Are there alternatives to the mechanism and timeframe to recoup the under collected balance that would provide less rate shock to North Dakota ratepayers?

Attachments: 3

Attachment 1 to DR ND-PSC-001

Attachment 2 to DR ND-PSC-001

Attachment 3 to DR ND-PSC-001

Response:

Before addressing the specific questions requested in this information request, Otter Tail Power Company (OTP) provides the following general comments about OTP's experience during the February 2021 cold weather event which OTP defined as occurring from February 12, 2021 through February 20, 2021.

**OTP Baseload Units:**

Big Stone Plant was on-line and available for full output throughout the entirety of the cold weather event. Except for one short derate for about 6 hours to deslag the boiler, Coyote Station was on-line and available for full output throughout the entirety of the cold weather event. Hoot Lake Plant had some ash loading derates from Friday February 12 to Monday February 15 but was available to run at full load for the remainder of the cold weather event.

**OTP Gas Units:**

Solway Station is a dual fuel natural gas/fuel oil unit. Intraday pricing for gas for February 13 spiked to over \$300 per MMBtu. Because of that price spike, the unit was switched over to fuel oil. However, an outage was required from February 13 through February 15 due to complications related to starting on fuel oil and a failed compressor discharge pressure (CDP) purge valve. The unit was returned to Service on February 16, utilizing more reasonably priced natural gas that was available at Solway via Emerson Hub and was operational for the balance of the event.

**OTP Wind Farms:**

OTP's four owned wind farms, Langdon, Ashtabula, Luverne and Merricourt were all substantially available during the event. While the Turbines have cold weather operating limits of -22F, at which point they will shut down to avoid potential structural damage, all units had a less than 10% reduction in availability during the event. Merricourt experienced a derate due to icing and a tie line out that had capability reduced to 134 MWs from 150 on February 12, but all units were re-energized by February 18. Despite high availability, low windspeeds resulted in below average generation during the event.

**Oil Peaking Units:**

The Jamestown 1, Jamestown 2, and Lake Preston peaking units were available and dispatched periodically throughout the cold weather event. Under normal market conditions, these units primarily serve as capacity resources. During times of extreme pricing, they serve as a backstop to high energy markets.

**Astoria Station:**

Astoria Station, OTP's new 245 MW natural gas fired simple cycle CT was conducting operational tests at the onset of the cold weather event. To avoid purchasing high priced natural gas during this time, OTP opted to suspend testing. While physical supplies would have always been available at the unit, the current price of natural gas during that time was too high to justify continuing testing.

**Load Control:**

OTP load control was available for the entirety of the cold weather event and performed as designed. Typical economic control events are less than 2 hours start to finish, but during Feb 12-19 we had 9 events that were over 4 hours long. More detail on load control is provided in the responses to specific questions in this information request.

**Forward Energy Purchase and Wholesale Market Charges:**

In February of 2020, OTP executed a forward energy purchase for January, February, and December of 2021 to mitigate potential price volatility during those months. During February of 2021, OTP had 75 MWs of energy under contract which for the month, yielded a benefit of approximately \$1.67 million (OTP Total) relative to market prices during the month. OTP also benefited from significantly higher revenue credits from SPP of approximately \$833k as a result of SPP's extreme prices and market conditions. These benefits helped offset higher energy market charges incurred in MISO during the event.

**FTR Portfolio:**

In order to offset congestion pricing differences between OTP generation and load, OTP maintains a financial transmission rights (FTR) portfolio. The FTRs refund congestion differences between generation and load. These FTRs offset over \$1.9 million (OTP Total) of congestion costs during the February 12-20 cold weather event.

**Market Purchases and Asset Based Sales:**

There were certain hours during the event where OTP was short of energy and procured that energy from the MISO market. There were also hours during the event where OTP was selling energy back into the market. Those asset-based sales and associated margins helped to offset increased market purchase costs incurred during the event.

**Customer Outages:**

One incident occurred regarding OTP load located in the Southwest Power Pool (SPP) that is pseudo-tied into the MISO market. During SPP's need to implement rolling blackouts, the Western Area Power Administration inadvertently opened certain breakers on its system which OTP is integrated with, which impacted some OTP customers that caused an outage for those customers. Those outages were restored reasonably quickly in less than an hour. Further follow-up discussions between OTP system operations personnel and WAPA have occurred to address ways to avoid a similar situation in the future.

**Summary**

In general, OTP navigated the polar vortex event remarkably well with relatively minor customer impacts due in part to a healthy, generally available generation fleet, a favorable hedge through a forward purchase, and an FTR portfolio which offset high congestion costs between generation and load.

The following responses address the questions laid out in this information request as applicable to OTP.

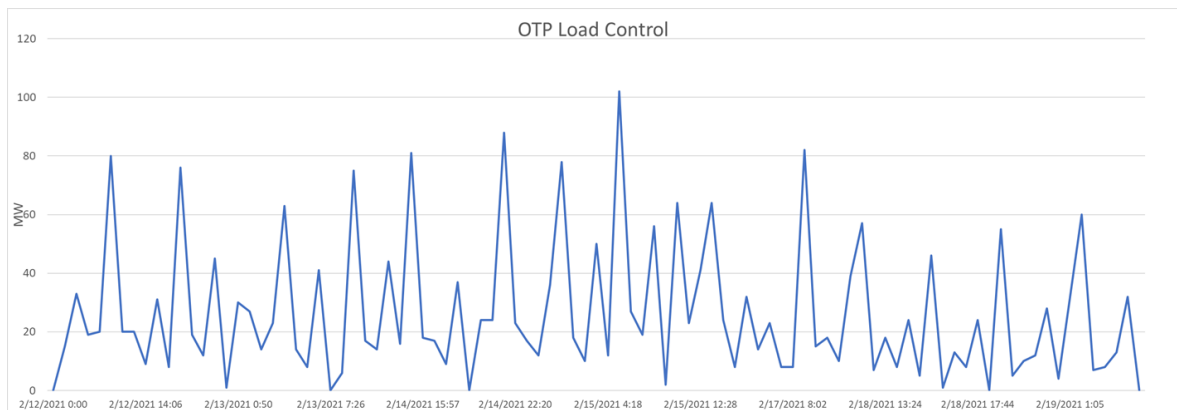
- 1.1 Attachment 1 to ND-PSC-001 provides a summary of November 2020 through February 2021 actual total system fuel and purchased power costs and associated monthly retail kWh billings and forecasted costs. OTP provides these amounts to reflect the costs that will set the April 2021 rate, which is the first month that includes February actual costs. These forecast and actual amounts are reflective of costs incurred to serve our retail load, before factoring in any asset-based sales margin. OTP does not forecast these system costs on a customer class basis.

Attachment 2 to ND-PSC-001 compares the monthly FCA costs per kWh for the November 2020 to February 2021 timeframe by customer class. Note that actual rates are set based on four-month average.

Attachment 3 is a copy of OTP's March 24, 2021 FCA filing and associated calculations determining the the April 2021 rates. This reflects the actual rates to be set for April. As you can see, the system average rate based on the four-month average is \$0.02540 per kWh, up from the \$0.02146 per kWh that was in effect for march of 2021.

- 1.2 See Attachment 2 for the cost per kWh by customer class.
- 1.3 See Attachment 2 for the actual and forecast cost per kWh by customer class.
- 1.4 OTP does not have gas storage at its Solway gas peaking plant nor at its new Astoria Station plant. As discussed earlier, Solway is a dual fuel facility that is designed to run on fuel oil if needed.

- 1.5 OTP’s Solway plant, being a peaking unit, is not conducive to entering forward contracts for supply due to the variability and uncertainty of when the facility will operate. As such, gas is typically procured daily as needed.
- 1.6 Based on how the billing cycles for OTP customers work and the associated reading of our analog meters throughout the course of the month, we are unable to capture specific usage of how much energy was still used by those customers on an interruptible rate for these specific days. Much of the usage during the cold weather event would ultimately be included in bills read in late February and throughout the first two-thirds of March.
- 1.7 The graph below illustrates OTP’s estimated levels of control that as utilized from Feb 12-19 on a total system basis. OTP does not attempt to quantify control amounts on a jurisdictional level. As noted earlier, OTP’s load control was available throughout the event. From February 12-19, a total of 33 different control events were initiated. OTP estimates these events controlled approximately 3,421 MWhs. As indicted in the graph below, the highest estimated level of control peaked at approximately 102 MWs on February 15, 2021 and consistently resulted in 40-80 MWs of control.



- 1.8 OTP believes it executed a maximum level of control that could reasonably be utilized during this event. At times it was necessary to disable our deferred load control sequence and remove our thermal storage customers from our economic control sequences. This occurred several times to allow recovery of the thermal storage units because of the length and frequency of control events (2/13, 2/15, 2/17).
- 1.9 OTP’s Residential Demand Control Service (Section 9.02) has the following Demand Signal criteria:

**DEMAND SIGNAL:** Service may receive a Demand signal for up to a total of 14 hours during any 24-hour period, as measured from midnight to midnight. Water heaters served on this tariff will also be included in the Company’s Summer water heater load control program.

OTP's Water Heating Control Rider (Section 14.01) has the following control criteria:

**CONTROL CRITERIA:** Service may be controlled for up to a total of 14 hours during any 24-hour period, as measured from midnight to midnight. Under normal circumstances the Company will schedule recovery time following control periods that approach 14 hours.

OTP's Controlled Service – Interruptible Load Rider - Large Dual Fuel tariff (Section 14.04), and OTP's Controlled Service – Interruptible Load Rider - Small Dual (Section 14.05) have the following control criteria:

**CONTROL CRITERIA:** Service may be controlled up to a total of 24 hours during any 24-hour period, as measured from midnight to midnight. Short-duration cycling is approximately 15 minutes off / 15 minutes on of appropriate cooling equipment during the summer season (June 1-September 30). Domestic water heating may be controlled up to 14 hours in the 24-hour period.

OTP's Controlled Service – Deferred Load Rider (Thermal Storage) (Section 14.06) has the following control criteria:

**CONTROL CRITERIA:** Service may be controlled for up to a total of 14 hours during any 24-hour period, as measured from midnight to midnight. Under normal circumstances the Company will schedule recovery time following control periods that approach 14 continuous hours. Short-duration cycling will be approximately 15 minutes off/15 minutes on of appropriate cooling equipment during the summer season (June 1-September 30).

- 1.10 All of OTP's fuel and purchased power costs are recovered through its Energy Adjustment Rider.
- 1.11 OTP's rate is updated monthly and is based on a trailing four-month average of costs and collections. For example, the rates to be implemented April 1, 2021 would be based on average costs, billed kWhs and collections from November 2020 – February 2021. April 1 rates will be the first month that would reflect the impact of February's costs incurred. Attachment 3 provides the calculation of the April 2021 rate, as filed in OTP's Energy Adjustment Rider case. February's results will ultimately be averaged into the monthly rates that are implemented in April, May, June, and July of 2021.
- 1.12 While OTP anticipates a slight increase in the rate for the April – July timeframe because of February's cold weather event, OTP does not believe alternative recovery is needed in this case. Were impacts more severe, one alternative would be to spread the under-recovery over a longer period.

ACTUALS		Period Ending	Period Ending	Period Ending	Period Ending
		November 2020	December 2020	January 2021	February 2021
		Effective January 2021	Effective February 2021	Effective March 2021	Effective April 2021
1	Purchased Power	\$ 2,063,781	\$ 2,345,738	\$ 1,590,391	\$ (271,097)
2	Wind Curtailment	\$ 33,016	\$ (41,939)	\$ 3,207	\$ 5,615
3	Steam Plant Generation	\$ 3,779,745	\$ 4,630,380	\$ 4,806,011	\$ 5,461,247
4	Other Plant Generation	\$ 50,080	\$ 78,030	\$ 84,113	\$ 809,579
5	Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -
6	Steam Plant Reagents	\$ 129,295	\$ 114,762	\$ 134,599	\$ 205,688
7	Coyote Lime	\$ 47,511	\$ 52,922	\$ 61,106	\$ 51,064
8	Emission Allowance Purchase	\$ 9	\$ 31	\$ 32	\$ 28
9	Less: Intersystem Sales (Rev) Cost	\$ (678,948)	\$ (596,056)	\$ (330,531)	\$ (1,048,149)
10	MISO Day 2 Charges (not Schedule 16 & 17)	\$ 2,391,405	\$ 3,521,510	\$ 3,058,605	\$ 10,078,088
11	SPP Charges	\$ (181,945)	\$ (81,398)	\$ (142,539)	\$ (832,796)
12	Net System Energy Costs	\$ 7,633,950	\$ 10,023,978	\$ 9,264,994	\$ 14,459,268
<u>ASSET-BASED MARGINS</u>					
13	Effective Month - Forecast of Margins - 85%	\$ (164,470)	\$ (71,514)	\$ (63,122)	\$ (137,730)
14	True-up of prior months margin forecast	\$ (46,528)	\$ 51,198	\$ 169,913	\$ (1,540,066)
15	Total Margin Credit	\$ (210,998)	\$ (20,316)	\$ 106,791	\$ (1,677,796)
16	Prior (Over) Under Recovery	\$ (115,388)	\$ 974,016	\$ 258,424	\$ 4,745,462
17	<b>Total System Energy Costs</b>	<b>\$ 29,182,944</b>	<b>\$ 32,149,598</b>	<b>\$ 34,866,453</b>	<b>\$ 44,325,333</b>
18	Total Retail kWh	381,354,135	420,149,651	482,448,774	461,377,536
19	<b>Cost per kWh</b>	<b>0.02025</b>	<b>0.02157</b>	<b>0.02146</b>	<b>0.02540</b>

FORECAST		Period Ending	Period Ending	Period Ending	Period Ending
		November 2020	December 2020	January 2021	February 2021
		Effective January 2021	Effective February 2021	Effective March 2021	Effective April 2021
20	Purchased Power	\$ 6,237,384	\$ 5,411,446	\$ 5,211,418	\$ 5,298,988
21	Wind Curtailment	\$ 2,354	\$ 6,311	\$ 9,740	\$ 5,479
22	Steam Plant Generation	\$ 2,877,436	\$ 4,902,716	\$ 5,766,635	\$ 4,964,026
23	Other Plant Generation	\$ 14,850	\$ 441,925	\$ 385,513	\$ 211,068
24	Hydro Plant Generation	\$ -	\$ -	\$ -	\$ -
25	Steam Plant Reagents	\$ 102,238	\$ 232,004	\$ 283,702	\$ 232,843
26	Coyote Lime (included in Steam Plant Reagents)	\$ -	\$ -	\$ -	\$ -
27	Emission Allowance Purchase	\$ 274	\$ 445	\$ 522	\$ 462
28	Less: Intersystem Sales (Rev) Cost	\$ (9,845)	\$ (195,080)	\$ (530,017)	\$ (198,892)
29	MISO Day 2 Charges (not Schedule 16 & 17)	\$ 286,194	\$ 291,057	\$ 107,542	\$ 113,161
30	SPP Charges	\$ (51,612)	\$ (58,014)	\$ (90,852)	\$ (82,862)
31	Net System Energy Costs	\$ 9,459,273	\$ 11,032,808	\$ 11,144,204	\$ 10,544,273
<u>ASSET-BASED MARGINS</u>					
32	Effective Month - Forecast of Margins - 85%	\$ (106,013)	\$ (8,472)	\$ (63,122)	\$ (137,730)
33	True-up of prior months margin forecast	\$ 26,091	\$ (152,586)	\$ 169,913	\$ (1,540,066)
34	Total Margin Credit	\$ (79,922)	\$ (161,058)	\$ 106,791	\$ (1,677,796)
35	Prior (Over) Under Recovery	\$ 1,243,742	\$ (258,553)	\$ (1,572,574)	\$ (1,704,766)
36	<b>Total System Energy Costs</b>	<b>\$ 36,259,038</b>	<b>\$ 36,484,827</b>	<b>\$ 38,290,442</b>	<b>\$ 38,663,809</b>
37	Total Retail kWh	419,505,323	472,502,111	504,002,585	459,589,495
38	<b>Cost per kWh</b>	<b>0.02456</b>	<b>0.02288</b>	<b>0.02181</b>	<b>0.02084</b>

Deviation of Actual to Forecast	(0.004311)	(0.001305)	(0.000347)	0.004560
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CLASS ENERGY ADJUSTMENT FACTOR (EAF)

	Delivered Cost per kWh	NORTH DAKOTA SERVICE CATEGORY									
		Residential	Farms	General Service	Large General Service	Irrigation Services	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Deferred
E8760 Ratios		1.0250	0.9690	1.0160	0.9670	0.9370	0.7840	1.0110	1.0350	1.0370	0.9630
February 2021 Actual	<b>0.03134</b>	0.03212	0.03037	0.03184	0.03031	0.02937	0.02457	0.03168	0.03244	0.03250	0.03018
February 2021 Forecast	<b>0.02294</b>	0.02351	0.02223	0.02331	0.02218	0.02149	0.01798	0.02319	0.02374	0.02379	0.02209
January 2021 Actual	<b>0.01920</b>	0.01968	0.01860	0.01951	0.01857	0.01799	0.01505	0.01941	0.01987	0.01991	0.01849
January 2021 Forecast	<b>0.02211</b>	0.02266	0.02142	0.02246	0.02138	0.02072	0.01733	0.02235	0.02288	0.02293	0.02129
December 2020 Actual	<b>0.02078</b>	0.02130	0.02014	0.02111	0.02009	0.01947	0.01629	0.02101	0.02151	0.02155	0.02001
December 2020 Forecast	<b>0.02335</b>	0.02393	0.02263	0.02372	0.02258	0.02188	0.01831	0.02361	0.02417	0.02421	0.02249
November 2020 Actual	<b>0.01582</b>	0.01622	0.01533	0.01607	0.01530	0.01482	0.01240	0.01599	0.01637	0.01641	0.01523
November 2020 Forecast	<b>0.02255</b>	0.02311	0.02185	0.02291	0.02181	0.02113	0.01768	0.02280	0.02334	0.02338	0.02172

NORTH DAKOTA  
OTTER TAIL POWER COMPANY  
ENERGY ADJUSTMENT RIDER BY SERVICE CATEGORY  
FOR BILLING TO BE EFFECTIVE APRIL 1, 2021

Line	ENERGY COSTS & CREDITS	(A)	(B)	(C)	(D)	(E)
		2020	2020	2021	2021	Total
		November	December	January	February	This Period
1	Purchased Power	\$2,063,781	\$2,345,738	\$1,590,391	(\$271,097)	\$5,728,813
2	Wind Curtailment	\$33,016	(\$41,939)	\$3,207	\$5,615	(\$101)
3	Steam Plant Generation	\$3,779,745	\$4,630,380	\$4,806,011	\$5,461,247	\$18,677,383
4	Other Plant Generation	\$50,080	\$78,030	\$84,113	\$809,579	\$1,021,802
5	Hydro Plant Generation	\$0	\$0	\$0	\$0	\$0
6	Steam Plant Reagents	\$129,295	\$114,762	\$134,599	\$205,688	\$584,344
7	Coyote Lime	\$47,511	\$52,922	\$61,106	\$51,064	\$212,602
8	Emission Allowance Purchase	\$9	\$31	\$32	\$28	\$101
9	Less: Intersystem Sales	(\$678,948)	(\$596,056)	(\$330,531)	(\$1,048,149)	(\$2,653,684)
10	Net Retail MISO Day 2	\$2,391,405	\$3,521,510	\$3,058,605	\$10,078,088	\$19,049,608
11	Net Retail SPP	(\$181,945)	(\$81,398)	(\$142,539)	(\$832,796)	(\$1,238,678)
12						
13	NET ENERGY COSTS	\$7,633,950	\$10,023,978	\$9,264,994	\$14,459,268	\$41,382,190

Line	ASSET-BASED MARGINS	2021	2021	2021	2021	Total
		January	February	March	April	This Period
14	Forecast of Margins - 85%	(\$164,470)	(\$71,514)	(\$63,122)	(\$137,730)	(\$436,836)
15	True-up of prior months margin forecast	(\$46,528)	\$51,198	\$169,913	(\$1,540,066)	(\$1,365,483)
16	Total Margin Credit	(\$210,998)	(\$20,316)	\$106,791	(\$1,677,796)	(\$1,802,319)
17	Prior (over) under recovery (line 27)					\$4,745,462
18	Adjusted Net Energy Costs (lines 13 + 16 + 17)					<u>\$44,325,333</u>

Line	ENERGY -- KWH	2020	2020	2021	2021	Total
		November	December	January	February	This Period
19	Retail Sales - kWhs	381,354,135	420,149,651	482,448,774	461,377,536	1,745,330,096
20	System Delivered Cost per kWh					\$0.02540

21	Service Category	E2-E8760 Alloc. Ratio	Class Energy Adjustment Factor (EAF)	
21a	Residential	1.0250	\$	0.02604
21b	Farms	0.9690	\$	0.02461
21c	General Service	1.0160	\$	0.02581
21d	Large General Service	0.9670	\$	0.02456
21e	Irrigation Services	0.9370	\$	0.02380
21f	Outdoor Lighting	0.7840	\$	0.01991
21g	OPA	1.0110	\$	0.02568
21h	Controlled Service Water Heating	1.0350	\$	0.02629
21i	Controlled Service Interruptible	1.0370	\$	0.02634
21j	Controlled Service Deferred	0.9630	\$	0.02446

TRUE UP FOR FEBRUARY

22	Retail Sales (kWhs) (Col D, Line 19)	461,377,536
23	Net Energy Costs for the System -- Most recent month (Col D Line 13, Col B Line 16)	\$14,438,952
24	COE Recovery Rate Effective for February	\$0.02157
25	Amount Recovered by COE (Line 24 x Line 22)	\$9,951,914
26	(Over) / Under Recovery (Line 23 minus Line 25)	\$4,487,038
27	Cumulative (Over) / Under Recovery (prior month cumulative (over)/under) (Line 26 + Line 27 prior month)	<b>\$4,745,462</b>