Appendix A: Plan Cross Reference

Table 1: Status of 5-year Action Plan in 2016 Integrated Resource Plan[1]

Year	Activity	Status
2016	June 1 Triennial CIP filing for 2017, 2018, 2019	Filed on June 1, 2016 (MN Docket CIP-16-116) July 1, 2019, we filed to extend the three year plan to include four years 2017, 2018, 2019, and 2020
	MISO interconnection process and preparation for permitting effort for Astoria CT	Construction complete, plant in full operation Q1 2021
2017	Permitting and approvals for 248 MW Astoria CT including ongoing MISO interconnection process	Construction complete, plant in full operation Q1 2021
	Begin construction on 100 MW wind project	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
2018	Commercial operation of 100 MW wind project[2]	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
	Ongoing permitting and approvals for 248 MW Astoria CT including MISO interconnection process	Construction complete, plant in full operation Q1 2021
	Initiate work on utility-scale solar project to meet the Minnesota Solar Mandate by 2020	OTP purchased SRECs to meet its 2020 and 2021 SES requirements. OTP received approval to construct a 49.9 MW Hoot Lake Solar project in March 2021, currently expected to be operational by end of 2022.
2019	June 1 Triennial CIP filing for 2020, 2021, 2022	Was filed July 1, 2020, for 2021, 2022, 2023 (MN Docket CIP-20-475)
	Engineering and procurement for 248 MW Astoria CT	Construction complete, plant in full operation Q1 2021
	Begin construction on 100 MW wind project	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
	Construct or obtain PPA for an approximate 30 MW solar installation	OTP purchased SRECs to meet its 2020 and 2021 SES requirements. OTP received approval to construct a 49.9 MW Hoot Lake Solar project in March 2021, currently expected to be operational by end of 2022.

[1] Minnesota Docket No. E017/RP-16-386, North Dakota Case No. PU-16-308, South Dakota non-docketed item provided to South Dakota Public Utility Commission on June 15, 2016.
[2] The 150 MW Merricourt Project with its approximately 50 percent net capacity factor is basically equivalent to the 200 MW addition of wind resource with an approximately 40 percent capacity factor in the Order due to the difference of the net capacity factor assumed.

2020	Construction of 248 MW Astoria CT	Construction complete, plant in full operation Q1 2021
	File MISO Attachment Y for retirement of Hoot Lake Plant	Plant retired and decommissioning began Q2 2021
	Commercial operation of 100 MW wind project	150 MW Merricourt Wind Energy Facility construction complete, plant in full operation Q4 2020
	Commercial operation of 30 MW solar project	OTP purchased SRECs to meet its 2020 and 2021 SES requirements. OTP received approval to construct a 49.9 MW Hoot Lake Solar project in March 2021, currently expected to be operational by end of 2022.
2021	Start-up and commercial operation of 248 MW Astoria CT	Construction complete, plant in full operation Q1 2021
	Retirement of Hoot Lake Plant	Plant retired and decommissioning began Q2 2021

Table 2: Minnesota Public Utilities Commission Orders since 2016 IRP

Docket No. E017/RP-16-386 **Order Approving Plan with Modifications and Setting Requirements for Next Resource Plan, dated April 26, 2017**	**Section/Reference**
1. The Commission hereby approves Otter Tail Power Company's 2017-2031 Integrated Resource Plan, as modified below.	
2. The Commission finds that the Company's demand and net energy forecasts are acceptable for planning purposes.	
3. Otter Tail shall file its next integrated resource plan no later than June 3, 2019.	The Minnesota Commission's December 30, 2019, Order approved the September 1, 2021, filing date for this IRP in Docket No. E-017/RP-16-386.
4. The Commission hereby approves a five-year action plan that includes the addition of:	
a. 200 MW of wind in the 2018 to 2020 timeframe;	Petition Section 4, Merricourt Wind Energy Facility
b. 30 MW of solar in about 2020;	Petition Section 4, Hoot Lake Solar
c. Up to 250 MW of peaking capacity in 2021; and	Petition Section 4, Astoria Station simple-cycle natural gas combustion turbine

	d. Average annual energy savings of 46.8 GWh (1.6 percent of retail sales)	Petition Section 4, DSM and Conservation Requirements
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.	Petition Section 6, Preferred Plan covers 2022-2026 time frame
6.	The Commission hereby finds that Otter Tail is adequately tracking environmental regulations that might impact its operations.	The IRS has extended the Solar ITC so Otter Tail has not procured any utility scale solar at this time. Sufficient solar to meet Minnesota's SES is included in its Preferred Plan. (See Petition Section 6 and Appendix F)
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.	Energy and Demand Forecast Models Information Filing
	b. A discussion of how incremental levels of new wind could be reasonably procured and worked into the system while maintaining reliability of service.	Petition Section 4, Renewable Energy Objectives and Standards
	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.	Petition Section 4, DSM and Conservation Requirements
	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 kilowatt as a percentage of technical potential and include any overall specific benchmarks.	Petition Section 4, DSM and Conservation Requirements
	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.	Petition Section 6, Oil Peaker Evaluation Sensitivities
	f. The status of Clean Power Plan compliance plans in the states included in Otter Tail's service territory.	Appendix E
8.	This order shall become effective immediately.	

Docket No. E017/RP-16-386 Order Extending Deadline for Filing Resource Plan, Requiring Supplemental Filing, and Completing Competitive Bidding Process December 30, 2019		**Section/Reference**
1.	The Commission approves Otter Tail's request to delay the filing date for its next Integrated Resource Plan from June 1, 2020, to September 1, 2021.	
2.	Otter Tail shall make a supplemental filing by December 31, 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 externalities and carbon regulatory costs. The compliance filing will be limited to Otter	Otter Tail's December 31, 2020, Supplemental Filing *In the Matter of Otter Tail Power Company's 2017-2031 Resource Plan* in Minnesota Docket No. E017/RP-16-386.

	Tail's EnCompass modeling results and is not subject to all items required by Minn. R. 7843.0400 and Minn. Stat. § 216B.2422	
3.	By June 1, 2020, Otter Tail shall complete a competitive-bidding process to procure approximately 30 MW or more of installed solar capacity. The process shall allow for the option of solar plus storage. The bidding process and timeline must be filed by April 15, 2020. By July 1, 2020, the Company shall make a compliance filing detailing the process and its proposed next steps for contract negotiations and filing with the Commission.	Addressed *In the Matter of Otter Tail Power Company's Petition for Approval of the Hoot Lake Solar Project*, Minnesota Docket No. E-017/M-20-844
4.	This order shall become effective immediately.	

Table 3: North Dakota Century Code

North Dakota Century Code 49-05-17 Resource Planning	**Section/Reference**
1. An integrated resource plan must include: a. The electric public utility's forecast of demand for electric generation supply over the planning period with recommended plans for meeting the forecasted demand plus an additional planning reserve margin for ensuring adequate and sufficient reliability of service; and b. Any additional information the commission requests related to how an electric public utility intends to provide sufficient electric generation service for sue by retail customers within the state over the planning period.	Energy and Demand Forecast Models Information Filing
2. An electric public utility shall include a least cost plan for providing adequate and reliable service to retail customers which is consistent with the provisions of this title and the rules and orders adopted and issued by the commission.	Petition, Section 6 Preferred Resource Plan
3. The commission may consider the qualitative benefits and provide value to a base-load generation and load-following generation resource and its proximity to load.	
4. The commission may contract or consult with an expert to evaluate qualitative benefits of resources and to review reliability planning. The commission may require an electric public utility to pay a fee necessary for completion of an evaluation in an amount not to exceed two hundred fifty thousand dollars. a. If additional funds are necessary for completion of the evaluation, upon approval of the emergency commission, the electric public utility shall pay the additional fees reasonably necessary for the completion. b. If the evaluation applies to more than one electric public utility, the commission may assess each electric public utility the proportionate share of the fee	
5. An electric public utility shall report annually to the commission on cybersecurity preparedness, including an assessment of emerging threats and efforts taken by the electric public utility to implement cybersecurity measures. The commission may limit access to records and portions of a meeting relating to cybersecurity preparedness.	Otter Tail will comply with this requirement as part of an annual filing that is separate from the Integrated Resource Plan.

Table 4: Minnesota Orders from Other Dockets

Docket E-999/CI-07-1199 & E-999/DI-19-406 **Order Establishing Estimate of the Costs of Future Carbon Dioxide Regulation Costs, dated September 30, 2020**	**Section/Reference**
6. The Commission hereby quantifies and establishes the range of regulatory costs of carbon dioxide emissions as \$5 to \$25 per short ton effective 2025 and thereafter.	Appendix I, *Externalities Included*. Otter Tail applied the mid-point of the range, \$15, to all with externalities sensitivities except *T* and *U* where \$5 and \$25 were applied respectively.
7. Scenarios that incorporate, for all years, the low end of the range of environmental costs for carbon dioxide as approved by the Commission in its January 3, 2018, Order Updating Environmental Costs in Docket No. E-999/CI-14-643, In the Matter of the Further investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3, and set forth in Attachment A.	Appendix I, *Externalities Included*. Sensitivity *V* uses the Attachment A Low CO2 Externality Values for 2020-2024 and the median Regulatory Cost of Carbon thereafter.
8. Scenarios that incorporate, for all years, the high end of the range of environmental costs for CO2 as approved by the Commission in its January 3, 2018, order, and set forth in Attachment A.	Appendix I, *Externalities Included*. Sensitivity *W* uses the Attachment A High CO2 Externality Values for 2020-2024 and the median Regulatory Cost of Carbon thereafter.
9. Scenarios that incorporate the low end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the low end of the range of regulatory costs for CO2 regulations (\$5 per short ton) in lieu of environmental costs.	Appendix I, *Externalities Included*. Sensitivity *T* uses the Attachment A Low CO2 Externality Values for 2020-2024 and the Low Regulatory Cost of Carbon thereafter.
10. Scenarios that incorporate the high end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the high end of the range of regulatory costs for CO2 regulations (\$25 per short ton) in lieu of environmental costs.	Appendix I, *Externalities Included*. Sensitivity *U* uses the Attachment A High CO2 Externality Values for 2020-2024 and the High Regulatory Cost of Carbon thereafter.
11. A reference case scenario incorporating the Commission's middle or high values of the established environmental and regulatory cost ranges.	Appendix I, *Externalities Included*. Sensitivity *A* uses the middle values of the established cost ranges.

Table 5: Minnesota Statutes and Rules – IRPs

Statute	**Subsection**	**Subject**	**Section/Reference**
§216B.1691 Renewable Energy Objectives	Subd. 2a - Eligible energy technology standard.	Report on renewable energy objectives and standards.	Appendix G

	Subd. 2e - Rate impact of standard compliant; report.	Utility must submit a report containing an estimation of the rate impact of RES compliance.	Appendix G
	Subd. 2f - Solar energy standard	(a) Utility shall generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy. At least ten percent of the 1.5 percent goal must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less.	Petition Section 4, Renewable Energy Objectives and Standards
		(e) It is an energy goal of the state of Minnesota that by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.	With the addition of Hoot Lake Solar and our Preferred IRP, Otter Tail is on track to meet this requirement
	Subd. 3 – Utility plans filed with commission.	Report on efforts toward meeting renewable energy objective/renewable energy standard.	Appendix G
§216B.241 Energy Conservation Improvement	Subd. 1c(b) - Energy saving goals.	Utility shall have an annual energy-savings goal equivalent to at least 1.5 percent of annual retail energy sales unless modified by the commissioner. The savings goals must be calculated based on the most recent three-year weather-normalized average.	Petition, Section 4 – DSM and Conservation Requirements
§216B.2422 Resource Planning; Renewable Energy	Subd. 2 - Resource plan filing and approval.	Utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.	Petition, Preferred IRP meets capacity needs entirely through conservation and renewable energy resources.
	Subd. 2a – Historical data and advance forecast.	Utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Otter Tail filed its energy and demand forecast with the Commission on August 2, 2021
	Subd. 3 - Environmental costs.	Utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Appendix F

	Subd. 4 - Preference for renewable energy facilities.	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. 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.	Petition, Sections 3 and 7 - Preferred Plan is in the Public Interest
	Subd. 6 - Consolidation of resource planning and certificate of need.	Utility shall indicate in its resource plan whether it intends to site or construct a large energy facility.	Throughout Petition, Summarized in Section 7
§216B.2426 Opportunities for Distributed Generation	Distributed generation.	Report on opportunities for distributed generation.	Appendix J
§216H.02 Greenhouse Gas Emissions Control	Minnesota CO2 Goal	It is the goal of the state to reduce statewide greenhouse gas emissions to a level of 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.	Otter Tail's Preferred Plan meets the Emissions and Greenhouse Gas Reduction CO2 reduction Goal
§216H.03 Failure to adopt greenhouse gas control plan.		Long-term increased emissions from power plants is prohibited and includes new construction, import from source that would contribute to emissions, and long-term PPA of more than 50MW of capacity or more for a term exceeding five years.	None planned.
§216H.06 Emissions consideration in resource planning.	Carbon values	The Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate must be used in all electricity generation resource acquisition proceedings.	Appendix F and Appendix I, *Externalities Included*

Rule	Subpart	Subject	Section/Reference
7843.03 Utility Resource Planning Process	Subpart 5 - Copies of filings.	Utility shall submit 15 copies of its resource plan filing to the commission.	Included with filing
7843.04 Contents of Resource Plan Filings	Subpart 1 - Advance forecasts.	Utility shall include in the filing identified in subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the MEQB.	Appendix B
	Subpart 2 - Resource plan.	Utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. The utility is only required to identify a resource option generically unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.	Throughout Petition and Appendix I
	Subpart 3(A) - Supporting information.	Resource plan shall include a list of resource options considered.	Petition, Section 3 - Resource Alternatives and Appendix D
	Subpart 3(B)	Resource plan shall include a description of the process and analytical techniques used in developing the plan.	Petition, Section 5 - Planning Tools
	Subpart 3(C)	Response plan shall include a 5-year action plan with key construction activities and regulatory filings.	Petition, Section 7 - Five-Year Action Plan
	Subpart 3(D)	Resource plan shall include a narrative and quantitative discussion of why the plan is in the public interest.	Petition, Section 3 - Preferred Plan is in the Public Interest
	Subpart 4	Response plan shall include a nontechnical summary (not exceeding 25 pages in length).	Petition, Section 2 - Preface

Appendix B: Minnesota Electric Utility Annual Report

**PUBLIC DOCUMENT –
NOT PUBLIC (OR PRIVILEGED) DATA
HAS BEEN EXCISED**

SECTION 1

Electric Utility Information Reported Annually
Under Rules 7610.0100-7610.0700

Form EN-0003 – 20

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	87
REPORT YEAR	2020

Number of Power Plants	14

UTILITY DETAILS	
UTILITY NAME	Otter Tail Power Co
STREET ADDRESS	215 S Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	Nathan Jensen
CONTACT TITLE	Manager, Resource Planning
CONTACT STREET ADDRESS	215 S Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8989
CONTACT EMAIL ADDRESS	njensen@otpco.com

UTILITY OFFICERS	
NAME	TITLE

PREPARER INFORMATION	(do not type "Same as Above")
PERSON PREPARING FORMS	Bryce Haugen
PREPARER'S TITLE	Senior Resource Planner
DATE	6/21/2021
PREPARER'S EMAIL ADDRESS	bhaugen@otpco.com

COMMENTS

ALLOWABLE UTILITY TYPES

Code*

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

FEDERAL AGENCY (please spell out acronyms)	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell) MONTHLY	YEARLY	OTHER
US Dept of Energy, Energy Information Administration	EIA-826	Monthly Electric Utilility Report	X		
US Dept of Energy, Energy Information Administration	EIA-860	Annual Electric Generator Report		X	
US Dept of Energy, Energy Information Administration	EIA-861	Annual Electric Utility Report		X	
US Dept of Energy, Energy Information Administration	EIA-923	Power Plant Operations Report		X	
US Dept of Energy, Federal Energy Regulatory Commission	Form 714	Annual Electric Control and Planning Area Report		X	

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted in electronic format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted in electronic format.

See Instructions for details of the information required on the Minnesota Service Area Map.

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME (please spell out acronyms)	INTERCONNECTED UTILITY (please spell out acronyms)	MWH PURCHASED	RESALE ONLY MWH SOLD FOR RESALE
American Electric Power Service	Midcontinent Independent System Operator, Inc. (MISO)		
American UE	Midcontinent Independent System Operator, Inc. (MISO)		
Ashtabula Wind III, LLC	Midcontinent Independent System Operator, Inc. (MISO)	218,467	
Badger, SD	Badger Municipal Power		249
Basin Electric Power Cooperative			
Beltrami Electric Cooperative	Minnkota Power Cooperative	108,042	
Cargill Power Markets, LLC	Midcontinent Independent System Operator, Inc. (MISO)		
Constellation Energy Commodities Group	Midcontinent Independent System Operator, Inc. (MISO)		
Dakota Valley Services			
DTE Energy Trading, Inc.	Midcontinent Independent System Operator, Inc. (MISO)		
EDF Trading North America	Midcontinent Independent System Operator, Inc. (MISO)		
Excel Energy Under Reported Load Adj.	Midcontinent Independent System Operator, Inc. (MISO)		
Exelon			
Lake Region State College		3,724	
Lyon Lincoln Electric Cooperative			
MacQuarie Energy LLC	Midcontinent Independent System Operator, Inc. (MISO)		
Manitoba Hydro Electric Board	Midcontinent Independent System Operator, Inc. (MISO)		
MidAmerican Energy Company	Midcontinent Independent System Operator, Inc. (MISO)		
Minnesota Power	Midcontinent Independent System Operator, Inc. (MISO)		
Minnkota Power Cooperative	MAPP		
Missouri River Energy Services (MRES)	Midcontinent Independent System Operator, Inc. (MISO)		
Montana Dakota Utilities - Mountrail	Midcontinent Independent System Operator, Inc. (MISO)		
New Folden, MN	New Folden Municipal Power		1,797
Nextra Energy Power Marketing	Midcontinent Independent System Operator, Inc. (MISO)		
Nielsville, MN	Nielsville Municipal Power		27
Nodak Electric Cooperative	Nodak Electric Cooperative	7,636	
North Central Electric Cooperative			
Northern States Power	Midcontinent Independent System Operator, Inc. (MISO)	205,600	
NorthWestern Energy - NLE	MAPP		
P.K.M. Electric Co-operative, Inc.	P.K.M. Electric Co-operative, Inc.	6,064	
Rainbow Energy Marketing Corp	MAPP		
RBC Capital Markets Corporation	MAPP		
Red Lake Rural Electric Cooperative	MAPP	5,439	
Shelly, MN	Shelly Municipal Power		626
Southern Minnesota Municipal Power Agency (SMMPA)	MAPP		
The Energy Authority	Midcontinent Independent System Operator, Inc. (MISO)		
Transalta Energy Marketing	MAPP		
Western Area Power Administration (WAPA)	Midcontinent Independent System Operator, Inc. (MISO)	3	
Western Area Power Administration (WAPA) - WEC		29,972	
Willmar Municipal Utilities	Midcontinent Independent System Operator, Inc. (MISO)		
Midwest ISO			239,677
Southwest Power Pool ISO			
Non-asset based cost of sales			
OTHER NON UTILTY			

American Crystal Sugar		58	
Borderline Wind		1,345	
City of Detroit Lakes		876	
City of Perham			
Dakota Magic Casino			
Dakota Wind Exchacnge			
Energy Maintenance Service-Broadwind Srvcs			
Fleet Farm			
FPL Energy North Dakota Wind II		41,111	
H-D Electric COOP		0	
Hendricks Wind 1		1,398	
Kindred School			
Lac Qui Parle School			
Langdon Wind, LLC		73,931	
District 45 Methane			
Minnesota Small Power (Wind)		288	
North Dakota Small Power (Wind)		8	
South Dakota Co Generation		109	
Pembina Border Station			
State Auto Insurance			
Stevens Community Medical			
Turtle Mountain Community College		106	
University of MN - Morris		5,373	
Valley Queen Cheese			

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

A utility shall provide the following information for the last calendar year:

E. RATE SCHEDULES	**The rate schedule and monthly power cost adjustment information must be submitted in electronic format.**

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

F. REPORT FORM EIA-861	**A copy of report form EIA-861 filed with the US Department of Energy must be submitted in electronic format.**

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Department of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT	**If applicable, a copy of the Financial and Statistical Report filed with the US Department of Agriculture must be submitted in electronic format.**

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Department of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COLUMN 1 NUMBER OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COLUMN. 2 NUMBER OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COLUMN 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
na	na	188,019

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY IN 2020

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka		47	Meeker	
3	Becker	35646	48	Mille Lacs	
4	Beltrami	232977	49	Morrison	
5	Benton		50	Mower	
6	Big Stone	19,689	51	Murray	
7	Blue Earth		52	Nicollet	
8	Brown		53	Nobles	
9	Carlton		54	Norman	11434
10	Carver		55	Olmstead	
11	Cass	169632	56	Otter Tail	488358
12	Chippewa	4761	57	Pennington	2761
13	Chisago		58	Pine	
14	Clay	14661	59	Pipestone	
15	Clearwater	282576	60	Polk	190284
16	Cook		61	Pope	2,436
17	Cottonwood		62	Ramsey	
18	Crow Wing		63	Red Lake	194990
19	Dakota		64	Redwood	2857
20	Dodge		65	Renville	
21	Douglas	49,916	66	Rice	
22	Faribault		67	Rock	
23	Fillmore		68	Roseau	13618
24	Freeborn		69	St. Louis	
25	Goodhue		70	Scott	
26	Grant	33313	71	Sherburne	
27	Hennepin		72	Sibley	
28	Houston		73	Stearns	
29	Hubbard	13976	74	Steele	
30	Isanti		75	Stevens	93,029
31	Itasca		76	Swift	46,320
32	Jackson		77	Todd	49
33	Kanabec		78	Traverse	29171
34	Kandiyohi	9391	79	Wabasha	
35	Kittson	229235	80	Wadena	
36	Koochiching		81	Waseca	
37	Lac Qui Parle	59227	82	Washington	
38	Lake		83	Watonwan	
39	Lake of the Woods		84	Wilkin	17728
40	Le Sueur		85	Winona	
41	Lincoln	20880	86	Wright	
42	Lyon	24053	87	Yellow Medicine	25505
43	McLeod				
44	Mahnomen	37378		GRAND TOTAL (Entered)	2548449
45	Marshall	192598			
				GRAND TOTAL (Calculated)	2548449

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year (2020) Entire System		A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	47,205	1,763	1,361	9,991	0	707	0	500	61,527
	MWH	58,787	7,090	5,059	37,927	0	157,440	176	2,836	269,315
February	No. of Customers	47,182	1,760	1,350	9,975	0	710	0	502	61,479
	MWH	51,407	6,135	4,188	33,259	0	154,386	130	2,655	252,158
March	No. of Customers	46,929	1,751	1,355	9,934	0	713	0	500	61,182
	MWH	46,056	5,436	3,944	31,272	0	143,894	112	2,504	233,219
April	No. of Customers	47,226	1,762	1,352	10,015	0	716	0	504	61,575
	MWH	42,658	4,604	3,635	27,489	0	147,798	109	2,462	228,757
May	No. of Customers	46,708	1,745	1,692	9,817	0	687	0	498	61,147
	MWH	33,387	3,109	3,253	20,991	0	116,136	75	2,169	179,119
June	No. of Customers	47,975	1,763	1,696	10,151	0	714	0	502	62,801
	MWH	31,776	2,302	3,441	20,423	0	110,542	74	2,057	170,615
July	No. of Customers	47,042	1,749	1,712	9,792	0	687	0	484	61,466
	MWH	42,202	2,623	4,773	24,204	0	129,826	77	1,889	205,595
August	No. of Customers	48,044	1,762	1,714	10,174	0	721	0	506	62,921
	MWH	41,080	2,423	4,902	24,921	0	131,989	78	2,075	207,468
September	No. of Customers	48,094	1,767	1,716	10,172	0	720	0	507	62,976
	MWH	35,780	2,372	4,093	24,138	0	120,835	95	1,951	189,264
October	No. of Customers	47,848	1,765	1,731	10,135	0	716	0	507	62,702
	MWH	31,780	3,614	3,578	24,792	0	107,381	105	2,058	173,306
November	No. of Customers	47,374	1,760	1,725	10,068	0	717	0	504	62,148
	MWH	37,043	3,921	4,743	27,351	0	112,491	116	1,951	187,615
December	No. of Customers	46,982	1,742	1,347	9,936	0	704	0	499	61,210
	MWH	42,990	4,746	3,945	28,828	0	169,279	113	2,118	252,019
	Total MWH	494,946	48,373	49,555	325,595	0	1,601,997	1,260	26,725	2,548,449

COMMENTS

Street & Highway Lighting customers are counted as part of other classes. Including Street & Highway Lighting customers would be double counting as a customer would show up twice.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.
Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	This column reports the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. Number of Customers at End of Year	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. Megawatt hours (round to nearest MWH)	This column total will be used for the Alternative Energy Assessment and should NOT include revenues from sales for resale (Minnesota Statutes, Section 216B.62, Subd. 5). Revenue ($)
Farm	1,347	49,555	$4,955,634.00
Non-Farm Residential	48,724	543,318	$58,638,894.00
Commercial	9,936	325,595	$33,293,866.00
Industrial	704	1,601,997	$103,564,946.00
Street & Highway Lighting	0	1,260	$128,106.00
All other	499	26,725	$1,825,038.00
Entered Total	61,210	2,548,449	$202,406,484.00
		^ should match ElectricityByCounty Tab, cell G55)	
CALCULATED TOTAL	61,210	2,548,449	202,406,484
		^ should match ElectricityByCounty Tab, cell G55)	

COMMENTS	Street & Highway Lighting customers are counted as part of other classes. Including number of Street & Highway Lighting customers would be double counting as a customer would show up twice.

REMEMBER TO SEND/UPLOAD THE FOLLOWING ATTACHMENTS:	
DO NOT INSERT THE ATTACHMENT INTO THIS WORKBOOK	
1	If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers workbook was not used (pursuant to MN Rules Chapter 7610.0600 B)
2	Minnesota Service Area Map (pursuant to MN Rules Chapter 7610.0600 C)
3	Rate Schedules and Monthly Power Cost Adjustments (pursuant to MN Rules Chapter 7610.0600 E)
4	Report form EIA-861 filed with US Department of Energy (pursuant to MN Rules Chapter 7610.0600 F)
5	If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Department of Agriculture (pursuant to MN Rules Chapter 7610.0600 G)

When submitting this workbook and attachments, please following the file naming format of:

ELEC_###_2020 Annual Report (*this workbook*)
ELEC_###_2020 Largest Customer List
ELEC_###_2020 MN Service Area Map
ELEC_###_2020 Rate Schedules
ELEC_###_2020 Monthly Power Cost Adjustments
ELEC_###_2020 USDOE EIA-861
ELEC_###_2020 USDOA Financial and Statistical Report

NOTE: ### is your Utility Entity number found in Cell C5 on the Registration Tab

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME		**PLANT ID**	(leave this cell blank)
STREET ADDRESS			
CITY			
STATE		**NUMBER OF UNITS**	
ZIP CODE			
COUNTY			
CONTACT PERSON			
TELEPHONE			

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
Plant Total	0.00	0.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
***** Energy Source & Fuel Type**	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$
Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage
Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Big Stone Plant	**PLANT ID**	87004
STREET ADDRESS			
CITY	Big Stone City		
STATE	SD	**NUMBER OF UNITS**	2
ZIP CODE	57216		
COUNTY	Grant		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1975	COAL	897,937.00	
2	STB	IC	1975	FO2	0.00	
				Plant Total	897,937.00	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	255.90	255.90	38.90	92.3	1.4	
2	0.62	0.60				
Plant Total	256.52	256.50				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	614,158.00	TONS	8,197	REF		TONS	
1					FO2	79,683.00	GAL	

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use
	Stand-by
	Retired
	Future
	Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal
	Coal (general)
	Diesel
	Fuel Oil #2 (Mid Distillate)
	Fuel Oil #6 (Residual Fuel Oil)
	Lignite
	Liquefied Propane Gas
	Natural Gas
	Nuclear
	Refuse, Bagasse, Peat, Non-wood waste
	Steam
	Sub-Bituminous Coal
	Hydro (Water)
	Wind
	Wood
	Solar
	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$
Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage)
100 - Maintenance percentage - Forced Outage percentage
Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Coyote Station	**PLANT ID**	87009
STREET ADDRESS			
CITY	Beulah		
STATE	ND	**NUMBER OF UNITS**	1
ZIP CODE	58523		
COUNTY	Mercer		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1981	COAL	835,443.40	
				Plant Total	835,443.40	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	149.40	149.40	63.46	86.7	3.4	
Plant Total	149.40	149.40				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	687,810.00	TONS	7,062	FO2	160,040.00	GAL	

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use Stand-by Retired Future Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$
Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage
Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Hoot Lake Plant	**PLANT ID**	87014
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	5
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1948	COAL	0.00	
2	USE	ST	1959	COAL	100,483.90	
3	USE	ST	1964	COAL	98,030.60	
2A	STB	IC	1959	FO2		
3A	STB	IC	1964	FO2		
				Plant Total	198,514.50	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.00	0.00				
2	52.00	52.00	22.10	89.2	12.1	
3	73.00	73.00	15.20	83.3	20.1	
2A	0.20	0.25				
3A	0.18	0.18				
Plant Total	125.38	125.43				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB		TONS					
2	SUB	63,763.00	TONS	9,327	FO2	50,182.00	GAL	
3	SUB	62,677.00	TONS	9,253	FO2	53,690.00	GAL	
2A								
3A								

ALLOWABLE CODES

Cell Heading	Code Definition
* Unit Status	In-use Stand-by Retired Future Other - provide description
*** Energy Source & Fuel Type	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Potlatch Cogeneration	**PLANT ID**	87030
STREET ADDRESS			
CITY	Bemidji		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56601		
COUNTY	Hubbard		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	ST	1992	Wood Waste		Retired
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1						
Plant Total	0.00	0.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	Wood Waste		Tons					

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use Stand-by Retired Future Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Bemidji Hydro	**PLANT ID**	87002
STREET ADDRESS			
CITY	Bemidji		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE	56601		
COUNTY	Beltrami		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	HYD	27.00	
2	USE	HC	1907	HYD		
				Plant Total	27.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.10	0.10				
2	0.00	0.00				
Plant Total	0.10	0.10				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

ALLOWABLE CODES

Cell Heading	Code Definition
* Unit Status	In-use
	Stand-by
	Retired
	Future
	Other - provide description
*** Energy Source & Fuel Type	Bituminous Coal
	Coal (general)
	Diesel
	Fuel Oil #2 (Mid Distillate)
	Fuel Oil #6 (Residual Fuel Oil)
	Lignite
	Liquefied Propane Gas
	Natural Gas
	Nuclear
	Refuse, Bagasse, Peat, Non-wood waste
	Steam
	Sub-Bituminous Coal
	Hydro (Water)
	Wind
	Wood
	Solar
	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Dayton Hollow Hydro	**PLANT ID**	87010
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1909	HYD	7,789.00	
2	USE	HC	1919	HYD		
				Plant Total	7,789.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.55	0.55				
2	0.40	0.40				
Plant Total	0.95	0.95				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

ALLOWABLE CODES

Cell Heading	Code Definition
* Unit Status	In-use Stand-by Retired Future Other - provide description
*** Energy Source & Fuel Type	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available}}{\text{Hours Unit Called Upon to Produce}} \times 100$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Hoot Lake Hydro	**PLANT ID**	87013
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1914	HYD	5,125.00	
				Plant Total	5,125.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.30	0.30				
Plant Total	0.30	0.30				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use
	Stand-by
	Retired
	Future
	Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal
	Coal (general)
	Diesel
	Fuel Oil #2 (Mid Distillate)
	Fuel Oil #6 (Residual Fuel Oil)
	Lignite
	Liquefied Propane Gas
	Natural Gas
	Nuclear
	Refuse, Bagasse, Peat, Non-wood waste
	Steam
	Sub-Bituminous Coal
	Hydro (Water)
	Wind
	Wood
	Solar
	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available}}{\text{Hours Unit Called Upon to Produce}} \times 100$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Pisgah Hydro	**PLANT ID**	87023
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1918	HYD	5,134.00	
				Plant Total	5,134.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.60	0.60				
Plant Total	0.60	0.60				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use Stand-by Retired Future Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Taplin Gorge Hydro	**PLANT ID**	87026
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1925	HYD	2,850.00	
				Plant Total	2,850.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.40	0.40				
Plant Total	0.40	0.40				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							

ALLOWABLE CODES

Cell Heading	Code Definition
* Unit Status	In-use Stand-by Retired Future Other - provide description
*** Energy Source & Fuel Type	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Wright Hydro	**PLANT ID**	87029
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1922	HYD	1,667.00	
				Plant Total	1,667.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.30	0.30				
Plant Total	0.30	0.30				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use
	Stand-by
	Retired
	Future
	Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal
	Coal (general)
	Diesel
	Fuel Oil #2 (Mid Distillate)
	Fuel Oil #6 (Residual Fuel Oil)
	Lignite
	Liquefied Propane Gas
	Natural Gas
	Nuclear
	Refuse, Bagasse, Peat, Non-wood waste
	Steam
	Sub-Bituminous Coal
	Hydro (Water)
	Wind
	Wood
	Solar
	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Fergus Control Center	**PLANT ID**	87035
STREET ADDRESS			
CITY	Fergus Falls		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	56537		
COUNTY	Otter Tail		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1995	OIL	0.00	
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	2.05	2.02				
Plant Total	2.05	2.02				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2		GAL					

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use Stand-by Retired Future Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Jamestown Turbine Plant	**PLANT ID**	87015
STREET ADDRESS			
CITY	Jamestown		
STATE	ND	**NUMBER OF UNITS**	2
ZIP CODE	58401		
COUNTY	Stutsman		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1976	OIL	120.80	
2	STB	IC	1978	OIL	62.90	
				Plant Total	183.70	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	20.60	20.60				
2	20.40	20.40				
Plant Total	41.00	41.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	31,777.00	GAL					
2	FO2	23,617.00	GAL					

ALLOWABLE CODES

Cell Heading	Code Definition
* Unit Status	In-use Stand-by Retired Future Other - provide description
*** Energy Source & Fuel Type	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Lake Preston Turbine Plant
STREET ADDRESS	
CITY	Lake Preston
STATE	SD
ZIP CODE	57249
COUNTY	Kingsbury
CONTACT PERSON	Nathan Jensen
TELEPHONE	218-739-8989
PLANT ID	87016
NUMBER OF UNITS	1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1978	OIL	107.70	
				Plant Total	107.70	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	18.20	18.20				
Plant Total	18.20	18.20				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	33,294.00	GAL					

ALLOWABLE CODES

Cell Heading	Code Definition
*** Unit Status**	In-use
	Stand-by
	Retired
	Future
	Other - provide description
***** Energy Source & Fuel Type**	Bituminous Coal
	Coal (general)
	Diesel
	Fuel Oil #2 (Mid Distillate)
	Fuel Oil #6 (Residual Fuel Oil)
	Lignite
	Liquefied Propane Gas
	Natural Gas
	Nuclear
	Refuse, Bagasse, Peat, Non-wood waste
	Steam
	Sub-Bituminous Coal
	Hydro (Water)
	Wind
	Wood
	Solar
	Other - provide description

Cell Heading	Code	Code Definition
**** Unit Type**	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
****** Unit of Measure**	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2020

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Solway	**PLANT ID**	87036
STREET ADDRESS			
CITY	Solway		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	57960		
COUNTY	Beltrami		
CONTACT PERSON	Nathan Jensen		
TELEPHONE	218-739-8989		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	CT	2003	NG/OIL	51,707.30	
				Plant Total	51,707.30	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	42.40	42.40	13.14			
Plant Total	42.40	42.40				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	526,540.00	MMBtu		FO2	216.00	GAL	

ALLOWABLE CODES

Cell Heading	Code Definition
* Unit Status	In-use Stand-by Retired Future Other - provide description
*** Energy Source & Fuel Type	Bituminous Coal Coal (general) Diesel Fuel Oil #2 (Mid Distillate) Fuel Oil #6 (Residual Fuel Oil) Lignite Liquefied Propane Gas Natural Gas Nuclear Refuse, Bagasse, Peat, Non-wood waste Steam Sub-Bituminous Coal Hydro (Water) Wind Wood Solar Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - LARGEST CUSTOMER LIST

WHEN E-FILING THIS FORM, IT SHOULD BE UPLOADED AS TRADE SECRET

ENTITY ID#	87
REPORT YEAR	2020

UTILITY DETAILS

UTILITY NAME	Otter Tail Power Company
STREET ADDRESS	215 S Cascade St, PO Box 496
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[TRADE SECRET DATA BEGINS

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2020 MWH

TRADE SECRET DATA ENDS]

COMMENTS

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 05/31/2023

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

REPORT FOR: Otter Tail Power Co 14232
REPORTING PERIOD: 2020

Contact Tina Eberle
Title: Financial Reporting Accountant
Phone: (218) 739-8933 FAX: Email: teberle@otpco.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

Supervisor Heather Johnson
Title: Manager, Financial Reporting
Phone: (218) 739-8681 FAX: Email: hjohnson@otpco.com

1	Legal Name of Industry Participant	Otter Tail Power Co **Submission Status/Date:** Submitted 08/11/2021
2	Current Address of Principal Business Office	P O Box 496, 215 South Cascade Street Fergus Falls MN 56538 0496
3	Preparer's Legal Name Operator (if different than line 1)	
4	Current Address of Preparer's Office (if different than line 2)	
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility ☐ State ☐ Municipal ☒ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Community Choice Aggregator ☐ Transmission ☐ Behind the Meter ☐ Wholesale Power Marketer ☐ DSM Administrator

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Stephen Scott Phone: (202) 586-5140 Email: stephen.scott@eia.gov

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SCHEDULE 2. PART A. GENERAL INFORMATION

LINE NO.		
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] FRCC [x] MRO [ ] NPCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] SERC [ ] SPP [ ] WECC
2	Name of RTO or ISO	[ ] California ISO [ ] Electric Reliability Council of Texas [ ] PJM Interconnection [ ] New York ISO [ ] Southwest Power Pool [X] Midwest ISO [ ] ISO New England [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [x] Transmission [x] Buying transmission services on other electrical system [x] Distribution using owned/leased electric wires [ ] Buying distribution on other electrical system [x] Wholesale power marketing [ ] Retail power marketing [ ] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 690.7 Prior Year 742.3 Winter (Megawatts) 865.1 Prior Year 924.0
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[x] Yes [ ] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes [ ] No
	If "Yes", Please Provide Additional Contact Information	Name: Kyle Rich Title: Manager, Transportation Telephone: 218 - 739 - 8590 Fax: 218 - 739 - 8734 Email: krich@otpco.com

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SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY		MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation		2,514,831	11	Sales to Ultimate Consumers	4,776,688
2	Purchases from Electricity Suppliers		2,875,162	12	Sales For Resale	242,376
3	Exchanged Received (In)			13	Energy Furnished Without Charge	
4	Exchanged Delivered (Out)			14	Energy Consumed By Respondent Without Charge	7,500
5	Exchanged Net					
6	Wheeled Received (In)					
7	Wheeled Delivered (Out)		263,017	15	Total Energy Losses (positive number)	100,412
8	Wheeled Net		-263,017			
9	Transmission by Others Losses (Negative Number)					
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)		5,126,976	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	5,126,976

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SCHEDULE 2. PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	386,364.4
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	4,857.3
4	Electric Credits/Other Adjustments	$	
5	Revenue from Transmission	$	43,520.1
6	Other Electric Operating Revenue	$	6,805.1
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	441,546.9

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SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **MN**

1	Total Number of Distribution Circuits	290.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	.0

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SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **ND**

1	Total Number of Distribution Circuits	354.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	.0

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SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **SD**

1	Total Number of Distribution Circuits	91.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	.0

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SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. [x] Yes [ ] No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. [x] Yes [ ] No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State: MN
3a.	SAIDI value including Major Event days	107.660
3b.	SAIDI value excluding Major Event days	107.660
4	SAIDI value including Major Event days minus loss of supply	
5a.	SAIFI value including Major Event days	1.400
5b.	SAIFI value excluding Major Event days	1.400
6.	SAIFI value including Major Event days minus loss of supply	
7.	Total number of customers used in these calculations	63,290.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)	25.0
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[x] Yes [ ] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1	Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A.	x Yes	No
2	Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C.	x Yes	No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State	SD
3a.	SAIDI value including Major Event days		79.200
3b.	SAIDI value excluding Major Event days		79.200
4	SAIDI value including Major Event days minus loss of supply		
5a.	SAIFI value including Major Event days		1.100
5b.	SAIFI value excluding Major Event days		1.100
6.	SAIFI value including Major Event days minus loss of supply		
7.	Total number of customers used in these calculations		11,930.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		25.0
9.	Do you receive information about a customer outage in advance of a customer reporting it?	x Yes	No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1 Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A. [x] Yes [ ] No

2 Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C. [x] Yes [ ] No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State	**ND**
3a.	SAIDI value including Major Event days		105.900
3b.	SAIDI value excluding Major Event days		105.900
4	SAIDI value including Major Event days minus loss of supply		
5a.	SAIFI value including Major Event days		1.700
5b.	SAIFI value excluding Major Event days		1.700
6.	SAIFI value including Major Event days minus loss of supply		
7.	Total number of customers used in these calculations		59,761.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		25.0
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[x] Yes	[ ] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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Part C: SAIDI and SAIFI calculated by other methods

	State
10a. SAIDI value including Major Events	
10b. SAIDI value excluding Major Events	
11a. SAIFI value including Major Events	
11b. SAIFI value excluding Major Events	
12. Total number of customers used in these calculations	
13. Do you include inactive accounts?	☐ Yes ☐ No
14. How do you define momentary interruptions	☐ Less than 1 min. ☐ Less than 5 min. ☐ Other
15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system?	kv
16. Is information about customer outages recorded automatically?	☐ Yes ☐ No

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SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State MN **Balancing Authority**	56669				
Revenue (thousand dollars)	56,414.7	88,868.6	56,723.9	0.0	202,007.2
Megawatthours	545,911	1,032,208	981,838	0	2,559,957
Number of Customers	49,403	13,051	11	0	62,465
Are your rates decoupled?	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	N automatic	N automatic	N automatic	N automatic	
	N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh	10.334	8.610	5.777		7.891
State ND **Balancing Authority**	56669				
Revenue (thousand dollars)	58,408.3	87,957.3	1,456.7	0.0	147,822.3
Megawatthours	602,118	1,115,223	20,545	0	1,737,886
Number of Customers	45,673	13,613	3	0	59,289
Are your rates decoupled?	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	N automatic	N automatic	N automatic	N automatic	
	N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh	9.700	7.887	7.090		8.506

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SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State SD **Balancing Authority**	56669				
Revenue (thousand dollars)	11,753.6	24,781.3	0.0	0.0	36,534.9
Megawatthours	118,203	360,642	0	0	478,845
Number of Customers	8,858	2,879	0	0	11,737
Are your rates decoupled?	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	N automatic	N automatic	N automatic	N automatic	
	N proceeding	N proceeding	N proceeding	N proceeding	
Cents/Kwh	9.944	6.871			7.630
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Are your rates decoupled?					
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?					
Cents/Kwh					

Total					
Revenue (thousand dollars)	126,576.6	201,607.2	58,180.6	0.0	386,364.4
Megawatthours	1,266,232	2,508,073	1,002,383	0	4,776,688
Number of Customers	103,934	29,543	14	0	133,491

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SCHEDULE 4. PART B. SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total

Revenue (thousand dollars)

Megawatthours

Number of Customers

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SCHEDULE 4. PART C. SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total	
Revenue (thousand dollars)	
Megawatthours	
Number of Customers	

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SCHEDULE 4. PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total

Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 5. MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS
Adjusted Gross Energy and Demand Savings -- Energy Efficiency

If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory **MN** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	22,388.486	26,937.536	21,323.590		70,649.612
2	Peak Demand Savings (MW)	18.734	5.836	3.061		27.631
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	284022.194	399,158.409	311,060.311		994,240.914
4	Peake Demand Savings (MW)	18.734	5.836	3.061		27.631
	Reporting Year Incremental Costs					
5	Customer Incentives	1,488.950	2,536.920	1,851.078		5,876.948
6	All other costs	2,030.831	1,062.461	673.442		3,766.734
	Incremental Life Sycle Costs					
7	Customer Incentives	1,488.950	2,536.920	1,851.078		5,876.948
8	All other costs	2,030.831	1,062.461	673.442		3,766.734
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	12.686	14.818	14.588		42.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS
Adjusted Gross Energy and Demand Savings -- Energy Efficiency

State/Territory **SD** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	894.303	10,014.878			10,909.181
2	Peak Demand Savings (MW)	0.540	1.684			2.224
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	15587.770	151,484.149			167,071.919
4	Peake Demand Savings (MW)	0.540	1.684			2.224
	Reporting Year Incremental Costs					
5	Customer Incentives	106.030	521.177			627.207
6	All other costs	29.044	104.340			133.384
	Incremental Life Sycle Costs					
7	Customer Incentives	106.030	521.177			627.207
8	All other costs	29.044	104.340			133.384
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	17.430	15.725			33.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

DMS Administration only. List all utilities that you provide service for.

State	Utility Name

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **MN** **Balancing Authority** **56669**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	16,745	1,756		0	18,501
2	Energy Savings (Mwh)	0.000	0.000	0.000	0.000	0.000
3	Potential Peak Demand Savings (MW)	17.000	35.000	0.000	0.000	52.000
4	Actual Peak Demand Savings (MW)	17.000	35.000	0.000	0.000	52.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
5	Customer Incentives	34.492	23.005	0.000	0.000	57.497
6	All other costs	25.365	16.918	0.000	0.000	42.283

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **ND** **Balancing Authority** **56669**		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	15,414	1,958	0	0	17,372
2	Energy Savings (Mwh)	0.000	0.000	0.000	0.000	0.000
3	Potential Peak Demand Savings (MW)	16.000	16.000	0.000	0.000	32.000
4	Actual Peak Demand Savings (MW)	16.000	16.000	0.000	0.000	32.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
5	Customer Incentives	227.702	111.315	0.000	0.000	339.017
6	All other costs	179.137	87.573	0.000	0.000	266.710

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory SD **Balancing Authority 56669**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	3,448	367	0	0	3,815
2	Energy Savings (Mwh)	0.000	0.000	0.000	0.000	0.000
3	Potential Peak Demand Savings (MW)	4.000	8.000	0.000	0.000	12.000
4	Actual Peak Demand Savings (MW)	4.000	8.000	0.000	0.000	12.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
5	Customer Incentives	8.120	15.550	0.000	0.000	23.670
6	All other costs	5.579	10.864	0.000	0.000	16.443

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory MN Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	17,634	1,902	11	0	19,547

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory ND Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	15,881	2,276	0	0	18,157

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS
Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **SD** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	3,405	370	0	0	3,775

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **MN** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	0	145	23	0	168
2	Number of AMI Meters	253	261	5	0	519
3	Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4	Number of non AMR/AMI Meters	66,910	14,258	22	0	81,190
5	Total Number of Meters (All Types), line 1+2+4	67,163	14,664	50	0	81,877
6	Energy Served Through AMI	3,710	142,539	12,379	0	158,628
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					
8	Number of customers with direct load control					

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **ND** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	0	162	1	0	163
2	Number of AMI Meters	355	376	1	0	732
3	Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4	Number of non AMR/AMI Meters	60,552	15,454	1	0	76,007
5	Total Number of Meters (All Types), line 1+2+4	60,907	15,992	3	0	76,902
6	Energy Served Through AMI	6,948	930,425	102	0	937,475
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					
8	Number of customers with direct load control					

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State **SD** **Balancing Authority** **56669**

	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1 Number of AMR Meters	0	46	0	0	46
2 Number of AMI Meters	71	74	0	0	145
3 Number of AMI Meters with home area network (HAN) gateway enabled	0	0	0	0	0
4 Number of non AMR/AMI Meters	12,545	3,079	0	0	15,624
5 Total Number of Meters (All Types), line 1+2+4	12,616	3,199	0	0	15,815
6 Energy Served Through AMI	1,239	106,747	0	0	107,986
7 Number of Customers able to access daily energy usage through a webportal or other electronic means					
8 Number of customers with direct load control					

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SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State MN **Balancing Authority** 56669		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photovoltaic	Net Metering Installed Capacity (MW)	0.168	0.919	0.000	0.000	1.087
	Net Metering Installations	21	21	0	0	42
	Storage Installed Capacity (MW)					
	Storage Installations					
	Virtual NM Installed Capacity (1 MW and greater)					
	Virtual NM Customers (1 MW and greater)					
	Virtual NM Installed Capacity (less than 1MW)					
	Virtual NM Customers (less than 1MW)					
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	123.026	160.531	0.000	0.000	283.557
Wind	Installed Net Metering Capacity (MW)	0.044	0.214	0.000	0.000	0.258
	Number of Net Metering Customers	3	9	0	0	12
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.228	4.614	0.000	0.000	4.842
Other	Installed Net Metering Capacity (MW)	0.000	0.035	0.000	0.000	0.035
	Number of Net Metering Customers	0	1	0	0	1
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	0.000	0.000	0.000	0.000
Total	Installed Net Metering Capacity (MW)	0.212	1.168	0.000	0.000	1.380
	Number of Net Metering Customers	24	31	0	0	55
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	123.254	165.145	0.000	0.000	288.399

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SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State **ND**	**Balancing Authority** **56669**	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photovoltaic	Net Metering Installed Capacity (MW)		0.107			0.107
	Net Metering Installations		4			4
	Storage Installed Capacity (MW)					
	Storage Installations					
	Virtual NM Installed Capacity (1 MW and greater)					
	Virtual NM Customers (1 MW and greater)					
	Virtual NM Installed Capacity (less than 1MW)					
	Virtual NM Customers (less than 1MW)					
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)		7.680			7.680
Wind	Installed Net Metering Capacity (MW)	0.002	0.030			0.032
	Number of Net Metering Customers	1	1			2
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	0.000			0.000
Other	Installed Net Metering Capacity (MW)					0.000
	Number of Net Metering Customers					0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0.000
Total	Installed Net Metering Capacity (MW)	0.002	0.137	0.000	0.000	0.139
	Number of Net Metering Customers	1	5	0	0	6
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	7.680	0.000	0.000	7.680

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SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State	**SD** **Balancing Authority** **56669**	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
Photovoltaic	Net Metering Installed Capacity (MW)		0.040			0.040
	Net Metering Installations		2			2
	Storage Installed Capacity (MW)					
	Storage Installations					
	Virtual NM Installed Capacity (1 MW and greater)					
	Virtual NM Customers (1 MW and greater)					
	Virtual NM Installed Capacity (less than 1MW)					
	Virtual NM Customers (less than 1MW)					
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)		28.721			28.721
Wind	Installed Net Metering Capacity (MW)	0.003	0.112			0.115
	Number of Net Metering Customers	1	3			4
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	80.239			80.239
Other	Installed Net Metering Capacity (MW)					0.000
	Number of Net Metering Customers					0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)					0.000
Total	Installed Net Metering Capacity (MW)	0.003	0.152	0.000	0.000	0.155
	Number of Net Metering Customers	1	5	0	0	6
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	0.000	108.960	0.000	0.000	108.960
Grand Total All States	**Net Metering Installed Capacity (MW)**	.217	1.457	0	0	1.674
	Net Metering Installations/customers	26	41	0	0	67
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)	123.254	281.785	0	0	405.039

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REPORT FOR Otter Tail Power Co

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SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS

If your company owns and/or operates a distribution system, please report information on known distributed generation (grid connected/synchronized) capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State	**Balancing Authority**	< 1MW

1. Number of generators	3. Capacity that consists of backup-only units
2. Total combined capacity (MW)	4. Capacity owned by respondent

Capacity by Technology and Sector (MW)

	Residential	**Commercial**	**Industrial**	**Transportation**	**Direct Connected**	**Total**
5. Internal combustion						
6. Combustion turbine(s)						
7. Steam turbine(s)						
8. Fuel Cell(s)						
9. Hydroelectric						
10, Photovoltaic						
11. Storage						
12. Wind turbine(s)						
13. Other						
14. Total						

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SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN - Becker		21	MN - Polk	
2	MN - Beltrami		22	MN - Pope	
3	MN - Big Stone		23	MN - Red Lake	
4	MN - Cass		24	MN - Redwood	
5	MN - Chippewa		25	MN - Roseau	
6	MN - Clay		26	MN - Stevens	
7	MN - Clearwater		27	MN - Swift	
8	MN - Douglas		28	MN - Todd	
9	MN - Grant		29	MN - Traverse	
10	MN - Hubbard		30	MN - Wilkin	
11	MN - Kandiyohi		31	MN - Yellow Medicine	
12	MN - Kittson		32	ND - Barnes	
13	MN - Lac Qui Parle		33	ND - Benson	
14	MN - Lincoln		34	ND - Bottineau	
15	MN - Lyon		35	ND - Burleigh	
16	MN - Mahnomen		36	ND - Cass	
17	MN - Marshall		37	ND - Cavalier	
18	MN - Norman		38	ND - Dickey	
19	MN - Otter Tail		39	ND - Eddy	
20	MN - Pennington		40	ND - Foster	

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SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
41	ND - Grand Forks		61	ND - Towner	
42	ND - Griggs		62	ND - Traill	
43	ND - Kidder		63	ND - Walsh	
44	ND - LaMoure		64	ND - Ward	
45	ND - Logan		65	ND - Wells	
46	ND - McHenry		66	SD - Brookings	
47	ND - McLean		67	SD - Codington	
48	ND - Mountrail		68	SD - Day	
49	ND - Nelson		69	SD - Deuel	
50	ND - Pembina		70	SD - Grant	
51	ND - Pierce		71	SD - Hamlin	
52	ND - Ramsey		72	SD - Kingsbury	
53	ND - Ransom		73	SD - Lake	
54	ND - Renville		74	SD - Marshall	
55	ND - Richland		75	SD - Moody	
56	ND - Rolette		76	SD - Roberts	
57	ND - Sargent				
58	ND - Sheridan				
59	ND - Steele				
60	ND - Stutsman				

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SCHEDULE 9. COMMENTS

SCHEDULE (a)	PART (b)	LINE NO. (c)	COLUMN (d)	NOTES (e)

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EIA861 ERROR LOG

Part	State	BA ID	Error No.	Error Description/Override Comment	Type	Override
2 B	--	0	309	Schedule 2B lines 6 (Wheeling In) must be greater than line 7 (Wheeling Out). Please review the data and provide revisions. Prior to WAPA joining SPP, this calculation was made up of Received Interchange (various points of interconnect with WAPA and East River loads), (Delivered Interchange) (various points of interconnect with WAPA, East River loads, and CPEC loads), (Wheeling Delivered), and (Line Loss) allowance. Which could also be referred to as OTP load in WAPA balancing authority (BA) and (WAPA load in OTP BA). When WAPA joined SPP effective October 2015, the various points of interconnect are now settled within SPP (like MISO) and all that remains in this calculation is tribal allocation delivery (WAPA load in OTP BA), wheeling deliveries (WAPA load in OTP BA and MPC wheeling in OTP BA) and line loss allowance.	W	

SECTION 2

Electric Utility Information Reporting
Forecast Section

Form EN-0005 – 20

7610.0310 CONTENT OF HISTORICAL AND FORECAST

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS
These worksheet tabs correspond closely to the tables in the forecast instructions received by the utility.
The forecast instructions pertain to the data to be entered in each of the worksheet tabs.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS OR CHANGE THE NAME OF THIS WORKBOOK.

In general, the following color scheme is used on each worksheet:
Cells shown with a light green background correspond to headings for sections, columns, row, or individual fields on each worksheet tab.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet tab contains a section labeled "Comments" below the main data entry area.
You may enter any comments in that section to provide an explaination or clarification on the data entered; OR
why data IS NOT being entered on the worksheet tab (for example: cells left blank).

Cells with automatic calculations (typically totals) are provided on some worksheets to assist with the accuracy of the data provided by the utility. It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

Please complete the required worksheet tabs and save the completed workbook to your local computer.
Then attach the completed workbook to an email message, include your contact information, and send it to the following email address:
rule7610.reports@state.mn.us

If you have any questions please contact:
Anne Sell
MN Department of Commerce
rule7610.reports@state.mn.us
651-539-1851

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	87
REPORT YEAR	2020

RILS ID#	

UTILITY DETAILS	
UTILITY NAME	Otter Tail Power Company
STREET ADDRESS	215 S Cascade St, PO Box 496
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8635
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	Nathan Jensen
CONTACT TITLE	Manager, Resource Planning
CONTACT STREET ADDRESS	215 S Cascade St
CITY	Fergus Falls
STATE	MN
ZIP CODE	56538-0496
TELEPHONE	218-739-8989
CONTACT E-MAIL	njensen@otpco.com

COMMENTS

PREPARER INFORMATION	(do not type "Same as Above")
PERSON PREPARING FORMS	Bryce Haugen
PREPARER'S TITLE	Senior Resource Planner
DATE	6/21/2021
PREPARER'S EMAIL ADDRESS	bhaugen@otpco.com

ALLOWABLE UTILITY TYPES

Code

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.
Please remember that the number of customers *should reflect the* ***number of customers*** *at year's end,* ***not the number of meters*** .

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2020	No. of Customers	2,639	99,450	20,581	0	1,003	0	951	124,624	124,624
		MWH	108,037	1,269,198	879,229	0	2,463,339	20,047	58,826	4,798,675	4,798,675
Present Year	2021	No. of Customers	2,667	100,103	20,985	0	995	0	966	125,716	125,716
		MWH	100,660	1,259,736	903,404	0	2,510,155	17037.87	55,113	4,846,106	4,846,106
1st Forecast Year	2022	No. of Customers	2,695	100,509	21,178	0	996	0	975	126,353	126,353
		MWH	104,543	1,255,052	908,322	0	2,680,220	15859.2	55,847	5,019,844	5,019,844
2nd Forecast Year	2023	No. of Customers	2,710	100,809	21,313	0	997	0	981	126,810	126,810
		MWH	105,936	1,251,160	907,682	0	2,652,926	14880.4	56,232	4,988,815	4,988,815
3rd Forecast Year	2024	No. of Customers	2,723	101,040	21,444	0	998	0	985	127,190	127,190
		MWH	107,313	1,246,427	906,741	0	2,661,859	14592.78	56,472	4,993,405	4,993,405
4th Forecast Year	2025	No. of Customers	2,737	101,231	21,575	0	1,000	0	987	127,530	127,530
		MWH	108,700	1,241,182	905,685	0	2,694,830	14570.8	56,647	5,021,615	5,021,615
5th Forecast Year	2026	No. of Customers	2,752	101,399	21,706	0	1,001	0	990	127,848	127,848
		MWH	110,099	1,235,637	904,567	0	2,728,827	14548.82	56,790	5,050,469	5,050,469
6th Forecast Year	2027	No. of Customers	2,766	101,554	21,837	0	1,003	0	993	128,153	128,153
		MWH	111,507	1,229,899	903,279	0	2,786,845	14526.84	56,916	5,102,973	5,102,973
7th Forecast Year	2028	No. of Customers	2,779	101,695	21,967	0	1,005	0	995	128,441	128,441
		MWH	112,922	1,223,987	901,791	0	2,819,865	14504.86	57,033	5,130,102	5,130,102
8th Forecast Year	2029	No. of Customers	2,793	101,822	22,097	0	1,007	0	998	128,717	128,717
		MWH	114,340	1,217,911	900,151	0	2,826,869	14482.88	57,145	5,130,898	5,130,898
9th Forecast Year	2030	No. of Customers	2,806	101,935	22,227	0	1,009	0	1,000	128,977	128,977
		MWH	115,759	1,211,671	898,435	0	2,830,853	14460.9	57,254	5,128,434	5,128,434
10th Forecast Year	2031	No. of Customers	2,819	102,039	22,357	0	1,011	0	1,001	129,227	129,227
		MWH	117,179	1,205,277	896,590	0	2,839,808	14438.92	57,362	5,130,655	5,130,655
11th Forecast Year	2032	No. of Customers	2,833	102,131	22,487	0	1,013	0	1,004	129,468	129,468
		MWH	118,591	1,198,754	894,572	0	2,848,701	14416.94	57,468	5,132,503	5,132,503
12th Forecast Year	2033	No. of Customers	2,847	102,210	22,616	0	1,015	0	1,006	129,694	129,694
		MWH	119,993	1,192,117	892,389	0	2,857,511	14394.96	57,574	5,133,979	5,133,979
13th Forecast Year	2034	No. of Customers	2,860	102,285	22,744	0	1,017	0	1,008	129,914	129,914
		MWH	121,392	1,185,403	890,019	0	2,866,288	14372.98	57,680	5,135,154	5,135,154
14th Forecast Year	2035	No. of Customers	2,872	102,350	22,872	0	1,019	0	1,010	130,123	130,123
		MWH	122,781	1,178,635	887,543	0	2,874,988	14351	57,785	5,136,084	5,136,084

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS
Street & Highway Lighting customers are counted as part of other classes. Including the number of Street & Highway Lighting customers would be double counting as a customer would show up twice.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.
Please remember that the number of customers should reflect the ***actual number of customers*** the utility has in that category at year's end, ***not the number of meters*** .

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2020	No. of Customers	1,330	47,344	8,835	0	602	0	417	58,528	58,528
		MWH	50,237	544,380	328,639	0	1,602,559	6,622	26,891	2,559,329	2,559,329
Present Year	2021	No. of Customers	1,361	47,746	9,012	0	589	0	422	59,130	59,130
		MWH	49,957	538,386	347,017	0	1,632,226	5512.45	27,753	2,600,851	2,600,851
1st Forecast Year	2022	No. of Customers	1,373	47,979	9,107	0	590	0	428	59,477	59,477
		MWH	51,085	536,389	350,784	0	1,789,142	4355.76	28,295	2,760,051	2,760,051
2nd Forecast Year	2023	No. of Customers	1,379	48,128	9,167	0	591	0	431	59,696	59,696
		MWH	51,722	533,253	353,073	0	1,756,296	3398.94	28,492	2,726,234	2,726,234
3rd Forecast Year	2024	No. of Customers	1,385	48,234	9,225	0	592	0	433	59,869	59,869
		MWH	52,366	529,605	355,298	0	1,759,694	3133.3	28,594	2,728,690	2,728,690
4th Forecast Year	2025	No. of Customers	1,391	48,313	9,283	0	594	0	434	60,015	60,015
		MWH	53,015	525,645	357,520	0	1,787,096	3133.3	28,663	2,755,072	2,755,072
5th Forecast Year	2026	No. of Customers	1,397	48,377	9,341	0	595	0	435	60,145	60,145
		MWH	53,668	521,498	359,742	0	1,815,507	3133.3	28,719	2,782,267	2,782,267
6th Forecast Year	2027	No. of Customers	1,403	48,431	9,399	0	597	0	436	60,266	60,266
		MWH	54,321	517,227	361,964	0	1,867,900	3133.3	28,770	2,833,314	2,833,314
7th Forecast Year	2028	No. of Customers	1,409	48,474	9,457	0	599	0	437	60,376	60,376
		MWH	54,974	512,833	364,186	0	1,895,277	3133.3	28,817	2,859,220	2,859,220
8th Forecast Year	2029	No. of Customers	1,415	48,505	9,515	0	601	0	438	60,474	60,474
		MWH	55,621	508,302	366,408	0	1,896,615	3133.3	28,864	2,858,943	2,858,943
9th Forecast Year	2030	No. of Customers	1,420	48,522	9,573	0	603	0	439	60,557	60,557
		MWH	56,261	503,632	368,630	0	1,894,904	3133.3	28,911	2,855,471	2,855,471
10th Forecast Year	2031	No. of Customers	1,426	48,530	9,631	0	605	0	439	60,631	60,631
		MWH	56,893	498,848	370,852	0	1,898,140	3133.3	28,957	2,856,823	2,856,823
11th Forecast Year	2032	No. of Customers	1,432	48,526	9,689	0	607	0	440	60,694	60,694
		MWH	57,510	493,949	373,074	0	1,901,293	3133.3	29,003	2,857,963	2,857,963
12th Forecast Year	2033	No. of Customers	1,437	48,511	9,747	0	609	0	441	60,745	60,745
		MWH	58,110	488,944	375,296	0	1,904,352	3133.3	29,049	2,858,884	2,858,884
13th Forecast Year	2034	No. of Customers	1,442	48,490	9,805	0	611	0	442	60,790	60,790
		MWH	58,697	483,868	377,518	0	1,907,340	3133.3	29,095	2,859,651	2,859,651
14th Forecast Year	2035	No. of Customers	1,447	48,460	9,862	0	613	0	443	60,825	60,825
		MWH	59,267	478,718	379,740	0	1,910,243	3133.3	29,141	2,860,243	2,860,243

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS
Street & Highway Lighting customers are counted as part of other classes. Including the number of Street & Highway Lighting customers would be double counting as a customer would show up twice.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES MWH [7610.0310 B(3)]	DELIVERED FOR RESALE MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2020	2,559,329	2,239,346	2,873,290	233,830	2,514,831	355,616	2,639,271	2,159,404	0
Present Year	2021	2,600,851	2,245,255	2,294,509	142,873	3,047,011	352,540	2,665,358	2,180,748	0
1st Forecast Year	2022	2,760,051	2,259,792	2,741,358	175,212	2,820,800	367,102	2,760,914	2,258,930	0
2nd Forecast Year	2023	2,726,234	2,262,581	2,402,727	96,041	3,041,445	359,315	2,743,848	2,244,967	0
3rd Forecast Year	2024	2,728,690	2,264,715	2,425,401	137,580	3,068,159	362,575	2,746,373	2,247,032	0
4th Forecast Year	2025	2,755,072	2,266,543	2,576,611	95,451	2,902,046	361,591	2,761,888	2,259,727	0
5th Forecast Year	2026	2,782,267	2,268,201	2,571,472	115,510	2,959,554	365,048	2,777,758	2,272,711	0
6th Forecast Year	2027	2,833,314	2,269,659	2,627,687	115,510	2,959,554	368,758	2,806,635	2,296,338	0
7th Forecast Year	2028	2,859,220	2,270,882	2,656,733	115,510	2,959,554	370,675	2,821,556	2,308,546	0
8th Forecast Year	2029	2,858,943	2,271,955	2,657,585	115,510	2,959,554	370,731	2,821,994	2,308,904	0
9th Forecast Year	2030	2,855,471	2,272,963	2,654,947	115,510	2,959,554	370,557	2,820,639	2,307,795	0
10th Forecast Year	2031	2,856,823	2,273,832	2,657,325	115,510	2,959,554	370,714	2,821,860	2,308,795	0
11th Forecast Year	2032	2,857,963	2,274,540	2,659,304	115,510	2,959,554	370,845	2,822,877	2,309,626	0
12th Forecast Year	2033	2,858,884	2,275,095	2,660,884	115,510	2,959,554	370,949	2,823,688	2,310,291	0
13th Forecast Year	2034	2,859,651	2,275,503	2,662,142	115,510	2,959,554	371,032	2,824,335	2,310,819	0
14th Forecast Year	2035	2,860,243	2,275,841	2,663,137	115,510	2,959,554	371,098	2,824,846	2,311,238	0

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2020	19.02	223.44	154.79	0.00	433.67	3.53	10.36	844.80	844.8

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2020	844.8	820.1	758.7	643.8	575.0	679.5	661.9	690.3	593.3	724.3	714.2	783.1

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MegaWatts)

		NAME OF OTHER UTILITY =>									
Past Year	2020	Summer									
		Winter									
Present Year	2021	Summer									
		Winter									
1st Forecast Year	2022	Summer									
		Winter									
2nd Forecast Year	2023	Summer									
		Winter									
3rd Forecast Year	2024	Summer									
		Winter									
4th Forecast Year	2025	Summer									
		Winter									
5th Forecast Year	2026	Summer									
		Winter									
6th Forecast Year	2027	Summer									
		Winter									
7th Forecast Year	2028	Summer									
		Winter									
8th Forecast Year	2029	Summer									
		Winter									
9th Forecast Year	2030	Summer									
		Winter									
10th Forecast Year	2031	Summer									
		Winter									
11th Forecast Year	2032	Summer									
		Winter									
12th Forecast Year	2033	Summer									
		Winter									
13th Forecast Year	2034	Summer									
		Winter									
14th Forecast Year	2035	Summer									
		Winter									

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2: FIRM SALES (Express in MegaWatts)

NAME OF OTHER UTILITY =>										
Past Year	2020	Summer								
		Winter								
Present Year	2021	Summer								
		Winter								
1st Forecast Year	2022	Summer								
		Winter								
2nd Forecast Year	2023	Summer								
		Winter								
3rd Forecast Year	2024	Summer								
		Winter								
4th Forecast Year	2025	Summer								
		Winter								
5th Forecast Year	2026	Summer								
		Winter								
6th Forecast Year	2027	Summer								
		Winter								
7th Forecast Year	2028	Summer								
		Winter								
8th Forecast Year	2029	Summer								
		Winter								
9th Forecast Year	2030	Summer								
		Winter								
10th Forecast Year	2031	Summer								
		Winter								
11th Forecast Year	2032	Summer								
		Winter								
12th Forecast Year	2033	Summer								
		Winter								
13th Forecast Year	2034	Summer								
		Winter								
14th Forecast Year	2035	Summer								
		Winter								

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MegaWatts)

[PROTECTED DATA BEGINS…

NAME OF OTHER UTILITY =>										
Past Year	2020	Summer								
		Winter								
Present Year	2021	Summer								
		Winter								
1st Forecast Year	2022	Summer								
		Winter								
2nd Forecast Year	2023	Summer								
		Winter								
3rd Forecast Year	2024	Summer								
		Winter								
4th Forecast Year	2025	Summer								
		Winter								
5th Forecast Year	2026	Summer								
		Winter								
6th Forecast Year	2027	Summer								
		Winter								
7th Forecast Year	2028	Summer								
		Winter								
8th Forecast Year	2029	Summer								
		Winter								
9th Forecast Year	2030	Summer								
		Winter								
10th Forecast Year	2031	Summer								
		Winter								
11th Forecast Year	2032	Summer								
		Winter								
12th Forecast Year	2033	Summer								
		Winter								
13th Forecast Year	2034	Summer								
		Winter								
14th Forecast Year	2035	Summer								
		Winter								

…PROTECTED DATA ENDS]

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MegaWatts)

		NAME OF OTHER UTILITY =>									
Past Year	2020	Summer									
		Winter									
Present Year	2021	Summer									
		Winter									
1st Forecast Year	2022	Summer									
		Winter									
2nd Forecast Year	2023	Summer									
		Winter									
3rd Forecast Year	2024	Summer									
		Winter									
4th Forecast Year	2025	Summer									
		Winter									
5th Forecast Year	2026	Summer									
		Winter									
6th Forecast Year	2027	Summer									
		Winter									
7th Forecast Year	2028	Summer									
		Winter									
8th Forecast Year	2029	Summer									
		Winter									
9th Forecast Year	2030	Summer									
		Winter									
10th Forecast Year	2031	Summer									
		Winter									
11th Forecast Year	2032	Summer									
		Winter									
12th Forecast Year	2033	Summer									
		Winter									
13th Forecast Year	2034	Summer									
		Winter									
14th Forecast Year	2035	Summer									
		Winter									

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MegaWatts)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (Column 3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (Column 4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (Column 9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (Column 7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (Column 12 - 14)
Past Year	2020	Summer	662	16	628	738	0	0	628	738	752	50	0	802	0	628	174
		Winter	845	90	738	738	0	0	738	738	752	50	0	802	0	738	64
Present Year	2021	Summer	771	16	737	737	0	0	737	737	834	0	0	834	0	737	97
		Winter	830	90	722	737	0	0	722	737	834	0	0	834	0	722	112
1st Forecast Year	2022	Summer	785	16	751	796	0	0	751	796	819	0	0	819	0	751	68
		Winter	905	90	796	796	0	0	796	796	819	0	0	819	0	796	23
2nd Forecast Year	2023	Summer	789	16	754	798	0	0	754	798	819	0	0	819	0	754	65
		Winter	908	90	798	798	0	0	798	798	819	0	0	819	0	798	21
3rd Forecast Year	2024	Summer	793	16	758	801	0	0	758	801	819	0	0	819	0	758	61
		Winter	912	90	801	801	0	0	801	801	819	0	0	819	0	801	18
4th Forecast Year	2025	Summer	796	17	761	803	0	0	761	803	820	0	0	820	0	761	59
		Winter	916	91	803	803	0	0	803	803	820	0	0	820	0	803	17
5th Forecast Year	2026	Summer	800	18	764	805	0	0	764	805	821	0	0	821	0	764	57
		Winter	920	92	805	805	0	0	805	805	821	0	0	821	0	805	16
6th Forecast Year	2027	Summer	804	19	767	807	0	0	767	807	822	0	0	822	0	767	55
		Winter	924	93	807	807	0	0	807	807	822	0	0	822	0	807	15
7th Forecast Year	2028	Summer	808	20	770	808	0	0	770	808	823	0	0	823	0	770	53
		Winter	927	94	808	808	0	0	808	808	823	0	0	823	0	808	15
8th Forecast Year	2029	Summer	812	21	774	809	0	0	774	809	821	0	0	821	0	774	47
		Winter	931	95	809	809	0	0	809	809	821	0	0	821	0	809	12
9th Forecast Year	2030	Summer	816	22	777	811	0	0	777	811	822	0	0	822	0	777	45
		Winter	935	96	811	811	0	0	811	811	822	0	0	822	0	811	11
10th Forecast Year	2031	Summer	819	23	779	812	0	0	779	812	823	0	0	823	0	779	44
		Winter	939	97	812	812	0	0	812	812	823	0	0	823	0	812	11
11th Forecast Year	2032	Summer	823	24	782	813	0	0	782	813	824	0	0	824	0	782	42
		Winter	943	99	813	813	0	0	813	813	824	0	0	824	0	813	11
12th Forecast Year	2033	Summer	827	25	785	814	0	0	785	814	824	0	0	824	0	785	39
		Winter	947	101	814	814	0	0	814	814	824	0	0	824	0	814	10
13th Forecast Year	2034	Summer	831	26	788	815	0	0	788	815	824	0	0	824	0	788	36
		Winter	951	103	815	815	0	0	815	815	824	0	0	824	0	815	9
14th Forecast Year	2035	Summer	835	27	791	816	0	0	791	816	824	0	0	824	0	791	33
		Winter	955	105	816	816	0	0	816	816	824	0	0	824	0	816	8

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MegaWatts)

		ADDITIONS	RETIREMENTS
Past Year	2020	150	
Present Year	2021	248	128.5
1st Forecast Year	2022		
2nd Forecast Year	2023		
3rd Forecast Year	2024		
4th Forecast Year	2025		
5th Forecast Year	2026		
6th Forecast Year	2027		
7th Forecast Year	2028		
8th Forecast Year	2029		
9th Forecast Year	2030		
10th Forecast Year	2031		
11th Forecast Year	2032		
12th Forecast Year	2033		
13th Forecast Year	2034		
14th Forecast Year	2035		

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of this worksheet tab.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel	Coal	Name of Fuel	HYD	Name of Fuel	NG	Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure	Tons	Unit of Measure	Gal	Unit of Measure	Mmbtu	Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2020	1,428,408	1,931,612	na	22592	526,540	51,999						
Present Year	2021	1,285,116	1,782,949	0	20000	1,052,744	117,248						
1st Forecast Year	2022	1,080,007	1,488,626	0	20000	1,674,356	186,480						
2nd Forecast Year	2023	1,140,100	1,560,805	0	20000	1,984,881	221,064						
3rd Forecast Year	2024	1,144,896	1,567,052	0	20000	2,150,037	239,458						
4th Forecast Year	2025	1,040,840	1,429,417	0	20000	1,944,154	216,529						
5th Forecast Year	2026	1,074,222	1,461,857	0	20000	2,172,681	241,980						
6th Forecast Year	2027	1,074,222	1,461,857	0	20000	2,172,681	241,980						
7th Forecast Year	2028	1,074,222	1,461,857	0	20000	2,172,681	241,980						
8th Forecast Year	2029	1,074,222	1,461,857	0	20000	2,172,681	241,980						
9th Forecast Year	2030	1,074,222	1,461,857	0	20000	2,172,681	241,980						
10th Forecast Year	2031	1,074,222	1,461,857	0	20000	2,172,681	241,980						
11th Forecast Year	2032	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						
12th Forecast Year	2033	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						
13th Forecast Year	2034	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						
14th Forecast Year	2035	1,074,222	1,461,857	0	19999.99928	2,172,681	241,980						

LIST OF FUEL TYPES

BIT - Bituminous Coal	LPG - Liquefied Propane Gas	HYD - Hydro (Water)
COAL - Coal (General)	NG - Natural Gas	WIND - Wind
DIESEL - Diesel	NUC - Nuclear	WOOD - Wood
FO2 - Fuel Oil #2 (Mid-Distillate)	REF - Refuse, Bagasse, Peat, Non-wood waste	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual Fuel Oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	**To Be Built** (enter X for selection)	**To Be Retired** (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
x			230.	954	ACSR	AC	Winger Substation to Wilton Substation		54
x			230.	795	ACSR	AC	Sheyenne Sub to Audubon Substation		42
x			230.	795	ACSR	AC	Audubon Substation to Hubbard Substation		50
x			230.	795	ACSR	AC	Fergus Falls Sub to Wahpeton Substation		28
x			230.	795	ACSR	AC	Fergus Falls Sub to Silver Lake GRE		2.8
x			230.	795	ACSR	AC	Silver Lake GRE to Henning Substation		16.6
x			230.	954	ACSR	AC	Harvey Substation to Balta Substation		
x			230.	954	ACSR	AC	Balta Substation to Rugby Substation		
x			230.	954	ACSR	AC	Coal Creek Sub to Underwood Substation		
x			230.	954	ACSR	AC	Underwood Sub to Harvey Substation		
x			345.	2-1272	ACSR	AC	Center Sub to Jamestown Substation		
x			230.	954	ACSR	AC	Drayton Substation to Prairie Substation		
x			230.	795	ACSR	AC	Wahpeton Sub to Hankinson Substation		
x			230.	954	ACSR	AC	Browns Valley Sub to Hankinson Sub		
x			230.	1,272	ACSR	AC	Big Stone Substation to Blair Substation		
x			230.	795	ACSR	AC	Hankinson Sub to Forman Substation		
x			230.	1,272	ACSR	AC	Forman Substation to Oakes Substation		
x			230.	954	ACSS	AC	Oakes Substation to Ellendale Substation		
x			230.	795	ACSR	AC	Pillsbury Substation to Luverne Substation		
x			345.	2-954	ACSS	AC	St. Cloud (Quarry) Sub to Monticello 345 kV Sub 2		29
x			230.	795	ACSS	AC	Wilton Sub to Cass Lake Sub 1		19
x			230.	795	ACSS	AC	Cass Lake Sub to Boswell Sub 1		51
x			345.	2-954	ACSS	AC	Bison 345 kV Sub to Alexandria Switch Station 2		98
x			345.	2-954	ACSS	AC	Alexandria Switch St. to St. Cloud (Quarry) Sub 2		77
x			345.	2-954	ACSS	AC	Cedar Mountain Sub to Helena Switch Sub#1 3		72
x			345.	2-954	ACSS	AC	Cedar Mountain Sub to Helena Switch Sub#2 3		72
x			345.	795	ACSS	AC	Cedar Mountain Sub to Franklin Sub 3		4
x			345.	2-954	ACSS	AC	Helena Switch Sub to Chub Lake Sub 3		20
x			345.	2-954	ACSS	AC	Chub Lake Sub to Hampton Corners Sub 3		18
x			345.	2-954	ACSS	AC	Lyon County Sub to Hazel Creek Sub 3		24.5
x			345.	2-954	ACSS	AC	Hazel Creek Sub to MN Valley Sub 3		5
x			345.	2-954	ACSS	AC	Brookings County Sub to Lyon County Sub 3		50
x			345.	2-954	ACSS	AC	Lyon County Sub to Cedar Mountain Sub#1 3		50
x			345.	2-954	ACSS	AC	Lyon County Sub to Cedar Mountain Sub#2 3		50
x			230.	T2-477	ACSR	AC	Big Stone Plant Sub to Big Stone South Sub #1		
x			230.	T2-477	ACSR	AC	Big Stone Plant Sub to Big Stone South Sub #2		
x			345.	2-T2-477	ACSR	AC	Elllendale Sub to Twin Brooks Sub4		
x			345.	2-T2-477	ACSR	AC	Big Stone South Sub to Twin Brooks Sub4		
x			345.	2-T2-556	ACSR	AC	Big Stone South Sub to Deuel County Sub5		
x			345.	2-T2-556	ACSR	AC	Deuel County Sub to Astoria Sub5		
x			345.	2-T2-556	ACSR	AC	Astoria Sub to Brookings County Sub5		

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:
A table of the demand in megawatts by the hour over a 24-hour period for:
1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest.

	DATE OF PEAK DAY DEMAND	DATE OF PEAK DAY DEMAND	
	8/13/20	1/16/20	**<= ENTER DATES**
TIME OF DAY	MW USED ON **SUMMER** PEAK DAY	MW USED ON **WINTER** PEAK DAY	
0100	448	768	
0200	435	741	
0300	425	729	
0400	420	733	
0500	420	737	
0600	423	740	
0700	451	771	
0800	494	795	
0900	534	835	
1000	557	845	
1100	576	830	
1200	608	816	
1300	637	797	
1400	659	793	
1500	670	786	
1600	680	775	
1700	690	771	
1800	682	779	
1900	669	811	
2000	647	819	
2100	616	814	
2200	596	811	
2300	558	775	
2400	513	788	

COMMENTS

SECTION 3

Electric Utility Information Reporting
<u>Forecast Section</u>

Form EN-0005 – 20

7610.0320 FORECAST DOCUMENTATION

7610.0320 FORECAST DOCUMENTATION.

Subpart 1. Forecast methodology. *An applicant may use the forecast methodology that yields the most useful results for its system. However, the applicant shall detail in written form the forecast methodology employed to obtain the forecasts provided under parts 7610.0300 to 7610.0315, including:*

A. the overall methodological framework that is used;

Aggregate econometric models of use-per-meter and number of meters were developed for each customer class, using historical data on monthly sales, number of meters, economic activity, and weather conditions. Monthly use-per-meter and number of meters forecasting models were estimated as a function of these explanatory variables, plus month-specific variables to capture any seasonal patterns that are not related to the other explanatory variables. Monthly sales forecasts for most classes were developed by multiplying use-per-meter forecasts by meter forecasts for each customer class. The exception to this is the Large Commercial class, which forecasts kWh directly, and Street Lights, which incorporates knowledge of switchover to LED fixtures. To forecast system peak demand, an econometric model was developed that explains monthly system peak demands as a function of weather, economic conditions, and month-specific variables.

B. the specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied;

1. **Econometric Analysis.** Otter Tail Power Company used econometric analysis to develop jurisdictional MWh sales forecasts for the following classes: Residential, Farm, Small Commercial, Large Commercial, Other Public Authority, and Unclassified. The Street Light forecast is created using historical sales and knowledge of changes currently occurring in the change to LED fixtures.

2. **Judgment.** Judgment is inherent to the development of any forecast. Whenever possible, Otter Tail Power Company tries to use appropriate statistical tests of quantitative models to structure its judgment in the forecasting process.

3. **Loss Factor Methodology.** Loss factors were applied to convert the sales forecasts into system energy requirements.

4. **Peak Demand Forecast.** Econometric analysis was used to produce a total system MW demand forecast for each month of the forecast period.

A MWh sales forecast was developed for each customer class and jurisdiction. Summing the various jurisdictional class forecasts yields the total system sales forecast.

A monthly loss factor is applied to convert MWh sales to MWh native energy requirements.

For the sales forecasting models and system demand forecasting model, we used a standard ordinary least squares (OLS) regression model. The purpose of this model is to estimate the relationship between a dependent variable and explanatory variables (*e.g.*, heating degree days, or GDP).

> ***C. the manner in which these specific techniques are related in producing the forecast;***

The econometric techniques described in Section B are applied to historical data to produce estimated effects of weather, economic factors, and demographic factors on class usage or system demand. Forecast values for the explanatory values (derived either from Woods and Poole forecasts or based on weather normal conditions) are then inserted into the estimated equations to produce forecast values of class-level sales and system demand.

> ***D. where statistical techniques have been used, the purpose of the technique, typical computations (e.g., computer printouts, formulas used) specifying variables and data, and the results of appropriate statistical tests;***

Models used

The basic structure for the use-per-meter models estimates monthly use-per-meter as a function of economic conditions, weather conditions, and month-specific variables. The economic variables that are most often used are Gross Regional Product and Total Personal Income. Weather conditions are represented using monthly heating degree days and cooling degree days. In some cases, indicator variables were included in the equation to account for events in the historical time period.

The basic form of the use-per-meter models is represented by the equation below. In this equation "m2" equals one in February and zero in all other months.

$$\text{Use-per-meter} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The basic structure for the meter models estimates monthly meters as a function of economic conditions and month-specific variables. The economic variables that are most often used are Number of Households and Total Population. The meter model is shown in the equation below.

$$\text{Meters} = a + b_1 * \text{Economic Variable} + b_2 * \text{CDD/day} + b_3 * \text{HDD/day} + b_4 * m2 + \ldots + b_{14} * m12$$

The system peak demand model uses the equation below.

kW = a + b_1 * Winter * HDD Buildup + b_2 * Summer * Temperature Humidity Index Buildup + b_3 * Swing Month * CDD & HDD Buildup + b_4 * Gross Regional Product + b_5 * m2 + … + b_{15} * m12

The weather buildup variables are constructed as follows: 40/75 * X_t + 20/75 * X_{t-1} + 10/75 * X_{t-2} + 5/75 * X_{t-3}, where X is the weather variable in question, t is the peak day and t-3 is three days prior to the peak day. The CDD & HDD variable used in the swing months (May and September) is constructed by adding the HDD value to three times the CDD value.

The models use information from Woods and Poole Economics, Inc. for its forecasts of economic demographic variables.

The table under Subp. 2 (data base for forecasts) shows the variables that are included in each model. Specifications that included more variables were also tested to determine the final model used.

E. forecast confidence levels or ranges of accuracy for annual peak demand and annual electrical consumption; and

The estimated effect of each variable in the equations above (*e.g.*, the effect of heating degree days on system peak demand) has a standard error associated with it that is used to generate a confidence interval around the forecasted demand value (*e.g.*, there is some probability that the “true” value of the parameter is actually larger than the estimated value, which would imply that the effect of weather on demand would be larger, leading to a higher peak demand for a given assumed weather condition). In calculating the confidence intervals around the demand forecast, the values of the explanatory variables, such as weather, economic growth, and demographics are all maintained at fixed assumed or expected levels. TABLE 1 (below) shows the results of the confidence levels in 5 year increments.

Table 1
Forecast Confidence Levels
2021 Econometric Forecast
Percent Deviation from Base

	Low Scenario		High Scenario	
Year	**Peak**	**Sales**	**Peak**	**Sales**
2021	(7.7%)	(9.4%)	7.6%	9.2%
2026	(7.4%)	(9.7%)	7.5%	9.5%
2031	(7.3%)	(10.3%)	7.4%	10.2%
2036	(7.2%)	(11.1%)	7.3%	11.1%

F. a brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered significant by the utility.

Methodology As discussed in A the Company uses Econometric models to forecast energy sales requirements and system peak demand. This method is used as it is a standard methodology in the industry and thus facilitates review.

Strengths and Weaknesses As mentioned above, one of the main strengths is the ability of the econometric model to be understood because as mentioned above, the econometric model is an industry standard. The model is reasonably easy to fine tune as it was developed in-house. One of the weaknesses is that the data it uses is not as detailed as the data used in an end-use forecast.

Suitability to the system The econometric methodology is a very good fit to Otter Tail Power Company's system. Serving three states with distinct economic differences, using the econometric model makes it easy to utilize the different economic data for each state and determine whether particular variables are drivers for each state.

Cost Considerations The econometric approach, relative to an end-use model approach, is inexpensive to maintain while being very reliable.

Data Requirements
The forecast utilizes about 20 years of monthly historical energy data and demand data along with their corresponding weather and econometric variables. As described in detail in subpart 2, the sources of data for the explanatory variables was Otter Tail Power Company weather monitoring stations for weather data; the Otter Tail Power Company Customer Information System for meter counts; Woods and Poole Economics, Inc. for econometric data; and the High Plains Regional Climatic Center for weather data that was not available from Otter Tail Power Company weather monitoring stations.

Past Accuracy
Otter Tail Power Company does look back to see how the model predicts past energy and demand. If the model predicts backwards well, there is a reasonable confidence that it will predict well in the future. We've looked at the 20 year backcast for the energy and demand forecasts models. The energy model has an Average Absolute Error of 1.73 percent over the past ten years. The demand model has an Average Absolute Error of 3.00 percent over the past ten years.

Subp. 2. Data base for forecasts. The utility shall discuss in written form the data base used in arriving at the forecast presented in part 7610.0310, including:

> ***A. a complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., monthly observations, billing data, consumer survey, etc.) or a citation to the source (e.g., population projection from the state demographer); and***
>
> ***B. a clear identification of any adjustments made to raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.***

Sales Forecast

Table 2

Independent Variables Used in the Sales Forecast Models

		State	CDD65	HDD65	Mean Household Income	Number Of Households	Gross Regional Product	Total Employment	Billing Days	AR Terms	Trend Variable	Miscellaneous Binaries
Residential	Use Per Meter	MN	X	X					X	X	X	X
		ND	X	X					X	X	X	X
		SD	X	X	X				X	X		X
	Meters	MN				X						X
		ND								X	X	X
		SD								X	X	X
Farm	Use Per Meter	MN	X	X			X			X		X
		ND		X			X		X	X		X
		SD		X						X	X	X
	Meters	MN					X			X		X
		ND								X	X	X
		SD								X	X	X
Small Commercial	Use Per Meter	MN	X	X					X	X		X
		ND	X	X					X	X	X	X
		SD	X	X				X	X	X	X	X
	Meters	MN								X	X	X
		ND								X	X	X
		SD						X				X
Large Commercial	KWH	MN	X	X			X		X	X		X
		ND		X			X		X	X		X
		SD							X	X	X	X
Other Public Authority	Use Per Meter	MN		X					X	X		X
		ND		X					X			X
		SD		X					X	X		X
	Meters	MN								X	X	X
		ND								X	X	X
		SD								X	X	X

Database: Otter Tail Power Company’s Customer Information System (CIS)

Variables Used:

Use-per-meter: kwh sales divided by the number of meters

Meters: number of meters

Description/Source:

KWH and the number of meters were read from SAS CISA data sets. The SAS data sets were created from extracts of the CIS taken the last day of each month. Each record was assigned to one of 40 rate groups within each state based on rate and revenue class combinations. Records were summed to the rate group level within each state. Each rate group was then assigned to one of the eight classes used in the forecast. The variable *Use-per-meter* was calculated by dividing the monthly KWH by the monthly number of meters.

Adjustments Made:

Each record was checked to be sure it was assigned a rate group. Any record not assigned a rate group had its rate and/or revenue class corrected so a rate group was properly assigned. Monthly group KWH data was graphed and values were reviewed for errors due to meters not being billed, being billed twice one month, etc. In most cases the data used for corrections was taken from a second CIS download that was run later the following month after billing corrections had been made. In some cases judgment was used.

Database: DEGREE DAYS

Variables Used:

cdd65: average cooling degree days for each month with a 65 degree base

hdd55: average heating degree days for each month with a 55 degree base

Description/Source:

Hourly temperature data was obtained from 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. The data comes from Schneider Electric, who does multiple data “cleansing” processes to ensure the data is correct and that missing values are filled. Scheduled billing cycle start and stop dates were obtained from the Customer Information System (CIS). Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on 65 degree base and the rounded average of the twenty-four hourly temperatures. Daily degree days were then averaged and weighted for each state and added to calculate billing month and calendar month heating degree days and cooling degree days. Average monthly *hdd* and *cdd* were calculated over a 20 year period to calculate normal billing month and calendar month *hdd* and *cdd*. Billing month *hdd* and *cdd* were used for the historical period and calendar month *hdd* and *cdd* were used for the forecast period.

Adjustments Made:

Hourly monitoring station temperatures are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Database: WOODS AND POOLE
Variables Used:

Total Personal Income
Number of Households
Gross Regional Product
Farm Employment
Total Employment
Net Earnings
Farm Earnings
Total Population

Description/Source:

2020 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 (www.woodsandpoole.com). The 2020 state profile data contains annual historical data for 1969-2018 and annual forecast data for 2020-2050 at the county level.

Adjustments Made:

Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Grand Forks and Minot in North Dakota and Moorhead, Minnesota. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10 percent of the population of the county. County population data was downloaded from www.census.gov .The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the county. Counties with a percentage of less than 10 percent were not included. Town populations were obtained from an internal database of towns served. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

Demand Forecast

Table 3

Independent Variables Used in the Peak Demand Forecast Model	Monthly Binaries	whdd55buildup	sthibuildup	swcdd65hdd55buildup	Gross Regional Product
System Peak Demand	X	X	X	X	X

Database: Otter Tail Power Company's System Load Data
Variables Used: *System Peak Demand*
Description/Source: Annual hourly system load (MAPP) files and annual hourly net controlled load (NCL) files were obtained from System Operations. System load data was combined with the net controlled load data to give hourly system demands without control.
Adjustments Made: The hourly system load files are graphed and reviewed by System Operations personnel each month.

Database: WOODS AND POOLE
Variables Used: *Gross Regional Product*
Description/Source: 2020 state profile econometric data for Minnesota, North Dakota and South Dakota was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Ste 208, Washington, DC 20016-4368 (www.woodsandpoole.com). The 2019 state profile data contains annual historical data for 1969-2017 and annual forecast data for 2020-2050 at the county level.
Adjustments Made: Otter Tail Power Company does not serve all of the load in the counties within its service territory. This is especially problematic when Otter Tail Power Company does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, Moorhead, Grand Forks and Minot. To reflect this, a decision was made to not use econometric data from counties where Otter Tail Power Company served less than 10 percent of the population of the county. County population data was downloaded from www.census.gov .The percentage of the population served by Otter Tail Power Company in each county was determined by dividing the sum of populations of towns served by Otter Tail Power Company in each county by the population of the

county. Counties with a percentage of less than 10 percent were not included. Town populations were obtained from an internal database of towns served. The data was then summed to the state level and graphed as a reasonability check. Annual Woods and Poole data was converted from annual data to monthly by interpolating between annual values with a flat line.

Database: FARGO WEATHER DATA
Variables Used: *sthibuildup*: summer temperature humidity index buildup
Description/Source: Hourly weather data files were obtained from the High Plains Regional Climatic Center (**www.hprcc.unl.edu**) for Fargo, North Dakota. Fargo is used as a proxy for the system average weather data (other than temperatures which come from Otter Tail Power Company division weather stations). The hourly temperature humidity index (*thi*) was calculated from the hourly dry bulb temperatures and the hourly relative humidity (*thi*=*db*-(.55-.55**rh*/100)*(*db*-58)). The average daily temperature humidity index (*thi*) was calculated from the hourly values. The variable *thibuildup* was calculated from *thi* for the day of monthly system peak and *thi* from the previous three days so that each previous day has half the influence of following day ((40/75)**thi*+(20/75)**lag1thi*+(10/75)**lag2thi*+(5/75)* *lag3thi*). The variable *sthibuildup* has the value of *thibuildup* for the months of June, July and August and zero for all other months. The forecast period *sthibuildup* variable was calculated by determining the value of *thi* for each monthly system peak day and the three days previous to the peak for the last 20 years.
Adjustments Made: High Plains Climatic Center data was used rather than NOAA data because the High Plains Climatic Center data has been reviewed and edited where necessary and the NOAA data has not.

Database: DEGREE DAYS
Variables Used:
Whdd65buildup: winter heating degree day buildup
swcdd65hdd65buildup: swing month cooling and heating degree day buildup
Description/Source: Average hourly temperature data was obtained by averaging hourly temperatures across 14 monitoring stations throughout Minnesota, North Dakota and South Dakota. Daily heating degree days (*hdd*) and cooling degree days (*cdd*) were calculated based on a 65 degree base and the rounded average of the twenty-four hourly temperatures. The variables *hddbuildup* and *cddbuildup* were calculated from the degree days for the day of monthly system peak and the degree days from the previous three days so that each previous day has half the influence of following day (for example, (40/75)**hdd*+(20/75)**lag1hdd*+(10/75)**lag2hdd*+(5/75)* *lag3hdd*). The variable *whdd65buildup* has the value of *hddbuildup* for the months of January, February, March, April, October, November and December and zero for all other months. The variable *cddhdd* was calculated by adding three times *cdd* to one times *hdd* (3**cdd*+1**hdd*). The variable *swcdd65hdd65buildup* has the value *cddhdd* for the months of May and September and zero for all other months. Forecast period *whdd65buildup* and *swcdd65hdd65builup* variables were calculated by determining

the value of *hdd* and *cdd* for each monthly system peak day and the three days previous to the peak for the last 20 years.

Adjustments Made: Hourly monitoring station temperatures are graphed each month after the data is downloaded. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Subp. 3. Discussion. The utility shall discuss in writing each essential assumption made in preparing the forecasts, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions.

Some assumptions should be listed individually for emphasis.

1). No load management:
Need: Load management is used at Otter Tail Power during peak conditions, summer, and winter. The use of the control is not always predictable. To build a forecast to match a load subject to load management is not practical.

Assumption: The forecast is made to match uncontrolled load. Therefore, to match forecast to load, the observed load must have the estimated load management added. This simplifies the process of reconciling the forecast.

Sensitivity: There is nothing to test.

2). Woods and Poole Economics, Inc.
Need: Economic forecasts are needed to provide projections of population and employment. The forecasts must be consistent among county, state, and national projections, so the forecasts need to be from similar sources or be based on similar assumptions. For this reason, these elements of the forecast are taken from a single source.

Assumption: Woods and Poole data provides a consistent scenario of the future that connects national, state and county projections. Population and employment follow this story of the future economy.

Sensitivity: No consistent alternatives are provided.

See also the above discussions and the discussion below regarding subject of assumption.

Subp. 4. Subject of assumption. The utility shall discuss the assumptions made regarding the availability of alternative sources of energy, the expected conversion from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will likely have on the utility's system demand, the assumptions made in arriving at

any data requested in part 7610.0310 that is not available historically or not generated by the utility in preparing its own internal forecast, the effect of existing energy conservation programs under federal or state legislation on long term electrical demand, the projected effect of new conservation programs that the utility deems likely to occur through future state and federal legislation on long term electrical demand, and any other factor considered by the utility in preparing the forecast. In addition the utility shall state what assumptions were made, if any, regarding current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area. If a utility makes no assumptions in preparing its forecast with regard to current and anticipated saturation levels of major electrical appliances and electric space heating it shall simply state this in its discussion of assumptions.

Otter Tail Power Company's forecast assumes availability of alternative sources of energy will continue in similar patterns as have been historically.

Otter Tail Power Company did not assume any changes in the availability of alternative sources of energy, the expected conversions from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will have on the utility's system demand. The current forecast by default assumes any prices changes would be in small increments that demand is not noticeably impacted. While price changes due to rate cases are not necessarily smooth in the short-term (reality), for the purposes of the long-term forecast any price changes smooth out over time. This reality is due to the long-term planning process. The utility itself and regulatory bodies are involved in the integrated resource planning process in part to mitigate significant price changes.

Otter Tail Power Company's forecast does not make any explicit assumptions about current and anticipated saturation levels of major electric appliances and electric space heating within the utility's service area.

Subp. 5. Coordination of forecasts with other systems.
The utility shall provide in writing:

A. ***a description of the extent to which the utility coordinates its load forecasts with those of other systems, such as neighboring systems, associate systems in a power pool, or coordinating organizations; and***
B. ***a description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate load forecasts.***

Otter Tail Power Company does not coordinate its long-term load forecasts with those of other systems.

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HIST: L 1987 c 312 art 1 s 9; 16 SR 1400

Appendix C: Existing Resources

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Existing Resources

Otter Tail Power Company has a variety of existing resources available to meet the energy needs of its customers, both reliably and economically. These resources consist of existing generating facilities, the radio load management system, the Midcontinent Independent System Operator (MISO), purchases from other utilities, customer owned generation, the transmission and distribution network, and current Company sponsored conservation programs.

Figure 1-1 shows the composition of the 2021 Planning Year capacity by fuel source for the Company.

Figure 1-1: 2021 Planning Year Accredited Capacity Resources Fuel Source Percent of Total = 807 MW

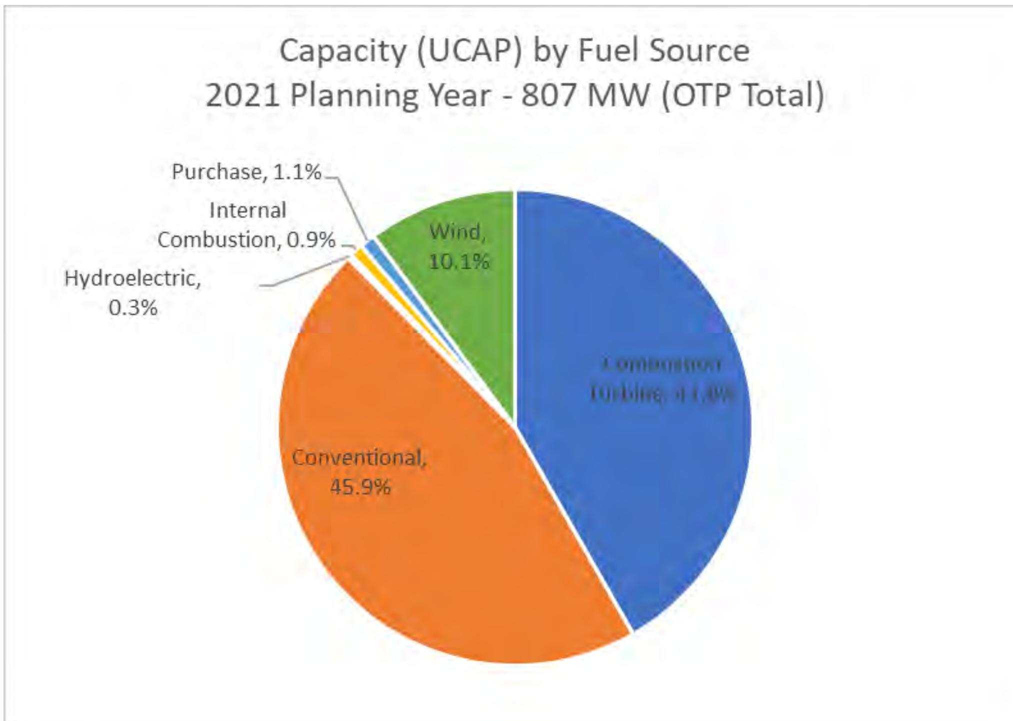

Table 1-1 shows a listing of the Company's resources and their capacity ratings for the 2021 Planning Year. The capacity ratings data provided is based on current MISO ratings under Module E's resource adequacy requirements in effect for the Planning Year June 1, 2021, through May 31, 2022.

Table 1-1: 2021 Otter Tail Capacity Resources

Capacity - Owned Resources	ICAP (MW)	UCAP (MW)
Coal		
Big Stone Plant	257.7	252.8
Coyote	149.1	131.3
Gas CT		
Astoria	249.7	237.8
Solway 1	42.4	41.6
Wind		
Ashtabula	48.0	8.2
Langdon	40.5	7.7
Luverne	49.5	9.8
Merricourt	150.0	24.5
Hydro		
Garrison Hydro	4.3	4.3
Garrison Hydro 2	4.4	4.4
Dayton Hollow Hydro 1	0.5	0.5
Dayton Hollow Hydro 2	0.4	0.4
Hoot Lake Hydro	0.5	0.5
Pisgah Hydro	0.7	0.7
Taplin Gorge Hydro	0.5	0.5
Wright Hydro		
Oil		
Lake Preston	19.4	18.4
Jamestown 1	20.6	20.2
Jamestown 2	20.4	20.4
Load Control		
Otter Tail Load Control	16.0	18.5
Total Owned:	1074.6	802.5

Capacity Purchased Resources	ICAP (MW)	UCAP (MW)
Wind		
Edgeley (ND Wind II)	21.0	2.8
Langdon	19.5	3.9
Ashtabula III	62.4	11.7
Customer Owned	4.3	4.1
Total Purchased:	107.2	22.5

1.1 Hydroelectric Facilities

Otter Tail Power Company has 6 units located at five dams on the Otter Tail River near Fergus Falls, MN and 2 units located at a dam on the outlet of Lake Bemidji at Bemidji, MN. These hydro units were constructed in the early 1900's and were the backbone of the generating resources for Otter Tail for many years in the early days of the Company. The total capability of all of the hydro units is about 3.7 MW.

The hydro units located on the Otter Tail River are under FERC jurisdiction and were licensed for the first time in 1991. All of these units were built prior to licensing requirements. The units are predominantly operated in run of river mode without pondage capability except for Hoot Lake and Wright Lake behind the Hoot Lake Hydro. Prior to the FERC licensing, there was a small amount of pondage and cycling capability with these units that increased the amount of energy obtained from the water flow. The FERC license required a change to strict run of river operation.

All of the hydro units in run of river mode have had updated reservoir level monitoring systems installed to aid in complying with the operating requirements of the FERC license. Automatic level control systems have also been installed at a number of the units to control the reservoir level using the signal from the reservoir level monitoring system. Significant other equipment upgrades were completed in the past 15 years, to upgrade electrical control and protection equipment.

The FERC re-licensing process is approximately 5 years and OTP has been preparing for submission for license renewal. This submission known as the Notice of Intent (NOI) and Project Application Document (PAD) is being prepared and the process through FERC will begin officially in the summer of 2016.

Bemidji Hydro
The Bemidji Hydro units were built in 1907. These units were authorized by Congress and are not subject to FERC jurisdiction. Otter Tail acquired ownership of these units in the 1940's. The Unit #1 generator stator and rotor field was rewound in 2008.

Dayton Hollow Hydro
Dayton Hollow Dam was built in 1909 with two generators installed. A third generator was added in 1917. One of the original generators was retired and removed in 1964. The Unit #2 turbine and generator were refurbished in 2006 and the turbine also had a major repair in 2008 – 2009. Annual generation from the Dayton Hollow units is about 5,000 – 7,000 MWh.

Hoot Lake Hydro
The Hoot Lake Hydro was built in 1914. The hydro originally had two units, but one unit was retired with the addition of the Hoot Lake #3 steam unit in 1964. The Hoot Lake Hydro is part of a system that was developed to make further use of the Otter Tail River. Diversion Dam was built on the Otter Tail River and part of the water from the river is diverted through an underground tunnel to Hoot Lake that flows into Wright Lake. The two lakes were created from the diverted water. The water from Wright Lake flows through the Hoot Lake structure, and is used in the hydro unit and for cooling water for the Hoot Lake steam units. Hoot Lake Hydro has been generating about 3,000 - 4,000 MWh annually. The City of Fergus Falls also makes use of the Diversion Dam system as water supply for the city.

Pisgah Hydro
Pisgah Hydro was built in 1918. The generator stator and rotor was rewound in 2001. The turbine was rebuilt in 2005. This unit provides about 3,500 – 4,500 MWh during normal years.

Taplin Gorge (Friberg) Hydro
Taplin Gorge, also known as Friberg, was constructed in 1925. The structure is well known in the Fergus Falls area because the powerhouse is a replica of the tomb of the former Italian ruler, Theodoric. The generator was rewound in 1999. Annual generation is in the 3,000 – 4,200 MWh range.

Wright (Central) Hydro
Wright Dam (also called Central) is located in downtown Fergus Falls, and has been the location of a dam since the 1880's. It originally provided power via drive belts to industries located nearby. The current structure was built in 1922. The turbine was rebuilt and the generator cleaned and rewedged in 2002 – 2003. Annual generation is in the range of 2,000 – 3,000 MWh.

1.2 Peaking Facilities

Otter Tail Power Company has a number of peaking units on the system. Some are internal combustion units, but most of the capacity is comprised of combustion turbines. Astoria and Solway are frequently dispatched by the MISO centralized market. Otter Tail's other peaking units operate on a very limited basis annually, either for emergency or extreme peak times, or for testing purposes.

Astoria Station

Astoria Station is natural gas fired, Mitsubishi 501GAC, combustion turbine that was placed into service in 2021. Astoria Station's summer rating is 245 MW. At colder ambient temperatures, the Unit can generate up to its transmission interconnection limit of 286 MW. Astoria Station was designed with fast start capability; allowing it to achieve 80% load within 10 minutes from the initiation of a start command.

Jamestown Combustion Turbines
Otter Tail has two fuel oil-fired combustion turbines located at Jamestown, ND. These units are of 1976 and 1978 vintage. These units are operated for emergency, peaking, and testing situations, as well as for economy during periods when market prices support it. The Frame 5 units at Jamestown operate a very limited number of hours during the year.

Lake Preston Combustion Turbine
Lake Preston is a third combustion unit, identical to the Jamestown units, located at Lake Preston, SD. This unit was installed in 1978. This unit is also fired with fuel oil and has limited operation. The unit usually operates for emergencies, peak loads, and testing, but is also used for area voltage support under certain transmission line switching and outage scenarios. The Frame 5 unit at Lake Preston operates a very limited number of hours during the year.

Solway Combustion Turbine Plant
Otter Tail brought on-line a General Electric LM6000 dual-fuel combustion turbine just prior to the 2003 summer season. The unit includes inlet chilling to improve the summer rating and efficiency, as well as water injection for NOX control and increased output. Interruptible natural gas is the primary fuel with

fuel oil as the back-up fuel supply. The combustion turbine also includes a clutch to allow synchronous condensing service to support the transmission system. The LM6000 is an aeroderivative machine, powered by a Boeing 747 engine.

Big Stone Diesel
The Big Stone Plant has an internal combustion emergency diesel unit. This unit operates only for extreme emergency or testing purposes, but can synchronize with the system and is submitted as a capacity resource. The unit was installed in 1975 with the construction of the Big Stone Plant.

Fergus Control Center Diesel
A 2,000 kW diesel unit was installed at Otter Tail's System Control Center to serve as a standby generator for the facility, in accordance with NERC reliability criteria. The System Control Center was added to an existing Company building that contains the main business computers for Otter Tail. The system is staffed 24 hours per day and must have firm electric service to keep the System Control Center in operation during outages. The standby generator will supply emergency power, when required, to the total System Control Center and to the computer facilities.

New EPA Emission Standards for Stationary Engines
On March 3, 2010 the U.S. Environmental Protection Agency issued new national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The new standards include emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements. By May 1, 2016 all of Otter Tail's engines affected by the RICE Rule will be considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests. Only minimal efforts will be needed to comply with the rule.

1.3 Baseload Resources

Otter Tail Power has partial or full ownership of three coal-fired generators, all at different locations. Until 1988 Otter Tail's coal-fired units had burned primarily North Dakota lignite. Some early units, long since retired, had used eastern coals, but lignite had been the fuel of choice for many years. Following a fuel switch in 1995 at Big Stone Plant to low-sulfur western sub-bituminous coal, Coyote is the only plant still burning lignite coal. The coal-fired units also use fuel oil for startup, and flame stabilization at times. The use of fuels at each facility is discussed in the following sections.

Otter Tail is always reviewing opportunities to improve the efficiency and operation of its units. The improvements and conservation efforts within the generating stations have helped Otter Tail maintain some of the lowest system heat rates in its history.

Big Stone Plant
The Big Stone Plant, of which Otter Tail owns 53.9 percent, became commercial on May 1, 1975. Improvements have come about as the result of conservation, operational efforts, and equipment updates within the plant. The current output rating for the Big Stone Plant is 475,000 kw (total plant).

The switch to sub-bituminous coal in late 1995 helped to reduce the plant net heat rate. Other efficiency improvements, and the installation of a new low-pressure rotor in 1996, have also helped to lower the heat rate level at Big Stone Plant. A new high-pressure/intermediate pressure rotor was installed in 2005 and improved efficiency by about two percent.

The POET Bio-refining ethanol plant (formerly Northern Lights Ethanol) is located on the Big Stone Plant site. Big Stone Plant supplies steam for ethanol production. The steam is extracted part of the way through the electrical production process, so by serving the ethanol plant, Big Stone is truly a cogeneration plant involving the sequential use of the energy for two different purposes. The cogeneration operation does not impact the plant's ability to generate electricity.

In 2015, the largest capital project in Otter Tail Power history, at that time, was undertaken as the AQCS project was installed at Big Stone Plant to meet the regional haze rule requirements. The AQCS project was a project to install controls for NOx (SCR and SOFA), SO2 (circulating dry fluidized bed scrubber), particulate (baghouse) and Hg control (activated carbon injection to meet MATS rule). The original budget for the AQCS project was $491 million, and through efforts related to project team management and overall project timing, the final cost of the project was about $384 million.

Coyote Station
The Coyote Station, located near Beulah, ND is a lignite-fired mine mouth facility. Otter Tail owns 35 percent of this unit. The Coyote Station was declared commercial on May 1, 1981 and is equipped with a flue gas desulfurization unit and a baghouse. Otter Tail became the operating agent of the facility on July 1, 1998. The other co-owners of this facility are Northern Municipal Power Agency, Montana-Dakota Utilities, and Northwestern Public Service. Minnkota Power Cooperative acts as the agent for Northern Municipal Power Agency.

The Coyote Station is a sister unit to Big Stone, but six years newer. The Coyote Station approved outlet rating is limited to 427,000 kW due to transmission limitations. The facility also has two emergency diesel generators that are not accredited in MISO due to the transmission limitations.

Coyote completed a high-pressure/intermediate pressure rotor replacement in 2009 that resulted in about a two percent increase in efficiency. It also increased the UCAP rating of the plant by about 6,000 kW.

Coyote completed the installation of activated carbon injection for Hg control in 2015 as well as a SOFA (separated over-fire air) system for NOx reduction during 2016.

Additionally, the Owners of Coyote Station entered into a 25-year lignite supply agreement with Coyote Creek Mining Company to supply the Coyote Station with lignite from a new, efficient mine.

1.4 Demand Resources

Otter Tail Power Company has two demand resources that can be registered under Module E with the MISO. Both resources are load modifying resources (LMR) that are netted from the demand forecast and available to MISO in emergency events. These resources are obligated to provide sustained load reduction for up to 4 hours at a time and be available ten times a year to the MISO in the event of an emergency. This obligation does not preclude the Company from relying on these resources to control for capacity events or economic reasons outside of a MISO emergency event.

Direct Load Control – The Radio Load Management System
The first resource, "Direct Load Control" represents the Company's extensive radio load management system that is used to control customer load during economic or capacity events. This resource was accredited at 16 MW for MISO planning year 2021/2022 based on summer capability but has proven capability as high as 130 MW during the winter months. Otter Tail has approximately 129,800 customers and approximately 42,000 of those customers have some type of load control. The level of control that is available can vary with temperature, customer behavior, and load control responsiveness. For example, more load control is available during extremely cold temperatures in the winter than during moderate temperatures and customers with dual-fuel load may choose to switch to an alternate fuel, particularly during a period of lower prices.

Winter season manageable loads are in several categories and can reach as high as 130 MW. These manageable loads include water heaters, thermal storage, residential demand controllers, commercial time of use rates, small dual fuel heating systems, and large dual fuel (industrial and bulk interruptible loads). The radio load management system also has the capability of interrupting as much as 15 MW of peak load in the summer-season months, June through September. These summer loads consists primarily of water heaters, large dual fuel industrials, small dual fuel and deferred load heat pumps used for cooling, and standard air conditioning. Otter Tail continues to add customers to the direct load control rates to maintain and grow manageable loads.

Although measurement data shows the load management system as able to achieve higher levels than the level accredited, those higher levels related to peak control levels during a minimum number of hours and were impacted by weather and load diversity. Those higher levels do not represent the typical levels of control that Otter Tail is confident can be sustained. The measurement and verification requirements for continued accreditation and the risk of potential penalties were also significant factors in the lower accreditation level registered by the Company.

Firm Service Level – Customer Contracts
The second demand resource registered with MISO is a "Firm Service Level" resource that represents Otter Tail's contract with a large industrial customer to shed load to a firm service level in the event of a capacity event. Unlike the "Direct Load Control" resource that reduces load when called upon by our load management system, this resource must demonstrate that it did not exceed the registered load level during a capacity event.

1.5 Transactions

Otter Tail has a number of large commercial customers that are shared loads with local rural electric cooperatives. These loads are in areas that may be in one utility's service territory, but are located where the other utility already had the necessary facilities to handle the load. In order to reduce costs and avoid duplication of facilities, these loads have been shared. In the accounting process, these loads are usually served as if they are Otter Tail customers, and then 50 percent of the energy is purchased wholesale from the other utility at the retail rate used to serve the customer. All of the retail energy shows up as Otter Tail energy with a 50 percent wholesale energy purchase, even though Otter Tail only served half of the load.

WAPA Allocation to Native American Tribes

The Western Area Power Administration (WAPA) is a federal Power Marketing Agency that provides capacity and energy from hydroelectric facilities located on the Missouri River to preference customers. Otter Tail does not qualify as a preference customer. Native American tribes are preference customers eligible to receive the federal power. The tribes, however, are not utilities in the same manner as typical WAPA preference customers such as municipals and rural electric cooperatives. The tribal lands are typically served by a combination of existing utilities.

In order to facilitate the delivery of the electricity to the tribes, or the economic benefits of the low-cost federal electricity, WAPA developed a process in which the electricity is delivered to the utilities providing electric service on tribal lands. Each tribe has the right to determine which tribal entities receive the benefits. For the customers designated by the tribe as receiving the benefits, WAPA delivers the electricity to Otter Tail at the WAPA rate, and then Otter Tail provides a bill credit to the customer. The bill credit is essentially equal to the difference in cost between the WAPA power and the embedded Otter Tail cost of generation, less expenses to administer the program. Otter Tail has filed the appropriate information with and received approval from the state regulatory commissions in the states involved.

Otter Tail has five tribes that receive the benefits of the WAPA power. The current capacity amount varies monthly from a low of 4.3 MW to a high of 5.6 MW, with annual energy of 32,158,236 kWh. Otter Tail also receives the load based reserve margin benefit with the capacity. Because the tribes have the right to change who receives the benefit and such changes may move benefits from tribal customers served by Otter Tail to tribal customers served by another utility, the amount of capacity and energy received for the tribal loads may vary over time. The current amount of tribal allocation that is received through Otter Tail is included in all analysis scenarios. None of the WAPA power qualifies for compliance with the Minnesota Renewable Energy Objective, as all of the WAPA hydroelectric facilities are greater than 100 MW when considering all units at a specific location.

Customer Owned Generation

Otter Tail has worked with several customers who desired to install small diesel generators for back-up emergency power. These units are owned by the customers and capable of being interconnected to Otter Tail's system. The capacity from these units is purchased by Otter Tail and submitted as behind the meter capacity resources registered with MISO. Currently the NDC rating of these units is 4,300 kW in total and the UCAP rating is 4,100 kW in total.

On March 3, 2010 the U.S. Environmental Protection Agency issued new national emission standards for hazardous air pollutants for existing stationary compression ignition reciprocating internal combustion engines. The new standards include emissions limitations, operating limitations, maintenance requirements, performance tests, recordkeeping requirements, and reporting requirements. Effective May 1, 2016 all of Otter Tail's engines affected by the RICE Rule are considered emergency or blackstart in nature and therefore exempt from emissions limitations and performance tests.

Otter Tail also has power purchase agreements with several wind generation facilities as described in the following section.

1.6 Wind and Solar Generation Resources

Otter Tail has more than 405 MW of wind/solar generation on the system, including utility owned and contracted generation. The Company owns 288 MW of wind generation. This wind generation accounted for 18 percent of the Company's energy needs in 2020.

Langdon Wind Energy Center
Otter Tail owns 40.5 MW of wind generation located south of Langdon, ND consisting of 27 1.5MW GE wind turbines. This facility began operation in January 2008.

Ashtabula Wind Energy Center
Otter Tail owns 48.0 MW of wind generation located in Barnes County, ND consisting of 32 1.5MW GE wind turbines. This facility began operation in November 2008.

Luverne Wind Energy Center
Otter Tail owns 49.5 MW of wind generation located in Steele County, ND consisting of 33 1.5MW GE wind turbines. This facility began operation in September 2009.

Merricourt Wind Energy Center
Otter Tail owns 150 MW of wind generation located approximately fifteen miles south of Edgeley, North Dakota in McIntosh and Dickey Counties, consisting of 75 2 MW Vestas wind turbines. This facility became commercially operational in December 2020.

Approximately 117 MW of wind/solar generation is purchased by Otter Tail from customers or other entities and is identified in Table 1-2. Customer owned units do not have the ownership name included to protect customer information. Often generation from smaller, customer owned units is used to serve the customer and only the surplus generation is sold to Otter Tail.

Otter Tail is in the early stages of analyzing the potential purchase of the Ashtabula III wind facility from NextEra. This purchase would likely occur in the 2023 timeframe.

Table 1-2: Contracted Wind Generation Facilities

Name and Owner	State	kW Rating
FPL Energy ND Wind II - NextEra	ND	21,000
Langdon Wind Energy Center – NextEra	ND	19,500
Ashtabula III – NextEra	ND	62,400
Various Small Wind/solar Producers	ND	3,318
Various Small Wind/solar Producers	MN	10,620
Various Small Wind/solar Producers	SD	154

1.7 Energy Efficiency Programs

Otter Tail Power Company operates a number of Demand-Side Management Programs in its service territory. In Minnesota, some of these projects are part of the Company's Conservation Improvement Program (CIP) filing, Docket No. E017/CIP-20-475. The Company also operates an energy efficiency program in South Dakota; Otter Tail's 2021 Energy Efficiency Plan (EEP) status report and annual filing was filed in Docket No. EL21-015. North Dakota does not have a formal energy efficiency program. The Company's Minnesota and South Dakota energy efficiency results have been on target with the energy efficiency goals in historical integrated resource plan filings.

This resource plan reflects an average annual energy savings of 1.86 percent, which exceeds the newly established 1.75 percent goal in Minnesota's Energy Conservation and Optimization Act of 2021.

1.8 Midcontinent Independent System Operator, Inc. (MISO)

Otter Tail continues to play an active role in the regional transmission planning efforts. While Otter Tail still leads and conducts studies to ensure the adequacy of the transmission system to serve its customers, all transmission planning activities related to regional transmission are coordinated with the MISO and the surrounding non-MISO transmission owners.

Transmission planning occurs through the course of performing transmission studies at several different levels, from individual utility plans, to joint utility plans with utility neighbors, to broad regional studies. Regardless of the type of studies, the forum for which these studies are discussed is through a regional transmission planning process. Otter Tail actively participates in several MISO study groups, such as the West Subregional Planning Meetings (WSPM) and the West Technical Study Task Force meetings (WTSTF). These groups provide forums for regional transmission planners to discuss the needs and projects related to the transmission system in the Otter Tail and surrounding area that are within the western footprint of the MISO region.

Otter Tail closely coordinates its transmission planning efforts with the MISO. For transmission planning purposes, MISO performs three primary functions. The first two are federally mandated processes established by FERC, generator interconnection and delivery service, and the third process is related to expansion planning.

MISO administers and processes requests to use the transmission system of the MISO transmission owners. MISO has established procedures for processing generation interconnection and delivery service transmission requests of generators and market participants. Through this FERC mandated process, MISO offers the area utilities opportunities to participate in "ad-hoc" study groups to provide input and review of the technical studies completed for generation interconnection or delivery service. In addition to these FERC mandated requirements, MISO also performs expansion planning studies on an annual basis. These expansion planning studies are referred to as the MISO Transmission Expansion Plan (MTEP) and focuses on a variety of studies, from reliability assessments to targeted studies focused on a particular issue or item. Otter Tail's transmission system falls within the MISO West region. Through the MTEP process, MISO completes a reliability analysis assessing the transmission system performance against transmission owner's reliability criteria. In the event that reliability criteria is not met, additional analysis is completed to find mitigation to a particular system issue. Otter Tail actively participates in the MTEP, generator interconnection, and delivery service efforts by attending meetings, reviewing study results and providing input into the study process.

MISO has also sponsored targeted studies in the region as part of the MTEP process. Otter Tail actively participates in many of these targeted studies, including the Long-Range Transmission Plan (LRTP) and

Joint Targeted Interconnection Queue (JTIQ) studies, as well as other targeted studies. Through these various study efforts, Otter Tail attends meetings, reviews study results and provides input into the study processes.

In addition to the specific study opportunities, the MISO conducts meetings of several stakeholder groups, which include the Planning Subcommittee (PSC), the Planning Advisory Committee (PAC), the Regional Expansion Criteria and Benefits Working Group (RECB WG), the Interconnection Process Working Group (IPWG), among several others. These meetings are attended by various representatives of the different stakeholder groups at MISO. These meetings act as a forum between MISO staff and the stakeholders to provide input into the processes of the
MISO. Otter Tail regularly attends several of these meetings to stay engaged within the MISO transmission planning process as well as provide input and feedback to the MISO.

All of these transmission planning activities are then combined into, and are consistent with, the MN state transmission planning process.

Transmission Interconnections
On May 9, 2002, the Commission gave conditional authority to Otter Tail to transfer operating control of certain transmission facilities to the MISO. Since joining MISO and transferring operational control of its high voltage transmission facilities to MISO, Otter Tail has seen positive benefits in this relationship regarding the generator interconnection processes.

Since Otter Tail joined MISO, numerous generators have successfully interconnected to the Otter Tail electric system under MISO's generator interconnection procedures. Under MISO's Open Access Transmission and Energy Markets Tariff (TEMT), all generator interconnection requests (regardless of generator size or interconnecting voltage level) are required to abide by the MISO generator interconnection process if the generator intends on engaging in wholesale transactions. The MISO, as an independent system operator, ensures comparable treatment for all customers and it is staffed to provide and administer this service. Otter Tail receives value and efficiencies from the MISO process given that MISO is staffed to administer its procedures and, as an independent organization, ensures comparable treatment to all parties involved. Additionally, Otter Tail stays actively engaged in several MISO studies and provides information regarding the transmission system when reviewing study results and giving direction for future studies. This is an efficient process and a benefit to all parties since Otter Tail has ultimate knowledge and familiarity with its system and most efficiently and effectively provides this service. Project coordination, administration, and filing requirements fall upon MISO, thus freeing up Otter Tail's resources to focus on its key priority of providing clean, efficient, and low cost energy to its customers.

In the recent years, an unprecedented amount of renewable generation has been requested to be added to the MISO system. The increase in requests and generators interconnecting to the MISO system has caused congestion that has been reflected in the MISO interconnection queue. Due to the large amount of requests and recent generator interconnections, transmission interconnection costs for new resources are very high and impact the economic feasibility of adding new generation units of all types. Some of the challenges include additional uncertainties, large queue cycles, delayed studies, and very high interconnection costs. Recently the MISO has provided two alternative methods for interconnecting new resources. The two new interconnection methods are replacement interconnection and surplus interconnection. Both alternatives prevent having to go through the traditional MISO interconnection queue process. Replacement interconnection resources reuse the existing interconnection rights of an existing resource that is retiring. Surplus interconnection resources are built alongside an existing resource and share the interconnection rights while not exceeding the total output of the existing interconnection. Both interconnection methods are studied to confirm that there are no reliability impacts to the transmission system, and if issues are identified, the request goes to the standard queue.

Locational Marginal Pricing (LMP) Energy Market and Ancillary Services Market (ASM)
The MISO Locational Marginal Pricing (LMP) energy market was introduced on April 1, 2005. The MISO subsequently introduced the Ancillary Services Market (ASM) on January 6, 2009. Both market introductions went well, but utility operations and market functions have changed significantly.

Many of the key preparations and day-to-day activities since commencement of the markets include:
- Development of software interfaces and procuring or developing new software systems.
- Training of employees.
- Developing after-the-fact data flows to ensure a seamless transition in the accounting and regulatory areas.
- Active involvement in filings related to the Energy Market at the Federal Energy Regulatory Commission (FERC) and state commissions. This includes settlement proceedings for the non-MISO Load Serving Entities located within the Otter Tail Power Company Control Area.

- Nominating and receiving Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTR) allocations to safeguard Otter Tail's native load.
- Developing business practices, strategies and risk management policies to accommodate an LMP and ASM Market.
- Actively participating in the numerous MISO committees seeking to ensure that Otter Tail's best interests and the interests of its customers were not adversely impacted by decisions and policies resulting out of these committees.

Market operations continue to go smoothly, and the company is generally pleased with the transition to the centralized energy and ancillary services markets.

MISO Resource Adequacy (Module E)
Otter Tail's reserve requirements are established by MISO under Module E of the MISO Tariff. For planning year 2021 (June 2021 – May 2022) the MISO reserve margin requirement is 9.4 percent.

MISO currently operates in an annual construct with a system wide coincident peak occurring in the summer months. The Company's coincident peak demand diversity factor is approximately 9 percent of its non-coincident peak demand.

Resource accreditations change annually and are based on summer ratings. Ratings for non-wind generators are based on historic generator availability data or, if that is unavailable, class averages are used.

Wind generation is accredited based on unit specific historical capacity factors. Accreditation for the 2021 planning year for the Company's wind farms varied from 20 percent at the Langdon Wind Farm to 16 percent (MISO average) at the Merricourt Wind Farm. The accredited capacity rating is expected to increase at Merricourt in the future as historic generation data becomes available.

1.9 Transmission Facilities

Otter Tail serves many very small communities located in a geographical area about the size of the State of Wisconsin. The characteristics of the customer loads and locations have required an extensive transmission system. When compared to many investor-owned utilities, Otter Tail's customer count per mile of transmission facilities is quite small. To minimize cost, Otter Tail has become party to several integrated transmission agreements. The Company participates in many shared networks with other investor owned utilities, municipals, G & T cooperatives, and rural electric cooperatives. In many cases, a 41.6 kV or 69 kV transmission line will serve an equal number of non-Otter Tail and Otter Tail distribution substations.

These agreements have resulted in over 200 points of interconnection with other utilities. Such a network adds to the complexity of operating the electrical system, but also adds the capability for the facilities of one utility to provide either full time or emergency service to another utility. The ultimate result is reduced cost and increased reliability for the customer. Table 1-4 lists the mileage of various voltage classes of transmission lines. All of these lines are overhead lines except for less than one mile of underground cable in the 41.6 kV class.

Table 1-3: Circuit Miles of Transmission by Voltage

Voltage (kilovolts)	Circuit length
345 kV	*875 miles
230 kV	*496 miles
115 kV	*916 miles
69 kV	209 miles
41.6 kV	3796 miles

**Mileage includes Otter Tail Power Company joint ownership in CapX2020 transmission projects. See CapX2020.com for more information.*

Appendix D: Potential Resources

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Potential Resources

This appendix provides a description of the resources that were evaluated in the development of the 2021 Integrated Resource Plan by Otter Tail. The development of the resource plan focused on the evaluation of resources that are available to the Company, taking into account a number of factors. These factors include available size increments of the technology, the maturity and commercial availability of the technology, the availability of interested co-owners of large facilities, operational parameters, and available data. Not every resource that was evaluated was included in the Company's model. In order to reduce run time of the EnCompass software, an initial screening was performed to limit the number of potential new resources that would be made available for the model to select.

Specific cost and performance data used for modeling came from a variety of sources and is provided in detail in Appendix F: Assumptions for EnCompass Modeling Assumptions.

Supply-Side Generation

A discussion of each of the coal- and gas-fired technologies and other supply-side technologies is included in the following pages. The technologies are grouped into the following two categories:

<u>Generation Alternatives in the Model</u>

- Simple Cycle Combustion Turbine (Large and Small)
- Wind
- Solar Photovoltaic
- Battery Storage

<u>Pre-screened Generation Alternatives Not in the Model</u>

- Nuclear
- Pulverized Coal - Subcritical
- Atmospheric Circulating Fluidized Bed Coal (ACFB)
    - Integrated Gasification Combined Cycle (IGCC)
    - Phosphoric Acid Fuel Cell (PAFC)
- Pulverized Coal – Supercritical and Ultra-supercritical (green field site)
- Supercritical Coal, using a brown field site
- Reciprocating Engine Plants
- Hydro (owned projects)
- Heat Recovery
- Anaerobic Digestion
- Landfill Gas
- Microturbines
- Biomass
- Geothermal

Whether a technology was pre-screened or included in the model for capacity expansion evaluation is indicated in the text. The effort on screening resources was necessary to develop a useful modeling tool that was practical in terms of run-time while simultaneously comprehensive in evaluating the forwardlooking resource mix. It is important to note that any resource used as a potential future addition in the EnCompass model was intended to be generic and representative of the Company's needs. In no way do the alternatives selected for modeling purposes exclude future consideration of competing options in similar generation categories.

1.1 Technology options included in the model

Simple Cycle Combustion Turbine - Large
The model was given the preferred combustion turbine option. This is a heavy-duty frame unit with an ISO rating of about 248 MW. The heavy-duty frame units are characterized by a lower capital cost per kW and lower maintenance cost.

Aeroderivative Simple Cycle Combustion Turbine – Small
The 49 MW ISO-rated alternative is based on the existing GELM6000 aeroderivative technology that Otter Tail currently owns and operates at Solway, MN. As the name implies, aero derivative electric generation units were derived from gas turbine development for the aircraft industry. The traits of aeroderivative units compared to the frame-style gas turbines are typically, faster starts, higher efficiency, smaller overall size, and higher capital cost in $/kw. However, frame CT technology has advanced, and it should be noted that starts times and efficiency have dropped in recent years, as now some frame CT suppliers are offering units that can meet the 10 minute start time that was the hallmark of aero derivative units in the past.

Wind Generation
Wind generation was made available to the model in 50 MW blocks throughout the study period modeled as a purchased power transaction.

Solar Generation
Solar generation was made available to the model in 25 MW blocks throughout the study period modeled as a purchased power transaction.

Battery Storage
4-hour battery storage was made available to the model in 25 MW blocks throughout the study period modeled as a purchased power transaction.

Paired Battery Storage
4-hour paired battery storage was made available to the model in 10 MW blocks throughout the study period modeled as a purchased power transaction. This resource could only be selected in combination with a 25 MW solar resource.

1.2 Technology options not allowed in the model

Combined Cycle Gas Turbine (CCGT)
The basic principle of the Combined Cycle Gas Turbine is to use a gaseous fuel such as natural gas, or a liquid fuel such as no. 2 fuel oil, to produce power in a gas turbine and to use the hot exhaust gases from the gas turbine to produce steam in a Heat Recovery Steam Generator (HRSG). The steam is used to

generate electric power with a steam driven turbine-generator set. Typical CCGT units operate with natural gas as the operating fuel, but often dual-fuel capability with oil as a backup is used to increase the availability of the generation when natural gas supplies are curtailed. Given the size of Otter Tail's system and the lack of a significant capacity need during the planning period it was decided that a large CCGT unit would not be a reasonable option and was removed from the model.

Nuclear

Electricity from a nuclear power plant remains a very clean and safe form of electrical generation in the United States and the world. In 1994, the Minnesota Legislature passed a law that created a moratorium on the construction of new nuclear generation facilities in Minnesota (216B.243, subd. 3b). Nuclear energy was not considered as a resource alternative because of the law listed above, and what appear to be very high costs related to siting, permitting, and construction. Additionally, the Company is not aware of any nuclear project under development soliciting joint ownership. Due to the factors listed above, the addition of nuclear generation was not included in the model.

Carbon Capture and Sequestration (CCS)

There is significant research and development underway related to carbon dioxide capture and sequestration from fossil-fuel electric generating units; however, currently only two commercial power plants have been equipped with this technology worldwide. While there is much information in the public domain about development work, demonstration projects, and future-looking analysis for resource planning purposes, it is the position of Otter Tail that CCS development needs to continue to develop to understand cost certainty and feasibility. Additionally, it is Otter Tail's understanding that the current CCS technologies require very high levels of control of sulfur-dioxide prior to routing the flue gas to the CCS equipment. Therefore, the Coyote Station sulfur-dioxide scrubber would first need to be upgraded to the high-control scenario being considered by the Regional Haze Rule, which would result in additional capital and operational costs, before employing carbon capture technology (if the addition of CCS became viable). Due to these increased scrubber costs and due to the uncertainties around CCS, since the base assumption in the resource planning modeling analysis is that no Regional Haze Rule upgrades are necessary, and since that analysis supports that Coyote is uneconomic and planning for withdrawal is prudent, Otter Tail has not included CCS as an option to the resource planning model. If MISO requirements, or the MISO market changes, and if CCS cost estimates and operational efficiencies are proven acceptable, the Company will reconsider this position.

Pulverized Coal - Subcritical

Pulverized coal boiler technology is a mature and reliable energy producing technology around the world. The operating pressure of conventional coal-fired power plants can be classified as sub-critical and super-critical. Sub-critical and super-critical technologies refer to the state of the water that is used in the steam generation process. The critical point of water is 3208.2 psia and 705.47° F. At this critical point, there is no difference in the density of water and steam. At pressures of about 3208.2 psia, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. A sub-critical pulverized coal unit was eliminated from consideration as an option because of higher emissions and a less efficient heat rate.

Pulverized Coal – Supercritical and Ultra-Supercritical
The current Minnesota Next Generation Act of 2007 eliminates any reasonable chance of construction of coal-fired generation for Minnesota and was not made available to the model. Super-critical pulverized coal units have been part of the U.S. power generation mix since the mid-1950's. Since the 1980's, the development of high strength materials and Distributed Control Systems (DCS) have helped to make supercritical units easier to control and operate. Supercritical units typically operate at 3500 psig and up to 1050° F or 1080° F. at the steam turbine inlet. In addition, while there is no current technical definition of an ultra-supercritical unit, it seems to be generally accepted that units designed to operate at 1100° F or higher are ultra-supercritical. There is currently at least one new unit that is being constructed in the United States where the design steam temperatures are above 1100° F. Heat rates for supercritical or ultra-supercritical units can be lower than 9,000 btu/kWh. If the average heat rate of the current coal fleet is 11,500 btu/kWh, use of a modern supercritical or ultra-supercritical unit would result in over 20% less coal being burned per MWh or 20% less CO_2 emissions per MWh.

Atmospheric Circulating Fluidized Bed Coal (ACFB)
The consideration of a baseload coal-fired unit at the Big Stone Plant (BSP) site included evaluation of a large ACFB facility. The combustion within a fluidized bed boiler occurs in a suspended bed of solid particles in the lower section of the boiler. Combustion within the bed occurs at a slower rate and lower temperature than a conventional pulverized coal-fired boiler. Deviations in fuel type, size, or Btu content have minimal effect on the furnace performance characteristics. The bed allows for re-injection of a sorbent, such as fly ash or limestone, to reduce SO_2 emissions. This type of operation requires approximately 1.5 times the quantity of limestone to achieve a reduction in SO_2 similar to that of a wet limestone scrubber.

One of the benefits of an ACFB facility would have been an increased ability to use biomass fuels. The BSP unit already has an alternative fuels handling facility and the capability to burn alternate fuels. There has been difficulty in expanding the use of biomass fuels at BSP due to cost and availability. The benefit of being able to use biomass fuels was outweighed by a number of other factors, and a large fluidized bed unit was eliminated from consideration. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 emissions. Any ACFB alternative would require CCS to be installed in order to serve load in Minnesota. Otter Tail Power's view of CCS is that it is a promising technology but not currently commercial.

Integrated Gasification Combined Cycle (IGCC)
IGCC technology produces a low energy value syngas from coal or solid waste, for firing in a conventional combined cycle plant. The gasification process in itself is a proven technology having been previously used extensively for production of chemical products such as ammonia for use in fertilizer. The U.S. Department of Energy (DOE) has jointly funded several power plant facilities through the U.S. The majority of the DOE test facilities use entrained flow gasification design with coal as feedstock. In that process, coal is fed in conjunction with water and oxygen from an air separation unit, into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exists at around 2400° F. and is then cooled to less than 400° F. in a gas cooler, which produces additional steam for both the steam turbine and the gasification process. Particulate, ammonia (NH_3), hydrogen chloride, and sulfur are then removed from the raw syngas stream. The cooled and treated syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific value syngas. Exhaust heat from the gas turbine then generates steam in a HRSG which in turn powers a steam turbine.

It is recognized that IGCC, in theory, shows potential to become a reliable, low emission source of electrical energy in the future that more easily adapts to the potential of CCS. Compared to supercritical pulverized coal, IGCC projects appear to have higher upfront capital costs, variable O&M, and fixed O&M. The Minnesota Next Generation Energy Act of 2007 requires new coal-based generation to offset CO2 emissions. Any IGCC alternative would require CCS to be installed. Otter Tail Power's view of CCS is that it is a promising technology but appear to not be economically viable today. Based on all of these considerations, Otter Tail did not include IGCC as an option in the planning model.

Reciprocating Engine Plants

Large-scale reciprocating engine power plants have begun to gain in popularity in some areas of the country in recent years. A reciprocating engine plant is constructed of incrementally sized engines (2 MW – 16 MW each). Most large-scale reciprocating engine plants are fueled with natural gas only. However, some systems may be dual fuel (natural gas and fuel oil). Typically speaking, the construction costs of a reciprocating engine plant are more expensive than a simple cycle combustion turbine (perhaps 10 percent – 20 percent higher). However, on a unit-to-unit comparison, the reciprocating engine is more efficient than a typical aeroderivative combustion turbine. If you consider partial load operation, the overall fuel savings can be considerable. Some energy providers have viewed the installation of reciprocating engine plants as a good fit to a region with high wind or other intermittent energy resources. A generation resource that is capable of high efficiency through a wide range of output may become attractive enough to overcome initial higher installation costs. Through the prescreening process, reciprocating engines were excluded from the alternatives made available to EnCompass, largely due to the higher O&M and capital costs.

Phosphoric Acid Fuel Cell (PAFC)

The model evaluation excluded the option to select fuel cells due to the resource's higher costs compared to other units of similar technology. Fuel cells function by converting hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cells can sustain high efficiency operation even under partial load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size facilities according to power requirements. One of the most significant benefits to fuel cells is the lack of emissions. The only significant emissions are water and carbon dioxide.

Hydro

For past resource plan filings Otter Tail has reviewed the potential for cost-effective small hydro development within its service territory. A Minnesota Department of Natural Resources (DNR) survey of potential sites within the state served as a basis for that review. The DNR conclusion was that the existing economic sites had already been developed. For that reason, Otter Tail did not include any potential development of small hydro within the model.

Even if potential sites existed within the Company's service territory, it is unlikely that they would be economic for development if the sites were under FERC jurisdiction. If a waterway has a designation as a navigable stream, then it falls under FERC jurisdiction. Otter Tail's small hydros on the Otter Tail River near Fergus Falls were all built prior to FERC licensing requirements. The Otter Tail River was designated as a navigable stream because in the 1800's it was used for transportation and to float logs to the sawmill. In the late 1980's and early 1990's, Otter Tail was ordered to obtain FERC licensing on these units. The licensing process took several years and cost about $400/kW, for existing units. The licensing cost for developing a new site is likely to be so high as to make the process uneconomic.

Anaerobic Digestion
Previous study work within Otter Tail concluded the amount of potential generation from anaerobic digestion within Otter Tail's system may result in minimal (less than 5 MW) opportunity and too small to be of consequence to this resource plan filing. Anaerobic digestion was not included as a generation option within the model.

Landfill Gas
According to an EPRI report completed in the late 1990's, the Otter Tail Service territory does not include any landfills of sufficient size to support a landfill gas generating facility. The only two landfills in the area that were identified as having sufficient size are located at Fargo and Grand Forks, both served by another utility. Fargo now has a unit installed. Each of those landfills was identified as having the potential to support two 2 MW generators. Landfill gas was not included as an option within the model.

Microturbines
Microturbines are miniature combustion turbines, similar in concept to the large combustion turbines used in conventional utility power plants. Whereas large combustion turbines range from 20,000 to over 330,000 kW, microturbines fit into the 25 to 400 kW range. The waste heat from the turbine exhaust can be collected to supply a useful thermal load, which improves the overall cycle efficiency and the economics. However, the capital costs are still higher than the cost of a standard utility size combustion turbine and the efficiencies are much worse. At this point in time, potential economic applications are somewhat limited. The model did not include consideration of microturbines due to their small size, limited application at this time, and high cost.

Biomass
Since the early 1990's Otter Tail has made an effort to use renewable fuels in its existing coal-fired plants. The Big Stone Plant has burned a number of renewable and alternate fuels over the years and has an alternative fuels handling facility to aid in blending such fuels in with coal. Some of the renewable fuels that have been tried or researched over the years include spoiled or research corn seed, wood waste in various types, soybeans, sunflower hulls, and similar agricultural wastes. Some of these materials caused significant problems in test burns by either plugging fuel handling systems (bark wood waste) or plugging boilers (soybeans). Sunflower hulls and soybeans have proven to be problematic due to their high content of potassium. As of January 1, 2010, Big Stone Plant has stopped the alternative fuel program. The primary reasons were the limited availability of fuel and the high cost of maintenance of the handling facilities.

Otter Tail did not include any other additional biomass alternatives in the model. As the cost of fossil fuels increases, other markets develop for biomass fuels such as wood waste. In many cases, the wood products companies that create the waste use it as fuel in their own process. Otter Tail has worked with customers on potential wood waste-fired biomass facility investigations. The fuel supply is limited, and the costs of such facilities are high. The development potential of these facilities is limited and very site specific. To date, Otter Tail has not found other opportunities for development of such facilities with costs being close to economic.

Geothermal

Otter Tail has worked with the Geology Dept. at the University of North Dakota on investigating the potential for geothermal energy. Western North Dakota has geothermal resources in temperature ranges that would be suitable for binary cycle geothermal technologies. A binary cycle facility typically pumps natural water or brine from underground that has been heated by the earth to moderate temperature ranges of 200° F. - 500° F. The heat in the fluid is transferred to another working fluid such as iso-pentane which is used in place of water in a normal vaporization/condensation cycle. The brine is then reinjected back into the earth. The extraction and reinjection wells are typically from 1,000 – 3,000 feet deep and require significant horsepower to extract the fluid and then reinject it. The resources in western North Dakota are located much too deep to be economic for binary cycle operation, typically in the 10,000 – 12,000 foot range. Otter Tail did not include any geothermal options as potential generating resources in the model.

Otter Tail does have geothermal heat pumps as programs within its CIP process.

Appendix E: Assessment of Federal and State Environmental Regulations

Assessment of Federal and State Environmental Regulations

I. GREENHOUSE GAS REGULATION

In 2009 the Environmental Protection Agency (EPA) began addressing greenhouse gas (GHG) emissions using the Clean Air Act (CAA). The first step in the EPA rulemaking process was the publication of an endangerment finding in the Federal Register on December 15, 2009. The EPA found that carbon dioxide (CO_2) and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride – threatened public health and welfare. These findings did not themselves impose any requirements to control GHG emissions, but they were a prerequisite to finalizing GHG standards for vehicles. Additionally, since the motor vehicle standard regulated GHG emissions for the first time under the CAA, GHG emissions were included in the pollutants subject to the requirements of the New Source Review program of the CAA.

A. Existing Source Guidelines

1. Background

The EPA has twice embarked upon developing GHG performance standards for existing power plants under CAA Section 111(d). Under Section 111(d), the EPA promulgates emission guidelines, and the states are then given a period of time to develop plans to implement the standard. The EPA reviews each state-developed standard and then approves it if the state's plan comports with the federal emission guidelines; if the state does not submit a plan or the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state.

A "standard of performance," is defined as:

> …a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.

Additionally, for existing sources, Section 111(d) requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."

2. Clean Power Plan

On August 3, 2015 EPA announced existing source guidelines under Section 111(d) of the CAA, termed the Clean Power Plan ("CPP"). The CPP set state-specific goals to limit CO2 emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the goals. EPA applied three building blocks to each grid interconnection that resulted in final rule national uniform emission rate standards. On February 9, 2016 the United States Supreme Court granted emergency applications seeking a stay of the rule.

3. Affordable Clean Energy Rule

On June 19, 2019 EPA announced the Affordable Clean Energy Rule ("ACE Rule"). The rule established guidelines for states to use in developing plans to address greenhouse gas emissions from existing coal fired power plants. The final rule established heat rate improvements as the best system of emissions reductions (BSER) for reducing carbon dioxide emissions. Simultaneous with the final ACE Rule, EPA took action to repeal the CPP, and EPA also finalized revisions to the timing and content requirements of Section 111(d) state implementation plan submissions.

Several petitioners filed challenges to the ACE Rule, and on January 19, 2021 the United States Court of Appeals for the District of Columbia vacated the rule and the repeal of the CPP, and remanded the record back to EPA. Since the ruling, EPA has clarified states do not have any obligations to submit plans under the ACE Rule or CPP. EPA has suggested that it will likely propose new rules to replace the CPP and ACE Rule in the near future.

B. New Source Performance Standards

On October 23, 2015 the EPA published final New Source Performance Standards (NSPS) under section 111(b) of the CAA that requires certain new units (as well as modified and reconstructed units) to meet CO_2 emission standards. New natural gas combustion turbines are required to meet a standard of 1,000 lbs. of CO_2 per gross megawatt hour averaged over a 12-month period if they meet the definition of a baseload unit. New natural gas combined cycle units are anticipated to fit into this category. Simple cycle combustion turbines are regulated in a non-baseload category that is required to meet a heat input based standard that can be met by primarily burning clean fuels such as natural gas.

II. CRITERIA AIR POLLUTANTS

The CAA requires EPA to set standards for six common air pollutants known as "criteria" pollutants. The criteria pollutants are: nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM), ozone, carbon monoxide and lead. These emissions are sometimes regulated under CAA programs when they are a precursor to other types of air pollution. NO_X, for example, is regulated because it is a precursor to fine particle formation, ozone formation, acid deposition and regional haze. Similarly, SO_2 is a precursor to fine particle formation, acid deposition and regional haze. Particulate matter is a precursor to regional haze. This section describes the effect of anticipated regulations to limit criteria pollutant emissions from power plants, with a specific focus on OTP's generating facilities.

A. Acid Deposition and National Ambient Air Quality Standards

Acid Deposition

The Acid Rain Program (ARP) was created under Title IV of the 1990 amendments to the CAA. Under the ARP, emissions of SO_2 and NO_X from the electric utility industry have been reduced substantially.

1. ARP SO_2 Program

The SO_2 program sets a permanent cap on the total amount of SO_2 that may be emitted by electric generating units greater than 25 megawatts in the contiguous United States. The program was phased in, with the final 2010 SO_2 cap set at 8.95 million tons, which represents a level of about one-half of the emissions from the power sector in 1980.

Under this program, EPA allocates allowances to each source for use in or after a specified year. Each allowance permits a unit to emit one ton of SO_2. At the end of the year, if a source's emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source's annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market.

Otter Tail's compliance strategy has always been, and continues to be, to work within our free allowance allocation and use banked allowances when necessary to avoid having to purchase allowances on the open market.

2. ARP NO_X Program

Title IV requires NO_X emission reductions for certain coal-fired electric generating units (EGUs) by limiting the NO_X emission rate (expressed in lb/mmBtu) in lieu of having an emissions allowance trading program. Congress applied these rate-based emission limits based on a unit's boiler type. The goal of the program is to limit NO_X emission levels from the affected coal-fired boilers so that their emissions are at least two million tons less than the projected level for the year 2000 without implementation of Title IV. Otter Tail is able to maintain compliance with the Title IV NO_X emission rates by operating existing NOx control equipment at Big Stone Plant and Coyote Station.

National Ambient Air Quality Standards

The CAA requires EPA to set two types of National Ambient Air Quality Standards (NAAQS). Primary standards provide public health protection, while secondary standards provide public welfare protection.

In general, compliance with NAAQS is achieved through development of State Implementation Plans (SIPs) that limit emissions from sources located in areas designated as non-attainment.

To help states attain the NAAQS in local areas, the EPA evaluates whether certain regional or nationally applicable emission limitations should be put into place in order to assist the states in attaining the NAAQS, or states may petition EPA to impose reductions in upwind states. Additionally, federal regulations require that any permit issued under the Prevention of Significant Deterioration (PSD) provisions of the CAA must contain a demonstration of source compliance with the NAAQS.

1. NO_2 and SO_2 NAAQS

In 2010, the EPA promulgated new NAAQS for nitrogen dioxide (NO_2) and SO_2 averaged over one hour. In 2018 for NO_2 and in 2019 for SO_2, EPA completed another review and decided to retain the 2010 standards without modification.

For the 2010 NO_2 NAAQS, the States of Minnesota, North Dakota, and South Dakota recommended that their entire states be designated as attainment based on multiple years of air sampling data. The EPA reviewed the recommendations, and on January 20, 2012, EPA determined that no area in the United States is violating the 2010 NO_2 NAAQS. Therefore, EPA designated all areas of the country as "unclassifiable/attainment".

For the 2010 SO_2 NAAQS, EPA proceeded with different rounds of designations. In one round of designations, EPA promulgated SO_2 designations for areas that either 1) had newly monitored violations of the 2010 SO_2 standard, and 2) areas that contain any stationary source that emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons of SO_2 and had an emission rate of at least 0.45 lb/mmbtu in 2012. Based on that criteria, the areas surrounding Big Stone Plant and Coyote Station were subject to review. Air dispersion modeling was completed for each site, and based on that analysis, in July 2016 EPA designated the areas surrounding Coyote Station in Central Mercer County, ND and Big Stone Plant in Grant County, SD as "unclassifiable/attainment".

2. Ozone and PM NAAQS

In the electric power industry, the rule currently being used to assist with attainment of the NAAQS for ozone and particulate matter from regional sources is EPA's Cross-State Air Pollution Rule (CSAPR) that first went into effect on January 1, 2015. CSAPR requires SO_2 and NO_x emission reductions from fossil fuel-fired power plants located in the eastern portion of the United States. The Rule establishes two new types of SO_2 allowances (Group 1 and Group 2) and two new types of NO_X allowances (Annual and Ozone). Minnesota is classified as a Group 2 SO_2 state (along with six other states - Alabama, Georgia, Kansas, Nebraska, South Carolina and Texas) and an Annual NO_X state (along with 22 other states). South Dakota and North Dakota are not included in CSAPR. On March 15, 2021, EPA finalized revisions to CSAPR for the 2008 ozone NAAQS; however, the revised CSAPR update does not impact Minnesota, North Dakota, or South Dakota.

Similar to the Acid Rain Program, under CSAPR, EPA allocates allowances to each source for use in or after a specified year. At the end of the year, if a source's emissions are less than its annual allowance allocation, it can bank the extra allowances forward for use in future years. If a source's annual emissions are more than its annual allocation, the source can then either use banked allowances from previous years, transfer allowances from another facility, or purchase allowances on the open market. However, a Group 2 SO_2 unit can only use Group 2 SO_2 allowances. Since Hoot Lake Plant has retired and Big Stone Plant and Coyote Station are not subject to CSAPR, this rule does not currently significantly impact OTP.

On October 1, 2015, the EPA announced that it tightened the primary and secondary NAAQS for ozone from 75 parts per billion (ppb) to 70 ppb. Minnesota, North Dakota, and South Dakota do not have any nonattainment areas at the 70 ppb level.

For particulate matter, EPA has established both an annual and a 24-hour standard for fine particulates (PM2.5), and a 24-hour standard for course particulate (PM10). The PM2.5 standards were last revised in 2012, and in December 2020 EPA announced its decision to retain the standards without revision. However, in June 2021 EPA announced it will reconsider the December 2020 decision and that it expects to issue a final rule in Spring 2023. The states of Minnesota, North Dakota, and South Dakota are all currently in compliance with the particulate matter NAAQS.

B. Regional Haze Program

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution." Federal Class I areas include 156 national parks, memorial parks, and wilderness areas.

In 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing the Regional Haze Rule (RHR) as the comprehensive visibility protection program for Federal Class I areas. The RHR did not mandate specific milestones or rates of progress, but instead called for states to establish goals that provide for reasonable progress towards achieving natural visibility conditions by the year 2064.

States are required to submit RHR state implementation plans (SIPs) that evaluate reasonable progress in approximately 10-year increments. The first Regional Haze planning period covered the years 2008-2018, while the second planning period will focus on the next timeframe ending in 2028.

For the first Regional Haze planning period, Big Stone Plant installed selective catalytic reduction in conjunction with separated over-fire air for control of nitrogen oxides, a scrubber for reducing SO_2, and a baghouse to control particulate matter. The equipment began commercial operation on December 29, 2015. No additional emission reductions are anticipated to be required at Big Stone Plant for the second planning period.

At Coyote Station for the first planning period, separated overfire air equipment to reduce nitrogen oxide emissions was installed during a Spring 2016 outage. For the second planning period, Otter Tail, as operating agent for the co-owned Coyote Station, has provided the North Dakota Department of Environmental Quality (ND DEQ) with an analysis of technically feasible RHR control measures. When evaluating these potential control measures, the ND DEQ must consider four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected source.

Additionally, as described by an EPA August 2019 guidance document, states may choose to consider visibility benefits along with the four required statutory factors. The ND DEQ is part of a 15-state Western Regional Air Partnership (WRAP) that worked collaboratively to evaluate visibility conditions for the 118 Class I Areas in the WRAP region. As part of this evaluation, WRAP conducted two rounds of visibility modeling scenarios of "Potential Additional Controls" to allow states to weigh the projected visibility benefits of emission controls. The ND DEQ provided the following Coyote Station scenarios to WRAP:

- An emissions-controls case consistent with either a new dry scrubber or significant upgrades for sulfur dioxide control, and a new selective non-catalytic reduction system for nitrogen oxides control (both of which would require significant capital investment in emissions controls equipment at Coyote Station, and associated annual operation and maintenance costs).
- An emissions-controls case consistent with operational improvements for sulfur dioxide control, and no additional controls for nitrogen oxides (neither of which would require additional capital investment in emissions controls equipment at Coyote Station, but the first of which would require additional operation and maintenance costs).

Otter Tail anticipates that the ND DEQ will provide a draft SIP for public review in late 2021 or early 2022. Ultimately, EPA is responsible for final review and approval of the ND DEQ SIP, or alternatively disapproval and promulgation of a Federal Implementation Plan (FIP). The duration of the EPA review process is uncertain; for example, for the first 10-year reasonable progress increment, several SIPs were rejected by EPA and FIPs were proposed, resulting in several years of administrative proceedings and subsequent judicial review.

C. New Source Review

Under the New Source Review Program, the Prevention of Significant Deterioration (PSD) program applies to areas of the country that attain (or are unclassifiable) the National Ambient Air Quality Standards (NAAQS), such as the areas in which Otter Tail's facilities are located. PSD review requires persons constructing new major air pollution sources or implementing significant modifications to existing air pollution sources that constitute a significant net emissions increase to obtain a permit prior to such construction or modification. In order to obtain a PSD permit, the owner or operator of an affected facility must undergo a review which requires the identification and implementation of best-available control technology (BACT) for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

Otter Tail's existing facilities are not contemplating any changes that would result in PSD review.

III. HAZARDOUS AIR POLLUTANTS

Mercury and Other Hazardous Air Pollutant Emissions Rulemaking

The 1990 Amendments to the CAA required EPA to study the effects of emissions of listed hazardous air pollutants (HAPs) by electric steam generating plants. On March 16, 2011, EPA proposed Section 112 air toxics standards for all coal- and oil-fired EGUs that reflect the application of the maximum achievable control technology consistent with the requirements of the CAA. EPA signed a final rulemaking, termed the mercury and air toxics standards (MATS) rule, on December 16, 2011.

Coyote Station is meeting MATS by utilizing activated carbon injection in combination with its existing spray dryer and fabric filter. Big Stone Plant is meeting MATS through the installation activated carbon injection in conjunction with its existing selective catalytic reduction, circulating dry scrubber, and baghouse. Emissions monitoring equipment and stack testing is being utilized to verify compliance with the standards at each facility.

On June 29, 2015, the U.S. Supreme Court held that EPA must consider cost, including cost of compliance, before deciding whether regulation of mercury emissions is appropriate and necessary. The MATS rule, however, remained in effect while the case was remanded to the D.C. Circuit for further proceedings. On December 15, 2015, the D.C. Circuit ordered that the MATS rule be remanded to EPA without vacating the rule. On April 25, 2016, EPA issued a final supplemental finding that concludes that a consideration of cost does not change their determination that regulation of HAPs from coal and oil-fired EGUs is appropriate and necessary. On April 16, 2020, EPA finalized a rule that revises the 2016 cost finding, and now concludes MATS is not appropriate and necessary. However, even with this revision, EPA left MATS in place because electric generating units remain subject to regulation under Section 112 of the Clean Air Act. EPA also concluded that based on a risk and technology review, no changes to the current MATS emission standards are necessary. Challenges to these rulemakings are ongoing, and the current EPA Administration has announced they intend to review the MATS related actions of the prior Administration.

IV. COAL COMBUSTION RESIDUALS REGULATION

On December 19, 2014, EPA signed a final rule to further regulate coal combustion residuals (CCR) as non-hazardous waste under subtitle D of the Resource Conservation and Recovery Act (RCRA).

The final subtitle D rule required OTP to meet several new requirements, including installing additional groundwater monitoring wells, publishing data on our CCR units on a website, conduct structural integrity assessments, determine compliance with location restrictions, and develop and implement plans for fugitive dust, hydrologic capacity, run-on & run-off control, and closure & post-closure care.

The Hoot Lake Plant operates a dry ash disposal site that is regulated, permitted and inspected by the Minnesota Pollution Control Agency ("MPCA"). The existing operating site is lined with a synthetic liner with a leachate collection system, and it will be closed with a synthetic cover and an engineered soil cover following plant demolition activities. The site has a groundwater monitoring system and annual reports have been provided to the MPCA.

Big Stone Plant operates a dry disposal site that is regulated, permitted, and inspected by the South Dakota Department of Agriculture and Natural Resource ("DANR"). The site is underlain with native clay, and each portion of the designated disposal area is covered with clay and topsoil once it is filled to capacity. Monitoring of groundwater is ongoing and annual reports are provided to the DANR. In accordance with the CCR rule, during a fall 2018 outage, Big Stone Plant closed a surface impoundment via removal of all CCR and replaced it with new ash handling technology. Boiler slag is either dry disposed in the permanent disposal site or beneficially reused.

Coyote Station has one active dry disposal site that is regulated, permitted, and inspected by the ND DEQ. The site has an engineered clay liner for acceptance of flue gas desulfurization product and boiler slag. The site has a groundwater monitoring system and annual reports have been provided to the ND DEQ. Similar to Big Stone, in 2019 Coyote Station closed its surface impoundments via removing the CCR and installed new ash handling technology. Boiler slag is either dry disposed in the permanent disposal site or beneficially reused.

V. WATER REGULATION

A. 316(b)

Section 316(b) of the Clean Water Act (CWA) requires facilities with cooling water intake structures to ensure that the location, design, construction and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. EPA first promulgated regulations to implement section 316(b) in 1976. In 1977 the U.S. Court of Appeals for the Fourth Circuit remanded these regulations to EPA, which withdrew them and left in place a provision that directed permitting authorities to determine best technology available for each facility on a case-by-case basis. After numerous years of proceedings, on May 9, 2014, EPA signed the final rule setting national standards for cooling water intake structures at existing facilities with National Pollutant Discharge Elimination System (NPDES) permits that withdraw at least 2 million gallons of water per day (MGD) and use at least 25% of that water for cooling purposes.

Under the final rule, all affected facilities need to comply with one of seven Best Technology Available (BTA) alternatives for reducing impingement, while site-specific BTA for reducing entrainment will be up to the states. However, in addition to the seven BTA options for impingement, another option identified as "*de minimus*" impingement is provided in the rule. In this option, facilities with very low levels of impingement are not required to use any additional impingement controls. In any case, new requirements will be incorporated into NPDES permits to achieve 316(b) compliance "as soon as practicable according to the schedule of requirements set by the Director."

Both Big Stone Plant and Coyote Station use closed cycle cooling, and thus have not been significantly impacted by the 316(b) rule.

B. Effluent Limit Guidelines

The Clean Water Act establishes a structure for regulating discharges of pollutants to surface waters of the United States. As part of the implementation, EPA issues effluent limit guidelines (ELG) for industrial dischargers. EPA first issued ELG for steam electric power plants in 1974, with subsequent revisions in 1977 and 1982. EPA announced its decision to proceed with further possible revisions on September 15, 2009 and published a proposed rulemaking on June 7, 2013. On November 3, 2015, the EPA published the final rule that sets technology-based effluent limitations on certain types of discharges. Generally, the final rule establishes "no discharge" requirements for waste water discharge streams from wet flue gas desulfurization, fly ash transport, and bottom ash transport.

Effluent limits specific to Coyote Station is incorporated into its NPDES permits. Big Stone Plant is a zero-discharge facility and therefore does not have a NPDES permit Coyote Station's permit limits are based on a combination of state water quality standards, the Federal ELG, and best professional judgment. Coyote Station's primary effluent discharge is cooling tower blowdown. Moreover, by recently installing new ash handling technology and utilizing existing dry flue gas desulfurization technology, neither Coyote Station nor Big Stone Plant discharge any ash transport water or flue gas desulfurization wastewater.

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SUMMARY

Environmental Regulatory Assessment Summary

Legend:	Air related	Solid Waste related	Water related

Rule	Status	Anticipated Big Stone Plant Impact	Anticipated Coyote Station Impact	Anticipated Compliance Timeframe
Greenhouse Gas Regulation – 111(d)	Remanded	Unknown	Unknown	Unknown
Greenhouse Gas Regulation – NSPS	Final	N/A – Applicable to New Plants Only	N/A – Applicable to New Plants Only	New plants
Acid Rain Program	Final	Low impact. Maintain banked allowances (SO2); Operate existing SCR and overfire air	Low impact. Maintain banked allowances (SO2); Operate existing separated overfire air	Ongoing
2010 NO2 and SO2 NAAQS	Final	Low impact. Based on SO2 modeling, EPA has classified the area around Big Stone as attainment/unclassifiable.	Low impact. Based on SO2 modeling, EPA has classified the area around Coyote as attainment/unclassifiable.	Ongoing
Cross-State Air Pollution Rule	Final	None -- Rule does not apply to SD	None -- Rule does not apply to ND	N/A
Regional Haze Program Round 1	Final	Selective Catalytic Reduction and separated overfire air for NOx, scrubber for SO2, and baghouse for PM	Separated overfire air for NOx	Ongoing
Regional Haze Program Round 2	SIP under development	Low	TBD. Possible SO2 and NOx reductions	2028
Mercury and other Hazardous Air Pollutants (MATS)	Final	Existing pollution control equipment plus activated carbon injection	Existing pollution control equipment plus activated carbon injection	Ongoing
Coal Combustion Residuals	Final	CCR was removed from one surface impoundment and new ash handling technology installed. BSP manages an active dry ash disposal site. Future horizontal disposal site sequences may require a synthetic liner and leachate collection.	CCR was removed from three surface impoundments and new ash handling technology was installed. Coyote manages an active dry ash disposal site. Future horizontal disposal site sequences may require a synthetic liner and leachate collection.	Ongoing
Clean Water Act Section 316(b)	Final	Big Stone uses cooling ponds that qualify as closed cycle cooling	Coyote Station uses a cooling tower that qualifies as closed cycle cooling	Ongoing
Effluent Guidelines	Final	Big Stone does not generate ash transport or FGD wastewater.	Coyote does not generate ash transport or FGD wastewater.	Ongoing

Appendix F: EnCompass Modeling Assumptions

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1 Sensitivities Evaluated

Otter Tail produced 123 modeling runs for this resource plan. Figure 1 shows a grid of sensitivities evaluated in this resource plan. As further described in the Petition, for each sensitivity, this filing includes EnCompass modeling runs to provide insight into the impacts of Otter Tail continuing with its interest in Coyote Station through 2041, 2028, and 2026. This results in 57 modeling runs without externalities and 66 modeling runs with externalities. Otter Tail includes all modeling runs with and without externalities in Appendix I.

Figure 1: Sensitivities Evaluated

<table>
<tr><th>Sensitivity</th><th>Description</th><th></th><th></th></tr>
<tr><td>A</td><td>Base Case</td><td rowspan="19">Zero Externalities</td><td rowspan="23">Externality Values Applied</td></tr>
<tr><td>B</td><td>Preferred IRP</td></tr>
<tr><td>C</td><td>Regional Haze Mid Cost</td></tr>
<tr><td>D</td><td>Regional Haze High Cost</td></tr>
<tr><td>E</td><td>NG and Energy Markets +25%</td></tr>
<tr><td>F</td><td>NG and Energy Markets +50%</td></tr>
<tr><td>G</td><td>NG and Energy Markets +100%</td></tr>
<tr><td>H</td><td>NG and Energy Markets -25%</td></tr>
<tr><td>I</td><td>NG and Energy Markets -50%</td></tr>
<tr><td>J</td><td>Low Wind</td></tr>
<tr><td>K</td><td>Low Solar</td></tr>
<tr><td>L</td><td>Low Wind & Solar</td></tr>
<tr><td>M</td><td>Low Storage</td></tr>
<tr><td>N</td><td>High Interconnection Costs</td></tr>
<tr><td>O</td><td>Additional 10% MISO Capacity Requirement</td></tr>
<tr><td>P</td><td>Capacity Purchase Limit</td></tr>
<tr><td>Q</td><td>10% Increased Load</td></tr>
<tr><td>R</td><td>25% Increased Load</td></tr>
<tr><td>S</td><td>Carbon Tax</td></tr>
<tr><td>T</td><td>Low Externalities 2020-2024,
Low Cost of Carbon 2025-2050</td><td></td></tr>
<tr><td>U</td><td>High Externalities 2020-2024,
High Cost of Carbon 2025-2050</td><td></td></tr>
<tr><td>V</td><td>Low Externalities 2020-2024,
Median Cost of Carbon 2025-2050</td><td></td></tr>
<tr><td>W</td><td>High Externalities 2020-2024,
Median Cost of Carbon 2025-2050</td><td></td></tr>
</table>

2 Wind Energy Assumptions

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

The wind energy price assumptions for 2023 through 2026 include current legislation and Internal Revenue Service (IRS) guidance provided in IRS Notice 2020-41 which allows for 60 percent production tax credit (PTC) for projects that meet certain criteria. The wind energy price assumptions after 2026 do not include PTCs.

Wind project sizes are assumed to be 50 MW in size with a 50 percent net capacity factor and an accredited capacity of 16 percent. Otter Tail models wind projects as purchased power agreements with a fixed levelized cost of energy.

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

Figure 2: Base Wind Energy Assumptions

				Base Case $/MWh				
Year available	Wind Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	PTC adjustment	Inconnection adder assuming $500/kW	Congestion adder	Base Case ($/MWh)
2022-2036	Generic	50	16%	$35.00	$0.00	$10.00	$3.50	$48.50
2023-2026	Generic - 60% PTC	50	16%	$30.00	($8.00)	$10.00	$3.50	$35.50
2027-2036	Surplus Interconnection	50	0%	$35.00	$0.00	$0.00	$0.00	$35.00
2033-2036	Replacement Interconnection	50	16%	$35.00	$0.00	$0.00	$0.00	$35.00

Figure 3 provides the assumptions included in the Low Sensitivity wind energy assumptions. The low wind price sensitivities are included in sensitivities *J* and *L* in Appendix I.

Figure 3: Low Sensitivity Wind Energy Assumptions

				Low Sensitivity $/MWh				
Year available	Wind Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	PTC adjustment	Inconnection adder assuming $500/kW	Congestion adder	Low Wind ($/MWh)
2022-2036	Generic	50	16%	$26.00	($10.00)	$10.00	$3.50	$29.50
2023-2026	Generic - 60% PTC	50	16%	$26.00	($10.00)	$10.00	$3.50	$29.50
2027-2036	Surplus Interconnection	50	0%	$26.00	($10.00)	$0.00	$0.00	$16.00
2033-2036	Replacement Interconnection	50	16%	$26.00	($10.00)	$0.00	$0.00	$16.00

3 Solar Energy Assumptions

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

Similar to wind, the solar energy price assumptions for 2023 through 2026 include current legislation and Internal Revenue Service (IRS) guidance provided in IRS Notice 2020-41 which allows for 26 percent investment tax credit (PTC) for projects that meet certain criteria. The solar energy price assumptions after 2026 include a 10 percent ITC.

Solar project sizes are assumed to be 25 MW in size with 24 percent net capacity factor and an accredited capacity of 30 percent. Otter Tail includes Figure 4 below with the solar project alternatives included in the base model.

Figure 4: Base Case Solar Energy Assumptions

				Base Case $/MWh				
Year available	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	ITC adjustment	Inconnection adder assuming $200/kW	Congestion adder	Base Case ($/MWh)
2023-2026	Generic - 26% ITC	25	30%	$42.00	($7.00)	$7.00	$0.00	$42.00
2023-2026	Surplus Interconnection - 26% ITC	25	0%	$42.00	($7.00)	$0.00	$0.00	$35.00
2023-2026	Surplus Interconnection - 26% ITC w/ Capacity	25	30%	$42.00	($7.00)	$0.00	$0.00	$35.00
2023-2026	Replacement Interconnection - 26% ITC	25	30%	$42.00	($7.00)	$0.00	$0.00	$35.00
2022-2036	Generic	25	30%	$39.00	($2.25)	$7.00	$0.00	$43.75
2027-2036	Surplus Interconnection	25	0%	$39.00	($2.25)	$0.00	$0.00	$36.75
2026-2036	Surplus Interconnection	25	30%	$39.00	($2.25)	$0.00	$0.00	$36.75
2033-2036	Replacement Interconnection	25	30%	$39.00	($2.25)	$0.00	$0.00	$36.75

Similar to wind, Otter Tail includes three categories for solar projects: (1) Generic solar resources require a new generation site, (2) Surplus interconnection solar may be added alongside an existing generating facility where the generation of both resources does not exceed the existing interconnection amount of the original facility, and (3) Replacement interconnection solar resources reuse the existing interconnection rights of an existing resource that is retiring. Figure 5 provides the assumptions included in the Low Sensitivity solar energy assumptions.

The low solar price sensitivities are *K* and *L* in Appendix I.

Figure 5: Low Sensitivity Solar Energy Assumptions

				Low Sensitivity $/MWh				
Year available	Solar Project Alternatives	Size (MW)	Accredited capacity (% of Nameplate)	LCOE modeled as a fixed price PPA	ITC adjustment	Inconnection adder assuming $200/kW	Congestion adder	Low Solar ($/MWh)
2023-2026	Generic - 26% ITC	25	30%	$30.00	($7.00)	$7.00	$0.00	$30.00
2023-2026	Surplus Interconnection - 26% ITC	25	0%	$30.00	($7.00)	$0.00	$0.00	$23.00
2023-2026	Surplus Interconnection - 26% ITC w/ Capacity	25	30%	$30.00	($7.00)	$0.00	$0.00	$23.00
2023-2026	Replacement Interconnection - 26% ITC	25	30%	$30.00	($7.00)	$0.00	$0.00	$23.00
2022-2036	Generic	25	30%	$27.00	($7.00)	$7.00	$0.00	$27.00
2027-2036	Surplus Interconnection	25	0%	$27.00	($7.00)	$0.00	$0.00	$20.00
2026-2036	Surplus Interconnection	25	30%	$27.00	($7.00)	$0.00	$0.00	$20.00
2033-2036	Replacement Interconnection	25	30%	$27.00	($7.00)	$0.00	$0.00	$20.00

4 Battery Storage Assumptions

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

The battery storage price assumptions included below are based on Otter Tail's industry knowledge and estimates specific to Otter Tail. The low price storage costs include a 25 percent reduction from the base assumptions.

Figure 6: Battery Storage Assumptions

Year available	Battery Storage Alternative	Size (MW)	Accredited capacity (% of Nameplate)	Base Cost Fixed Cost ($/Year)	Low Cost Fixed Costs ($/Year)
2022-2036	10 MW Paired Battery	10	95%	$828,000	$621,000
2022-2036	25 MW Battery	25	95%	$3,000,000	$2,250,000

5 Natural Gas Fuel Price Assumptions

Figure 7 shows the forecasted monthly natural gas fuel prices used in the 2021 resource plan. Otter Tail used the Wood Mackenzie March 2021 North American Power Service for determining the natural gas fuel prices used in the resource plan. Otter Tail evaluated natural gas prices at +/- 25percent of the base case and +/- 50 percent of the base case and at +100 percent of the base case. The natural gas price sensitivities are *E, F, G, H*, and *I* in Appendix I.

Figure 7: Natural Gas Fuel Price Assumptions

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

6 Coal Price Assumptions

Otter Tail's coal price forecasts for its two coal-fired thermal units are developed using existing coal and freight contracts. For modeling purposes in this resource plan coal fuel prices are broken into two portions: fixed fuel costs and variable fuel costs. The 2021 fixed fuel costs modeled for Big Stone reflect the rail car lease costs of **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** (OTP portion) annually. The 2021 fixed fuel costs modeled for Coyote station are modeled at **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** (OTP portion) annually and represent the non-variable portion of the fuel supply agreement.

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

Figure 8: Big Stone Plant Variable Portion Coal Price Assumptions

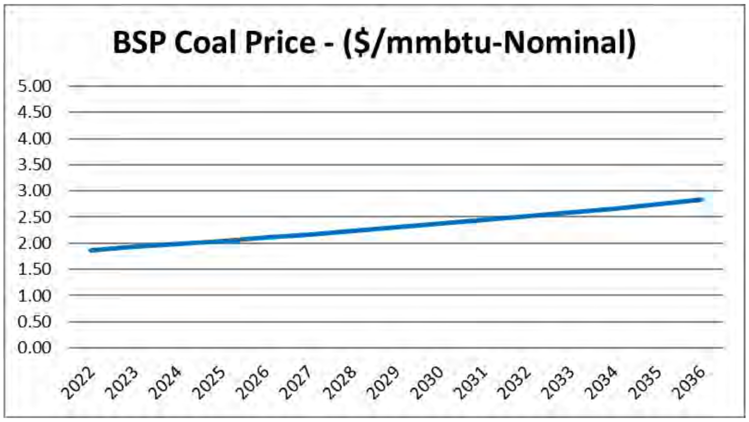
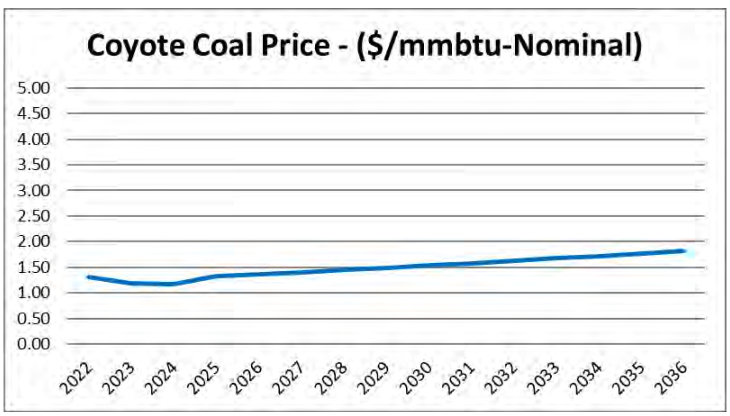


Figure 9: Coyote Station Variable Portion Coal Price Assumptions

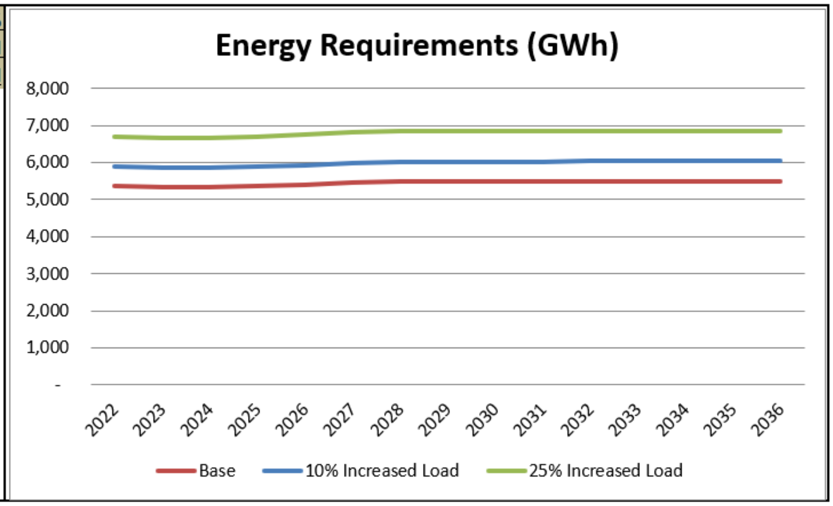


7 Increased Load Assumptions

Figure 10 shows the energy requirement assumptions used in the resource plan. The increased load sensitivities are provided in Appendix I as Sensitivity *Q* and *R*, respectively.

Figure 10: Increased Load Assumptions

Year	Base	10% Increased Load	25% Increased Load
2022	5,361	5,898	6,701
2023	5,328	5,862	6,660
2024	5,333	5,867	6,666
2025	5,363	5,900	6,704
2026	5,394	5,934	6,742
2027	5,450	5,996	6,812
2028	5,479	6,028	6,849
2029	5,480	6,029	6,850
2030	5,477	6,026	6,846
2031	5,479	6,029	6,849
2032	5,481	6,031	6,852
2033	5,483	6,032	6,854
2034	5,484	6,034	6,855
2035	5,485	6,035	6,857
2036	5,486	6,036	6,858

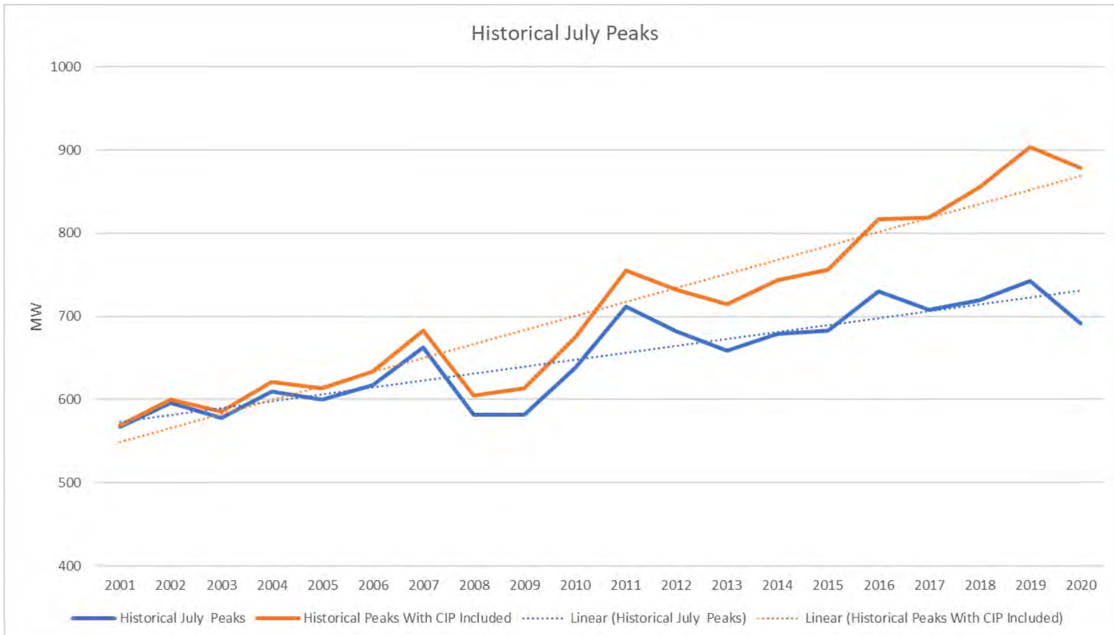


8 Energy Efficiency Assumed in Forecast

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

Figure 11 shows the historical DSM for 2001 through 2020 where the solid blue line provides the actual historical July peaks, and the solid orange line provides the historical July peak had Otter Tail not had any demand reductions. The dotted blue line provides the actual historical slope of 8.36 compared to the orange dotted line slope of 16.84 if Otter Tail had not had any demand reductions.

Figure 11: DSM Assumptions



The values for each year are listed in Figure 12.

Figure 12: Built-In DSM/EE

Year	Historical CIP Demand Reduction	12-Year Cumulative Total	Historical July Peaks	Historical Peaks With CIP Included
2001	2.2	2.2	567	569.2
2002	1.9	4.2	596	600.2
2003	3.0	7.2	578	585.2
2004	3.6	10.7	610	620.7
2005	2.9	13.6	600	613.6
2006	3.2	16.8	617	633.8
2007	3.0	19.8	663	682.8
2008	3.4	23.2	582	605.2
2009	8.2	31.4	582	613.4
2010	5.8	37.2	638	675.2
2011	6.3	43.5	712	755.5
2012	6.4	49.9	682	731.9
2013	7.7	55.4	659	714.4
2014	10.6	64.0	679	743.0
2015	12.3	73.3	683	756.3
2016	17.3	87.1	730	817.1
2017	26.7	110.9	708	818.9
2018	28.1	135.8	719	854.8
2019	28.5	161.3	742	903.3
2020	29.9	187.8	691	878.8

	SLOPE	8.36	16.84

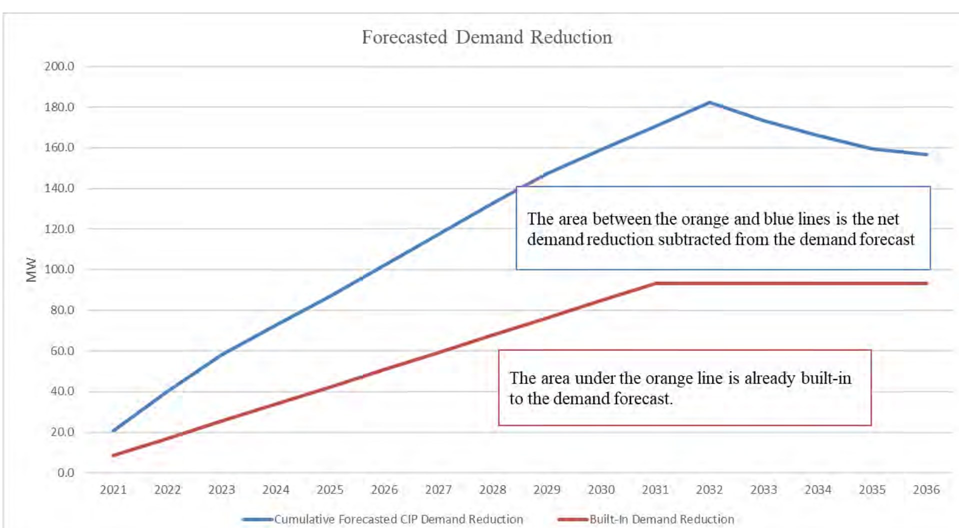
Otter Tail forecasts expected demand reductions for the resource planning period. Figure 13 below provides those forecasted demand reductions and utilizes the historical data provided above to determine the amount of those forecasted demand reductions already built-in to the forecast. This amount assumed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

Figure 13: Net CIP Demand Reduction to Forecast

Year	Forecasted CIP Demand Reduction	Cumulative Forecasted CIP Demand Reduction	Built-In Demand Reduction	Net CIP Demand Reduction
2021	20.8	20.8	8.5	**12.3**
2022	19.2	40.0	17.0	**23.1**
2023	18.2	58.2	25.4	**32.8**
2024	14.4	72.7	33.9	**38.7**
2025	14.5	87.1	42.4	**44.7**
2026	15.2	102.3	50.9	**51.4**
2027	15.2	117.5	59.4	**58.2**
2028	15.2	132.7	67.8	**64.9**
2029	14.5	147.3	76.3	**70.9**
2030	11.7	159.0	84.8	**74.2**
2031	11.7	170.7	93.3	**77.4**
2032	11.7	182.4	93.3	**89.2**
2033	11.7	173.4	93.3	**80.1**
2034	11.7	165.9	93.3	**72.6**
2035	11.8	159.4	93.3	**66.2**
2036	11.8	156.8	93.3	**63.5**

Figure 14 below shows the growth of these demand reductions included in Otter Tail's forecast.

Figure 14: Forecast Demand Reduction



9 Market Energy Price Assumptions

Otter Tail used the Wood Mackenzie March 2021 North American Power Service as the basis for the market energy prices used in this resource plan. Otter Tail applied the Wood Mackenzie forecasted monthly on-peak and off-peak energy prices to an hourly profile to reflect the hourly variability/volatility of the energy market. Otter Tail evaluated market energy at +/- 25 percent, +/- 50 percent, and +100 percent of the base case. Figure 15 shows the market energy price basis for the assumptions used in the resource plan. The market energy price sensitivities are provided in Appendix I as Sensitivity *E, F, G, H,* and *I*, respectively.

Figure 15: Market Energy Price Assumptions

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

10 Externality Price Assumptions

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

Figure 16: Application of Externalities for Otter Tail Generating Resources

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

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

Figure 17: Externality Values

CO2 Externality Values (2020-2024)

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

Regulatory Cost of Carbon (2025-2050)

	Low	Median	High
2025+	$5.00	$15.00	$25.00

Criteria Values (2020-2050)

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

11 New Thermal Alternative Assumptions

Figure 18 shows key assumptions used for new thermal alternatives in the resource plan.

Figure 18: New Thermal Alternatives

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

12 Existing Unit Input Assumptions

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

Figure 19: Existing Baseload Unit Assumptions

Existing Baseload Units		
Name	**Big Stone Plant**	**Coyote Station**
Coal Type	sub-bituminous	lignite
Retirement Date	2046	2041
Nameplate Capacity (MW)	255.8	149.8
Firm Capacity (MW)	244.1	121.4
Heat Rate at Minimum (Btu/kwh)	11,770	12,786
Heat Rate at Maximum (Btu/kwh)	10,286	11,011
O&M Escalation	2%	2%
Fixed O&M (2022$/kw-yr)	$57.69	$70.52
Variable O&M (2022$/MWh)	$1.71	$1.51

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

Figure 20: Existing Peaking Unit Assumptions

Existing Peaking Units					
Name	Astoria Station	Solway	Lake Preston	Jamestown 1	Jamestown 2
Fuel	natural gas	natural gas	fuel oil	fuel oil	fuel oil
Retirement Date	2056	2038	2033	2033	2033
Nameplate Capacity(MW)	248	42.5	20.4	20.7	21.1
Firm Capacity(MW)	241.0	41.5	18.7	19.7	19.3
Heat Rate at Minimum (Btu/kwh)	11,513	14,023	27,156	25,135	25,339
Heat Rate at Maximum (Btu/kwh)	9,120	9,293	14,629	13,507	13,845
O&M Escalation	2%	2%	2%	2%	2%
Fixed O&M (2022$/kw-yr)	$3.56	$21.43	$3.35	$3.42	$3.35
Variable O&M (2022$/MWh)	$0.77	$3.68	$18.82	$24.18	$24.18

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

Figure 21: Existing Wind Energy Purchases

Existing Wind Purchased Power Transactions			
Name	ND Wind II (Edgeley)	Langdon PPA	Ashtabula III
Transaction End Date	Nov-2028	Nov-2032	Sep-2038
Nameplate Capacity(MW)	21	19.5	62.4
Firm Capacity(MW)	3.6	4.7	15.4
Net Capacity Factor	26%	41%	39%

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

Figure 22: Existing Otter Tail-Owned Wind Facilities

Existing Otter Tail-Owned Wind				
Name	Langdon	Ashtabula	Luverne	Merricourt
End of Life Date	Dec-2042	Dec-2043	Dec-2044	Dec-2055
Nameplate Capacity(MW)	40.5	48	49.5	150
Firm Capacity(MW)	9.5	11.5	13.5	24.0
Net Capacity Factor	40%	36%	41%	50%

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

Figure 23: Existing Otter Tail-Owned Solar Facility

Existing Otter Tail Owned Solar	
Name	Hoot Lake Solar
Expected Commission Date	Jan-2023
Nameplate Capacity(MW)	49
Firm Capacity(MW)	12.3
Net Capacity Factor	24%

13 Other Assumptions

General Inflation Rate – 2%

Capital Cost Escalation Rate – 1%

Debt Rate – 4.77%

Debt Ratio – 47.50

Discount Rate – 7.51%

Composite Tax Rate – 26.26%

Appendix G: Otter Tail's REO/RES Compliance Strategy

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REO/RES Compliance Strategy

This document identifies and discusses the renewable energy requirements of the three states in which Otter Tail Power Company (Otter Tail or the Company) operates. The Company has developed significant wind generation resources and is currently developing the 49.9 MW Hoot Lake Solar Project. These renewable energy resources comprise a substantial percentage of the Company's total energy resources.

Renewable energy used for compliance with state requirements must be tracked through the Midwest Renewable Energy Tracking System (M-RETS) through the use of renewable energy credits. The discussion leads to a strategy for managing the renewable energy credits to the benefit of customers and Otter Tail while simultaneously complying with renewable energy requirements.

1. Jurisdictional Requirements

Otter Tail serves retail customers in Minnesota, North Dakota, and South Dakota. All three state jurisdictions have a renewable energy objective (REO) or renewable energy standard (RES.) Discussion of compliance efforts with any single jurisdiction also requires a discussion of the other two jurisdictions so that a complete understanding of the Company's compliance efforts can be obtained. Table 1 describes the requirements in each of the state jurisdictions. Additional detail regarding the state rules follows.

Table 1 **Jurisdictional REO/RES Requirements**			
	Minnesota	**North Dakota**	**South Dakota**
REO	2007-2009 1% 2010-2011 7% *(as percentage of retail sales after conservation)*	Prior to 2015 0% 2015 10% *(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)*	Prior to 2015 0% 2015 and on 10% *(as percentage of retail sales with an adjustment for hydro energy that cannot be counted toward compliance)*
RES[1]	2012-2015 12% 2016-2019 17% 2020-2024 21.5% (1.5% solar) 2025 and on 26.5% (1.5% solar)	N/A	N/A

Minnesota

Eligible energy technologies for compliance include solar, wind, hydroelectric with a capacity of less than 100 MW, hydrogen,[2] or biomass. Biomass includes landfill gas, anaerobic digestion, and mixed municipal solid waste or refuse-derived-fuel from mixed municipal solid waste as a primary fuel. Electricity generated by the combustion of biomass through co-firing with other fuels can be used for compliance, up to the percentage amount of biomass fuel relative to total fuel, only if the generating facility was constructed in compliance with new source performance standards promulgated under the federal Clean Air Act or if the facility employs the maximum achievable or best available control technology (MACT or BACT) for that type of facility.

The Minnesota Public Utility Commission (MPUC)has ruled that RECs will have a shelf life for compliance with the REO/RES requirements of the year in which they are created plus four more calendar years. The PUC has also ruled that kWh sold under green pricing programs do not count toward REO/RES requirements.

The solar portion of the RES is a Minnesota requirement enacted in 2013 to be effective in 2020. The addition of the Hoot Lake Solar facility will be sufficient to meet the utility scale portion of the solar

[1] These MN REO and RES requirements only apply to utilities without nuclear generating assets. Utilities with nuclear generating assets have a more aggressive standard as detailed in Minn. Stat. §216B.1691.

[2] After January 1, 2010, the hydrogen must be generated from the other eligible energy technologies listed.

energy standard. Otter Tail's preferred plan includes the 49.9 MW Hoot Lake Solar project as well as 150 MW of solar in 2025; these two solar projects in the five year action window move Otter Tail closer to the energy goal of the state of Minnesota that by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.[3]

North Dakota

The North Dakota REO is 10 percent of retail sales in 2015 and includes both renewable energy and recycled energy. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy that cannot be counted toward the REO.[4] Renewable electricity and recycled energy includes electricity generated from solar, wind, biomass,[5] geothermal, hydrogen,[6] hydroelectric (must be from a facility with an in-service date of no earlier than January 1, 2007 or from efficiency improvements to a hydroelectric facility existing as of August 1, 2007), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes and which do not use an additional combustion process for the electricity. Recycled energy does not include any system whose primary purpose is the generation of electricity.

The North Dakota Public Service Commission (ND PSC) has not made a determination of the shelf life of RECs for compliance purposes. The ND PSC has not ruled in any manner on whether kWh sold under green pricing programs count toward REO compliance. Until such a determination is made it is being assumed that North Dakota green pricing electricity will count toward the REO as long as the source of the electricity is a qualifying technology.

South Dakota

The South Dakota REO is 10 percent of retail sales which started in year 2015 and includes both renewable energy and recycled energy. The legislation is very similar to the North Dakota requirements. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy from a facility with an in-service date prior to July 1, 2008.[7] Renewable electricity

[3] Minnesota Statute §216B.1691, Subd. 2f(e)
[4] North Dakota Century Code §49-02-30.
[5] Including agricultural crops and wastes and residues, wood and wood wastes and residues, animal wastes, and landfill gas.
[6] Provided that the hydrogen is generated from a source listed in this section of North Dakota Century Code §49-02-25.
[7] South Dakota Codified Laws §49-34A-103.

and recycled energy include electricity generated from solar, wind, biomass,[8] geothermal, hydrogen,[9] hydroelectric (statutes seem to imply it must be from a facility with an in-service date of no earlier than July 1, 2008), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes which do not use an additional combustion process to produce the electricity. Recycled energy does not include any system whose primary purpose is the generation of electricity.

The South Dakota PUC has not made a determination of the shelf life of RECs for REO compliance. The PUC has not ruled in any manner whether kWh sold under a green pricing program count toward REO compliance. Until the PUC makes a determination it is assumed that green pricing electricity does count toward the REO as long as the source of the electricity is a qualifying technology.

2. **Midwest Renewable Energy Tracking System (M-RETS)**

Otter Tail has registered renewable energy resources within the M-RETS. There are small customer-owned wind units, generally less than 50 kW each, which the Company has not registered. These customers self-serve a portion of their own load with Otter Tail receiving the remaining surplus energy. Otter Tail does pay the cost, both initial and annual fees, to register a facility in M-RETS.

Otter Tail has developed an account structure within M-RETS to help segregate RECs by type and usage. For customer-owned facilities that self-serve customer load, all of the generation is reported within M-RETS. Otter Tail then transfers RECs associated with the energy used to self-serve load into an account in the customer's name, for their use as they deem appropriate. The RECs associated with energy purchased by Otter Tail will remain in the Company account.

The Otter Tail M-RETS accounts include a retirement account by state jurisdiction by year. Thus it will be easy to verify the amount of RECs retired annually for compliance with each state's requirements. RECs associated with Tail*Winds*, the Company's green pricing program, are retired into separate state jurisdiction accounts to ensure proper accounting for the green pricing tracker balance.

[8] Includes agricultural crops and wastes and residues, wood and wood wastes and residues, animal and other degradable organic wastes, and landfill gas.
[9] Provided that the hydrogen is generated from a source listed in this section of South Dakota Codified Laws §49-34A-94.

Retired RECs are tracked on a calendar year basis. The M-RETS system became operational in the last half of 2007. While Otter Tail began recording renewable energy within M-RETS late in 2007, the Company began full use of the M-RETS system for reporting compliance verification beginning with the first full calendar year commencing January 1, 2008. Otter Tail retired its first Solar RECs in 2021 for compliance with 2020 Solar Energy Standard (SES.)

Renewable energy used for REO-RES compliance must be tracked through M-RETS. The states are relying on the system to verify and track renewable energy to ensure that the renewable energy is not double counted and that a company's actual compliance performance can be readily tracked.

3. Jurisdictional Ownership of RECs

Retail customers pay for resources through the ratemaking cost allocation process. All existing generating resources are used to serve all customers, so the customers in each jurisdiction are paying a portion of the cost of each resource. The Company allocates the RECs to each jurisdiction based on a load/ratio share in the month the RECs are generated. For the Hoot Lake Solar project, Otter Tail has received MN PUC approval for 100 percent of the project costs and benefits to be attributed to Minnesota customers. So all of the Hoot Lake Solar RECs will be allocated to MN.

4. Allowance Banking

Otter Tail can and should bank some allowances for future use. There are several reasons for maintaining a bank balance of RECs including:

- Provide a compliance safety margin for years in which renewable energy generation may be lower than expected.
- Provide a construction safety margin in case planned future renewable energy resources are delayed or canceled.
- Provide a supplemental balance to be used in those years when there is a step increase in the REO-RES compliance levels.
- Provide a reserve for the time when Otter Tail may become deficit for its REO/RES compliance needs.

A number of RECs should be banked, only as long as Otter Tail has surplus RECs to bank for contingencies and future use. Once a jurisdiction is required to purchase RECs for REO/RES compliance, it does not make sense to purchase RECs simply to maintain a bank balance, unless it is expected that RECs will not be available for purchase in the future or if a particularly economic REC purchase opportunity arises.

While the prior discussion identifies the various purposes for banking RECs, the current Otter Tail situation becomes very simple. All RECs in the Minnesota jurisdiction that qualify for compliance in Minnesota should be banked as long as there is not a risk of those RECs exceeding the allowable shelf life for MN compliance.

In all cases, the oldest RECs possible should be used for compliance as newer RECs will tend to have a higher value and a longer remaining shelf life for MN compliance.

In summary:

- All MN jurisdiction RECs eligible for MN compliance should be banked.
- Wherever possible, non-eligible jurisdictional RECs should be swapped between MN and the Dakotas to make optimum use of these RECs (which are all non-wind), for compliance purposes.
- All surplus Dakotas jurisdiction RECs should be sold.

5. RES/SES Rate Impacts

As ordered by the Minnesota Commission, each utility that files a Resource Plan must calculate the cost of complying with Minn. Stat. §216B.1691. Utilities are required to do the following:

- Analyze costs for the period 2005 until the last reported year.
- Analyze costs from the year following the last reported year, and for the following 15 years.
- Include all facilities used to comply with the Renewable Energy Standard and the Solar Energy Standard, regardless of when the facilities were constructed.
- Calculate direct costs to include payments under power purchase agreements and revenue requirements associated with utility-owned renewable energy projects.

- Provide a narrative discussion about the impact that adding generators powered by renewable sources may have on the utilities indirect costs, such as the cost for ancillary services and base load cycling.
- Include transmission improvement costs.
- Calculate Energy and Capacity savings arising from avoiding costs that the utility would have incurred directly in the absence of the RES and SES.
- Calculate past and future emission compliance savings arising from avoiding costs that the utility would have incurred indirectly in the absence of the RES and SES.
- Report estimated annualized and estimated levelized costs.
- Calculate the costs of complying with the RES and SES separately.
- Calculate the ultimate rate impact of Minn. Stat. §216B.1691 to reflect the fact that renewable energy comprises only a fraction of a utility's total energy costs, and consequently most of a utility's energy costs are unaffected by the RES and SES.

Table 2
Past RES Rate Impacts

RES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total RES Generation (GWh)	95.4	79.3	83.2	307.3	648.1	735.6	818	750	658	902.5	839.3	873.2	899.5	824.1	784.7	815.9
RES Generation Costs																
PPA + Owned Generation Costs (millions)	$2.6	$2.2	$2.3	$13.0	$20.7	$28.4	$26.9	$27.3	$27.2	$31.3	$31.0	$30.7	$28.5	$29.0	$28.3	$28.5
RES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total RES Costs (millions)	$2.6	$2.2	$2.3	$13.0	$20.7	$28.4	$26.9	$27.3	$27.2	$31.3	$31.0	$30.7	$28.5	$29.0	$28.3	$28.5
RES Costs ($/MWh)	$27.25	$27.74	$27.64	$42.30	$31.94	$38.61	$32.89	$36.40	$41.34	$34.68	$36.92	$35.19	$31.63	$35.24	$36.00	$34.88
Avoided Costs Due to RES																
Avoided Energy Costs (millions)	$4.5	$3.5	$4.3	$14.8	$16.3	$20.6	$20.3	$16.0	$18.6	$30.9	$18.4	$17.7	$20.7	$22.5	$18.0	$13.5
Avoided Capactiy Costs (millions)	$0.4	$0.2	$0.3	$1.0	$1.4	$0.5	$0.4	$0.4	$1.1	$0.5	$0.8	$1.5	$1.9	$2.1	$2.9	$2.7
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$4.9	$3.7	$4.6	$15.8	$17.7	$21.1	$20.7	$16.4	$19.7	$31.5	$19.3	$19.1	$22.6	$24.6	$21.0	$16.2
Total Avoided Costs ($/MWh)	$51.68	$47.13	$55.33	$51.42	$27.27	$28.65	$25.24	$21.85	$29.95	$34.87	$22.95	$21.89	$25.14	$29.81	$26.70	$19.86
Total RES Premium/Discount (millions)	($2.3)	($1.5)	($2.3)	($2.8)	$3.0	$7.3	$6.2	$10.9	$7.5	($0.2)	$11.7	$11.6	$5.8	$4.5	$7.3	$12.3
Total RES Premium/Discount ($/MWh)	($24.43)	($19.39)	($27.69)	($9.12)	$4.67	$9.96	$7.64	$14.55	$11.39	($0.19)	$13.97	$13.30	$6.49	$5.44	$9.30	$15.02
Annualized RES Rate Impacts																
Total Company Sales (GWh)	3903	3988	4118	4215	4248	4284	4303	4216	4449	4684	4597	4723	4784	4967	4997	4780
Rate Impact ($/MWh)	($0.60)	($0.39)	($0.56)	($0.66)	$0.71	$1.71	$1.45	$2.59	$1.68	($0.04)	$2.55	$2.46	$1.22	$0.90	$1.46	$2.56
Rate impact (¢/kWh)	(0.06)	(0.04)	(0.06)	(0.07)	0.07	0.17	0.15	0.26	0.17	(0.00)	0.26	0.25	0.12	0.09	0.15	0.26

Table 3
Past SES Rate Impacts

SES Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total SES Generation (GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Generation Costs																
PPA + Owned Generation Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Transmission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total SES Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SES Costs ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Costs Due to SES																
Avoided Energy Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Capactiy Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Transmission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Emission Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Avoided Costs (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Avoided Costs ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total SES Premium/Discount (millions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total SES Premium/Discount ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annualized SES Rate Impacts																
Total Company Sales (GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate Impact ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate impact (¢/kWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 4
Future RES Rate Impacts

RES Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total RES Generation (GWh)	1484	1584	1595	1899	1897	2323	2336	2291	2300	2292	2287	2329	2324	2322	2335
RES Generation Costs															
PPA + Owned Generation Costs (millions)	$29.0	$33.2	$33.7	$44.6	$44.8	$60.1	$60.6	$59.5	$60.0	$60.0	$60.0	$57.8	$58.0	$58.3	$58.8
RES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total RES Costs (millions)	$29.0	$33.2	$33.7	$44.6	$44.8	$60.1	$60.6	$59.5	$60.0	$60.0	$60.0	$57.8	$58.0	$58.3	$58.8
RES Costs ($/MWh)	$19.56	$20.99	$21.11	$23.51	$23.61	$25.89	$25.94	$25.99	$26.08	$26.19	$26.25	$24.83	$24.96	$25.09	$25.19
Avoided Costs Due to RES															
Avoided Energy Costs (millions)	$41.6	$44.4	$41.7	$41.2	$41.6	$54.5	$58.0	$60.8	$63.8	$67.1	$69.5	$68.9	$70.6	$76.9	$83.6
Avoided Capactiy Costs (millions)	$0.2	$0.2	$2.3	$6.2	$7.4	$7.5	$7.6	$7.7	$7.8	$7.8	$7.9	$8.1	$8.2	$8.0	$8.2
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$41.8	$44.6	$44.0	$47.4	$49.0	$62.0	$65.6	$68.5	$71.6	$74.9	$77.5	$76.9	$78.9	$84.9	$91.7
Total Avoided Costs ($/MWh)	$28.17	$28.18	$27.58	$24.98	$25.85	$26.69	$28.10	$29.90	$31.15	$32.68	$33.88	$33.04	$33.93	$36.57	$39.29
Total RES Premium/Discount (millions)	($12.8)	($11.4)	($10.3)	($2.8)	($4.2)	($1.9)	($5.0)	($9.0)	($11.7)	($14.9)	($17.5)	($19.1)	($20.8)	($26.7)	($32.9)
Total RES Premium/Discount ($/MWh)	($8.61)	($7.19)	($6.48)	($1.47)	($2.24)	($0.81)	($2.16)	($3.91)	($5.07)	($6.49)	($7.63)	($8.21)	($8.97)	($11.49)	($14.10)
Annualized RES Rate Impacts															
Total Company Sales (GWh)	5361	5328	5333	5363	5394	5450	5479	5480	5477	5479	5481	5483	5484	5485	5486
Rate Impact ($/MWh)	($2.38)	($2.14)	($1.94)	($0.52)	($0.79)	($0.34)	($0.92)	($1.63)	($2.13)	($2.72)	($3.19)	($3.49)	($3.80)	($4.86)	($6.00)
Rate impact (¢/kWh)	(0.24)	(0.21)	(0.19)	(0.05)	(0.08)	(0.03)	(0.09)	(0.16)	(0.21)	(0.27)	(0.32)	(0.35)	(0.38)	(0.49)	(0.60)

Table 5
Future SES Impacts

SES Generation	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Total SES Generation (GWh)	0	104	104	416	415	415	416	416	416	416	416	519	519	520	521
SES Generation Costs															
PPA + Owned Generation Costs (millions)	$0.0	$4.1	$4.1	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0
SES Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total SES Costs (millions)	$0.0	$4.1	$4.1	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0	$15.0
SES Costs ($/MWh)	$0.00	$39.29	$39.29	$36.07	$36.07	$36.07	$36.07	$36.07	$36.07	$36.07	$36.07	$28.85	$28.85	$28.84	$28.85
Avoided Costs Due to SES															
Avoided Energy Costs (millions)	$0.0	$3.1	$2.9	$11.6	$11.7	$11.9	$12.6	$13.5	$14.1	$14.9	$15.5	$19.8	$20.3	$22.2	$24.0
Avoided Capactiy Costs (millions)	$0.0	$0.0	$0.0	$1.0	$1.2	$1.2	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4
Avoided Transmission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Avoided Costs (millions)	$0.0	$3.1	$2.9	$12.6	$12.9	$13.1	$13.8	$14.8	$15.4	$16.2	$16.8	$21.1	$21.7	$23.6	$25.4
Total Avoided Costs ($/MWh)	$0.00	$29.99	$27.94	$30.29	$31.07	$31.58	$33.27	$35.51	$37.02	$38.89	$40.34	$40.64	$41.77	$45.34	$48.78
Total SES Premium/Discount (millions)	$0.0	$1.0	$1.2	$2.4	$2.1	$1.9	$1.2	$0.2	($0.4)	($1.2)	($1.8)	($6.1)	($6.7)	($8.6)	($10.4)
Total SES Premium/Discount ($/MWh)	$0.00	$9.30	$11.35	$5.78	$5.01	$4.49	$2.80	$0.56	($0.95)	($2.82)	($4.28)	($11.80)	($12.92)	($16.49)	($19.94)
Annualized SES Rate Impacts															
Total Company Sales (GWh)	5361	5328	5333	5363	5394	5450	5479	5480	5477	5479	5481	5483	5484	5485	5486
Rate Impact ($/MWh)	$0.00	$0.18	$0.22	$0.45	$0.39	$0.34	$0.21	$0.04	($0.07)	($0.21)	($0.32)	($1.12)	($1.22)	($1.56)	($1.89)
Rate impact (¢/kWh)	0.00	0.02	0.02	0.04	0.04	0.03	0.02	0.00	(0.01)	(0.02)	(0.03)	(0.11)	(0.12)	(0.16)	(0.19)

Table 6
Levelized RES Rate Impacts

Levelized RES Generation	Historic	Future
Total RES Generation (GWh)	632	2106

Levelized RES Generation Costs		
PPA + Owned Generation Costs (millions)	$40.6	$22.1
RES Transmission Costs (millions)	$0.0	$0.0
Total RES Costs (millions)	$40.6	$22.1
RES Costs ($/MWh)	$64.24	$10.50

Levelized Avoided Costs Due to RES		
Avoided Energy Costs (millions)	$30.2	$32.3
Avoided Capactiy Costs (millions)	$1.9	$3.3
Avoided Transmission Costs (millions)	$0.0	$0.0
Avoided Emission Costs (millions)	$0.0	$0.0
Total Avoided Costs (millions)	$32.1	$35.6
Total Avoided Costs ($/MWh)	$50.74	$16.91

Total RES Premium/Discount (millions)	$8.5	($13.5)
Total RES Premium/Discount ($/MWh)	$13.50	($6.42)

Levelized RES Rate Impacts		
Total Company Sales (GWh)	4454	5438
Rate Impact ($/MWh)	$1.92	($2.49)
Rate impact (¢/kWh)	0.19	(0.25)

Table 7
Levelized SES Rate Impacts

Levelized SES Generation	Historic	Future
Total SES Generation (GWh)	-	374

Levelized SES Generation Costs		
PPA + Owned Generation Costs (millions)	-	$7.2
SES Transmission Costs (millions)	-	$0.0
Total SES Costs (millions)	-	$7.2
SES Costs ($/MWh)	-	$19.12

Levelized Avoided Costs Due to SES		
Avoided Energy Costs (millions)	-	$7.0
Avoided Capactiy Costs (millions)	-	$0.6
Avoided Transmission Costs (millions)	-	$0.0
Avoided Emission Costs (millions)	-	$0.0
Total Avoided Costs (millions)	-	$7.6
Total Avoided Costs ($/MWh)	-	$20.33

Total SES Premium/Discount (millions)	-	($0.5)
Total SES Premium/Discount ($/MWh)	-	($1.21)

Levelized SES Rate Impacts		
Total Company Sales (GWh)	-	5438
Rate Impact ($/MWh)	-	($0.08)
Rate impact (¢/kWh)	-	(0.01)

Indirect Costs

As a member of the Midcontinent Independent System Operator, Inc. (MISO), Otter Tail is required to offer its generation units into the day-ahead energy market. Recently, energy prices have been very low due to the addition of renewable resources as well as low fuel costs for existing thermal units. Up until 2020, Otter Tail offered in its co-owned baseload thermal units as "must-run" units to prevent them from cycling on and off with fluctuating energy prices. This means that if the day-ahead price of energy dips below the cost of the unit, the unit will still clear at minimums in order to keep the unit online. Because these units stay online regardless of energy prices, there is no increase in cycling charges. In April 2020, the owners of Big Stone Plant agreed to a methodology to allow the operation of Big Stone Plant to be offered into the MISO/Southwest Power Pool (SPP) markets on an economic dispatch basis. This methodology includes weekly, bi-weekly, or as-needed meetings with all Co-Owners (Otter Tail, Montana-Dakota Utilities Co., and NorthWestern Energy) to review the economic dispatch or self-commitment status of Big Stone Plant. For the time periods agreed to by the Co-Owners, this unit is offered into the market economically meaning the day-ahead energy price has to be higher than the unit's cost for long enough to justify bringing the unit online. As a result, it could be argued that this unit cycles more because of the additional renewable resources on the system. The Co-Owners of Coyote Station have developed the capability to offer the plant under an economic offer. As with Big Stone Plant, each Coyote Co-Owner maintains the contractual right to request self-commitment. At the time of this filing, one of the plant's Co-Owners, not Otter Tail, has requested ongoing self-commitment. As a results, the plant has not been offered into the market on an economic dispatch basis.

In terms of ancillary services, Otter Tail has not identified any impacts which can be attributed to the implementation of the RES requirements so far. That being said, as the amount of renewable resources increases, so does the need for ancillary services. Eventually there will be a tipping point where the amount of renewable resources increases and the amount of available spinning reserves decreases to a level which causes the cost of ancillary services to rise.

Avoided Permitting and Emission Cost Impacts

All historical avoided permitting and emission costs are factored in when calculating the avoided energy and capacity costs. For the future avoided carbon dioxide (CO_2) costs, Otter Tail used the Commission approved value of $15.00/ton CO_2 penalty starting in 2025.

Transmission Costs

For the purpose of simplifying our modeling, all transmission costs for future RES/SES projects are built into the project energy price. It is also assumed that all avoided energy and capacity costs (both past and future) will be purchased from the market resulting in no added transmission costs.

6. Summary

The following strategy is being used to optimize the usage of RECs:

- Otter Tail allocates RECs from resources used to serve all customers based on a monthly energy allocation.
- Otter Tail banks all MN jurisdiction RECs which are eligible for MN compliance to be used for current and future REO/RES compliance.
- Otter Tail swaps MN jurisdiction RECs which cannot be used for MN compliance but can be used for Dakotas compliance for Dakotas jurisdiction RECs which cannot be used for ND or SD compliance but can be used for MN compliance. Equivalent monetary value will be maintained for all swaps.
- Otter Tail expects to transfer enough Dakotas RECs to Minnesota, as necessary, to maintain a bank balance for MN REO/RES compliance, but without risking shelf life expiration of RECs for compliance purposes.
- Otter Tail sells the surplus ND and SD allocated RECs.
- Otter Tail evaluates opportunities to purchase/use lower value RECs for compliance and banking, while selling higher value RECs. All benefits and costs flow to customers.
- When possible, sell higher value MN RECs and acquire older and lower value Dakotas RECs for compliance in MN. MN REC sales revenues, net of replacement purchase costs, will be treated in accordance with MN Commission Orders. Dakotas REC revenues from sales to the MN jurisdiction will be treated in accordance with the Commission Orders in those two states.
- The oldest RECs possible should be used for compliance or for sales in order to keep the REC inventory as fresh as possible and at as high a value as possible.
- Seek opportunities to sell wind generation energy either with or without RECs if lower cost replacement energy purchases can be made to reduce energy costs.

Appendix H: 2020 Otter Tail Power DR Potential Study

2020 Otter Tail Power DR Potential Study

FINAL REPORT

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PREPARED FOR
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DECEMBER 15, 2020

In this presentation

- Introduction
  - Overview
  - OTP's existing DR portfolio
- Approach
  - Modeling methodology
  - Key assumptions
- Findings
  - Base Case
  - High Value Sensitivity Case
- Conclusions
- Appendices

INTRODUCTION

Overview

This study summarizes the **cost-effective, achievable DR potential** in OTP's service territory

All estimates of potential are **incremental** to OTP's existing DR capability

The analysis considers a broad range of DR programs, including **traditional options** like air-conditioning direct load control as well as **emerging options** like dynamic pricing and smart water heating

The study spans the period from **2021 through 2036**, consistent with the upcoming IRP

Estimates are not a forecast of what will happen, but rather represent the potential cost-effective impacts that could be achieved from an expansion of OTP's existing DR portfolio

INTRODUCTION

OTP's existing DR programs span a range of offerings

Program Name	Type	Class (primary application)	Description
Residential Demand Control	DLC (Whole home)	Residential	25% rate discount. During a control event, end-uses are curtailed according to customer priorities to reach desired demand level. Effectively a demand subscription rate with automation. Focus on winter peak.
CoolSavings	DLC (A/C)	Residential	$33 annual bill credit (residential). 15-minute A/C cycling program.
Water Heating Control	DLC (Water heating)	Residential	25% rate discount for water heating load, or $8 monthly credit. Water heating service interruptions during control events (up to 14 hrs, typically much less).
Dual Fuel – Small	DLC (Heating)	Residential	Event-based switching to backup heating source. Roughly 40% rate discount with penalties for non-compliance.
EV Rate	TOU (EVs)	All	Discounted electricity for nighttime EV charging (10 pm to 6 am). Penalty rate for daytime charging (not intended as buy-through rate). Minnesota only
Deferred Load	DLC (Thermal storage)	All	25% rate discount for thermal storage systems. Event-based interruption
Fixed Time of Delivery	TOU (Thermal storage)	All	>50% rate discount for heating load during off-peak hours. Service only during off-peak hours.

INTRODUCTION

OTP's existing DR programs span a range of offerings (cont'd)

Program Name	Type	Class (primary application)	Description
Dual Fuel – Large	DLC (Heating)	Non-residential	Event-based switching to backup heating source.
General Time-of-Use	CPP (Whole facility)	Non-residential	TOU rate with day-ahead notification of critical peak pricing events.
Irrigation Time-of-Use	TOU	Non-residential	TOU rate with optional "courtesy" control for participants with ratio receivers
Enbridge contract	DLC	Non-residential	Contract with a single large customer that reduces peak coincident demand by between 40 and 60 MW during curtailment events

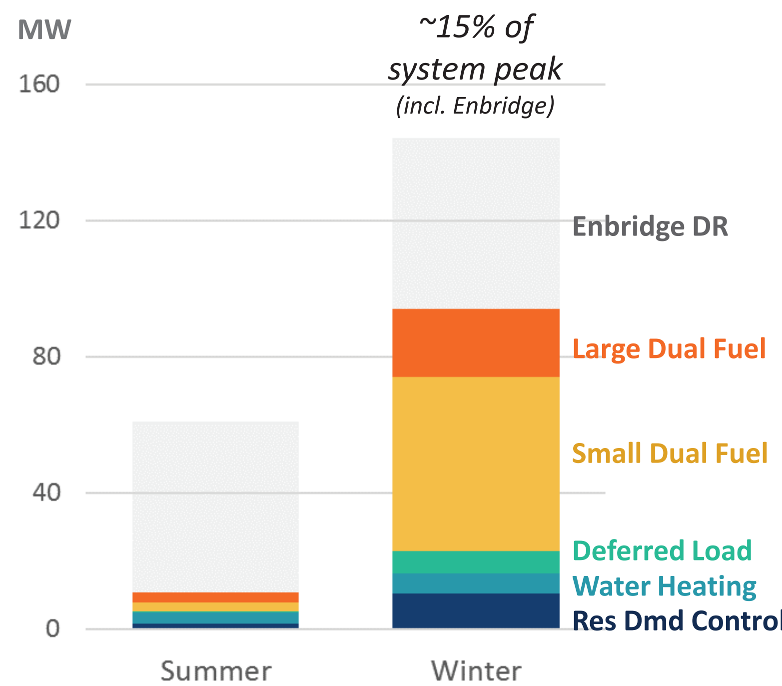
INTRODUCTION

OTP's existing DR programs represent 15% of its system peak

- **OTP has a large existing DR portfolio**
  - 15% peak reduction capability (winter)
  - Primarily from residential heating load & Enbridge contract

- **The programs are actively utilized**
  - Portfolio is dispatched both for economic and reliability reasons
  - DR event frequency higher than many other utilities, indicating that the portfolio is an active resource

System Peak Reduction Capability (2019)



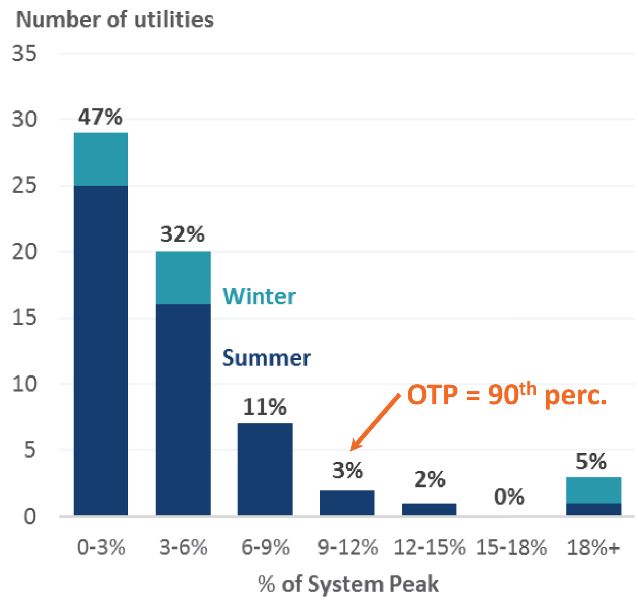
INTRODUCTION

OTP's existing DR capability is in the top 10% of U.S. IOUs

The Distribution of U.S. Investor Owned Utility DR Portfolios

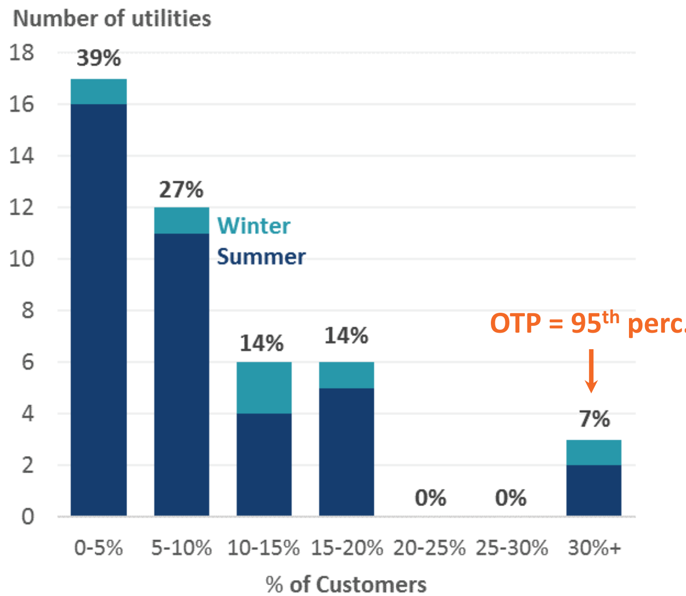
Peak Reduction Capability

(% of Sys Peak)



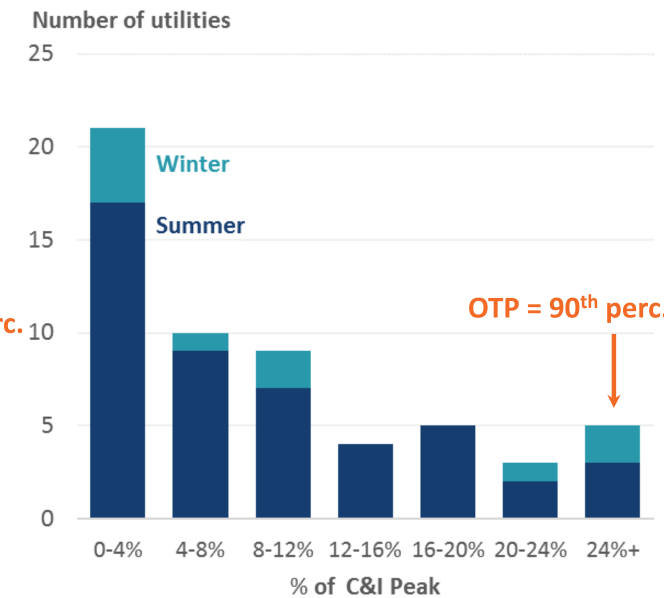
Residential Enrollment

(% of customers)



Non-residential Enrollment

(% of Non-Residential Peak)

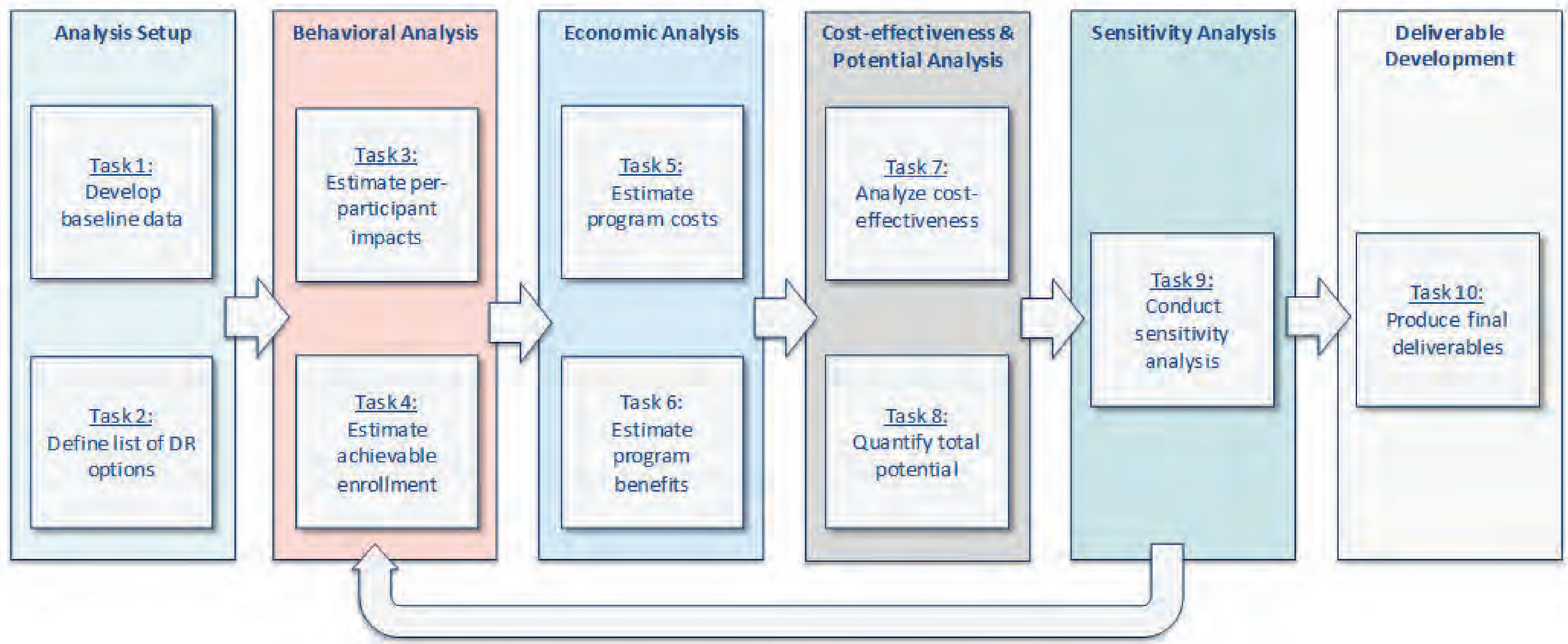


Source: Brattle analysis of 2019 Early Release EIA-861 data, and DR program data provided by OTP.

Modeling Approach

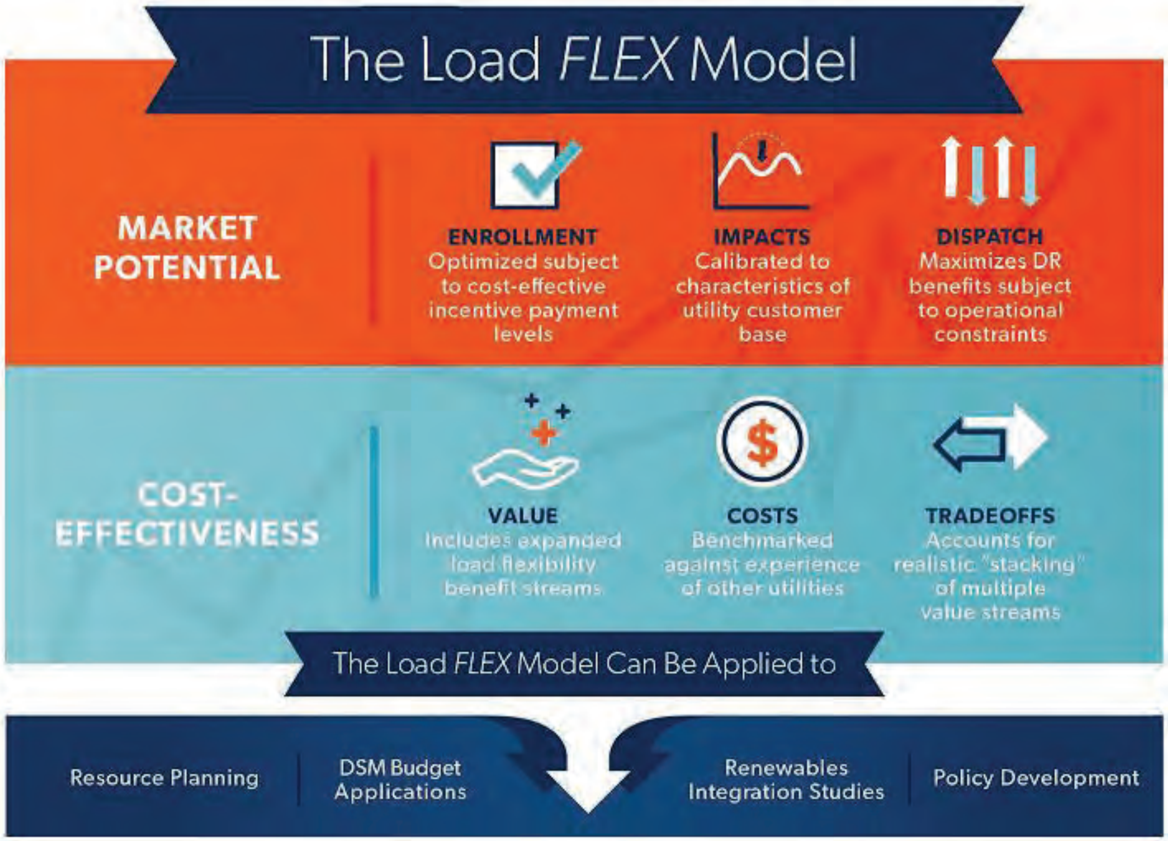
APPROACH

Methodology overview



APPROACH

The LoadFlex model



- Brattle's LoadFlex model was used to assess OTP's DR potential in this study
- The model was used in Brattle's 2019 load flexibility potential study for Xcel Energy, a study on the national potential for load flexibility, and is currently being used in a similar study for DOE
- Each DR measure is dispatched against an hourly forecast of marginal costs to determine value
- Enrollment is estimated based on the maximum cost-effective incentive level that can be offered

APPROACH

The modeled DR programs

- Our review of OTP's existing programs indicates that enrollment in space heating load control / thermal storage programs has reached maximum achievable levels of adoption; no additional potential is modeled for these programs

- Other programs vary in their applicability to customer classes and are modeled accordingly

Program	Residential	Small C&I	Med/Large C&I
Existing programs			
Heating load control/storage	*Maxed*	*Maxed*	*Maxed*
Water heating load control	✓		
A/C load control	✓	*Maxed*	
New programs			
Smart thermostat (A/C)	✓		
TOU (opt-in)	✓	✓	✓
TOU (opt-out)	✓	✓	✓
CPP (opt-in)	✓	✓	✓
CPP (opt-out)	✓	✓	✓
Smart water heating	✓		
Behavioral DR	✓		
EV managed charging (home)	✓		
EV managed charging (work)	✓		
Interruptible		✓	✓
Auto-DR (lighting)		✓	✓

APPROACH

Achievable participation

Achievable participation assumptions were developed based on a review of DR potential studies from a variety of jurisdictions, which use the following methods to establish participation rates:

- Primary market research (customer surveys)
- Review of achieved participation in successful DR programs
- Interviews with customer account managers
- Review of utility DR plans
- Expert judgement

These "base" participation rates are then adjusted in our modeling based on the cost-effectiveness of the program

- Participation is increased for highly cost-effective programs, given the potential to offer higher incentives
- The opposite is true for marginally cost-effective programs

Participation rates are inclusive of existing DR participants

- E.g., If existing participation in A/C DLC is 5% and total potential participation is 30%, then incremental potential participation is 25%

Base Participation Rate Assumptions

Class	Program	Participation (% of eligible)
Residential	A/C DLC	30%
	Smart thermostat (A/C)	30%
	TOU (opt-in)	30%
	TOU (opt-out)	80%
	CPP (opt-in)	20%
	CPP (opt-out)	80%
	Behavioral DR	80%
	Timed water heating	30%
	Smart water heating	30%
	EV managed charging (home)	20%
	EV managed charging (work)	20%
Small C&I	TOU (opt-in)	10%
	TOU (opt-out)	80%
	CPP (opt-in)	20%
	CPP (opt-out)	80%
Med/Large C&I	Interruptible	25% - 45%
	Auto-DR (lighting)	5%
	TOU (opt-in)	20%
	TOU (opt-out)	80%
	CPP (opt-in)	15% - 20%
	CPP (opt-out)	80%

See Appendix B for further detail.

APPROACH

Scenarios

The analysis includes a Base Case and a Sensitivity Case

Base Case

- Consistent with OTP’s current outlook for its system
- In particular, this reflects no anticipated need for new capacity during the study horizon

High Value Sensitivity Case

- Explores an illustrative scenario in which there is a need for new capacity during the study horizon
- Also assumes a higher MISO capacity price (based on analysis of historical data)

Specific assumptions behind each scenario are described on the next slide

APPROACH

Avoided costs

The analysis accounts for several possible DR value streams

Value stream	Avoided cost estimate	Source/notes
OTP system generation capacity (winter)	Base Case: $0/kW-yr High Case: $75/kW-yr	Base Case: IRP forecasts no need for new capacity High Case: Alternative case based on new capacity need
MISO capacity market (summer)	Base Case: $1.7/kW-yr High Case: $7.2/kW-yr	Base Case: 2013-19 historical *average* MISO auction price High Case: 2013-19 historical *maximum* MISO auction price
Energy	Top 10^{th} percentile: $33/MWh Bottom 10^{th} percentile: $14/MWh	2019 OTP MISO day-ahead energy prices scaled for consistency with OTP peak/off-peak price forecast through 2036
Ancillary services	Historical frequency regulation prices	Assume requirement equal to 0.5% of system peak (3 MW); Only smart water heating and Auto-DR are eligible
Transmission capacity	$15/kW-yr	Based on OTP CIP filing, avoided through reductions in top 100 OTP system load hours
Distribution capacity	$40/kW-yr (limited to 3.3 MW of benefit)	Avoided through geo-targeted DR deployment; based on reductions in top 300 OTP system load hours (reflecting diversity of distribution load)

See Appendix A for further detail.

APPROACH

Per-participant impacts

- Based on OTP experience and a review of impacts achieved through full scale deployments and pilots in other jurisdictions
- Winter impacts assumed to be the same as summer impacts on a percentage basis, unless inapplicable (e.g., A/C load control)
- Base Case TOU/CPP pricing program impacts reflect rates with low peak-to-off-peak price ratio due to low OTP system capacity costs; High Case impacts are 2-2.5x based on higher price ratios
- A/C DLC impacts reflect potential higher per-participant impacts achieved in other jurisdictions

Per-participant Impact Assumptions

Class	Program	Winter Impact (% of peak)	Summer Impact (% of peak)
Residential	A/C DLC	0%	27%
	Smart thermostat (A/C)	0%	50%
	TOU (opt-in)	4%	4%
	TOU (opt-out)	2%	2%
	CPP (opt-in)	10%	10%
	CPP (opt-out)	6%	6%
	Behavioral DR	3%	3%
	Timed water heating	11%	11%
	Smart water heating	11%	11%
	EV managed charging (home)	23%	40%
	EV managed charging (work)	3%	5%
Small C&I	TOU (opt-in)	0.2%	0.2%
	TOU (opt-out)	0.1%	0.1%
	CPP (opt-in)	0.5%	0.5%
	CPP (opt-out)	0.3%	0.3%
Med/Large C&I	Interruptible	20%	20%
	Auto-DR (lighting)	10% - 30%	10% - 30%
	TOU (opt-in)	2.5% - 3%	2.5% - 3%
	TOU (opt-out)	1.5% - 1.8%	1.5% - 1.8%
	CPP (opt-in)	6% - 6.5%	6% - 6.5%
	CPP (opt-out)	3.6% - 3.9%	3.6% - 3.9%

Note: Impacts in table are represented as a percentage of the average customer's seasonal peak-coincident demand.

APPROACH

Program costs

Cost assumptions are based on a review of utility program data and DR studies from other jurisdictions, as well as OTP's experience with its existing DR portfolio

Reflects all costs incurred by the utility (i.e., the "Utility Cost Test" perspective)

Example – Residential smart water heating:

- Variable equipment cost: $600/participant
- Other initial costs: $30/participant (includes recruitment & churn)
- Base annual incentive level ($/participant-yr): $96

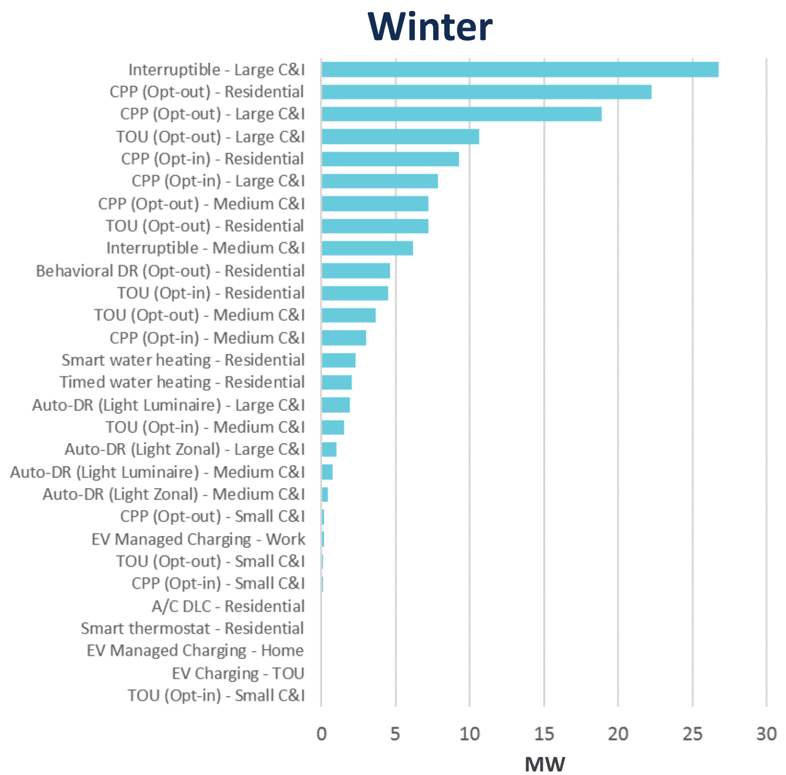
See Appendix C for details

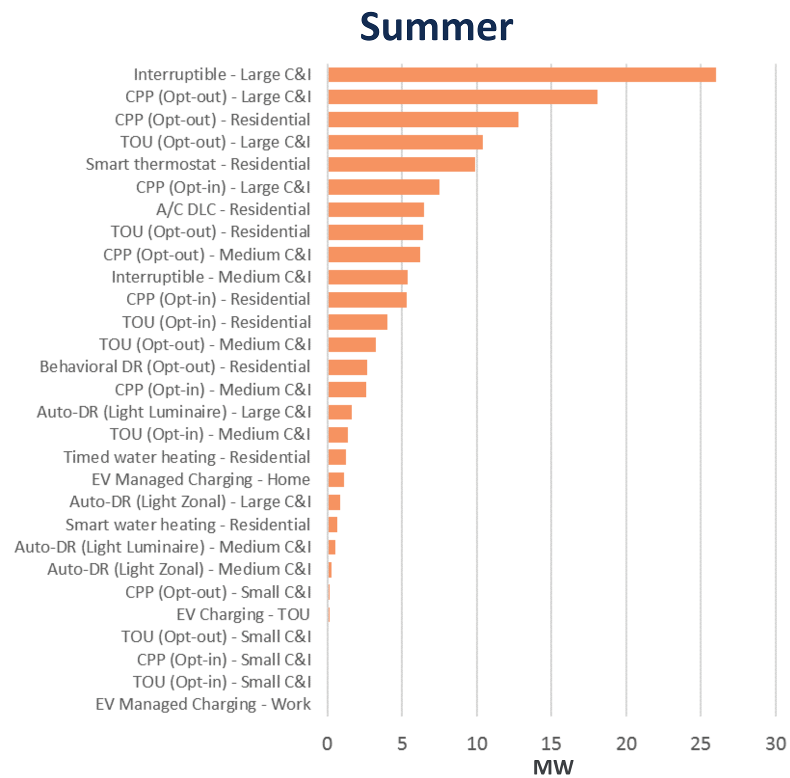
Findings

FINDINGS

Incremental technical potential by 2036

In this study, "technical potential" is defined as the maximum achievable potential irrespective of cost-effectiveness. It is incremental to OTP's existing DR portfolio.





Note: Measure impacts shown here are not additive to each other; some are mutually exclusive options for enrollment.

FINDINGS

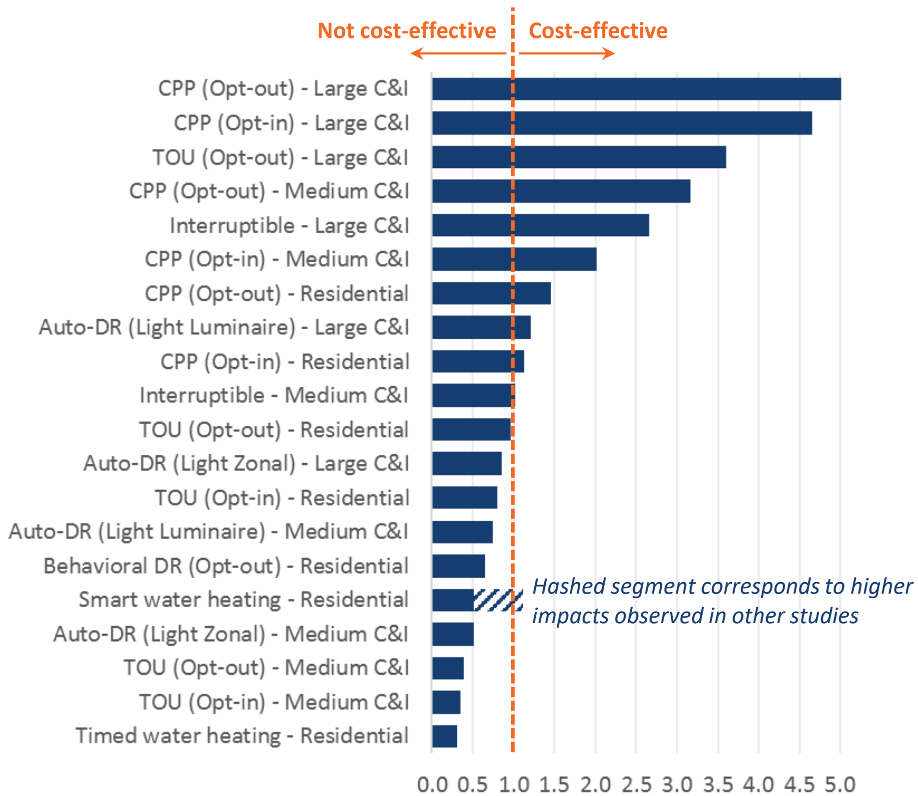
Cost-effectiveness of DR options: **Base Case**

Note: DR programs with a benefit-cost ratio of <0.1 are not shown

- **Base Case system conditions do not appear to support the cost-effective addition of new DR programs**
- Avoided generation capacity investment is the primary DR value proposition, but OTP does not forecast a need for new capacity
- Other value streams can be meaningful sources of benefit for some of the DR programs analyzed, but not enough to outweigh costs
- Pricing programs (CPP, TOU) may be an attractive option regardless of cost-effectiveness, since cost-reflective rates provide other benefits (i.e., improvements in fairness, equity)
- There may be opportunities for geographically targeted DR to cost-effectively defer the need for specific distribution investments; detailed analysis of distribution resource plans would be needed

FINDINGS

Cost-effectiveness of DR options: **High Value Sensitivity Case**

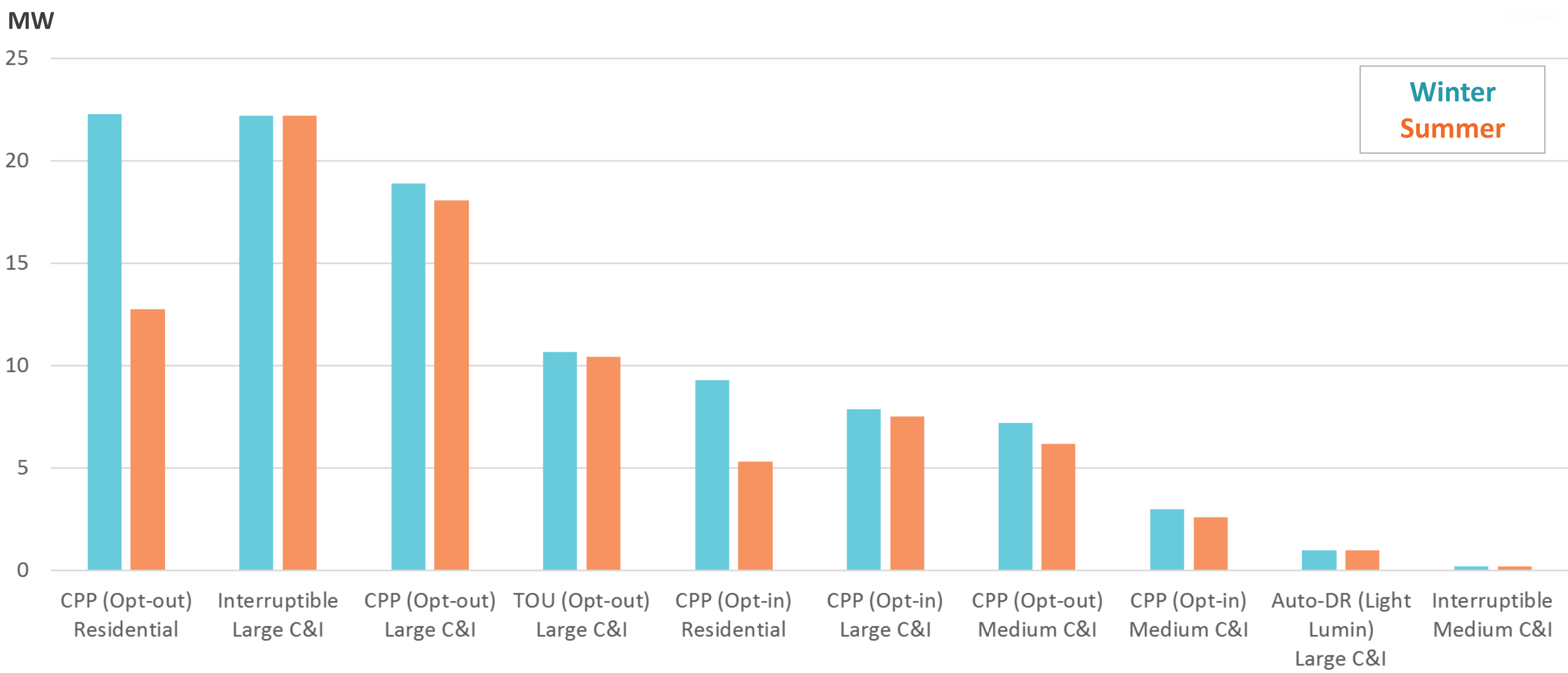


Note: DR programs with a benefit-cost ratio of <0.3 are not shown.
B/C ratio capped at 5.0 in chart.

- **In the High Value Sensitivity Case, the assumed need for capacity on the OTP system and higher capacity prices in MISO lead to cost-effective new DR opportunities**
- Dynamic pricing programs would be a cost-effective opportunity to leverage OTP’s AMI rollout
- Interruptible tariffs could potentially engage larger customers not enrolled in a heating control/storage program
- Smart water heating is not found to be cost-effective. However, if OTP’s per-participant impacts were to reach levels estimated in other studies (roughly 3x OTP’s current impacts), the program would be cost-effective

FINDINGS

Cost-effective achievable potential: **High Value Sensitivity Case**

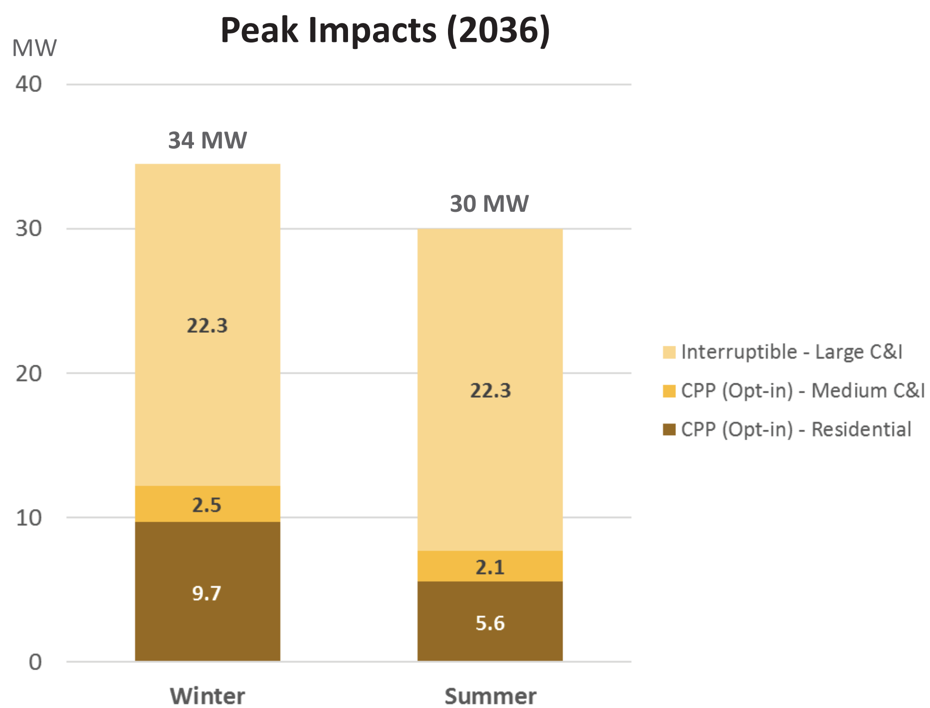


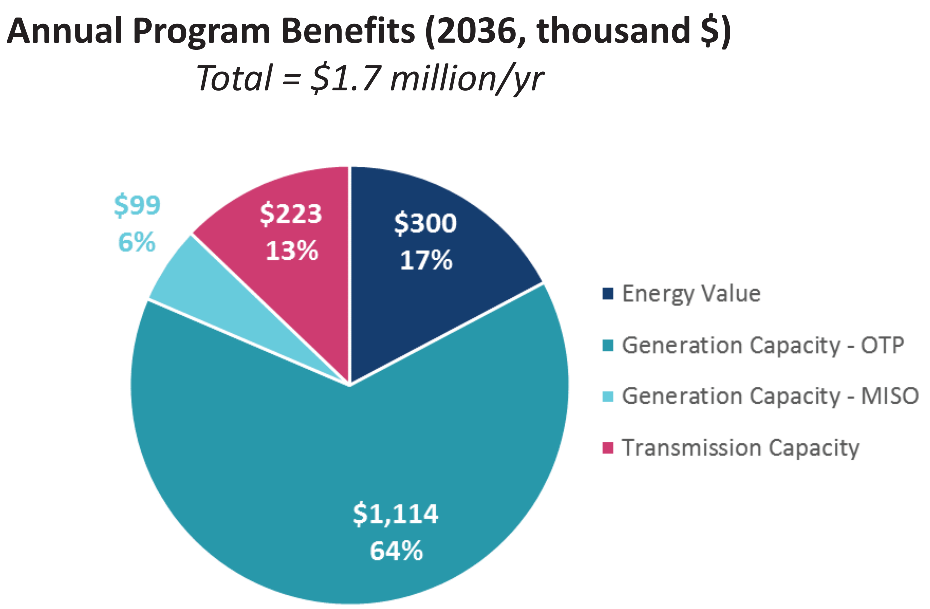
Note: Measure impacts shown here are not additive to each other; some are mutually exclusive options for enrollment.

FINDINGS

Illustrative DR Portfolio: **High Value Sensitivity Case**

An illustrative cost-effective portfolio of new DR programs was created for the High Value Sensitivity Case. Alternative portfolios could be created using other combinations of cost-effective DR measures.





Conclusions

CONCLUSIONS

Key observations

OTP has a robust existing DR portfolio

- The portfolio is regularly utilized to provide system value and is embedded in the company's resource adequacy planning

Base system conditions do not support new DR additions

- Generation capacity avoidance is the key driver of DR value, and it is not currently an opportunity for OTP
- There may be isolated opportunities for geo-targeted distribution deferral; requires detailed analysis of distribution plan
- Time-varying rates may be desirable as an option regardless, as they provide other benefits beyond avoided costs (e.g., equity, fairness, facilitating electrification)

If there is an unexpected need for capacity in the future, some DR programs will have value

- "Behavioral" options (rates, interruptible tariffs) for customers that have not opted into heating load control & storage could tap into interested customers that do not want a technology-based option
- Water heating load control may also be cost-effective if per-participant impacts can be increased
- There may also be room to grow C&I heating load control; while enrollment has reached best practices levels, market research could help to identify additional interested customer segments

Targeted program development/recruiting may improve program economics

- Specifically, further customer segmentation to focus on largest customers not currently enrolled in DR programs

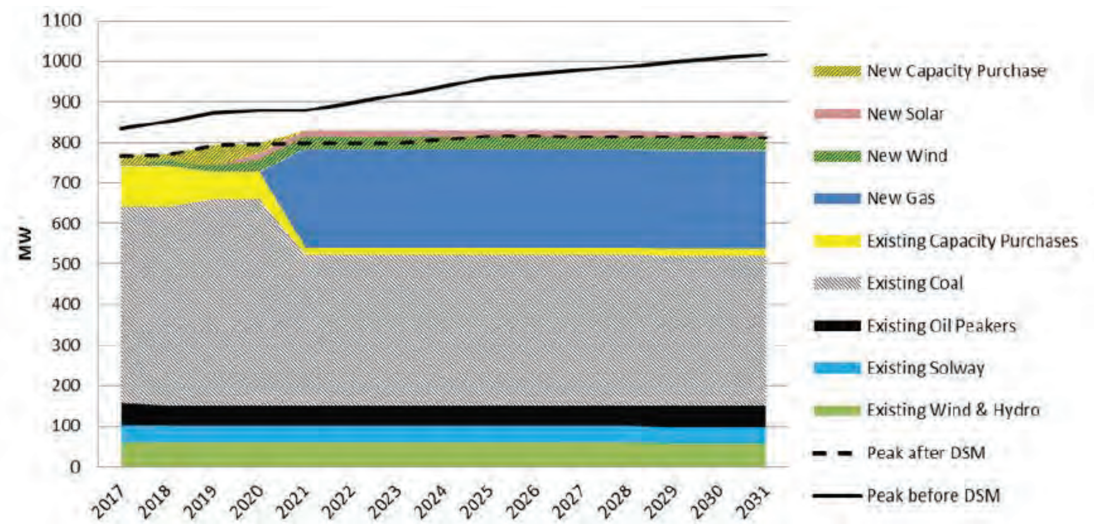
Appendix A:

Additional Detail on OTP System Conditions

APPENDIX A

Generation capacity value

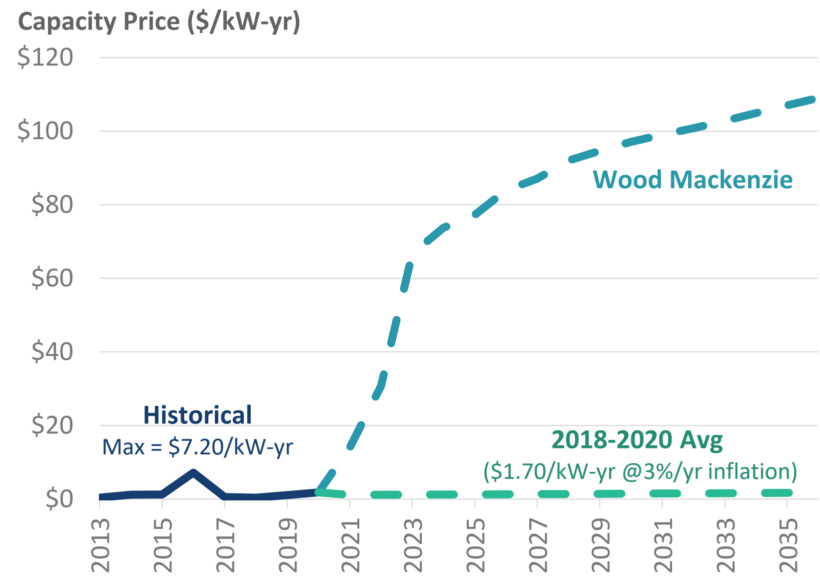
OTP Online Capacity vs Reserve Obligation



Source: 2017 - 2031 OTP IRP.

OTP does not forecast a need for additional capacity for at least the next decade *due to new gas capacity that is under construction and will come online in 2021*

MISO (Zone 1) Capacity Market Prices



MISO capacity market prices are very low. *While Wood Mackenzie projects that the prices will eventually rise to Net CONE, market experience does not support this projection*

APPENDIX A

MISO capacity market price outlook

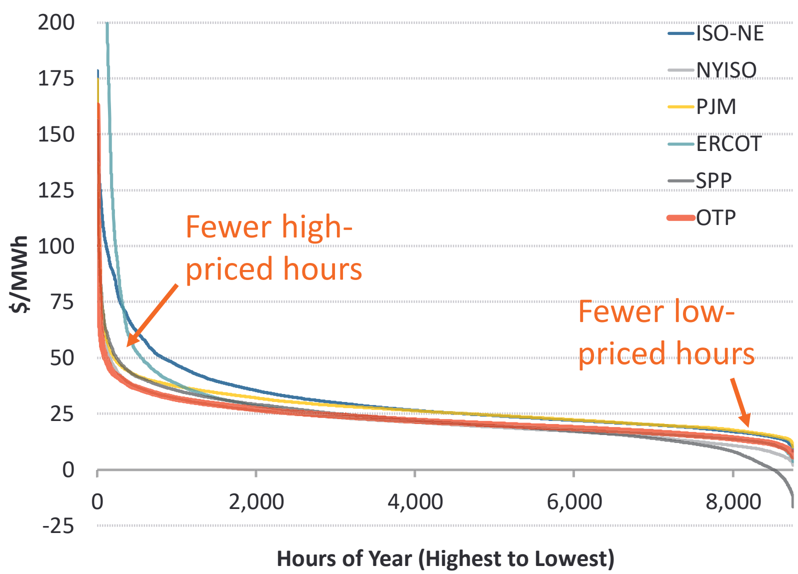
Historically, MISO capacity market prices have been very low. The fundamentals of the market suggest that prices will remain low for the study horizon:

- Utilities in MISO are responsible for maintaining sufficient resource adequacy on their systems. Due to the “lumpy” nature of generation capacity investments, MISO utilities typically invest in new capacity when their reserve margin begins to approach the minimum required level. Utilities often are long on capacity as a result.
- The MISO capacity auction is just a one-year forward auction where load serving entities can purchase capacity if they are short on supply for that one-year forward timeframe. When participants are long on capacity, the price drops all the way to zero (i.e., the demand curve for capacity is vertical).
- Generally, retailers create some demand for capacity in the auction, but their impact on the market is small and not expected to create large revenue opportunities for DR that is selling into the auction

APPENDIX A

Energy value

Day Ahead Energy Price Duration Curves



Recent OTP day ahead LMPs are relatively low and flat *compared to some other regions. Ample existing flexible generation and transmission does not suggest likelihood of significant future divergence in peak/off-peak energy price differentials for OTP due to renewables growth.*

Energy Value of Load Curtailment and Shifting
($/kW-yr)

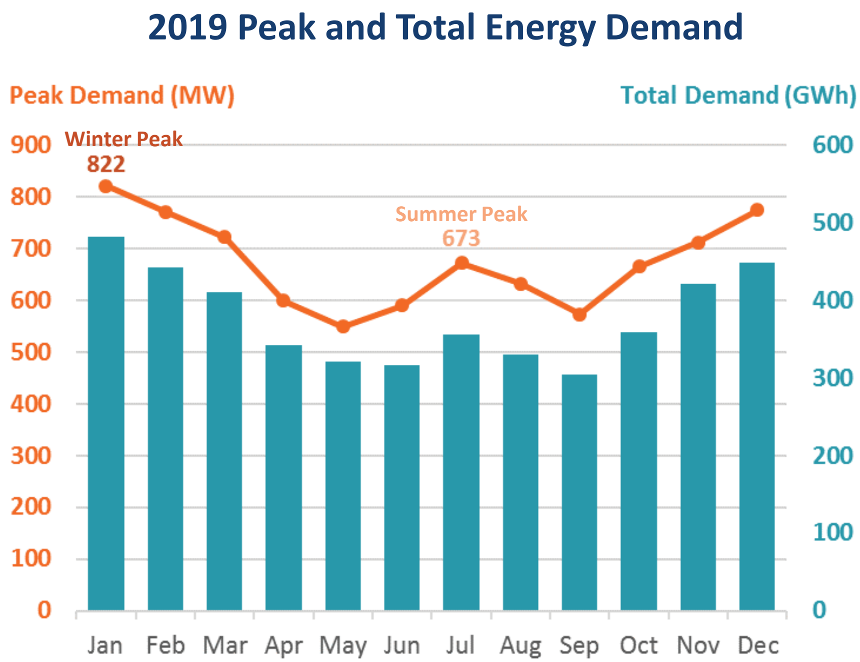
	2017	2018	2019
Value of reducing load during highest-priced 100 hours of year	$5.5	$9.7	$7.1
Value of shifting load from 4 highest-priced hours to 4 lowest-prced hours each day	$25.2	$26.9	$20.2

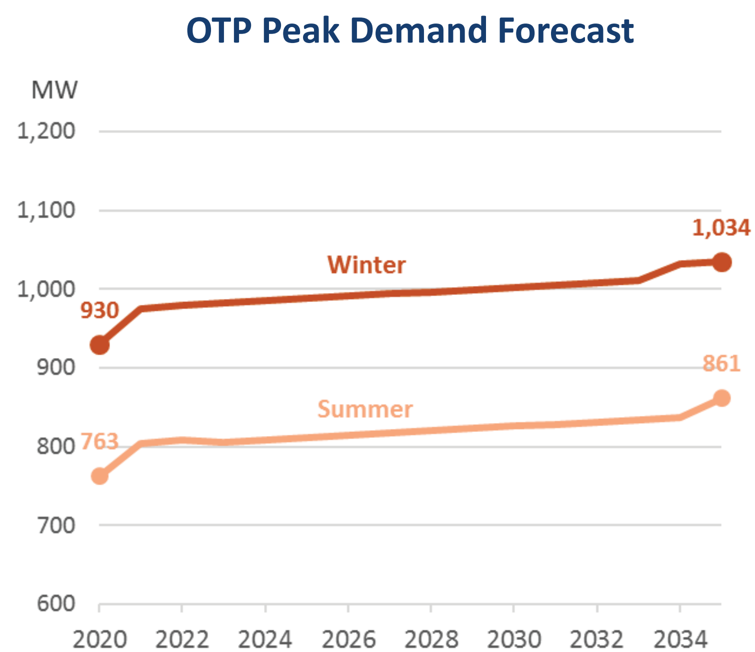
The energy value of DR programs is modest, *representing only a fraction of the total value that many DR programs have provided historically (e.g., $100/kW-yr)*

APPENDIX A

OTP Load Summary

OTP is expected to remain winter peaking across the study horizon, with 0.7% average annual growth in system peak demand





Appendix B:

Adoption Rates

APPENDIX B

DR adoption rates: Methodology overview

DR measure adoption is based on a review of recent DR potential studies

The reviewed DR potential studies use a variety of methods to establish **maximum achievable** adoption rates, for different jurisdictions across North America:

- Primary market research (customer surveys)
- Review of achieved participation in successful DR programs
- Interviews with customer account managers
- Review of utility DR plans
- Expert judgement

Notes on the adoption assumptions

- Consistent with typical incentive payments in utility/aggregator DR programs
- Expressed as a % of the eligible customer base
- Reflects steady state enrollment (i.e., after ramping up to “full” adoption)

APPENDIX B

The reviewed DR potential studies

We analyzed 7 studies with a significant focus on DR, mostly conducted in the past 5 years

Study	Geographic Coverage	Year	Author
The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory	MN, WI, ND, SD	2019	The Brattle Group
Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045	Nova Scotia, Canada	2019	Navigant Consulting
Demand Response Potential in Bonneville Power Administration's Public Utility Service Area	Primarily OR, WA, MT, ID	2018	The Cadmus Group
2017 IRP Demand-Side Resource Conservation Potential Assessment Report	Washington	2017	Navigant Consulting
State of Michigan Demand Response Potential Study	Michigan	2017	Applied Energy Group
Demand Response Market Research: Portland General Electric, 2016 to 2035	Oregon	2016	The Brattle Group
Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential	Colorado	2013	The Brattle Group

Note: Additional studies were reviewed but did not report participation assumptions or otherwise included only a very narrow set of DR measures.

APPENDIX B

Residential DR adoption

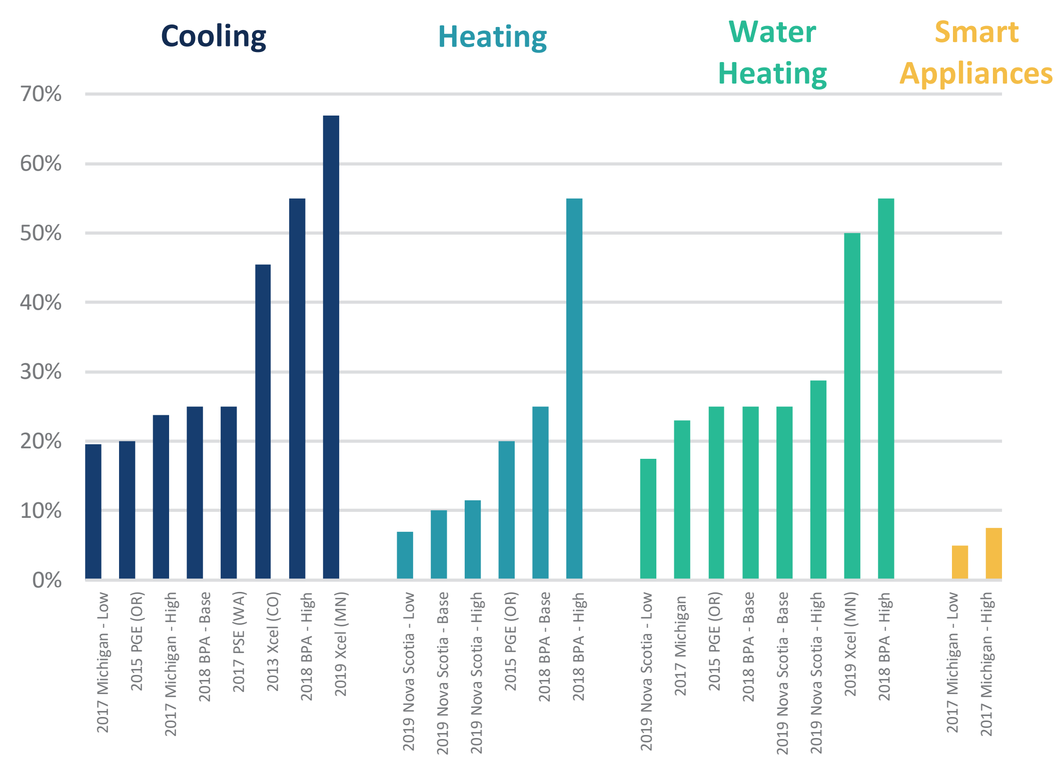
Generally, studies assume **20%-30%** at the lower end of the adoption range, and **50-60%** at the upper end of the range, regardless of end-use

This range is supported by historical data

- According to historical FERC data, a few *states* have achieved DLC enrollment rates of 20% or more
- At the upper end, Xcel Energy has achieved roughly 50% enrollment in its A/C DLC program

Research on smart appliances is limited, but suggests lower adoption than for cooling, heating, and water heating (due to low experience with the technology)

Residential Load Control Adoption Potential



APPENDIX B

Residential DR adoption (cont'd)

Participation in time-varying rate offerings also can be a useful indication of customer willingness to participate in DR opportunities

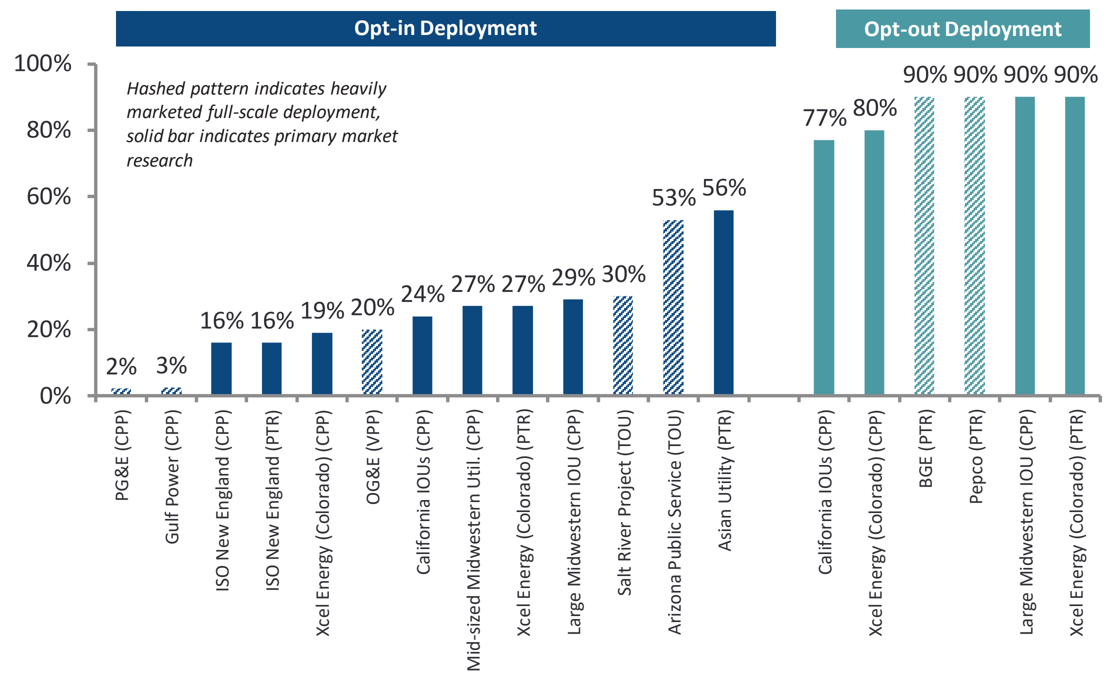
Research supports the observation that **more than 20% adoption** is achievable on a voluntary (opt-in) basis

- In fact, APS has enrolled more than half of its residential customers on voluntary TOU rates

Time-varying rates can also be offered on a default (opt-out) basis, with enrollment rates that **exceed 80%**

- BGE and Pepco have achieved this level of enrollment in full-scale peak time rebates deployed on an opt-out basis
- However, opt-out deployment would be without precedent for technology-based load control programs

Residential Time-Varying Rate Enrollment Estimates



APPENDIX B

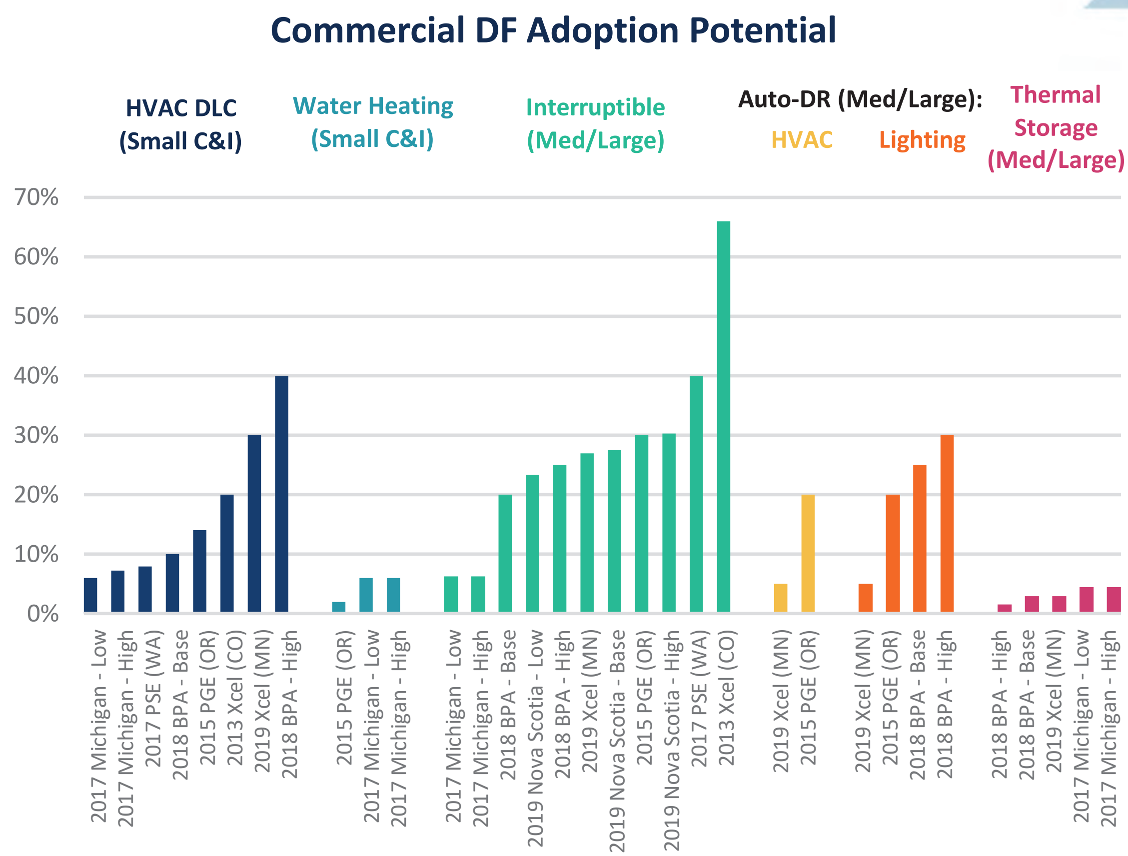
Commercial DR adoption

More diversity in DR adoption rate estimates is observed for commercial customers than for residential

Generally, adoption rates can range from **less than 10%** to around **30% to 40%**

Observations

- Larger customers tend to have higher adoption potential than smaller customers, though the differences are not as stark as one may think
- Interruptible tariffs have the highest adoption potential and typically do not require advanced technology deployment (though may involve partnering with an aggregator)
- Estimates of Auto-DR adoption potential are varied and the data is fairly limited



APPENDIX B

References

The following studies were reviewed to establish achievable participation rates

- *"The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory",* prepared by The Brattle Group for Xcel Energy, June 2019.
- *"Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045"*, prepared by Navigant for EfficiencyOne, August 2019.
- *"Demand Response Potential in Bonneville Power Administration's Public Utility Service Area – Final Report"*, prepared by The Cadmus Group for Bonneville Power Administration, March 2018.
- *"2017 IRP Demand-Side Resource Conservation Potential Assessment Report"*, prepared by Navigant Consulting for Puget Sound Energy, September 2017.
- *"State of Michigan Demand Response Potential Study"*, prepared by Applied Energy Group for the State of Michigan, September 2017.
- *"Demand Response Market Research: Portland General Electric, 2016 to 2035"*, prepared by The Brattle Group for Portland General Electric, January 2016.
- *"Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential"*, prepared by The Brattle Group for Xcel Energy, June 2013.

Appendix C:

Additional Analysis Details

APPENDIX C

The LoadFlex modeling framework

1 Parameterize DR programs

- Build database of new flexible load programs
- Estimate per-participant costs and participation
- Identify value proposition and applicable grid services
- Establish load impacts and operational constraints

2 Establish marginal costs and market depth

- Generation capacity value
- Frequency regulation value
- Average & targeted T&D value
- Energy value

3 Develop 8,760 hourly avoided costs

Allocate marginal costs based on hourly LOLP

Combine hourly costs to create stacked value profile

4 Optimally dispatch programs and calculate B/C metrics

Simulate optimized hourly dispatch

Calculate total benefits across value streams

5 Identify cost-effective incentive and participation

Establish relationship between adoption and incentives

Identify economic incentive level and associated participation

6 Estimate incremental cost-effective DR potential

Calculate cost-effective potential by program

Estimate portfolio impacts after participation overlap

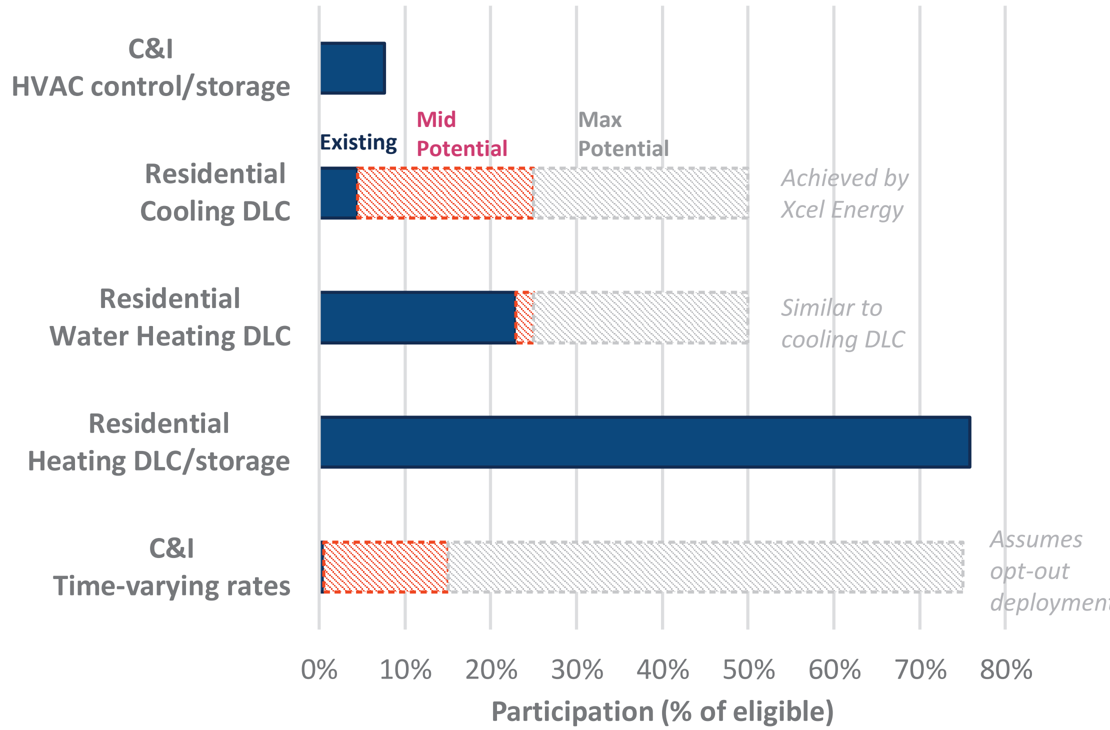
FINDINGS

The potential to expand participation in existing programs

OTP's existing programs are mature and have mostly reached maximum achievable participation levels

- There is room for increased participation in Residential Cooling DLC, based on observed enrollment rates of other utilities (not accounting for cost-effectiveness)
- Non-residential TOU participation could be increased significantly through default (opt-out deployment), though there likely is room for growth in an expanded voluntary program as well
- There may be modest room for growth in Residential Water Heating programs
- Current participation in C&I HVAC and Residential Heating has effectively reached estimates of maximum achievable potential

Enrollment in Existing OTP's DR Programs



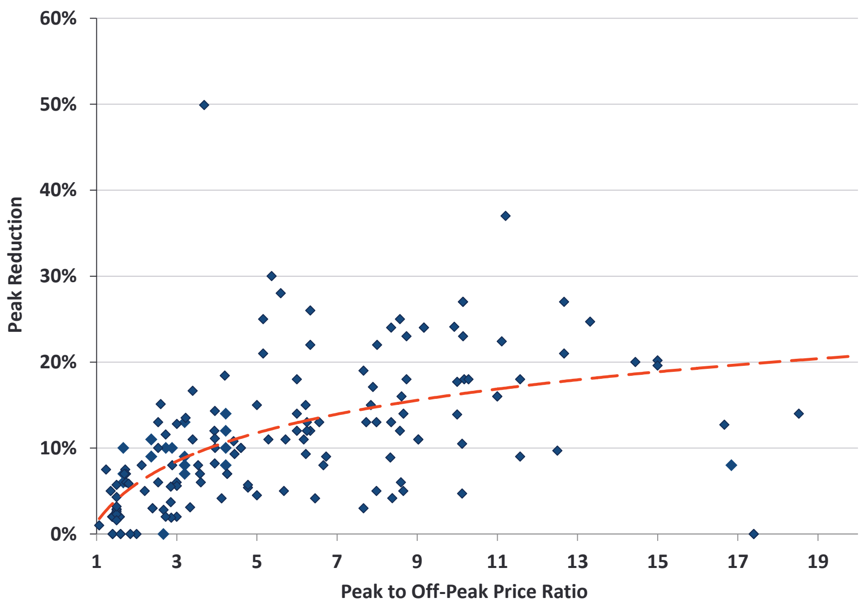
Note: Incremental participation rates shown here are based on typical program incentive payment levels and do not account for cost-effectiveness. As shown in this report, depending on system conditions, expansion of the programs in the chart may not be cost-effective.

APPENDIX C

Estimating per-participant impacts

Per-participant impacts are derived from OTP program experience, the experience of programs in other jurisdictions, and a review of engineering studies that identify theoretical load flexibility potential

Relationship Between Price Ratio and Response



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

For example, the impacts of time-varying pricing programs are based on a review of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs. Price response is expressed as a function of the assumed peak-to-off-peak price ratio in the time-varying rates

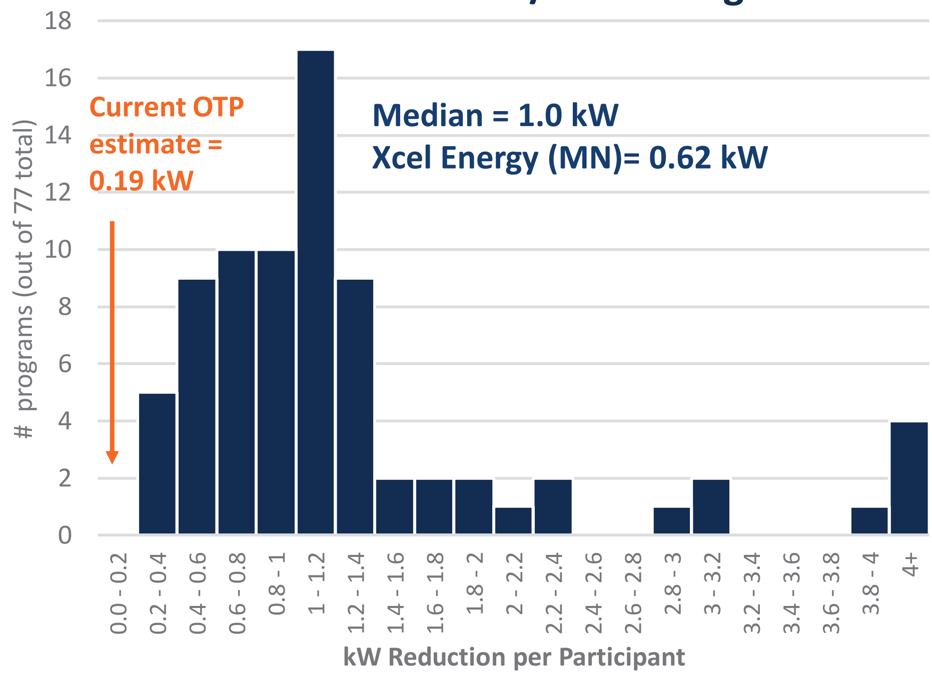
APPENDIX C

Impacts of the CoolSavings program

It appears possible to increase the per participant impacts in the CoolSavings program

- A/C DLC programs commonly achieve impacts of 1.0 kW per participant
- OTP's current assumption of 0.19 kW is significantly lower and likely could be increased, either through revised analysis or modifications to the cycling strategy
- Smart thermostat-based programs can potentially achieve deeper load reductions through more sophisticated pre-cooling strategies

Per-participant Impacts Across 77 Residential A/C DLC Programs



Source: Brattle analysis of 2012 FERC DR Program Database.

APPENDIX C

The cost-effectiveness test

We use the Utility Cost Test* (UCT) to determine the cost-effectiveness of the incremental DR portfolio

The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement

This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process

Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective

According to the National Action Plan for Energy Efficiency:

"The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements"

UCT Costs & Benefits
Benefits
Avoided generation capacity
Avoided peak energy
Avoided transmission capacity
Avoided distribution capacity
Costs
Incentive payments
Utility equipment & installation
Administration/overhead
Marketing/promotion

* Also sometimes known as the Program Administrator Cost Test (PACT)

APPENDIX C

DR Program Costs

DR program costs are based on a review of experience and studies in other jurisdictions, and conversations with vendors. The costs in the table below are in 2018 dollars.

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Residential	A/C DLC - Residential	$0	$150	$80	$0	$12	$33	15
Residential	Smart thermostat - Residential	$0	$110	$80	$0	$10	$25	10
Residential	Timed water heating - Residential	$0	$400	$30	$0	$0	$96	10
Residential	Smart water heating - Residential	$0	$600	$30	$0	$0	$96	10
Residential	Behavioral DR (Opt-out) - Residential	$0	$0	$0	$0	$4	$0	15
Residential	TOU (Opt-in) - Residential	$50,000	$0	$50	$75,000	$1	$0	15
Residential	TOU (Opt-out) - Residential	$50,000	$0	$25	$75,000	$1	$0	15
Residential	CPP (Opt-in) - Residential	$50,000	$0	$70	$75,000	$2	$0	15
Residential	CPP (Opt-out) - Residential	$50,000	$0	$35	$75,000	$2	$0	15
Residential	EV Managed Charging - Home	$0	$200	$0	$0	$15	$40	15
Residential	EV Managed Charging - Work	$0	$200	$0	$0	$15	$40	15
Residential	EV Charging - TOU	$0	$0	$0	$75,000	$0	$0	15
Small C&I	CPP (Opt-in) - Small C&I	$16,667	$0	$70	$25,000	$1	$0	15
Small C&I	CPP (Opt-out) - Small C&I	$16,667	$0	$35	$25,000	$1	$0	15
Small C&I	TOU (Opt-in) - Small C&I	$16,667	$0	$50	$18,750	$2	$0	15
Small C&I	TOU (Opt-out) - Small C&I	$16,667	$0	$25	$18,750	$2	$0	15

Note: Assumed 2.20% annual inflation rate to convert 2018 dollars to 2036 dollars. Used a discount rate of 7.53% to annualize fixed costs.

APPENDIX C

DR Program Costs (cont'd)

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Medium C&I	Interruptible - Medium C&I	$0	$0	$0	$251,000	$0	$431	15
Medium C&I	CPP (Opt-in) - Medium C&I	$16,667	$0	$70	$25,000	$6	$0	15
Medium C&I	CPP (Opt-out) - Medium C&I	$16,667	$0	$35	$25,000	$6	$0	15
Medium C&I	TOU (Opt-in) - Medium C&I	$16,667	$0	$1,000	$18,750	$20	$0	15
Medium C&I	TOU (Opt-out) - Medium C&I	$16,667	$0	$500	$18,750	$20	$0	15
Medium C&I	Auto-DR (Light Luminaire) - Medium C&I	$0	$0	$2,969	$0	$20	$399	15
Medium C&I	Auto-DR (Light Zonal) - Medium C&I	$0	$0	$2,209	$0	$20	$399	15
Large C&I	Interruptible - Large C&I	$0	$0	$0	$283,000	$0	$7,042	15
Large C&I	CPP (Opt-in) - Large C&I	$16,667	$0	$1,000	$25,000	$20	$0	15
Large C&I	CPP (Opt-out) - Large C&I	$16,667	$0	$500	$25,000	$20	$0	15
Large C&I	TOU (Opt-out) - Large C&I	$16,667	$0	$1,000	$18,750	$20	$0	15
Large C&I	Auto-DR (Light Luminaire) - Large C&I	$0	$0	$44,681	$0	$20	$8,020	15
Large C&I	Auto-DR (Light Zonal) - Large C&I	$0	$0	$33,170	$0	$20	$8,020	15

Note: Assumed 2.20% annual inflation rate to convert 2018 dollars to 2036 dollars. Used a discount rate of 7.53% to annualize fixed costs.

Appendix I: Integrated Resource Plan

Sensitivity Summary

Appendix I - 2021 Integrated Resource Plan Sensitivity Summary

NPVRR Comparison			A	B	C	D	E	F	G	H	I
No Externalities Included			Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%	NG and Energy Markets -25%	NG and Energy Markets -50%
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,515,096	$2,530,668	$2,567,790	$2,577,779	$2,620,023	$2,694,024	$2,800,779	$2,339,340	$2,087,191
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,466,554	**$2,479,385**	$2,466,554	$2,466,554	$2,589,304	$2,672,032	$2,803,209	$2,263,486	$1,980,644
	2028 Difference from 2040 Exit NPVRR	($000)	-$48,542	-$51,283	-$101,236	-$111,225	-$30,719	-$21,992	$2,430	-$75,854	-$106,547
3	Withdraw from Coyote 12/31/2026	NPVRR ($000)	$2,460,904	$2,473,146	$2,460,904	$2,460,904	$2,590,992	$2,675,855	$2,801,899	$2,249,553	$1,958,680
	2026 Difference from 2040 Exit NPVRR	($000)	-$54,192	-$57,522	-$106,886	-$116,875	-$29,031	-$18,169	$1,120	-$89,787	-$128,511

Annual Resource Additions - Withdraw from Coyote 12/31/2040		A	B	C	D	E	F	G	G	I
		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%	NG and Energy Markets -25%	NG and Energy Markets -50%
4	2022									
5	2023						100 MW Sur Solar	175 MW Sur Solar 50 MW Gen Wind		
6	2024									
7	2025		150 MW Sur Solar				50 MW Sur Solar	25 MW Sur Solar 50 MW Gen Wind		
8	2026	25 MW Sur Solar		25 MW Sur Solar	25 MW Sur Solar	150 MW Sur Solar	50 MW Gen Wind			
9	2027		100 MW Sur Wind							
10	2028									
11	2029						50 MW Sur Wind	50 MW Sur Wind		
12	2030									
13	2031									
14	2032									
15	2033		50 MW Rep Solar			25 MW Rep Solar 50 MW Sur Wind	25 MW Rep Solar 50 MW Sur Wind	50 MW Sur Wind		
16	2034					50 MW Rep Wind	25 MW Rep Solar			
17	2035									
18	2036									

Annual Resource Additions - Withdraw from Coyote 12/31/2028		A	B	C	D	E	F	G	G	I
		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%	NG and Energy Markets -25%	NG and Energy Markets -50%
19	2022									
20	2023						100 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind		
21	2024									
22	2025		**150 MW Sur Solar**				50 MW Sur Solar	50 MW Gen Wind		
23	2026	100 MW Sur Solar		100 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	25 MW Sur Solar 50 MW Gen Wind	25 MW Sur Solar		
24	2027		**100 MW Sur Wind**							
25	2028									
26	2029					50 MW Sur Wind	150 MW Sur Wind	150 MW Sur Wind		
27	2030					50 MW Sur Wind				
28	2031									
29	2032									
30	2033		**50 MW Rep Solar**			75 MW Rep Solar	50 MW Rep Solar 50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind		
31	2034					50 MW Rep Wind			50 MW Rep Solar	
32	2035	50 MW Rep Wind 50 MW Sur Wind		50 MW Rep Wind 50 MW Sur Wind	50 MW Rep Wind 50 MW Sur Wind	50 MW Rep Wind	25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Solar	
33	2036								25 MW Rep Solar	

Annual Resource Additions - Withdraw from Coyote 12/31/2026		A	B	C	D	E	F	G	G	I
		Base Case	Preferred IRP	Regional Haze Mid Cost	Regional Haze High Cost	NG and Energy Markets +25%	NG and Energy Markets +50%	NG and Energy Markets +100%	NG and Energy Markets -25%	NG and Energy Markets -50%
34	2022									
35	2023						100 MW Sur Solar	175 MW Sur Solar 50 MW Gen Wind		
36	2024									
37	2025		150 MW Sur Solar				50 MW Sur Solar	25 MW Sur Solar 50 MW Gen Wind		
38	2026	100 MW Sur Solar		100 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	25 MW Sur Solar 100 MW Gen Wind	50 MW Sur Solar		
39	2027		100 MW Sur Wind				50 MW Sur Wind	100 MW Sur Wind		
40	2028							50 MW Sur Wind		
41	2029					50 MW Sur Wind	50 MW Sur Wind			
42	2030					50 MW Sur Wind				
43	2031					50 MW Sur Wind				
44	2032									
45	2033		50 MW Rep Solar			75 MW Rep Solar	50 MW Rep Solar 50 MW Rep Wind	50 MW Rep Wind		
46	2034					50 MW Rep Wind		25 MW Rep Solar	50 MW Rep Solar	
47	2035	50 MW Rep Wind 50 MW Sur Wind		50 MW Rep Wind 50 MW Sur Wind	50 MW Rep Wind 50 MW Sur Wind	25 MW Rep Solar	25 MW Rep Solar		50 MW Rep Solar	
48	2036								25 MW Rep Solar	

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NPVRR Comparison			J	K	L	M	N	O	P	Q	R	S
No Externalities Included			Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,313,186	$2,420,794	$2,267,486	$2,508,819	$2,516,554	$2,538,457	$2,515,612	$2,743,014	$3,103,670	$2,856,648
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,243,321	$2,358,296	$2,178,450	$2,461,628	$2,467,223	$2,492,654	$2,466,747	$2,698,837	$3,093,980	$2,739,964
	2028 Difference from 2040 Exit NPVRR	($000)	-$69,865	-$62,498	-$89,036	-$47,191	-$49,331	-$45,803	-$48,865	-$44,177	-$9,690	-$116,684
3	Withdraw from Coyote 12/31/2026	NPVRR ($000)	$2,236,963	$2,348,150	$2,165,189	$2,456,132	$2,461,577	$2,486,887	$2,461,105	$2,693,597	$3,096,629	$2,726,702
	2026 Difference from 2040 Exit NPVRR	($000)	-$76,223	-$72,644	-$102,297	-$52,687	-$54,977	-$51,570	-$54,507	-$49,417	-$7,041	-$129,946

Annual Resource Additions - Withdraw from Coyote 12/31/2040		J	K	L	M	N	O	P	Q	R	S
		Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
4	2022										
5	2023		150 MW Sur Solar	150 MW Sur Solar							
6	2024										
7	2025									50 MW Sur Solar	
8	2026					100 MW Sur Solar	75 MW Sur Solar		100 MW Sur Solar	100 MW Sur Solar	175 MW Sur Solar
9	2027	300 MW Sur Wind	200 MW Sur Solar	50 MW Sur Solar 250 MW Sur Wind							
10	2028			50 MW Sur Wind							
11	2029										
12	2030										
13	2031										100 MW Sur Wind
14	2032										
15	2033	100 MW Rep Wind	50 MW Rep Solar	50 MW Rep Wind						25 MW Rep Solar	25 MW Rep Solar 50 MW Rep Wind
16	2034		25 MW Rep Solar	25 MW Rep Solar						50 MW Rep Solar	25 MW Rep Solar 50 MW Sur Wind
17	2035			25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind 50 MW Sur Wind		25 MW Rep Solar	50 MW Sur Wind	100 MW Rep Wind	25 MW Rep solar
18	2036	50 MW Rep Wind	25 MW Rep Solar							50 MW Rep Wind	50 MW Rep Wind

Annual Resource Additions - Withdraw from Coyote 12/31/2028		J	K	L	M	N	O	P	Q	R	S
		Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
19	2022										
20	2023		150 MW Sur Solar	150 MW Sur Solar							
21	2024										
22	2025									50 MW Sur Solar	
23	2026				50 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar 25 MW Gen Solar 10 MW Paired Batt	175 MW Sur Solar
24	2027	300 MW Sur Wind	200 MW Sur Solar	75 MW Sur Solar 250 MW Sur Wind							
25	2028		25 MW Sur Solar	50 MW Sur Wind							
26	2029									50 MW Gen Solar 20 MW Paired Batt	
27	2030										100 MW Sur Wind
28	2031										100 MW Sur Wind
29	2032										
30	2033	150 MW Rep Wind	125 MW Rep Solar	100 MW Rep Wind			100 MW Rep Solar		100 MW Rep Solar	250 MW Rep Solar	75 MW Rep Solar
31	2034		25 MW Rep Solar	50 MW Rep Wind	25 MW Rep Solar		25 MW Rep Solar		25 MW Rep Solar	100 MW Rep Wind	50 MW Rep Wind
32	2035	25 MW Rep Solar			25 MW Rep Solar 50 MW Rep Wind	50 MW Rep Wind 50 MW Sur Wind	100 MW Rep Wind	50 MW Rep Wind 50 MW Sur Wind	150 MW Rep Wind	50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind
33	2036	25 MW Rep Solar					25 MW Rep Solar			25 MW Gen Solar 10 MW Paired Batt	

Annual Resource Additions - Withdraw from Coyote 12/31/2026		J	K	L	M	N	O	P	Q	R	S
		Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs	Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Median Cost of Carbon Tax
34	2022										
35	2023		150 MW Sur Solar	150 MW Sur Solar							
36	2024										
37	2025									50 MW Sur Solar	
38	2026				50 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar	150 MW Sur Solar	100 MW Sur Solar 75 MW Gen Solar 30 MW Paired Batt	175 MW Sur Solar
39	2027	300 MW Sur Wind	250 MW Sur Solar	100 MW Sur Solar 300 MW Sur Wind							
40	2028										
41	2029										
42	2030										100 MW Sur Wind
43	2031										100 MW Sur Wind
44	2032										
45	2033	150 MW Rep Wind	100 MW Rep Solar	25 MW Rep Solar 100 MW Rep Wind			100 MW Rep Solar		100 MW Rep Solar	250 MW Rep Solar	75 MW Rep Solar
46	2034		25 MW Rep Solar	50 MW Rep Wind	25 MW Rep Solar		25 MW Rep Solar		25 MW Rep Solar	100 MW Rep Wind	50 MW Rep Wind
47	2035	25 MW Rep Solar			25 MW Rep Solar 50 MW Rep Wind 50 MW Sur Wind	50 MW Rep SWind 50 MW Sur Wind	100 MW Rep Wind	50 MW Rep Wind 50 MW Sur Wind	150 MW Rep Wind	50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind
48	2036	25 MW Rep Solar					25 MW Rep Solar				

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Externalities Included

NPVRR Comparison			A Base Case	B Preferred IRP	C Regional Haze Mid Cost	D Regional Haze High Cost	E NG and Energy Markets +25%	F NG and Energy Markets +50%	G NG and Energy Markets +100%
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,971,847	$2,991,608	$3,017,977	$3,029,243	$3,043,411	$3,097,960	$3,174,178
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,864,875	**$2,909,334**	$2,864,875	$2,864,875	$2,959,187	$3,022,602	$3,113,119
	2028 Difference from 2040 Exit NPVRR	($000)	-$106,972	-$82,274	-$153,102	-$164,368	-$84,224	-$75,358	-$61,059
3	Withdraw from Coyote 12/31/2026	NPVRR ($000)	$2,855,293	$2,895,349	$2,855,293	$2,855,293	$2,948,319	$3,011,247	$3,103,710
	2026 Difference from 2040 Exit NPVRR	($000)	-$116,554	-$96,259	-$162,684	-$173,950	-$95,092	-$86,713	-$70,468

Annual Resource Additions - Withdraw from Coyote 12/31/2040

		A Base Case	B Preferred IRP	C Regional Haze Mid Cost	D Regional Haze High Cost	E NG and Energy Markets +25%	F NG and Energy Markets +50%	G NG and Energy Markets +100%
4	2022							
5	2023	125 MW Sur Solar		125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind	200 MW Sur Solar 100 MW Gen Wind
6	2024							
7	2025	100 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar	75 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	50 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind
8	2026	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind		50 MW Gen Wind	
9	2027	50 MW Sur Wind	100 MW Sur Wind					
10	2028	50 MW Sur Wind		50 MW Sur Wind	50 MW Sur Wind	50 MW Sur Wind		50 MW Sur Wind
11	2029							
12	2030			50 MW Sur Wind				
13	2031				50 MW Sur Wind			
14	2032						50 MW Sur Wind	
15	2033	50 MW Rep Wind	50 MW Rep Solar	50 MW Rep Solar		50 MW Rep Wind		
16	2034	25 MW Rep Solar		25 MW Rep Solar	50 MW Rep Solar			
17	2035			50 MW Rep Wind				50 MW Rep Wind
18	2036							

Annual Resource Additions - Withdraw from Coyote 12/31/2028

		A Base Case	B **Preferred IRP**	C Regional Haze Mid Cost	D Regional Haze High Cost	E NG and Energy Markets +25%	F NG and Energy Markets +50%	G NG and Energy Markets +100%
19	2022							
20	2023	125 MW Sur Solar		125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind	175 MW Sur Solar 100 MW Gen Wind
21	2024							25 MW Sur Solar
22	2025	100 MW Sur Solar 50 MW Gen Wind	**150 MW Sur Solar**	100 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	50 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind
23	2026	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind		
24	2027		**100 MW Sur Wind**					
25	2028	50 MW Sur Wind		50 MW Sur Wind	50 MW Sur Wind			25 MW Sur Wind
26	2029	100 MW Sur Wind		100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	25 MW Sur Solar 100 MW Sur Wind
27	2030							
28	2031							
29	2032							
30	2033	25 MW Rep Solar	**50 MW Rep Solar**	25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Solar	50 MW Rep Wind	25 MW Rep Solar 25 MW Battery
31	2034	25 MW Rep Solar 100 MW Rep Wind		25 MW Rep Solar 100 MW Rep Wind	25 MW Rep Solar 100 MW Rep Wind		25 MW Rep Solar	50 MW Rep Wind
32	2035							
33	2036							

Annual Resource Additions - Withdraw from Coyote 12/31/2026

		A Base Case	B Preferred IRP	C Regional Haze Mid Cost	D Regional Haze High Cost	E NG and Energy Markets +25%	F NG and Energy Markets +50%	G NG and Energy Markets +100%
34	2022							
35	2023	125 MW Sur Solar		125 MW Sur Solar	125 MW Sur Solar	225 MW Sur Solar	200 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar 100 MW Gen Wind
36	2024							50 MW Sur Solar
37	2025	100 MW Sur Solar 50 MW Gen Wind	150 MW Sur Solar	100 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	25 MW Sur Solar 150 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind	75 MW Sur Solar 100 MW Gen Wind
38	2026	50 MW Gen Wind		50 MW Gen Wind	50 MW Gen Wind			25 MW Sur Solar
39	2027	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind	150 MW Sur Wind	150 MW Sur Wind
40	2028							
41	2029	50 MW Sur Wind		50 MW Sur Wind	50 MW Sur Wind	50 MW Sur Wind		
42	2030							
43	2031							
44	2032							
45	2033	50 MW Rep Solar	50 MW Rep Solar	50 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind	
46	2034	50 MW Rep Wind		50 MW Rep Wind	50 MW Rep Wind	25 MW Rep Solar		
47	2035					50 MW Rep Wind		50 MW Rep Solar
48	2036						25 MW Rep Solar	50 MW Sur Wind 25 MW Battery

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NPVRR Comparison			H	I	J	K	L	M	N
Externalities Included			NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,849,110	$2,642,896	$2,709,607	$2,848,076	$2,609,792	$2,967,662	$2,974,927
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,731,585	$2,503,367	$2,606,536	$2,737,058	$2,486,826	$2,861,538	$2,874,953
	2028 Difference from 2040 Exit NPVRR	($000)	-$117,525	-$139,529	-$103,071	-$111,018	-$122,966	-$106,124	-$99,974
3	Withdraw from Coyote 12/31/2026	NPVRR ($000)	$2,706,529	$2,475,659	$2,576,239	$2,716,959	$2,470,288	$2,855,648	$2,859,743
	2026 Difference from 2040 Exit NPVRR	($000)	-$142,581	-$167,237	-$133,368	-$131,117	-$139,504	-$112,014	-$115,184

Annual Resource Additions - Withdraw from Coyote 12/31/2040		H	I	J	K	L	M	N
		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs
4	2022							
5	2023			125 MW Sur Solar	300 MW Sur Solar	300 MW Sur Solar	125 MW Sur Solar	125 MW Sur Solar
6	2024							
7	2025	50 MW Sur Solar		25 MW Sur Solar			100 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar
8	2026	100 MW Sur Solar						
9	2027			300 MW Sur Wind	125 MW Sur Solar 50 MW Sur Wind	300 MW Sur Wind	50 MW Sur Wind	100 MW Sur Wind
10	2028						50 MW Sur Wind	50 MW Sur Wind
11	2029							
12	2030							
13	2031	50 MW Sur Wind						
14	2032				50 MW Sur Wind			
15	2033	25 MW Rep Solar 50 MW Rep Wind		150 MW Rep Wind	25 MW Rep Solar	100 MW Rep Wind	50 MW Rep Wind	50 MW Sur Wind
16	2034	50 MW Rep Solar 50 MW Sur Wind			50 MW Rep Wind		25 MW Rep Solar	25 MW Rep Solar
17	2035					50 MW Rep Wind		
18	2036					25 MW Rep Solar		

Annual Resource Additions - Withdraw from Coyote 12/31/2028		H	I	J	K	L	M	N
		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs
19	2022							
20	2023			125 MW Sur Solar	300 MW Sur Solar	300 MW Sur Solar		125 MW Sur Solar
21	2024							
22	2025	50 MW Sur Solar		25 MW Sur Solar	50 MW Gen Wind			100 MW Sur Solar
23	2026	100 MW Sur Solar	25 MW Sur Solar					
24	2027			300 MW Sur Wind	150 MW Sur Solar	300 MW Sur Wind		100 MW Sur Wind
25	2028					25 MW Sur Solar		50 MW Sur Wind
26	2029	50 MW Sur Wind		50 MW Gen Wind	100 MW Sur Wind	25 MW Sur Solar		100 MW Sur Wind
27	2030	50 MW Sur Wind						
28	2031	50 MW Sur Wind						
29	2032							
30	2033	75 MW Rep Solar 50 MW Rep Wind		150 MW Rep Wind	50 MW Rep Solar	25 MW Rep Solar 150 MW Rep Wind		50 MW Rep Solar
31	2034		25 MW Rep Solar		50 MW Rep Wind			50 MW Rep Wind
32	2035		50 MW Rep Solar			25 MW Rep Solar		
33	2036		25 MW Rep Solar					

Annual Resource Additions - Withdraw from Coyote 12/31/2026		H	I	J	K	L	M	N
		NG and Energy Markets -25%	NG and Energy Markets -50%	Low Wind	Low Solar	Low Wind & Solar	Low Storage	High Interconnection Costs
34	2022							
35	2023			100 MW Sur Solar 50 MW Gen Wind	300 MW Sur Solar	300 MW Sur Solar	125 MW Sur Solar	125 MW Sur Solar
36	2024							
37	2025	50 MW Sur Solar		50 MW Sur Solar			125 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar
38	2026	100 MW Sur Solar	25 MW Sur Solar		50 MW Gen Wind			
39	2027			300 MW Sur Wind	150 MW Sur Solar 50 MW Sur Wind	50 MW Sur Solar 300 MW Sur Wind	100 MW Sur Wind	200 MW Sur Wind
40	2028						50 MW Sur Wind	
41	2029	50 MW Sur Wind			50 MW Sur Wind			50 MW Sur Wind
42	2030	50 MW Sur Wind						
43	2031	50 MW Sur Wind						
44	2032							
45	2033	75 MW Rep Solar		150 MW Rep Wind	50 MW Rep Solar	25 MW Rep Solar 150 MW Rep Wind	50 MW Rep Solar 50 MW Rep Wind	50 MW Rep Solar
46	2034	50 MW Rep Wind	25 MW Rep Solar		50 MW Rep Wind			50 MW Rep Wind
47	2035	25 MW Rep Solar	50 MW Rep Solar		50 MW Rep Wind	25 MW Rep Solar		
48	2036		25 MW Rep Solar				50 MW Rep Wind	

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NPVRR Comparison			O	P	Q	R	T	U	V	W
Externalities Included			Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050
1	Withdraw from Coyote 12/31/2040	NPVRR ($000)	$2,979,416	$2,976,297	$3,247,652	$3,680,849	$2,718,105	$3,156,787	$2,963,754	$2,974,804
2	Withdraw from Coyote 12/31/2028	NPVRR ($000)	$2,883,950	$2,868,515	$3,147,845	$3,593,323	$2,660,195	$3,012,644	$2,862,582	$2,872,352
	2028 Difference from 2040 Exit NPVRR	($000)	-$95,466	-$107,782	-$99,807	-$87,526	-$57,910	-$144,143	-$101,172	-$102,452
3	Withdraw from Coyote 12/31/2026	NPVRR ($000)	$2,865,661	$2,854,019	$3,135,452	$3,572,003	$2,648,162	$2,985,027	$2,844,688	$2,853,201
	2026 Difference from 2040 Exit NPVRR	($000)	-$113,755	-$122,278	-$112,200	-$108,846	-$69,943	-$171,760	-$119,066	-$121,603

Annual Resource Additions - Withdraw from Coyote 12/31/2040		O	P	Q	R	T	U	V	W
		Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050
4	2022								
5	2023	125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	300 MW Sur Solar 50 MW Gen Wind		175 MW Sur Solar		125 MW Sur Solar
6	2024								25 MW Sur Solar
7	2025	75 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	25 MW Sur Solar 100 MW Gen Wind	150 MW Gen Wind		75 MW Sur Solar 150 MW Gen Wind	225 MW Sur Solar 50 MW Gen Wind	75 MW Sur Solar 50 MW Gen Wind
8	2026	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind	150 MW Sur Solar	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind
9	2027				50 MW Sur Wind				
10	2028	50 MW Sur Wind	50 MW Sur Wnd	100 MW Sur Wind				50 MW Sur Wind	
11	2029								50 MW Sur Wind
12	2030								
13	2031	50 MW Sur Wind							
14	2032								
15	2033	50 MW Rep Wind	50 MW Rep Wind		25 MW Rep Solar 50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind	50 MW Sur Wind	50 MW Sur Wind	50 MW Rep Wind
16	2034	25 MW Rep Solar	25 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar	50 MW Rep Wind	50 MW Sur Wind	25 MW Rep Solar	25 MW Rep Solar
17	2035					50 MW Rep Wind			
18	2036								

Annual Resource Additions - Withdraw from Coyote 12/31/2028		O	P	Q	R	T	U	V	W
		Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050
19	2022								
20	2023	125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	250 MW Sur Solar 50 MW Gen Wind		175 MW Sur Solar		125 MW Sur Solar
21	2024			25 MW Sur Solar					25 MW Sur Solar
22	2025	50 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind	150 MW Gen Wind	150 MW Gen Wind		100 MW Sur Solar 150 MW Gen Wind	225 MW Sur Solar 50 MW Gen Wind	75 MW Sur Solar 50 MW Gen Wind
23	2026	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind	150 MW Gen Wind	150 MW Sur Solar	50 MW Gen Wind	50 MW Gen Wind	50 MW Gen Wind
24	2027								
25	2028		50 MW Sur Wind					50 MW Sur Wind	50 MW Sur Wind
26	2029	100 MW Sur Wind	100 MW Sur Wind	100 MW Sur Wind			100 MW Sur Wind	100 MW Sur Wind	50 MW Sur Wind
27	2030								50 MW Sur Wind
28	2031					50 MW Sur Wind			
29	2032								
30	2033	100 MW Rep Solar	50 MW Rep Solar	75 MW Rep Solar	200 MW Rep Solar 50 MW Rep Wind	50 MW Sur Wind	25 MW Rep Solar	50 MW Rep Solar	25 MW Rep Solar
31	2034	50 MW Rep Wind	25 MW Rep Solar 50 MW Rep Wind		25 MW Rep Solar 50 MW Rep Wind	50 MW Rep Wind	50 MW Rep Wind		25 MW Rep Solar 50 MW Rep Wind
32	2035			100 MW Rep Wind		25 MW Rep Solar		25 MW Rep Solar 50 MW Rep Wind	50 MW Rep Wind
33	2036				25 MW Battery				

Annual Resource Additions - Withdraw from Coyote 12/31/2026		O	P	Q	R	T	U	V	W
		Additional 10% MISO Capacity Requirement	Capacity Purchase Limit	10% Increased Load	25% Increased Load	Low Externalities 2020-2024, Low Cost of Carbon 2025-2050	High Externalities 2020-2024, High Cost of Carbon 2025-2050	Low Externalities 2020-2024, Median Cost of Carbon 2025-2050	High Externalities 2020-2024, Median Cost of Carbon 2025-2050
34	2022								
35	2023	125 MW Sur Solar	125 MW Sur Solar	200 MW Sur Solar	225 MW Sur Solar 50 MW Gen Wind		175 MW Sur Solar		125 MW Sur Solar
36	2024			25 MW Sur Solar					25 MW Sur Solar
37	2025	50 MW Sur Solar 100 MW Gen Wind	100 MW Sur Solar 100 MW Gen Wind	200 MW Gen Wind	200 MW Gen Wind		100 MW Sur Solar 150 MW Gen Wind	225 MW Sur Solar 50 MW Gen Wind	100 MW Sur Solar 50 MW Gen Wind
38	2026	50 MW Gen Wind		50 MW Gen Wind	25 MW Gen Solar 200 MW Gen Wind 10 MW Paired Batt	150 MW Sur Solar		50 MW Gen Wind	50 MW Gen Wind
39	2027	50 MW Sur Wind	100 MW Sur Wind				100 MW Sur Wind	150 MW Sur Wind	100 MW Sur Wind
40	2028	50 MW Sur Wind		50 MW Sur Wind					
41	2029						50 MW Sur Wind		
42	2030		50 MW Sur Wind			50 MW Sur Wind			50 MW Sur Wind
43	2031					100 MW Sur Wind			
44	2032								
45	2033	100 MW Rep Solar	50 MW Rep Solar	75 MW Rep Solar	125 MW Rep Solar 50 MW Rep Wind	100 MW Rep Solar 50 MW Rep Wind	50 MW Rep Solar		25 MW Rep Solar
46	2034	50 MW Rep Wind	25 MW Rep Wind	50 MW Rep Wind	50 MW Rep Solar		50 MW Rep Wind	75 MW Rep Solar 50 MW Rep Wind	50 MW Rep Wind
47	2035				50 MW Rep Solar				
48	2036				25 MW Rep Solar				

Appendix J: Distributed Renewable Generation

Distributed Renewable Generation

Existing Distributed Renewable Generation Projects

Otter Tail currently has 69 interconnected facilities with over 1.7 MW of installed nameplate capacity of distributed renewable generation (DG) on its system. The majority of these facilities are customer owned units that are utilizing the small power producer tariffs that exist in all three jurisdictions that Otter Tail operates.

New Distributed Renewable Generation Projects

Otter Tail expects new small customer owned DG facilities to continue to grow over time. Otter Tail does not expect that the increase in distributed generation facilities on its system will have an impact on the current preferred resource plan.

In order for DG facilities to have an impact on Otter Tail's resource plan, the facilities will need to be competitive with other generation facilities available to Otter Tail including the cost of capacity and energy in the Midcontinent ISO market. That is a difficult hurdle in today's energy market.

Wholesale energy prices remain low following the increasing penetration of wind generation and continuing low natural gas prices. Annual average Locational Marginal Prices (LMP) at the OTP.OTP load zone in the day-ahead market remain low:

2016: $20.22/MWh
2017: $23.00/MWh
2018: $27.28/MWh
2019: $22.99/MWh
2020: $16.60/MWh
2021 (YTD May 13): $30.81/MWh

While it can be argued that there are transmission and distribution loss savings to be realized, the magnitude of those savings will not come close to offsetting the additional cost of the energy.

Otter Tail will continue to analyze renewable distributed generation projects that are submitted for consideration. However, with its RES/REO obligations met in all three states, Otter Tail will only consider projects that are competitive with the Midcontinent ISO energy market or are needed to meet renewable objectives or the solar mandate in the service territory that it serves.

In order to keep customers bills as low as possible, it is prudent for Otter Tail to enter into only projects that are cost competitive with the Midcontinent ISO market.