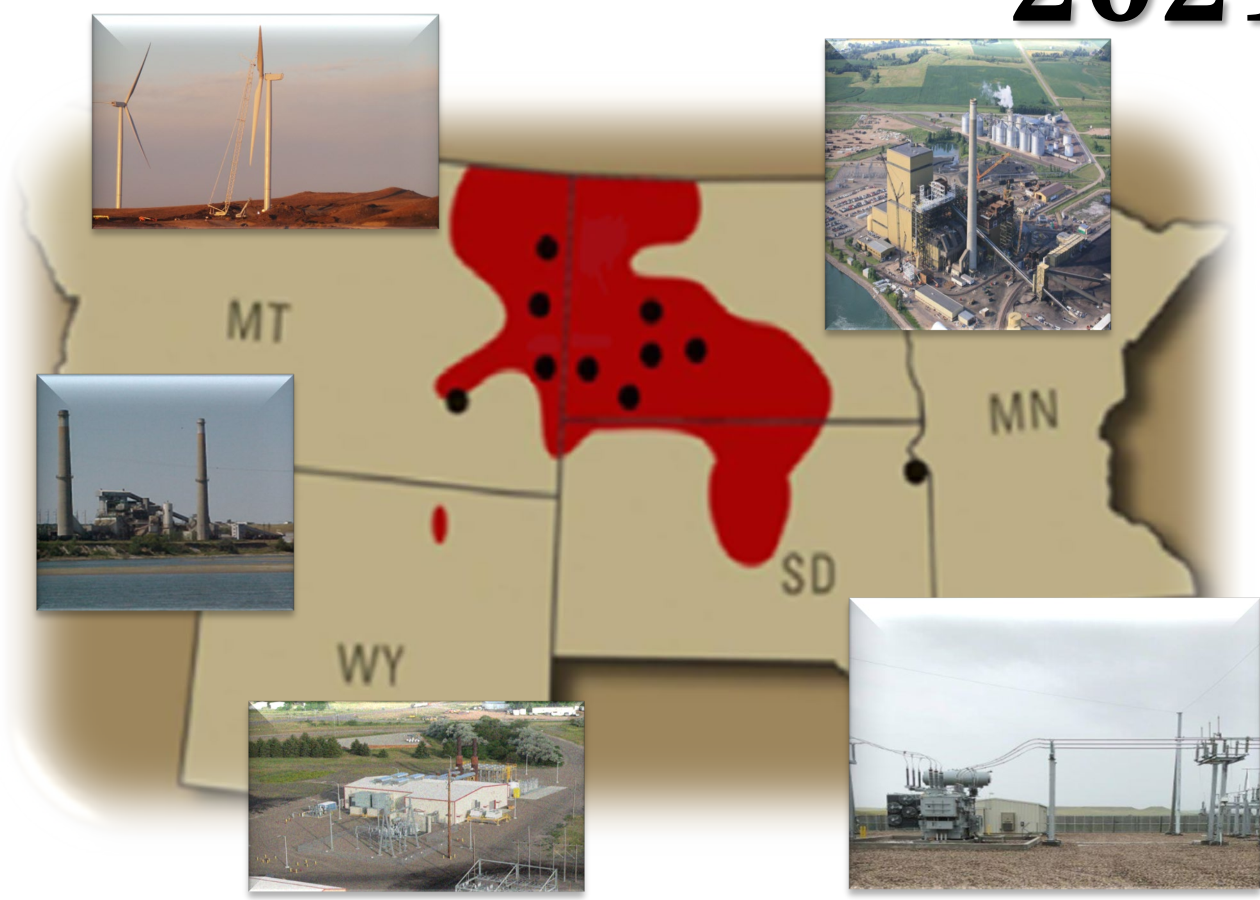
Integrated Resource Plan 2021



Submitted to the
Montana Public Service Commission
September 15, 2021

Volume IV: Attachment C-J

Montana-Dakota Utilities Co.

2021 Integrated Resource Plan

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Volume IV

Attachments C – J

MONTANA-DAKOTA UTILITIES CO.

A Subsidiary of MDU Resources Group, Inc.

Attachment C

SUPPLY-SIDE AND INTEGRATION ANALYSIS DOCUMENTATION

Supply Side and Integration Analysis

TABLE OF CONTENTS

Supply-Side

Overview

To determine the most cost-effective plan, a supply-side analysis was conducted to identify the feasible supply-side resources to be added to Montana-Dakota's generating system. Potential new planning resources consisting of both capacity resources (generation or external resources) and load modifying resources must be proven technology and be able to provide the same system reliability that Montana-Dakota's customers have come to expect over the years. The integration process considers the potential planning resources and integrates those resources into a single least-cost plan. The analysis also considered possible future economic and social issues.

The least-cost resource plan, developed through the integration process, provides the basis for evaluating and determining the most cost-effective, long-term plan for future supply. Criteria other than simply least cost must be considered in the ultimate future resource selection.

Capacity Needs

The resource expansion analysis considers all planning resource options available to Montana-Dakota and produces a least-cost plan which satisfies the energy and capacity requirements to reliably serve Montana-Dakota's customers. Montana-Dakota is a member of MISO, which currently requires a planning reserve margin (PRM) of 9.4 percent on an unforced capacity (UCAP) basis for the summer peak. The PRM is adjusted annually through MISO's Loss of Load Expectation (LOLE) study. To meet the PRM, enough planning resources are needed to cover the projected yearly MISO non-coincident summer peak demand with a 2.1 percent adder for MISO losses, plus 9.4 percent PRM, the product of which is referred to as the planning reserve margin requirement (PRMR).

Montana-Dakota is required to meet a PRMR based on an 81.1 percent coincident factor for the 2021-2022 Planning Year in MISO based on MDU's analysis of Montana-Dakota's peak at the time of the MISO system-wide peak.

MISO is developing new rules which will likely add a four-season resource adequacy requirement beginning in 2023. The impacts of the four-season resource adequacy requirement are not expected to have a large impact on the generation requirements for Montana-Dakota's fleet, but the ultimate impacts are still unknown.

Load and Capability

To further understand Montana-Dakota's capacity needs, a comparison of its zonal resource credits (ZRC) in MISO and the planning reserve margin requirement (PRMR) based on an 81.1 percent coincident factor is shown in Figures 1-1, 1-2, and 1-3 for the base, low-growth, and high-growth forecast scenarios. The ZRC is established by MISO annually through a Generator Verification Test Capability (GVTC) process. The GVTC is run annually by all Montana-Dakota's steam units and combustion turbines, as required by MISO for all generation resources, greater than 10 MW. All planning resources are corrected to MISO's summer peak to develop an Installed Capacity (ICAP) value to be used on an annual basis. Capacity resources are determined by applying the equivalent forced outage rate ($XEFOR_d$) to the ICAP value to establish an unforced capacity value (UCAP) for each resource:

$$UCAP = ICAP – (1\text{-}XEFOR_d).$$

UCAP values are then directly converted to a ZRC value to be used to meet the PRMR. The ZRC value shown in the forecast scenarios includes Montana-Dakota's existing and committed resources at this time.

Figure 1-1 shows that, under the current system forecast, Montana-Dakota has adequate capacity to meet its PRMR through 2025. The capacity deficit in 2026 will be 11.4 ZRC and grow to 92.3 ZRC by 2040. As shown in Figure 1-2, under the low-growth forecast, a capacity deficit occurs in 2034 at 7.6 ZRC and grows to 35.6 ZRC by 2040. With the high-growth forecast, as shown in Figure 1-3, a capacity deficit of 5.9 ZRC will occur in 2021 and grow to 698.5 ZRC by 2040.

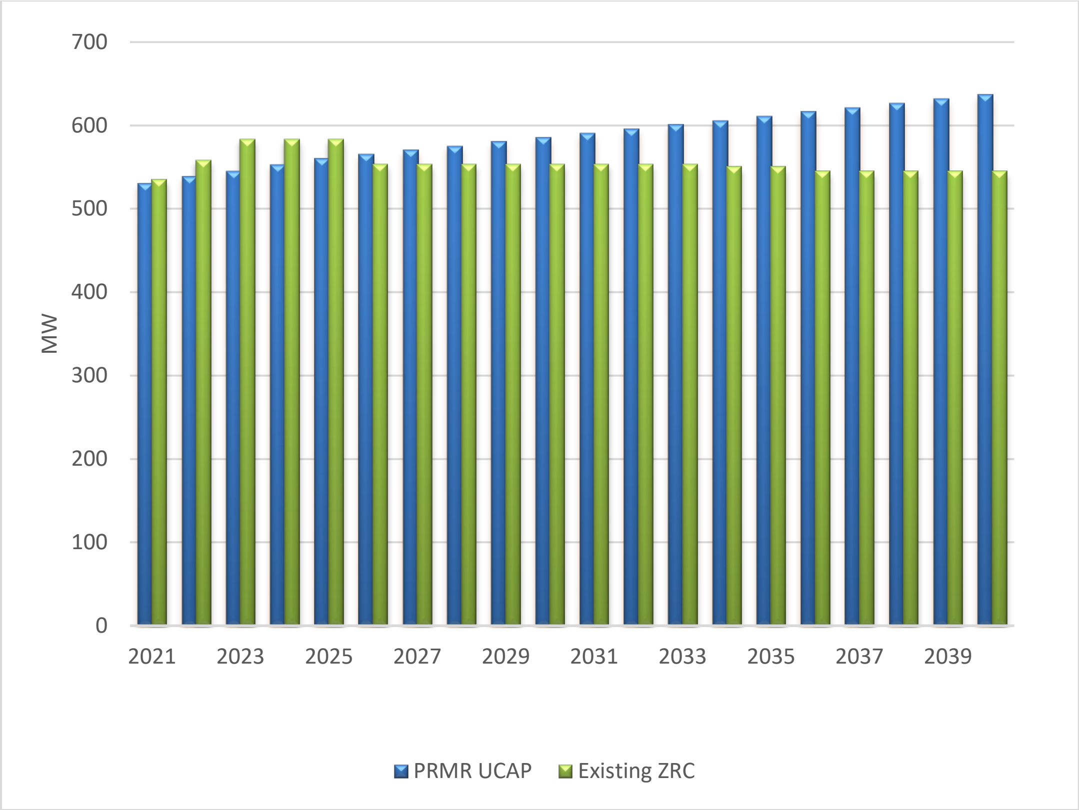

Figure 1-1: Zonal Resource Credit and Planning Reserve Margin Requirement Base Forecast

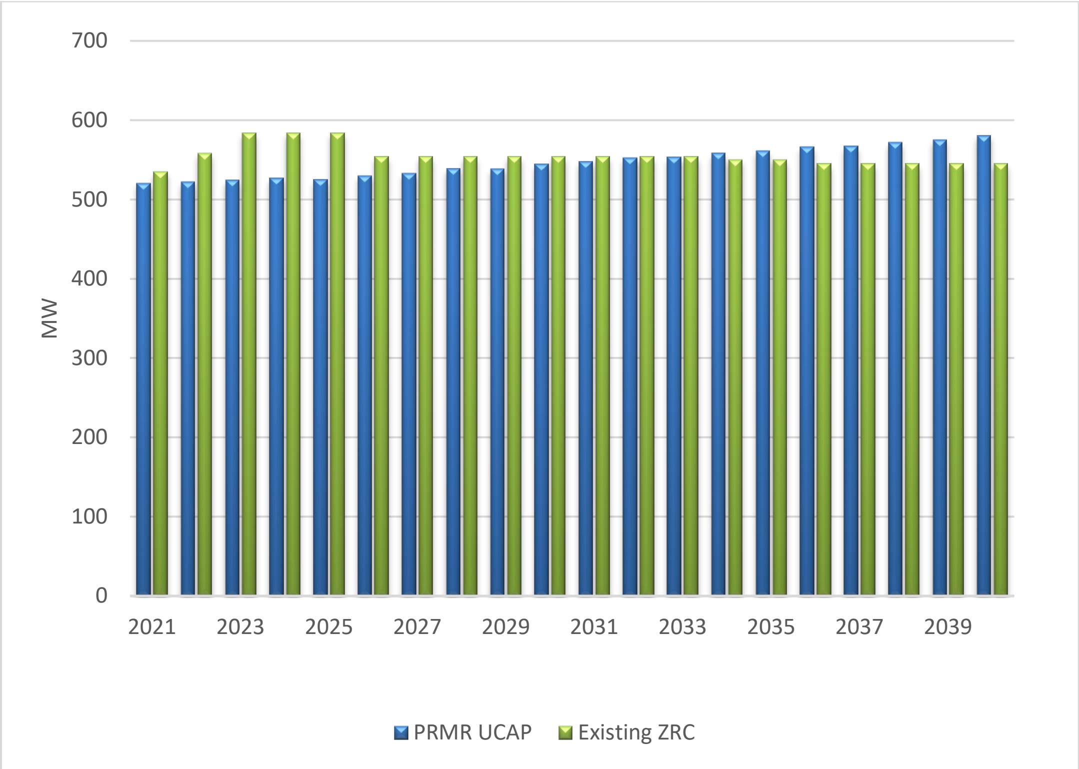

Figure 1-2: Zonal Resource Credit and Planning Reserve Margin Requirement Low Growth Forecast

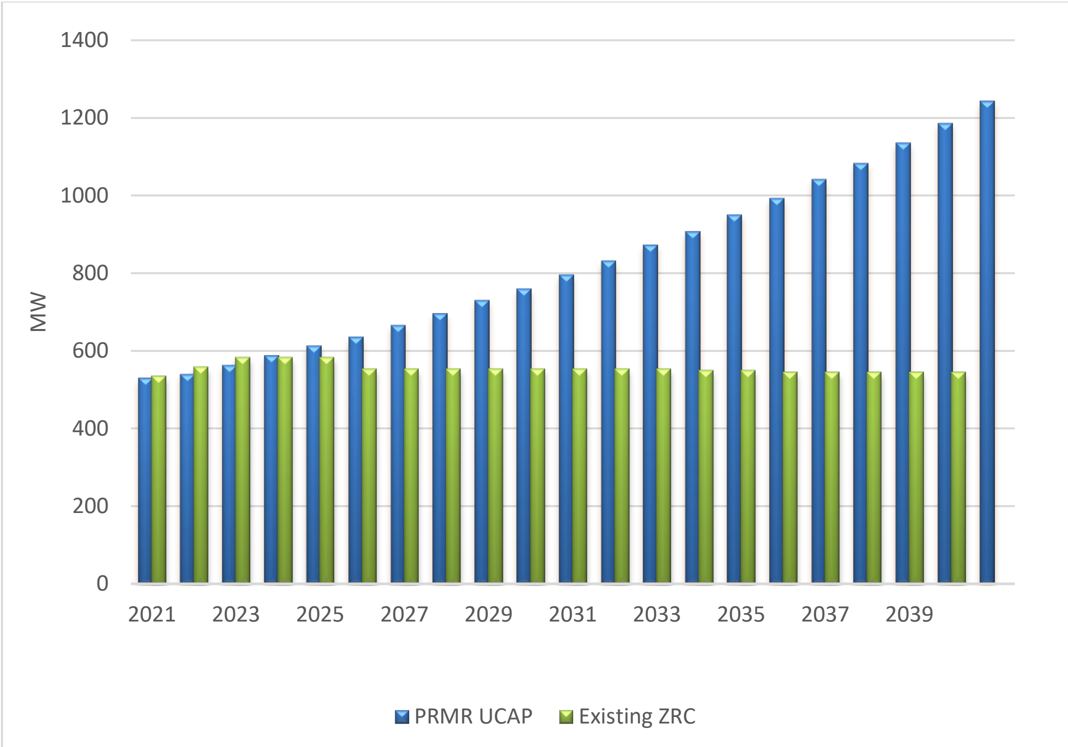

Figure 1-3: Zonal Resource Credit and Planning Reserve Margin Requirement High Growth Forecast

1. Analysis Method

The Electric Generation Expansion Analysis System (EGEAS) version 13, a computer model developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis and develop the least-cost integrated resource expansion plan. The analysis was performed on various scenarios based on the load forecasts, availability of resources, and economic variables. Each of the scenarios constitutes a resource expansion plan unique to the assumptions used in that scenario. The resource expansion analysis minimizes the present worth, or the net present value (NPV), of the total revenue requirement over fifty years by using an algorithm called “dynamic programming.” The dynamic programming utilized in EGEAS calculates each scenario one year at a time to satisfy the reliability constraints and to fulfill the forecasted energy and capacity requirements. This process identifies all possible states that satisfy the reliability requirements for each year. Finally, the annual results are combined to determine the least-cost plan.

The base year used in the resource expansion analysis was 2020 with the study period starting in 2021. Costs indicated in this report are in 2020 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2021-2040) in which new resources can be added to meet the forecasted load growth and to compensate for unit retirements. To model the remaining life of capital investments installed during the study period, an additional 30 years, called the extension period, was added. During this extension period, loads stayed the same as the final year of the study period. All associated operational and fuel costs continue to be escalated at specified rates through the extension period.

2. Resources

Montana-Dakota's existing generation portfolio includes coal, natural gas, diesel, waste heat and wind. The resource expansion analysis considered other potential available alternative resources to expand the generation portfolio to meet forecasted energy and capacity requirements. All resources were modeled with applicable ZRC amounts, fixed and variable O&M costs, and fuel costs that are shown in Tables 2-1 through 2-5 below.

For resource capacity accreditation, MISO considers wind generation resources differently than thermal resources. The ZRC for wind generation resources is only available if the wind resources have been designated as a network resource in MISO or if the wind resource has been granted a transmission service request and has been designated an energy only resource. The ZRC value for wind resources is based on an effective load carrying capability (ELCC) study performed annually by MISO. This study examines MISO's top eight annual summer peaks for the last five years to determine how much wind is generated during summer peak conditions and compares the amount of wind generated to MISO's peak load. This study is done on a MISO system-wide basis and on all single commercial pricing nodes (CPNode). On a system-wide basis for the 2021-2022 planning year, the ELCC study concluded that 16.3 percent of nameplate wind capacity could be converted into a ZRC value if the wind resource is a network resource (up to 20% of nameplate) or has a transmission service request (TSR) for the nameplate value. Based upon production data collected at Montana-Dakota's wind farms' CPNodes, Diamond Willow was determined to contribute up to 17.1 percent of its nameplate capacity to ZRCs, Cedar Hills was allowed up to 18.8 percent of its nameplate capacity to ZRCs, and Thunder Spirit was allowed up to 14.8 percent of its nameplate capacity to ZRCs. Diamond Willow, Cedar Hills, and Thunder Spirit are all designated network resources and have been granted a TSR from MISO. The facilities are accredited ZRC values by MISO of 5.1, 3.7, and 22.2 respectively.

2.1. Current Resources

The existing resource portfolio is broken down into five groups: coal, natural gas/oil, renewable, contract, and Demand Side Management ("DSM"). Figure 2-1 shows Montana-Dakota's 2021 current resource mix by zonal resource credits. Thirty eight percent of Montana-Dakota's ZRCs comes from coal generation, thirty four percent from gas-fired generation, fourteen percent from capacity contract eight percent from DSM and six percent from renewable resources.

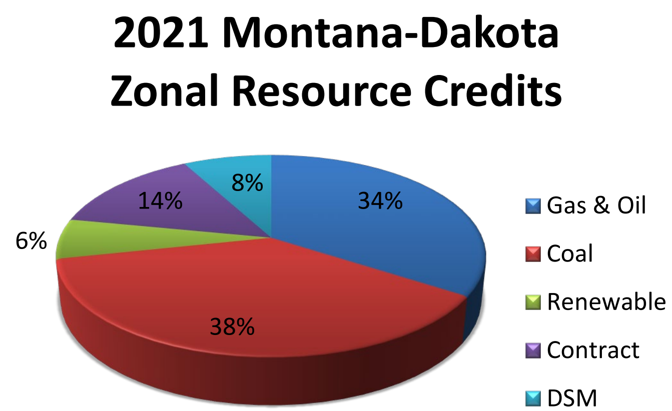

Figure 2-1: Montana-Dakota's Current Generation Mix by Zonal Resource Credits

2.1.1. Coal

Montana-Dakota currently owns four coal-fired units as part of its integrated system, two of which are jointly owned with other regional utilities. Coal-fired units currently account for 38 percent of the zonal resource credits on Montana-Dakota's system. Table 2-1 shows the capacity in MW established by the MISO Generator Verification Test Capability (GVTC) process, equivalent forced outage rate ($XEFOR_d$), number of zonal resource credits, and various costs for each coal-fired plant serving Montana-Dakota's customers.

Table 2-1: Montana-Dakota's Coal-Fired Units

Unit	GVTC (MW)	$XEFOR_d$	Zonal Resource Credit [1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	106.8	11.92	94.1	28.77	3.86	1.93
Big Stone[3]	108.6	1.91	106.5	25.51	2.31	1.80
Heskett 1	23.6	3.23	0	85.88	15.73	2.70
Heskett 2	69.5	6.31	0	56.28	7.29	2.70

1. Based on MISO 2021-22 Planning Year ICAP and XEFORd
2. Montana-Dakota's 25 percent ownership share
3. Montana-Dakota's 22.7 percent ownership share

2.1.2. Natural Gas and Diesel

Simple cycle combustion turbines capable of firing natural gas or fuel oil, along with reciprocating internal combustion engines firing natural gas or diesel, are operated as peaking units and make up about 34 percent of Montana-Dakota's existing zonal resource credits. To determine the natural gas price a combination of forward index prices at Henry Hub and

Montana-Dakota's knowledge of natural gas pricing was used to produce a forward-looking natural gas price and escalates the prices by three percent. The capacity in MW established by the MISO Generator Verification Test Capability (GVTC) process, equivalent forced outage rate ($XEFOR_d$), number of zonal resource credits, and various costs for Montana-Dakota's existing combustion turbines and diesel generator are shown in Table 2-2.

Table 2-2: Montana-Dakota's Natural Gas Combustion Turbines and Diesel Generators

Unit	GVTC	$XEFOR_d$	Zonal Resource Credit[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)[2]
Glendive 1	32.9	7.83	30.3	5.90	4.20	4.01
Glendive 2	40.9	5.72	38.6	7.07	4.20	4.01
Miles City	21.6	2.82	21.0	7.06	4.20	4.01
Heskett 3	81.3	12.81	70.9	31.13	2.68	2.68
Lewis & Clark 2	18.4	1.33	18.2	29.17	3.60	2.92
Diesel 2	2	10.05	1.8	28.00	4.20	16.19
Diesel 3	2	10.05	1.8	28.00	4.20	16.19

1. Based on MISO 2021-22 Planning Year ICAP and $XEFOR_d$
2. 2021 natural gas price

2.1.3. Renewable

In addition to coal, diesel, and natural gas, Montana-Dakota owns four renewable resources, as shown in Table 2-3. The renewable resources make up about eight percent of Montana-Dakota's existing zonal resource credits.

Table 2-3: Montana-Dakota's Renewable Generation

Unit	Zonal Resource Credits	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[1]	5.1	21.57	0	-
Cedar Hills[1]	3.7	26.48	0	-
Glen Ullin Station 6	3.4	81.83	7.77	-
Thunder Spirit[1,2]	22.2	21.82	-35.38	-

1. ZRC is based on MISO ELCC study.
2. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.

2.1.4. Demand Response

In addition to the supply side resources, two different demand response programs were included into the model. The totals below reflect the number of MWs and ZRCs contracted with the company in 2021.

- Montana-Dakota Interruptible loads – 15.4 MW converts to 14.9 ZRC
- Commercial DSM – 25 MW converts to 27.8 ZRC

2.1.5. MISO Energy Market

The MISO energy market provides a source of energy when prices are lower than Montana-Dakota's generating cost, or when energy is required due to planned maintenance or forced outages. Montana-Dakota develops the MISO energy market prices from a historical three-year average and escalates the prices by three percent. The model included a 300 MW block of energy for off-peak and on-peak periods.

2.1.6. Minnkota Power Capacity and Energy Purchase

The Company has entered into a power purchase agreement with Minnkota Power Cooperative to purchase capacity and energy from June 2021 through May 2026. The timing of the Minnkota Power Purchase Agreement (PPA) came about during the evaluation of the 2020 RFP as the Company was out contacting its neighboring utilities to determine availability and pricing of capacity and energy as a bridge product to the in-service date for Heskett 4. The Minnkota PPA includes the following purchased capacity and firm energy amounts.

Table 2-4: Minnkota Capacity and Energy

Year	Capacity (MWs)	Energy (MWh)
2021-2022	75	30
2022-2023	90	75
2023-2024	30	75
2024-2025	30	75
2025-2026	30	75

2.2. Considered Supply-Side Resource Alternatives

Montana-Dakota analyzed the following supply-side alternatives that are described in more detail below:

- Simple Cycle Combustion Turbine,
- Simple Cycle Reciprocating Internal Combustion Engines,

- Combined Cycle Combustion Turbine,
- Coal,
- Wind (self-built),
- Solar plus storage,
- Biomass,
- Montana Solar Qualified Facility, and
- Responses to 2020 RFP described in Attachment F.

Information regarding the resource alternatives available to Montana-Dakota is summarized in Table 2-5. Performance and cost estimates for the resource alternatives were developed by a consulting engineer using thermal engineering/costing software, budgetary quotations from original equipment manufacturers (OEMs), input from Montana-Dakota, published information, and engineering experience. More detail of the Supply-Side resource alternatives can be seen in Attachment E.

2.2.1. Simple Cycle Combustion Turbine

Simple cycle combustion turbines (SCCT) are primarily built to serve peaking capacity needs. SCCTs typically have one of the lower capital costs per MW compared to other generating types and can be installed within a relatively short lead time (three years). Two basic types of SCCT exist: aeroderivative (Aero), and heavy-duty Frame (Frame). Aero SCCTs are adapted from jet and turboshaft jet engines and are usually smaller and more thermally efficient than similar sized Frame units. However, they generally have a higher capital cost, more expensive maintenance costs, are more susceptible to cold weather reliability issues, and do not normally exceed 100 MWs generating capability in a single unit size. Frame units are designed to drive stationary generation and process plant equipment. They are usually less expensive than an Aero, more robust, require less frequent inspection and maintenance intervals, and are available in over 500 MWs in a single unit size. Montana-Dakota has operating experience with three Frame units, and one Aero unit. Four options for the SCCT were analyzed in the resource expansion analysis and are shown in Table 2-5: 78.3 MW summer net large frame greenfield unit, a 78.3 MW summer net large frame unit at a facility with existing infrastructure (Heskett Expansion), a 90.7 MW summer net aero-hybrid unit, and a 45.3 MW summer net Aero unit.

2.2.2. Simple Cycle Reciprocating Internal Combustion Engine

Simple cycle reciprocating internal combustion engines (RICE) are primarily built to serve peaking capacity needs. These units require a relatively short lead time (two to three years) and are normally more thermally efficient and require lower fuel pressure compared to SCCTs of similar power output. Two RICE natural gas fired plants were analyzed in the resource expansion analysis and are shown in Table 2-5: a 36.5 MW (net) four-engine unit, and a 55.0 MW (net) three-engine unit.

2.2.3. Combined Cycle Combustion Turbine

A conventional combined cycle combustion turbine (CCCT) burns natural gas or fuel oil in one or more SCCTs. The hot exhaust gases from the SCCT passes through a heat recovery steam generator to produce additional power in a steam turbine. CCCTs have the highest efficiency of any new power plant, at more than 60 percent. These units are usually used as an intermediate unit today, but in the future could be used as more of a baseload unit to replace retired coal units. Three natural gas fired CCCTs were analyzed in the resource expansion analysis and are shown in Table 2-5: a 174 MW (summer net) 2x1 large frame unit, 329.8 MW (summer net) 2x1 large frame unit (Heskett Expansion includes Heskett 3 and 4 in the total MW), and a 329.2 MW (summer net) 1x1 large frame unit.

2.2.4. Coal

Coal-fired power plants are primarily built to serve baseload power requirements. This type of generation provides a stable capacity and energy source and is characterized as having a high capital cost with relatively low operating and fuel costs. Due to existing federal regulations and high capital costs as compared to natural-gas fired units, coal-fired baseload generation is unlikely to be available as a new resource option. Two lignite coal-fired power plants, modeled in blocks of 30 MW, were included in the resource expansion analysis and are shown in Table 2-5: a 168 MW net circulating fluidized bed combustion (CFBC) boiler without CO_2 capture, and a 122 MW net CFBC boiler with CO_2 capture.

2.2.5. Wind

A wind energy resource is characterized as being a clean, renewable resource with low operating and maintenance costs. The main disadvantage of wind generation is that, because of the variability of wind, it cannot be relied on as a firm capacity resource. Unlike the thermal resources such as coal-fired and gas-fired units, wind energy resources are allowed limited zonal resource credits (ZRC) by MISO. Therefore, the installation of additional wind generation on Montana-Dakota's system would require adding other capacity resources to meet the MISO planning reserve margin requirements.

This option represents Montana-Dakota's self-built wind generation. Two wind options were analyzed in the resource expansion analysis and are shown in Table 2-5: 20 MW and 50 MW (net) options. Both projects assume no Federal Production Tax Credits (PTCs) are available for a future wind project.

2.2.6. Solar plus Storage

Solar resources are characterized as renewable, high capital cost, low operational and maintenance cost energy sources. Like wind, solar is a variable output energy resource and does not contribute its full nameplate capacity toward meeting Montana-Dakota's MISO planning reserve margin requirements. In MISO, solar generation receives a first-year capacity accreditation value of 50 percent while winds first-year capacity accreditation value is closer to 15 percent. The 50 percent first-year capacity accreditation makes solar generation very appealing for meeting peak demand requirements today. This could change significantly on an annual basis when MISO moves to a four-season planning model for resource adequacy, as solar will likely receive zero capacity credit in the winter to meet peak winter demand forecast requirements. Two photovoltaic solar options were included in the resource expansion analysis and are shown in Table 2-5: a 50 MW with an option to add 10 MW battery storage and a 5 MW with an option to add 1 MW battery storage. Both projects assume no Federal Earned Income Tax Credits (ITCs) are available for a future solar project.

2.2.7. Biomass

Similar in operation to a coal-fired power plant, a biomass-fired power plant burns a carbon-neutral organic based fuel instead of coal. The biomass option is considered a renewable resource with high capital and fuel costs as compared to coal and natural gas fired options. A 25 MW net biomass option was included in the resource expansion analysis and shown in Table 2-5.

2.2.8. Montana Solar Qualified Facility

On September 21, 2020, Montana-Dakota entered into a power purchase agreement (PPA) with a 20 MW solar developer located in Fallon County, MT. This project is an eligible FERC Public Utility Regulatory Policies Act (PURPA) Qualified Facility (QF) facility and the PPA for the project has a 20-year term with an expected in-service date the end of 2023.

Table 2-5
Considered Resource Alternatives Available to Montana-Dakota

EGEAS Model Input Summary, 2021 $	Plant Size (MW,net)	ZRC	Capital Cost ($/kW)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)	Fuel Gas Reservation Fee ($/kW-yr)	Total Fixed O&M ($/kW-year)	Full Load Heat Rate (BTU/kWh)	Carbon Intensity (ton/GWh)	Fuel Cost ($/MMBtu)
GE 7EA	78.3	74.6	$1,590.00	$1.40	$1.50	$2.61	$19.41	11770	730	$2.68
GE 7EA Heskett Expansion	78.3	74.6	$878.00	$0.93	$0.90	$2.61	$13.77	11770	730	$2.68
GELMS100PB	90.7	86.3	$1,760.00	$1.20	$1.70	$1.82	$16.22	9050	525	$2.68
GE LM6000PH	45.3	42.8	$2,320.00	$2.50	$1.60	$2.08	$32.08	9510	555	$2.68
GE 7EA (2x1) Heskett Expansion	329.8	311.6	$1,070.00	$1.40	$4.10	$3.23	$20.03	9990	515	$2.68
GE 7FA.05 (1X1)	329.2	311.0	$1,520.00	$1.10	$3.00	$3.22	$16.42	6530	430	$2.68
SIEMENS SGT-800 (2x1)	174	164.4	$2,180.00	$2.90	$4.00	$2.79	$37.59	7180	460	$2.68
WARTSILA 20V34SG	36.5	34.5	$2,710.00	$2.60	$4.40	$1.58	$32.78	8470	495	$2.68
WARTSILA 18V50SG	55.0	52.0	$2,180.00	$1.80	$4.60	$1.56	$23.16	8310	485	$2.68
BIOMASS	25	22.7	$7,980.00	$21.00	$5.60	-	$252.00	12300	1300	$5.11
PV SOLAR + Storage[1]	50+10	35.0	$1,390.00	$1.10	$0.00	-	$13.20	-	-	$0.00
PVSOLAR + Storage[2]	5+1	3.5	$2,500.00	$1.20	$0.00	-	$14.40	-	-	$0.00
CFBC WITHOUT CO2 Capture	168	152.3	$5,880.00	$21.00	$14.06	-	$252.00	10000	1000	$2.88
CFBC WITH CO2 Capture	122	110.6	$10,400.00	$29.00	$22.29	-	$348.00	13800	150	$2.88
ND Wind	20	3.4	$1,630.00	$4.20	$0.00	-	$50.40	-	-	$0.00
ND Wind	50	8.5	$1,580.00	$4.20	$0.00	-	$50.40	-	-	$0.00

1 - 10 MW battery storage additional $17.2 million capital and $0.35 MM$/Yr O&M
2 - 1 MW battery storage additional $2.5 million and $0.06 MM$/Yr O&M
3 – Updated renewable pricing remaining resources used 2019 IRP pricing

2.3. Retirements

Montana-Dakota retired Lewis & Clark 1 on March 31, 2021 and will retire Heskett 1 and 2 on March 31, 2022. The units are scheduled for retirement because of their size, age, and operating characteristics make them uneconomic as compared to other alternatives.

Additionally, Montana-Dakota's Diamond Willow, Cedar Hills, and Thunder Spirit wind projects are assumed to be retired in the model after a 25-year operating life or by year 19 of the IRP study period as a conservative assumption. This would require the model to replace the wind projects within the initial 20-year study period.

2.4. Integration of Demand-Side and Supply-Side Resources

As indicated in Chapter 2 of the current Integrated Resource Plan, the energy efficiency programs reductions have been included into the load forecast while the Rate 38/39 Interruptible Loads and the Commercial Demand Response programs are modeled as resources in EGEAS.

2.5. Transmission Alternatives

Montana-Dakota did not identify any transmission issues, including MISO and SPP capabilities, that could be mitigated with local generation resources additions as part of the 2021 IRP Analysis. Transmission limitations associated with SPP's transmission system within the Bakken Region have been mitigated with upgrades and new facilities constructed by Basin Electric in the area.

3. Summaries of Results

Nineteen planning scenarios, which include the base case, and 18 sensitivity runs, were considered. The least-cost resource plan and associated net present value (NPV) of the total revenue requirement for each scenario are shown in Table 3-1.

Table 3-1: Least-Cost Resource Expansion Plans for the Studied Scenarios

	All Sensitivities with Base Case										
	Base Case	High Gas $+2	High Gas $+5	Low Gas $-1	High Market +25%	High Market +50%	Low Market -25%	High Gas $+2 & High Market +25%	High Gas $+5 & High Market +50%	Low Gas $-1 & Low Market - 25%	Wood Mckenzie energy pricing
2021											
2022											
2023	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4
2024	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)
2025											
2026											
2027											
2028											
2029											
2030	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	Solar PPA (50)	PP(10)	PP(10)
2031	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)		PP(10)	PP(10)
2032	PP(20)	PP(20)	PP(20)	PP(20)	Solar PPA (50)	Solar PPA (50)	PP(20)	Solar PPA (50)		PP(20)	Solar PPA (50)
2033	PP(20)	PP(20)	PP(20)	PP(20)			PP(20)			PP(20)	
2034	Solar PPA (50), PP(10)	Solar PPA (50), PP(10)	Solar PPA (50), PP(10)	Solar PPA (50), PP(10)	PP(10)	PP(10)	Solar PPA (50), PP(10)	PP(10)	PP(10)	Solar PPA (50), PP(10)	PP(10)
2035	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)
2036	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	PP(20)
2037	Storage (10), PP(20)	Storage (10), PP(20)	Solar(50)	Storage (10), PP(20)	Storage (10), PP(20)	Solar(50)	Storage (10), PP(20)	Solar(50)	PP(20), Wind(50)	Storage (10), PP(20)	Storage (10), PP(20)
2038	PP(20)	PP(20)	PP(10)	PP(20)	PP(20)	PP(10)	PP(20)	PP(10)	PP(20)	PP(20)	PP(20)
2039	Storage (10), PP(20)	Storage (10), PP(20)	PP(10)	Storage (10), PP(20)	Storage (10), PP(20)	PP(10)	Storage (10), PP(20)	PP(10)	Wind(50), PP(20)	Storage (10), PP(20)	Storage (10), PP(20)
2040	Solar (50), PP(20)	PP(20), Solar(50)	PP(20), Storage(10), Wind(50)	PP(20), Solar(50)	Solar (50), PP(20)	Solar (50), PP(20)	PP(20), Solar(50)	Solar (50), PP(20)	Solar (50), PP(20)	PP(20), Solar(50)	PP(20), Solar(50)
NPV($M)	$2,320.68	$2,339.02	$2,351.50	$2,230.88	$2,516.05	$2,634.00	$2,081.29	$2,542.60	$2,725.37	$2,061.03	$2,362.21
Difference	0.00%	0.79%	1.33%	-3.87%	8.42%	13.50%	-10.32%	9.56%	17.44%	-11.19%	1.79%

Alternative Resources:

PP(XX) - Up Purchase Capacity with number representing MW value
Solar PPA (50) - 2020 RFP (Used $35.45/Mwh and added $16/Mwh for interconnection costs)
Solar QF (20) - Solar Qualified Facility in Montana at 20 MW
Solar (XX) - self-build solar option
Wind (XX) - self-build wind option
Storage (XX) - self-build storage option
Heskett CC Add (163.5) - Combined cycle Heskett 3 & 4
CT (90.7) - GE LMS100PB Simple Cycle Combustion Turbine
CC (329.2) - GE 7FA.05 (1x1) Combined Cycle Combustion Turbine

Table 3-2: Additional Least-Cost Resource Expansion Plans for the Studied Scenarios

	All Sensitivities with Base Case								
	Base Case	Low Growth	High Growth	MISO 90% Coincident Factor	Limit Energy(100 MW) over 5 years	Limit Energy(100 MW) over 10 years	Coyote retirement	Carbon $30 - 2023	Carbon $50 - 2023
2021									
2022									
2023	Heskett 4	Heskett 4	Heskett 4	PP(10), Heskett 4	Heskett 4	Heskett 4	Heskett 4	Heskett 4, Solar PPA (50), Wind (50)	Heskett 4, Solar PPA (50), Wind (70), Solar QF (20)
2024	Solar QF (20)		PP(10), Solar QF (20)	PP(10), Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	Solar QF (20)	
2025			Solar PPA (50)	PP(10)					
2026			PP(20), Storage (10)	PP(20)					
2027			Heskett CC Add (163.5)	CT(90.7)					
2028							PP(10), CT(90.7)		
2029							PP(10)		
2030	PP(10)				Solar PPA (50)	PP(10)	PP(20)		
2031	PP(10)					PP(10)	PP(20)		
2032	PP(20)		CT(90.7)			Solar PPA (50)	Solar PPA (50)		
2033	PP(20)						PP(10)		
2034	Solar PPA (50), PP(10)		PP(20)	PP(10)	Wind (20)	Wind (20)	PP(10)	Wind (50)	
2035	PP(10)		CC (329.2)	PP(20)	PP(10)	PP(10)	PP(20)		Wind (50)
2036	PP(20)	PP(10)		Solar PPA (50)	PP(20)	PP(20)	Solar (50), PP(10)	PP(10)	
2037	Storage (10), PP(20)	PP(10)		PP(10)	Wind (50), PP(20)	Wind (50), PP(20)	PP(10)	PP(10)	PP(10)
2038	PP(20)	PP(10)		PP(20)	PP(20)	PP(20)	PP(20)	PP(20)	Wind (50)
2039	Storage (10), PP(20)	Solar PPA (50)		PP(20)	Wind (20), PP(20)	Wind (20), PP(20)	PP(20)	PP(20)	PP(10)
2040	Solar (50), PP(20)	PP(20)	Solar (55)	Solar (50), PP(20)	Solar (55), Wind (50), Storage(10)	Solar (55), Wind (50), Storage(10)	PP(20), Solar(50)	PP(20), Solar(50)	Solar (100), PP(20)
NPV($M)	$2,320.68	$2,067.46	$4,618.90	$2,472.69	$2,499.71	$2,486.34	$2,508.94	$3,536.13	$4,194.36
Difference	0.00%	-10.91%	99.03%	6.55%	7.71%	7.14%	8.11%	52.37%	80.74%

Alternative Resources:

PP(XX) - Up Purchase Capacity with number representing MW value
Solar PPA (50) - 2020 RFP (Used $35.45/Mwh and added $16/Mwh for interconnection costs)
Solar QF (20) - Solar Qualified Facility in Montana at 20 MW
Solar (XX) - self-build solar option
Wind (XX) - self-build wind option
Storage (XX) - self-build storage option
Heskett CC Add (163.5) - Combined cycle Heskett 3 & 4
CT (90.7) - GE LMS100PB Simple Cycle Combustion Turbine
CC (329.2) - GE 7FA.05 (1x1) Combined Cycle Combustion Turbine

3.1. Base Case Plan Results

The Base Case least-cost plan consists of the following resource additions for 2021-2026:

- Retired Lewis & Clark 1 on March 31, 2021, and retire Heskett 1 and Heskett 2, by the end of March 2022.
- Install an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in early 2023.
- Continue to grow the Commercial Demand Response program to a total of 40 MW.
- Inclusion of the Minnkota Power capacity and energy purchase agreement.
- 20 MW solar QF project located in Fallon County, MT to be online the end of 2023.

The 20 MW solar QF project was also included as a resource option for the 2021 IRP model and selected as a least cost resource in 2024. The IRP model did select additional future solar from the 2020 RFP which the Company did not pursue due to project size, uncertainties in final costs associated with network upgrades, and location of resources as described in Attachment F – 2020 RFP Analysis. Additional 20 MW of storage, 50 MW of solar and capacity was selected in the later years of the study. The net present value of the Base Case least-cost plan over the 50-year study period equates to $2,321 million in 2020 dollars, as shown in Attachment C Table 3-1.

3.2. Sensitivity Analysis

The 18 sensitivity scenarios consist of various assumptions regarding carbon taxes, low and high natural gas prices, low and high load growth, combination of gas and market prices, 90 percent coincident factor for MISO Resource Adequacy, high and low market prices limiting energy, no coyote, and alternate energy source.

3.2.1. High and Low Gas Price

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, future combustion turbines, and future combined cycle plants were developed in-house for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. Considering the potential fluctuations of natural gas prices, there is a need to consider what impact both higher and lower gas prices would have on the Base Case. Therefore, high and low gas price scenarios were also developed, whereby the gas price used in the Base Case was increased by $2/MMBtu and $5/MMBtu and decreased by $1/MMBtu from the Base Case, respectively. The high and low gas price cases were escalated by three percent annually after 2025. The results of the higher natural gas price case selected additional wind and less storage compared to the Base Case. The NPV of the revenue requirement in this scenario increased 0.8 and 1.3 percent respectively over the Base Case. The results of the low natural gas price scenario were the same as the Base Case. This case decreased the NPV of the revenue requirement by 3.9 percent from the Base Case.

3.2.2. Low Growth

This scenario was used to evaluate the load growth potential at less than the optimal resource case with an average growth rate of 0.5 percent per year during the 20-year forecast. The results of this scenario indicate that there is less future capacity and energy needed, resulting in some purchase capacity and 50 MW solar in the outer years. This lowered the NPV by 10.9 percent over the Base Case.

3.2.3. High Growth

A high-growth scenario evaluated the effects of a continued long-term average load growth rate of 4.4 percent per year starting in 2021. The results of this scenario indicate the need for the following resources over the Base Case: a simple cycle combustion turbine and two combined cycle combustion turbines. This increased the NPV by 99 percent over the Base Case.

3.2.4. High and Low Market Prices

These scenarios were used to look at the effects the MISO market could have on the resource plan if the market prices went higher or lower than the Base Case. The high market price cases increased the on-peak and off-peak market prices of the Base Case by 25% and 50%. This resulted in the same results as the Base Case results except for the +50% did not select the storage instead it selected 50 MW of additional solar. These scenarios resulted in an increase of 8.4 and 13.5 percent respectively in NPV of the revenue requirement over the Base Case. The lower market price case decreased the base year on- and off-peak prices by 25%. This resulted in the same results as the Base Case but lowered the NPV by 3.9 percent.

3.2.5. Limiting Market Energy

The on-peak and off-peak markets were set at 300 MW in the Base Case. These two scenarios limited the amount of market energy that could be selected to 100 MW either over five or ten years. More wind and solar was selected in these sensitivities to replace the energy lost from the energy market. These sensitivities increased the NPV by 7.7 and 7.1 percent.

3.2.6. Ninety percent coincident factor for MISO Resource Adequacy (RA)

The ninety percent coincident factor sensitivity scenario results in a higher capacity need for MISO RA, however the energy needs do not change. This scenario was done in part to show the change in capacity need if there was a change to Montana-Dakota's current 81.1 percent coincident factor. The selected least-cost plan for this scenario was different from the Base Case with an additional simple cycle being selected. The results of this scenario indicate an increase of 6.6 percent in the NPV of the revenue requirement over the Base Case.

3.2.7. Carbon Tax

With the potential of a future carbon penalty applied to all fossil fuel units and MISO energy purchases, a carbon tax was modeled to assess the impact on the resource expansion plan. The assumed carbon tax was applied to all carbon emissions from Montana-Dakota's existing coal-fired units and natural gas-fired SCCTs, energy purchases from the MISO market, and new generating units added to the resource plan starting in 2023. While no carbon tax was modeled in the Base Case, Montana-Dakota modeled a carbon tax of $30 and $50 per ton for a sensitivity analysis. The results added additional wind and solar compared to the Base Case. The NPV increased by 52.4 percent and 80.7 percent over the Base Case.

3.2.8. Gas and Market Price Combinations

These sensitivities were looking at a combination of both natural gas prices and the energy market were both increasing or decreasing. Two combinations of a high gas price and market price (+$2 Gas and +25% market and +$5 and +50% market) and one sensitivity of lower natural gas prices and energy market prices (-$1 Gas and –25% market). The results from the high scenarios had more solar and wind compared to the Base Case results and increased the NPV by 9.6 and 17.4percent, while the lower sensitivity had the same results as the Base Case but decreased the NPV by 11.2 percent.

3.2.9. Coyote Retirement Scenario

As the technology requirements for Coyote Stations Regional Haze project are still unknown as this time, a single sensitivity was run to show the impacts on the Company's Resource Plan if Coyote Station was retired by the end of 2027. Additional Coyote Station sensitivities will be included in the 2023 IRP This sensitivity added an additional peaking unit and more solar while increasing the NPV by 8.1 percent over the Base Case.

3.2.10. Alternate Energy Forecast

A new sensitivity was run which utilized the MISO Energy Pricing Forecast developed by Wood MacKenzie. This sensitivity had slightly higher energy price than the Base Case which resulted in a similar plan but an increase in the NPV of 0.7 percent.

4. Conclusions

Based on the current results of the supply-side and integration analysis, the Base Case is the least-cost plan. In this plan, the following resources are selected as the least-cost options in meeting the forecasted capacity and energy requirements:

- Retired Lewis & Clark 1 on March 31, 2021, and retire Heskett 1 and Heskett 2, by the end of March 2022.
- Install an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit to be online in early 2023.
- Continue to grow the Commercial Demand Response program to a total of 40 MW.
- 20 MW solar QF project located in Fallon County, MT to be online the end of 2023.

Figures 4-1 and 4-2 show a comparison of the resource mix that Montana-Dakota has available to serve its customers' needs in 2021, as compared to the least cost plan in 2026 which includes a new simple cycle combustion turbine online in 2023. Note a Zonal Resource Credit (ZRC) represents one megawatt of accredited generating capacity under the MISO resource adequacy rules.

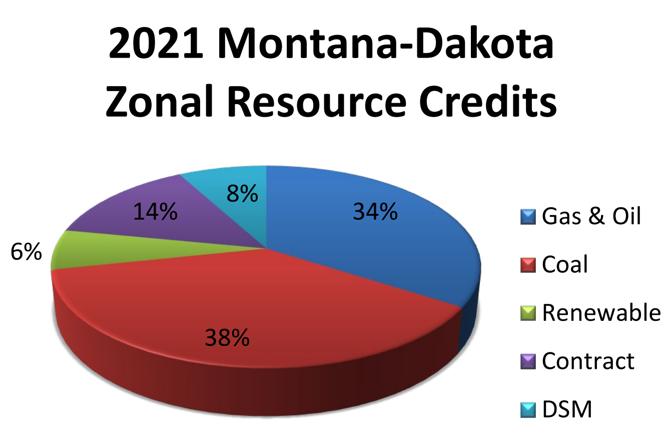

Figure 4-1: 2021 Montana-Dakota Zonal Resource Credits

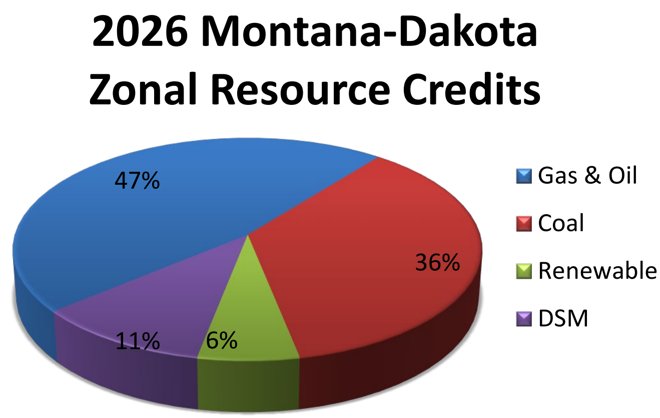

Figure 4-2: 2026 Montana-Dakota Zonal Resource Credits

As shown in Figures 4-1 and 4-2; in 2021 approximately 34 percent of Montana-Dakota's resource capacity comes from natural gas and oil-fired combustion turbines and reciprocating internal combustion engines while in 2026, based on the Base Case plan, approximately 47 percent of the Company's resource capacity would be made up by natural gas and oil-fired combustion turbines and reciprocating internal combustion engines. It should be noted that while natural gas makes up a large portion of the capacity, these are peaking resources that, while critical to the system, contribute very little to the actual energy usage.

Figures 6-6 and 6-7 shows the percentage of energy on a yearly basis in 2021 and after the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1 and the addition of Heskett 4 in 2026. In 2021, 43 percent of Montana-Dakota's energy will come from coal, 30 percent MISO energy market, 23 percent from renewable, and 4 percent from energy contract. In 2026, 45 percent of energy will come from coal, 25 percent will come from MISO energy market, 22 percent will come from renewable, and 8 percent from energy contract based upon forecasted fuel and MISO energy prices. In 2026, Coyote and Big Stone have an annual capacity factor around 85 percent. If MISO energy prices increase higher than forecasted, Montana-Dakota's natural gas-fired units could be dispatched to offset forecasted MISO energy purchases and provide pricing protection for customers.

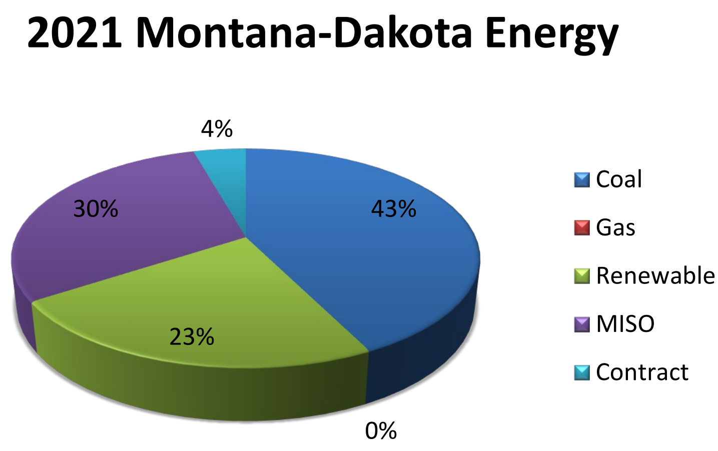

Figure 6-6: 2021 Montana-Dakota Energy by Resource Type

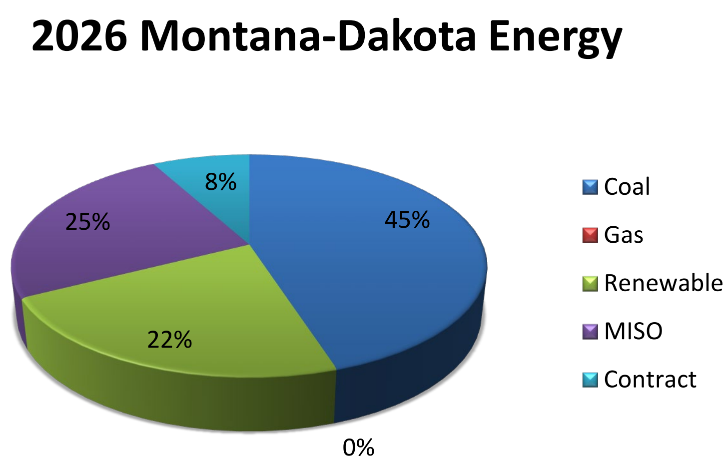

Figure 6-7: 2026 Montana-Dakota Energy by Resource Type

The sensitivity scenarios show that the largest variations in NPV of supply plans reflect potential carbon tax, high load growth scenarios, and high natural gas prices.

5. Future Resource Plan

Based on the analysis of the resource expansion models and the consideration of customer impacts, market availability of capacity and energy, and other factors such as environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan is to pursue the following resource changes to meet the requirements identified for the 2021-2026 period:

- Retired Lewis & Clark 1 on March 31, 2021; and retire Heskett 1 and Heskett 2 by the end of

March 2022.

- Continue to grow the Commercial Demand Response program to a total of 40 MW.
- Continue the design and engineering work on Heskett 4, a natural gas-fired simple cycle combustion turbine resource, to be online in early 2023.
- Issue a new request for proposal prior to the next IRP.

Montana-Dakota's recommended resource plan satisfies future customer requirements through the retirement of three older uneconomic coal-fired units and the continued reliance on Big Stone and Coyote to provide base load energy. The construction of a new simple cycle combustion turbine to add to the existing 200 MW of natural gas-fired peaking units, contract for capacity and energy through May 2026 and additional MISO energy market purchases to meet customer peak demands.

A new request for proposals will be issued prior to the next IRP to see if the uncertainties with final project pricing and network upgrade costs described in Attachment F – 2020 RFP analysis, are better known to help meet future customer demand and energy requirements.

6. References

MISO Resource Adequacy Business Practice Manual-11-r24 Resource Adequacy. (December 15, 2020)

EGEAS User's Guide Version 13. EPRI, Palo Alto, CA, November 2018.

MISO Planning Year 2021-2022 Loss of load Expectation Study Report. (December 8, 2020)

MISO Planning Year 2021-2022 Wind & Solar Capacity Credit. (January 26, 2021)

Appendix A

EGEAS INPUT DATA FOR THE BASE CASE

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ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

Montana-Dakota Utilities Co.
2021 Model
Base Case Run
-- Data updated for the 2021 Model

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3420 HILLVIEW AVENUE
PALO ALTO, CALIFORNIA 94304

NUMBER OF LOAD AREAS	1	
LOAD MODIFICATION OPTION	1	
NUMBER OF LOAD COMPONENTS	1	
COST ANALYSIS FORMAT	1	- NO CONSTRUCTION COSTS, LEVELIZED FIXED CHARGES
REPORT FILE OPTION	0	- STANDARD

REPORT OPTIONS

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MIRROR IMAGE	1	- GENERATE
ERROR	3	- ALL MESSAGES
DATA BASE CONTENTS	1	- GENERATE WITHOUT ORTHOG DATA

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HOURLY NDT							
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TECHNOLOGY 2	windCHcf	1	0				
TECHNOLOGY 3	windTScf	1	0				
TECHNOLOGY 4	wind46cf	1	0				
TECHNOLOGY 5	slr16cf	1	0				
TECHNOLOGY 6	slr20cf	1	0				

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                    *            Base Case Run                                                                             4
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                    *                                                                                                      6
                    *            Control record.                                                                           7
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                    *                                                                                                  105
 BASIC PLANT TYPE   BPA     2    ENERGY           THRM B C PURC MDU  MISO 100.0    1 2021  6  6                        106
                    BPB     2    30.0001.00001.0000      0.0000 10500                   0.0000                         107
                    BPC     2                              0.000021.000              2  0                              108
                    BPD     2  1             42    0    7    8    0    0    0    0    0    6                          109
                    BPD     2  2     0    0    0    0    0    0   28                                                   110
                    *                                                                                                  111
 BASIC PLANT TYPE   BPA     3    CAPACITY         THRM P C PURC MDU  MISO 100.0    1 2021  6  6                        112
                    BPB     3    75.0001.00001.0000      0.0000     1                   1.0000                         113
                    BPC     3         0.000                12.0001000.0              2  0                              114
                    BPD     3  1        21   23    0    7    8    0    0    0    0    0    0                          115
                    BPD     3  2     0    0    0    0    0    0   45                                                   116
                    BPF     3         0.000                   00.0000                                                  117
                    BPG     3    0.000000000.000000000.00000000                                                        118
                    *                                                                                                  119
 BASIC PLANT TYPE   BPA     4    SOLAR PPA        NDT  B G SOLR MDU  NDAK 100.0    1      20 20                        120
                    BPB     4    50.0001.00001.0000      0.0000                         0.5000                         121
                    BPC     4         0.000          10.1650.000051.450              1  1                              122
                    BPD     4  1             52    0    9         0    0    0    0    0    0                          123
                    BPD     4  2     6    0    0    0    0    0    0                                                   124
                    BPF     4      2558.000             30   380.0000                                                  125
                    BPG     4    0.000000000.000000000.00000000                                                        126
                    *                                                                                                  127
 BASIC PLANT TYPE   BPA     5    SOLAR QF         NDT  B G SOLR MDU  NDAK 100.0    1      20 20                        128
                    BPB     5    20.0001.00001.0000      0.0000                         0.5000                         129
                    BPC     5         0.000          10.16551.24024.770              1  1                              130
                    BPD     5  1        53   53    0   11         0    0    0    0    0    0                          131
                    BPD     5  2     6    0    0    0    0    0    0                                                   132
                    BPF     5      2558.000             30   380.0000                                                  133
                    BPG     5    0.000000000.000000000.00000000                                                        134
                    *                                                                                                  135
 BASIC PLANT TYPE   BPA    24    STORAGE10        STOR P G STRG MDU  NDAK 100.0    1      30 25                        136
                    BPB    24    10.0001.00001.00001.00000.0010       8.00 95.00      0.9500                           137
                    BPC    24      1720.000          10.16535.0000.0000              2  1                              138

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BASIC PLANT TYPE   BPD    24  1    30   22         0    0         0    0    0    0    0    0                         139
                   BPD    24  2     0    0    0    0    0    0    0                                                  140
                   *                                                                                                 141
BASIC PLANT TYPE   BPA    26    AC CYCLE         DTHR1P G PURC MDU  MISO 100.0    1      30 30                       142
                   BPB    26     2.0001.00001.0000      0.0000     1                  1.1000                         143
                   BPC    26         0.000                363.71100.00             2  0                              144
                   BPD    26  1         48   49    0   39    8    0    0    0    0    0    0                         145
                   BPD    26  2     0    0    0    0    0    0   26                                                  146
                   BPF    26         0.000                   00.0000                                                 147
                   BPG    26    0.000000000.000000000.00000000                                                       148
                   *                                                                                                 149
BASIC PLANT TYPE   BPA    27    STORAGE          STOR P G STRG MDU  NDAK 100.0    1      30 25                       150
                   BPB    27    10.0001.00001.00001.00000.0010        8.00 95.00      0.9500                         151
                   BPC    27      1720.000          9.500035.0000.0000             2  1                              152
                   BPD    27  1    51   22         0    0         0    0    0    0    0    0                         153
                   BPD    27  2     0    0    0    0    0    0    0                                                  154
                   *                                                                                                 155
BASIC PLANT TYPE   BPA    80    MISO - On peak   HYDR P E PURC MDU  MISO 100.0    1 2014 50 50                       156
                   BPB    80     250.01.00001.0000      0.0000 105001000.0            0.0000                         157
                   BPC    80                              0.000025.890             2  0                              158
                   BPD    80  1              29    0    0    8    0   41    0    0    0    7                         159
                   BPD    80  2     0    0    0    0    0    0   41                                                  160
                   *                                                                                                 161
BASIC PLANT TYPE   BPA    90    MISO - Off peak  HYDR P E PURC MDU  MISO 100.0    1 2014 50 50                       162
                   BPB    90     250.01.00001.0000      0.0000 105001000.0            0.0000                         163
                   BPC    90                              0.000023.230             2  0                              164
                   BPD    90  1              46    0    0    8    0    0    0    0    0    7                         165
                   BPD    90  2     0    0    0    0    0    0   41                                                  166
                   *                                                                                                 167
BASIC PLANT TYPE   BPA   100    INTERRUPTIBLES   DTHR1P E PURC MDU  MISO 100.0    1 2012 30 30                       168
                   BPB   100    15.2001.00001.0000      0.0000     1                  0.9474                         169
                   BPC   100         0.000                50.040300.00             1  1                              170
                   BPD   100  1         48   49    0   14    8    0    0    0    0    0    0                         171
                   BPD   100  2     0    0    0    0    0    0   16                                                  172
                   BPF   100         0.000                   00.0000                                                 173
                   BPG   100    0.000000000.000000000.00000000                                                       174
                   *                                                                                                 175
BASIC PLANT TYPE   BPA   110    COMMERCIAL DSM   DTHR1P E PURC MDU  MISO 100.0    1 2013 30 30                       176
                   BPB   110    25.0001.00001.0000      0.0000     1                  1.1000                         177
                   BPC   110         0.000                50.040300.00             2  0                              178
                   BPD   110  1         48   49    0   14    8    0    0    0    0    0    0                         179
                   BPD   110  2     0    0    0    0    0    0    4                                                  180
                   BPF   110         0.000                   00.0000                                                 181
                   BPG   110    0.000000000.000000000.00000000                                                       182
                   *                                                                                                 183
BASIC PLANT TYPE   BPA   120    MILES CITY C.T.  THRM P E GAS  MDU  MONT 100.0    1 1972 99 30                       184
                   BPB   120    25.2000.85711.0000      0.5000 14459                  0.8333                         185

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 BASIC PLANT TYPE   BPC   120                            7.06004.2000            2  0                                       186
                    BPD   120  1         3    5    0    2    1    0    0    0    0    0   12                                187
                    BPD   120  2    0    0    0    0    0    0    0                                                         188
                    *                                                                                                         189
 BASIC PLANT TYPE   BPA   130    GLENDIVE CT #1   THRM P E GAS  MDU  MONT 100.0    1 1979 99 30                               190
                    BPB   130    35.5000.84511.0000      0.5000 12465                 0.8535                                  191
                    BPC   130                            5.90004.2000            2  0                                       192
                    BPD   130  1         3    6    0    3    1    0    0    0    0    0    5                                193
                    BPD   130  2    0    0    0    0    0    0    0                                                         194
                    *                                                                                                         195
 BASIC PLANT TYPE   BPA   132    GLENDIVE CT #2   THRM P E GAS  MDU  MONT 100.0    1 2003 99 30                               196
                    BPB   132    43.3000.92381.0000      0.5000  9322                 0.8915                                  197
                    BPC   132                            7.07004.2000            2  0                                       198
                    BPD   132  1         3    7    0    4    1    0    0    0    0    0   13                                199
                    BPD   132  2    0    0    0    0    0    0    0                                                         200
                    *                                                                                                         201
 BASIC PLANT TYPE   BPA   136    DIESEL 2         THRM P E GAS  MDU  NDAK 100.0    1 2012 99 30                               202
                    BPB   136     2.0001.00001.0000      0.5000  8687                 0.9048                                  203
                    BPC   136                            28.0004.2000            2  0                                       204
                    BPD   136  1         3    8    0   23    2    0    0    0    0    0    0                                205
                    BPD   136  2    0    0    0    0    0    0    0                                                         206
                    *                                                                                                         207
 BASIC PLANT TYPE   BPA   138    DIESEL 3         THRM P E GAS  MDU  NDAK 100.0    1 2012 99 30                               208
                    BPB   138     2.0001.00001.0000      0.5000  8687                 0.9048                                  209
                    BPC   138                            28.0004.2000            2  0                                       210
                    BPD   138  1         3    8    0   23    2    0    0    0    0    0    0                                211
                    BPD   138  2    0    0    0    0    0    0    0                                                         212
                    *                                                                                                         213
 BASIC PLANT TYPE   BPA   140    HESKETT #1       THRM B E COAL MDU  NDAK 100.0    1 1954 69 30                               214
                    BPB   140    29.2000.75341.0000      0.0323 18731                 0.7192                                  215
                    BPC   140                            85.88015.730            2  0                                       216
                    BPD   140  1         3    9    0    5    3    0    0    0    0    0   14                                217
                    BPD   140  2    0    0    0    0    0    0    0                                                         218
                    BPE   140     M        0.0000    0    0       1980 2080                0                                  219
                    *                                                                                                         220
 BASIC PLANT TYPE   BPA   150    HESKETT #2       THRM B E COAL MDU  NDAK 100.0    1 1963 60 30                               221
                    BPB   150    74.6000.93831.0000      0.0631 12447                 0.8727                                  222
                    BPC   150                            56.2807.2900            2  0                                       223
                    BPD   150  1         3   10    0    6    4    0    0    0    0    0   15                                224
                    BPD   150  2    0    0    0    0    0    0    0                                                         225
                    BPE   150     M        0.0000    0    0       1980 2080                0                                  226
                    *                                                                                                         227
 BASIC PLANT TYPE   BPA   152    HESKETT #3       THRM P E GAS  MDU  NDAK 100.0    1 2014 40 25                               228
                    BPB   152    88.0000.95451.0000      0.5000 11482                 0.8057                                  229
                    BPC   152                            31.1302.6800            1  1                                       230
                    BPD   152  1         3   15    0   17   13    0    0    0    0    0    2                                231
                    BPD   152  2    0    0    0   27    0    0    0                                                         232

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                    *                                                                                                233
 BASIC PLANT TYPE   BPA   154    HESKETT #4       THRM P C GAS  MDU  NDAK 100.0    1 2023 40 35                      234
                    BPB   154    78.3000.88641.0000      0.5000 11770                  0.9515                        235
                    BPC   154       878.000          8.729013.7700.9000            1  1                              236
                    BPD   154  1    30   22   60    0   37   13    0    0    0    0    0    8                        237
                    BPD   154  2     0    0    0    0    0   20    0                                                 238
                    BPF   154       857.000               30   370.0000                                              239
                    BPG   154    0.000000000.000000000.00000000                                                      240
                    *                                                                                                241
 BASIC PLANT TYPE   BPA   160    LEWIS & CLARK1   THRM B E COAL MDU  NDAK 100.0    1 1958 64 30                      242
                    BPB   160    52.3000.86041.0000      0.1730 12909                  0.6807                        243
                    BPC   160                              85.0207.2200            2  0                              244
                    BPD   160  1          3   11    0   18    5    0    0    0    0    0   16                        245
                    BPD   160  2     0    0    0    0    0    0    0                                                 246
                    BPE   160     M        0.0000    0    0       1980 2080                0                         247
                    *                                                                                                248
 BASIC PLANT TYPE   BPA   162    LEWIS & CLARK2   THRM P E GAS  MDU  NDAK 100.0    1 2015 40 25                      249
                    BPB   162    18.6001.00001.0000      0.5000  8643                  0.9785                        250
                    BPC   162                              29.1703.6000            1  1                              251
                    BPD   162  1          3   20    0   19   11    0    0    0    0    0   11                        252
                    BPD   162  2     0    0    0    0    0    0    0                                                 253
                    *                                                                                                254
 BASIC PLANT TYPE   BPA   170    BIG STONE        THRM B E COAL MDU  SDAK 100.0    1 1975 99 30                      255
                    BPB   170     107.81.00001.0000      0.0191 10158                  0.9879                        256
                    BPC   170                              25.5102.3100            2  0                              257
                    BPD   170  1          3   12    0    8    6    0    0    0    0    0   17                        258
                    BPD   170  2     0    0    0    0    0    0    0                                                 259
                    BPE   170     M        0.0000    0    0       1980 2080                0                         260
                    *                                                                                                261
 BASIC PLANT TYPE   BPA   180    COYOTE           THRM B E COAL MDU  NDAK 100.0    1 1981 99 30                      262
                    BPB   180     106.71.00001.0000      0.1201 11031                  0.8806                        263
                    BPC   180                              28.7703.8600            2  0                              264
                    BPD   180  1          3   13    0   22    7    0    0    0    0    0   18                        265
                    BPD   180  2     0    0    0    0    0    0    0                                                 266
                    BPE   180     M        0.0000    0    0       1980 2080                0                         267
                    *                                                                                                268
 BASIC PLANT TYPE   BPA   190    DIAMOND WILLOW   NDT  B E WIND MDU  MONT 100.0    1 2008 28 25                      269
                    BPB   190    30.0001.00000.3810      0.0000                        0.1700                        270
                    BPC   190                              21.5700.0000            2  1                              271
                    BPD   190  1          3         0   10         0    0    0    0    0    0                        272
                    BPD   190  2     1    0    0    0    0    0   40                                                 273
                    *                                                                                                274
 BASIC PLANT TYPE   BPA   200    GLEN ULLIN ORMAT THRM B E PURC MDU  NDAK 100.0    1 2009 35 20                      275
                    BPB   200     7.5000.66670.6667      0.1058     1                  0.4533                        276
                    BPC   200                              81.8307.7700            2  1                              277
                    BPD   200  1         44   18    0   15    8    0    0    0    0    0    0                        278
                    BPD   200  2     0    0    0    0    0    0    0                                                 279

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 EGEAS   EDIT                                                      MIRROR IMAGE REPORT                          PAGE      8
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 BASIC PLANT TYPE   BPE   200     M        0.0000    0    0       1980 2080              0                                280
                    *                                                                                                     281
 BASIC PLANT TYPE   BPA   210    CEDAR HILLS      NDT  B E WIND MDU  MONT 100.0    1 2010 26 25                           282
                    BPB   210    19.5001.00000.3810      0.0000                           0.1897                          283
                    BPC   210                              26.4800.0000              2  1                                 284
                    BPD   210  1          3         0   10         0    0    0    0    0    0                             285
                    BPD   210  2     2    0    0    0    0    0    0                                                      286
                    *                                                                                                     287
 BASIC PLANT TYPE   BPA   220    THUNDER SPIRIT   NDT  B E WIND MDU  NDAK 100.0    1 2015 25 25                           288
                    BPB   220     150.01.00000.4186      0.0000                           0.1480                          289
                    BPC   220                              21.820-35.38              2  1                                 290
                    BPD   220  1          3   32    0   13         0    0    0    0    0    0                             291
                    BPD   220  2     3    0    0    0    0    0    0                                                      292
                    *                                                                                                     293
 BASIC PLANT TYPE   BPA   230    WAPA PUR-FT PECK HYDR B E HYDR MDU  NDAK 100.0    1 2001 50 30                           294
                    BPB   230     2.8000.89291.0000      0.0000      14.35                0.0000                          295
                    BPC   230         0.000                0.000024.000              2  0                                 296
                    BPD   230  1              14    0    0         0    0    0    0    0    0                             297
                    BPD   230  2     0    0    0    0    0    0    0                                                      298
                    BPE   230     M        0.0000    0    0       1980 2080              0                                299
                    *                                                                                                     300
 BASIC PLANT TYPE   BPA   310    PURCHASE POWER   THRM P G PURC MDU  MISO 100.0    1       1  1                           301
                    BPB   310    10.0001.00001.0000      0.0000    1                      1.0000                          302
                    BPC   310         0.000                12.0001000.0              2  0                                 303
                    BPD   310  1         21   23    0    0    8    0    0    0    0    0    0                             304
                    BPD   310  2     0    0    0    0    0    0    0                                                      305
                    BPF   310         0.000                   00.0000                                                     306
                    BPG   310    0.000000000.000000000.00000000                                                           307
                    *                                                                                                     308
 BASIC PLANT TYPE   BPA   320    GE 7EA           THRM P G GAS  MDU  NDAK 100.0    1      40 35                           309
                    BPB   320    78.3000.91951.0000      0.5000 11770                     0.9521                          310
                    BPC   320      1590.000          9.221019.4101.5000              1  1                                 311
                    BPD   320  1    30   22   60    0   28   13    0    0    0    0    0    2                             312
                    BPD   320  2     0    0    0    0    0   20    0                                                      313
                    BPF   320       857.000             30   370.0000                                                     314
                    BPG   320    0.000000000.000000000.00000000                                                           315
                    *                                                                                                     316
 BASIC PLANT TYPE   BPA   330    GE LMS100PB      THRM P G GAS  MDU  NDAK 100.0    1      40 35                           317
                    BPB   330    90.7000.90411.0000      0.5000  9050                     0.9519                          318
                    BPC   330      1760.000          9.221016.2201.7000              1  1                                 319
                    BPD   330  1    30   22   24    0   28   13    0    0    0    0    0   13                             320
                    BPD   330  2     0    0    0    0    0   20    0                                                      321
                    BPF   330       857.000             30   370.0000                                                     322
                    BPG   330    0.000000000.000000000.00000000                                                           323
                    *                                                                                                     324
 BASIC PLANT TYPE   BPA   340    GE LM6000PH      THRM P G GAS  MDU  NDAK 100.0    1      40 35                           325
                    BPB   340    45.3000.92721.0000      0.5000  9510                     0.9450                          326

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 BASIC PLANT TYPE   BPC   340      2320.000          9.221032.0801.6000             1  1                                  327
                    BPD   340  1    30   22   62    0   28   13    0    0    0    0    0   13                            328
                    BPD   340  2     0    0    0    0    0   20    0                                                      329
                    BPF   340       850.000             30   370.0000                                                     330
                    BPG   340    0.000000000.000000000.00000000                                                           331
                    *                                                                                                     332
 BASIC PLANT TYPE   BPA   370    GE 7EA 2x1 ADD   THRM I G GAS  MDU  NDAK 100.0    1      50 50                           333
                    BPB   370     329.80.90961.0000       0.0552  9990                    0.9448                          334
                    BPC   370       862.000          8.699020.0304.1000             1  1                                  335
                    BPD   370  1    59   59   59    0   21   13    0    0    0    0    0    4                            336
                    BPD   370  2     0    0    0    0    0   20    0                                                      337
                    BPF   370       750.000             30   370.0000                                                     338
                    BPG   370    0.000000000.000000000.00000000                                                           339
                    *                                                                                                     340
 BASIC PLANT TYPE   BPA   380    GE 7FA.05 1x1    THRM I G GAS  MDU  NDAK 100.0    1      50 50                           341
                    BPB   380     329.20.85711.0000       0.0552  6530                    0.9447                          342
                    BPC   380      1520.000          8.699016.4203.0000             1  1                                  343
                    BPD   380  1    30   22   54    0   24   13    0    0    0    0    0    2                            344
                    BPD   380  2     0    0    0    0    0   20    0                                                      345
                    BPF   380       750.000             30   370.0000                                                     346
                    BPG   380    0.000000000.000000000.00000000                                                           347
                    *                                                                                                     348
 BASIC PLANT TYPE   BPA   400    SMN SGT-800 2x1  THRM I G GAS  MDU  NDAK 100.0    1      50 50                           349
                    BPB   400     173.90.85711.0000       0.0552  7180                    0.9451                          350
                    BPC   400      2180.000          8.699037.5904.0000             1  1                                  351
                    BPD   400  1    30   22   69    0   25   13    0    0    0    0    0    3                            352
                    BPD   400  2     0    0    0    0    0   20    0                                                      353
                    BPF   400       750.000             30   370.0000                                                     354
                    BPG   400    0.000000000.000000000.00000000                                                           355
                    *                                                                                                     356
 BASIC PLANT TYPE   BPA   410    WRTSLA 18V50SG   THRM P G GAS  MDU  NDAK 100.0    1      40 25                           357
                    BPB   410    55.0001.00001.0000       0.5000  8310                    0.9455                          358
                    BPC   410      2180.000          9.221023.1604.6000             1  1                                  359
                    BPD   410  1    30   22   56    0    1   13    0    0    0    0    0    1                            360
                    BPD   410  2     0    0    0    0    0   20    0                                                      361
                    BPF   410       857.000             30   370.0000                                                     362
                    BPG   410    0.000000000.000000000.00000000                                                           363
                    *                                                                                                     364
 BASIC PLANT TYPE   BPA   420    WRTSLA 20V34SG   THRM P G GAS  MDU  NDAK 100.0    1      40 25                           365
                    BPB   420    36.5001.00001.0000       0.5000  8470                    0.9463                          366
                    BPC   420      2710.000          9.221032.7804.4000             1  1                                  367
                    BPD   420  1    30   22   56    0   28   13    0    0    0    0    0   10                            368
                    BPD   420  2     0    0    0    0    0   20    0                                                      369
                    BPF   420       857.000             30   370.0000                                                     370
                    BPG   420    0.000000000.000000000.00000000                                                           371
                    *                                                                                                     372
 BASIC PLANT TYPE   BPA   430    BIOMASS          THRM B G BMP  MDU  NDAK 100.0    1      40 25                           373

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                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0

 BASIC PLANT TYPE   BPB   430    25.0001.00001.0000      0.0928 12300                 0.9072                          374
                    BPC   430       7980.000          9.2210252.005.6000           1  1                               375
                    BPD   430 1    30   22   58    0   28   10    0    0    0    0    0   19                          376
                    BPD   430 2     0    0    0    0    0   20    0                                                   377
                    BPF   430       857.000             30   370.0000                                                  378
                    BPG   430    0.000000000.000000000.00000000                                                        379
                    *                                                                                                  380
 BASIC PLANT TYPE   BPA   450    PV SOLAR50       NDT  B G SOLR MDU  NDAK 100.0    1      30 25                        381
                    BPB   450    50.0001.00001.0000      0.0000                       0.5000                          382
                    BPC   450       1390.000          10.16513.2000.0000           1  1                               383
                    BPD   450 1    30   22         0   10         0    0    0    0    0    0                          384
                    BPD   450 2     6    0    0    0    0    0    0                                                   385
                    BPF   450      2558.000             30   380.0000                                                  386
                    BPG   450    0.000000000.000000000.00000000                                                        387
                    *                                                                                                  388
 BASIC PLANT TYPE   BPA   460    PV SOLAR5        NDT  B G SOLR MDU  NDAK 100.0    1      30 25                        389
                    BPB   460     5.0001.00001.0000      0.0000                       0.5000                          390
                    BPC   460       2500.000          10.16514.4000.0000           1  1                               391
                    BPD   460 1    30   22         0   10         0    0    0    0    0    0                          392
                    BPD   460 2     6    0    0    0    0    0    0                                                   393
                    BPF   460      2558.000             30   380.0000                                                  394
                    BPG   460    0.000000000.000000000.00000000                                                        395
                    *                                                                                                  396
 BASIC PLANT TYPE   BPA   490    CFBC             THRM B G LIGN MDU  NDAK 100.0    1      50 50                        397
                    BPB   490    30.0000.95001.0000      0.0936 10000                 0.9143                          398
                    BPC   490       5880.000          8.6990168.7214.060           1  1                               399
                    BPD   490 1    30   22   61    0   33   12    0    0    0    0    0    0                          400
                    BPD   490 2     0    0    0    0    0   20    0                                                   401
                    BPE   490     M        0.0000    0    0       1980 2080                0                          402
                    BPF   490      3900.000             30   310.0000                                                  403
                    BPG   490    0.000000000.000000000.00000000                                                        404
                    *                                                                                                  405
 BASIC PLANT TYPE   BPA   500    CFBC CO2         THRM B G COAL MDU  NDAK 100.0    1      50 50                        406
                    BPB   500    30.0000.95001.0000      0.0936 13800                 0.9143                          407
                    BPC   500     10400.000           8.6990267.4822.290           1  1                               408
                    BPD   500 1    30   22   25    0   33   12    0    0    0    0    0    0                          409
                    BPD   500 2     0    0    0    0    0   20    0                                                   410
                    BPE   500     M        0.0000    0    0       1980 2080                0                          411
                    BPF   500      3900.000             30   310.0000                                                  412
                    BPG   500    0.000000000.000000000.00000000                                                        413
                    *                                                                                                  414
 BASIC PLANT TYPE   BPA   510    WIND20           NDT  B G WIND MDU  NDAK 100.0    1      25 25                        415
                    BPB   510    20.0001.00000.3810      0.0000                       0.1690                          416
                    BPC   510       1630.000          10.16550.4000.0000           1  1                               417
                    BPD   510 1    30   22         0   10         0    0    0    0    0    0                          418
                    BPD   510 2     4    0    0    0    0   21    0                                                   419
                    BPF   510      2400.000             30   380.0000                                                  420

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
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 EGEAS   EDIT                                                      MIRROR IMAGE REPORT                              PAGE     11
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 RECORD DESCRIPTION TYP  REF  SQ                         DATA FIELDS                                                       NUM
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                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 BASIC PLANT TYPE   BPG   510    0.000000000.000000000.00000000                                                         421
                    *                                                                                                   422
 BASIC PLANT TYPE   BPA   520    WIND50           NDT  B G WIND MDU  NDAK 100.0    1      25 25                         423
                    BPB   520    50.0001.00000.3810      0.0000                           0.1690                        424
                    BPC   520      1580.000          10.16550.4000.0000             1  1                                425
                    BPD   520  1    30   22         0   10         0    0    0    0    0    0                           426
                    BPD   520  2     4    0    0    0    0   21    0                                                    427
                    BPF   520      2400.000             30   380.0000                                                   428
                    BPG   520    0.000000000.000000000.00000000                                                         429
                    *                                                                                                   430
                    *            == MAINTENANCE CYCLES ==                                                               431
                    *             Y YBO ----NUMBER OF WEEKS (W) AND STARTING WEEK (S)----                               432
                    *             I RAP   1    2    3    4    5    6    7    8    9   10                                 433
                    *             N PST  W S  W S  W S  W S  W S  W S  W S  W S  W S  W S                               434
                    *            ++--+- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++--                               435
                    *                                                                                                   436
 MAINTENANCE CYCLE  MC      1  1  1 110  2                                                                              437
                    *                                                                                                   438
 MAINTENANCE CYCLE  MC      2  1 101021  120  113  119  216  116  116  119  117  221  116                               439
                    *                                                                                                   440
 MAINTENANCE CYCLE  MC      3  1 101021  122  216  118  116  116  119  238  116  117  118                               441
                    *                                                                                                   442
 MAINTENANCE CYCLE  MC      4  1 101021  120 1133  120  120  116  120  220  120  120  120                               443
                    *                                                                                                   444
 MAINTENANCE CYCLE  MC      5  1  3 322  125  116 3914                                                                  445
                    MC      5  2         143  141  0                                                                    446
                    *                                                                                                   447
 MAINTENANCE CYCLE  MC      6  1  3 322  435  218 3914                                                                  448
                    MC      6  2         0    242  0                                                                    449
                    *                                                                                                   450
 MAINTENANCE CYCLE  MC      7  1  6 101 23 1  0    0    0    0   2923                                                   451
                    *                                                                                                   452
 MAINTENANCE CYCLE  MC      8  1 101021  440  838  341  440  838  341  342  838  342  342                               453
                    *                                                                                                   454
 MAINTENANCE CYCLE  MC      9  1  1 110  1                                                                              455
                    *                                                                                                   456
 MAINTENANCE CYCLE  MC     10  1  1 110  1                                                                              457
                    *                                                                                                   458
 MAINTENANCE CYCLE  MC     11  1  1 110  1                                                                              459
                    *                                                                                                   460
 MAINTENANCE CYCLE  MC     13  1  1 110  1                                                                              461
                    *                                                                                                   462
 MAINTENANCE CYCLE  MC     14  1  1 100  1                                                                              463
                    *                                                                                                   464
 MAINTENANCE CYCLE  MC     15  1  1 120  1                                                                              465
                    *                                                                                                   466
 MAINTENANCE CYCLE  MC     17  1 101011  0    0    0    0    0    238  0    0    0    0                                 467

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                  NUM
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                               1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

                   *                                                                                                   468
MAINTENANCE CYCLE  MC     18  1  2 221  234 3914                                                                       469
                   *                                                                                                   470
MAINTENANCE CYCLE  MC     19  1 101021  0    0    0    0    219  0    0    0    0    0                                 471
                   *                                                                                                   472
MAINTENANCE CYCLE  MC     21  1  1 110  2                                                                              473
                   *                                                                                                   474
MAINTENANCE CYCLE  MC     22  1 101022  122  223  814  122  122  713  122  123  714  124                               475
                   MC     22  2         144  138  149  150  150  150  150  150  150  150                               476
                   *                                                                                                   477
MAINTENANCE CYCLE  MC     23  1  1 110  2                                                                              478
                   *                                                                                                   479
MAINTENANCE CYCLE  MC     24  1  1 110  2                                                                              480
                   *                                                                                                   481
MAINTENANCE CYCLE  MC     25  1  1 110  2                                                                              482
                   *                                                                                                   483
MAINTENANCE CYCLE  MC     28  1  1 110  2                                                                              484
                   *                                                                                                   485
MAINTENANCE CYCLE  MC     33  1  1 110  3                                                                              486
                   *                                                                                                   487
MAINTENANCE CYCLE  MC     37  1  1 110  2                                                                              488
                   *                                                                                                   489
MAINTENANCE CYCLE  MC     39  1  1 100  1                                                                              490
                   *                                                                                                   491
                   *-- ----- -- ---------------------------------------------------------------------                 492
                   *            == FUEL TYPES ==                                                                       493
                   *                 MASS    HEAT    AVAILABLE   FUEL      AV   CS   AV   CS  LONG                    494
                   *            NAME UNIT   CONTENT    FUEL      COST      TJ   TJ   SM   SM  NAME                    495
                   *FL A        ---- ++++ ----------++++++++++----------+++++-----+++++-----++++++++                  496
                   *            MIN. FUEL    TJ   SM                                                                   497
                   *FL B        ----------+++++-----                                                                   498
                   *-- ----- -- ---------------------------------------------------------------------                 499
                   *                                                                                                   500
FUEL TYPE          FLA     1    GAS  DKT      1.1400 -1.000000  3.090000    0   33    0    0GAS                        501
                   *                                                                                                   502
FUEL TYPE          FLA     2    OIL2 GAL     39.1700 -1.000000 15.690000    0   34    0    0OIL2                       503
                   *                                                                                                   504
FUEL TYPE          FLA     3    COAL TON     14.2700 -1.000000  2.700000    0   35    0    0COAL                       505
                   *                                                                                                   506
FUEL TYPE          FLA     4    COAL TON     14.2700 -1.000000  2.700000    0   36    0    0COAL                       507
                   *                                                                                                   508
FUEL TYPE          FLA     5    COAL TON     13.2200 -1.000000  2.420000    0   37    0    0COAL                       509
                   *                                                                                                   510
FUEL TYPE          FLA     6    COAL TON     16.4800 -1.000000  1.800000    0   38    0    0COAL                       511
                   *                                                                                                   512
FUEL TYPE          FLA     7    COAL TON     13.6800 -1.000000  1.930000    0   39    0    0COAL                       513
                   *                                                                                                   514

                               1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                  NUM
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                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 FUEL TYPE          FLA     8    PURC NONE     0.0100 -1.000000  0.000000    0         0    0PURC                     515
                    *                                                                                                  516
 FUEL TYPE          FLA    10    BMP  TON     14.9000 -1.000000  6.750000    0   63    0    0BMP                      517
                    *                                                                                                  518
 FUEL TYPE          FLA    11    GAS  DKT      1.1400 -1.000000  3.460000    0   47    0    0GAS                      519
                    *                                                                                                  520
 FUEL TYPE          FLA    12    COAL TON     14.0700 -1.000000  2.880000    0   43    0    0COAL                     521
                    *                                                                                                  522
 FUEL TYPE          FLA    13    GAS  DKT      1.1400 -1.000000  3.100000    0   50    0    0GAS                      523
                    *                                                                                                  524
                    *            == PLANNING ALTERNATIVES ==                                                           525
                    *                                  1ST LAST T EXIST ---PREREQ ALT---                               526
                    *            NAME             BP   YEAR YEAR Y   RET   PA   NfR L L R                              527
                    *            ----------------+++++ ---- ++++ - +++++-----  ++-+ -++ +                              528
                    *                                                                                                  529
 PLANNING ALTERN    PA      1  1 GE 7EA           320 2024 2040 0     0    0    00 0-1 0                               530
                    *                                                                                                  531
 PLANNING ALTERN    PA      2  1 WRTSLA 18V50SG   410 2024 2040 0     0    0    00 0-1 0                               532
                    *                                                                                                  533
 PLANNING ALTERN    PA      3  1 STORAGE1           1 2023 2040 0     0   12   100 0-1 0                               534
                    *                                                                                                  535
 PLANNING ALTERN    PA      4  1 SOLAR PPA          4 2023 2040 0     0    0    00 0-1 0                               536
                    *                                                                                                  537
 PLANNING ALTERN    PA      5  1 CFBC             490 2027 2040 0     0    0    00 0-1 0                               538
                    *                                                                                                  539
 PLANNING ALTERN    PA      6  1 GE LM6000PH      340 2024 2040 0     0    0    00 0-1 0                               540
                    *                                                                                                  541
 PLANNING ALTERN    PA      7  1 PURCHASE POWER   310 2021 2040 1     0    0    00 0-1 0                               542
                    *                                                                                                  543
 PLANNING ALTERN    PA      8  1 GE 7EA 2x1 ADD   370 2026 2040 0   152    0    00 0-1 0                               544
                    *                                                                                                  545
 PLANNING ALTERN    PA      9  1 GE 7FA.05 1x1    380 2026 2040 0     0    0    00 0-1 0                               546
                    *                                                                                                  547
 PLANNING ALTERN    PA     10  1 BIOMASS          430 2024 2040 0     0    0    00 0-1 0                               548
                    *                                                                                                  549
 PLANNING ALTERN    PA     11  1 CFBC CO2         500 2027 2040 0     0    0    00 0-1 0                               550
                    *                                                                                                  551
 PLANNING ALTERN    PA     12  1 PV SOLAR5        460 2023 2040 0     0    0    00 0-1 0                               552
                    *                                                                                                  553
 PLANNING ALTERN    PA     13  1 SOLAR QF           5 2023 2024 0     0    0    00 0-1 0                               554
                    *                                                                                                  555
 PLANNING ALTERN    PA     14  1 GE LMS100PB      330 2024 2040 0     0    0    00 0-1 0                               556
                    *                                                                                                  557
 PLANNING ALTERN    PA     16  1 PV SOLAR50       450 2023 2040 0     0    0    00 0-1 0                               558
                    *                                                                                                  559
 PLANNING ALTERN    PA     19  1 SMN SGT-800 2x1  400 2026 2040 0     0    0    00 0-1 0                               560
                    *                                                                                                  561

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                  NUM
 ---------------------- ----- -- --------------------------------------------------------------------------------     ----
                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 PLANNING ALTERN     PA     20  1 WIND20            510 2023 2040 0     0    0    00 0-1 0                                 562
                     *                                                                                                     563
 PLANNING ALTERN     PA     22  1 WIND50            520 2023 2040 0     0    0    00 0-1 0                                 564
                     *                                                                                                     565
 PLANNING ALTERN     PA     23  1 WRTSLA 20V34SG    420 2024 2040 0     0    0    00 0-1 0                                 566
                     *                                                                                                     567
 PLANNING ALTERN     PA     40  1 STORAGE10          24 2023 2040 0     0   16   100 0-1 0                                 568
                     *                                                                                                     569
 PLANNING ALTERN     PA     42  1 AC CYCLE           26 2023 2040 0     0    0    00 0-1 0                                 570
                     *                                                                                                     571
 PLANNING ALTERN     PA     43  1 STORAGE            27 2023 2040 0     0    0    00 0-1 0                                 572
                     *                                                                                                     573
                     *            == TRAJECTORIES ==                                                                       574
                     *             T B                                                                                     575
                     *             Y A  N YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE                            576
                     *             - + -- ++++------ ++++------ ++++------ ++++------ ++++------                           577
                     *                                                                                                     578
 TRAJECTORY          TJ      1  1  1 1 21 2020.06187 20211.5663 20221.2378 20231.3830 20241.3048                           579
                     TJ      1  2         2025.87821 2026.88992 2027.86290 2028.89353 2029.88563                           580
                     TJ      1  3         2030.87783 2031.87022 2032.88105 2033.83698 2034.84807                           581
                     TJ      1  4         2035.84093 2036.85168 2037.84448 2038.81996 2039.83059                           582
                     TJ      1  5         20401.3700                                                                       583
                     *                                                                                                     584
 TRAJECTORY          TJ      2  1  1 1 21 20205.7271 20212.0176 20221.4042 20231.7108 20241.5203                           585
                     TJ      2  2         2025.67893 2026.75207 2027.69963 2028.74401 2029.74122                           586
                     TJ      2  3         2030.73577 2031.73575 2032.73303 2033.72769 2034.72768                           587
                     TJ      2  4         2035.72242 2036.71981 2037.71980 2038.71974 2039.71964                           588
                     TJ      2  5         20401.5600                                                                       589
                     *                                                                                                     590
 TRAJECTORY          TJ      3  1  1 1  1 20203.0000                                                                       591
                     *                                                                                                     592
 TRAJECTORY          TJ      4  1  1 1  4 2020.00000 202140.000 202228.571 2023.00000                                      593
                     *                                                                                                     594
 TRAJECTORY          TJ      5  1  1 1  1 20203.0000                                                                       595
                     *                                                                                                     596
 TRAJECTORY          TJ      6  1  1 1  1 20203.0000                                                                       597
                     *                                                                                                     598
 TRAJECTORY          TJ      7  1  1 1  1 20203.0000                                                                       599
                     *                                                                                                     600
 TRAJECTORY          TJ      8  1  1 1  1 20203.0000                                                                       601
                     *                                                                                                     602
 TRAJECTORY          TJ      9  1  1 1  1 20203.0000                                                                       603
                     *                                                                                                     604
 TRAJECTORY          TJ     10  1  1 1  1 20203.0000                                                                       605
                     *                                                                                                     606
 TRAJECTORY          TJ     11  1  1 1  1 20203.0000                                                                       607
                     *                                                                                                     608

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                NUM
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                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 TRAJECTORY         TJ     12  1  1 1  1 20203.0000                                                                  609
                    *                                                                                                610
 TRAJECTORY         TJ     13  1  1 1  1 20203.0000                                                                  611
                    *                                                                                                612
 TRAJECTORY         TJ     14  1  1 1  1 2020.00000                                                                  613
                    *                                                                                                614
 TRAJECTORY         TJ     15  1  1 1  1 20203.0000                                                                  615
                    *                                                                                                616
 TRAJECTORY         TJ     16  1  1 1  4 2020.00000 202115.789 202213.636 2023.00000                                 617
                    *                                                                                                618
 TRAJECTORY         TJ     18  1  1 1  6 20201.5444 20211.5209 20221.4981 20231.4760 20241.4545                      619
                    TJ     18  2         20251.5000                                                                  620
                    *                                                                                                621
 TRAJECTORY         TJ     20  1  1 1  1 20203.0000                                                                  622
                    *                                                                                                623
 TRAJECTORY         TJ     21  1  1 1  6 2020.00000 202125.000 202260.000 202325.000 202419.999                      624
                    TJ     21  2         20253.0000                                                                  625
                    *                                                                                                626
 TRAJECTORY         TJ     22  1  1 1  1 20213.0000                                                                  627
                    *                                                                                                628
 TRAJECTORY         TJ     23  1  1 1  1 20203.0000                                                                  629
                    *                                                                                                630
 TRAJECTORY         TJ     24  1  1 1  1 20213.0000                                                                  631
                    *                                                                                                632
 TRAJECTORY         TJ     25  1  1 1  1 20213.0000                                                                  633
                    *                                                                                                634
 TRAJECTORY         TJ     26  1  1 1  8 2020.00000 2021.00000 2022100.00 202350.000 202433.333                      635
                    TJ     26  2         202525.000 2026.00000 2027.00000                                            636
                    *                                                                                                637
 TRAJECTORY         TJ     27  1  1 1  4 2020.00000 20214.2289 20224.0595 2023.00000                                 638
                    *                                                                                                639
 TRAJECTORY         TJ     28  1  1 1  7 2020.00000 2021150.00 2022.00000 2023.00000 2024.00000                      640
                    TJ     28  2         2025.00000 2026.00000                                                       641
                    *                                                                                                642
 TRAJECTORY         TJ     29  1  1 1  6 20203.0127 20212.9996 20222.9850 20233.0000 20243.0000                      643
                    TJ     29  2         20253.0000                                                                  644
                    *                                                                                                645
 TRAJECTORY         TJ     30  1  1 1  1 20213.0000                                                                  646
                    *                                                                                                647
 TRAJECTORY         TJ     31  1  1 1  1 20203.0000                                                                  648
                    *                                                                                                649
 TRAJECTORY         TJ     32  1  1 1  9 2020.00000 2021.00000 2022.00000 2023.00000 2024.00000                      650
                    TJ     32  2         2025-66.70 2026.00000 2027-100.0 2028.00000                                 651
                    *                                                                                                652
 TRAJECTORY         TJ     33  1  1 1  6 202029.773 2021-6.483 20223.7333 20235.9125 20243.6407                      653
                    TJ     33  2         20253.0000                                                                  654
                    *                                                                                                655

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                          NUM
 ---------------------- ----- -- -------------------------------------------------------------------------------  ----
                                1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0

 TRAJECTORY         TJ     34  1  1 1  6 20203.1867 202168.499 20224.2155 2023.00000 2024.00000                    656
                    TJ     34  2         20253.0000                                                                657
                    *                                                                                              658
 TRAJECTORY         TJ     35  1  1 1  3 2020.00000 2021.00000 2022.00000                                          659
                    *                                                                                              660
 TRAJECTORY         TJ     36  1  1 1  3 2020-0.370 2021.00000 2022.00000                                          661
                    *                                                                                              662
 TRAJECTORY         TJ     37  1  1 1  2 2020.00000 2021.00000                                                     663
                    *                                                                                              664
 TRAJECTORY         TJ     38  1  1 1  6 20204.4444 20212.6595 2022.00000 2023.00000 2024.00000                    665
                    TJ     38  2         20253.0000                                                                666
                    *                                                                                              667
 TRAJECTORY         TJ     39  1  1 1  6 202010.362 20218.4507 2022-8.225 20231.4151 2024.00000                    668
                    TJ     39  2         20253.0000                                                                669
                    *                                                                                              670
 TRAJECTORY         TJ     40  1  1 1 17 2020.00000 2021.00000 2022.00000 2023.00000 2024.00000                    671
                    TJ     40  2         2025.00000 2026.00000 2027.00000 2028.00000 2029.00000                    672
                    TJ     40  3         2030.00000 2031.00000 2032.00000 2033-65.00 2034.00000                    673
                    TJ     40  4         2035.00000 2036.00000                                                     674
                    *                                                                                              675
 TRAJECTORY         TJ     41  1  1 1  4 202020.000 202133.333 2022-25.00 2023.00000                               676
                    *                                                                                              677
 TRAJECTORY         TJ     42  1  1 1  7 2020.00000 20212.7619 20224.6339 20234.4287 20244.2408                    678
                    TJ     42  2         20251.7087 2026.00000                                                     679
                    *                                                                                              680
 TRAJECTORY         TJ     43  1  1 1  1 20213.0000                                                                681
                    *                                                                                              682
 TRAJECTORY         TJ     44  1  1 1  1 20203.0000                                                                683
                    *                                                                                              684
 TRAJECTORY         TJ     45  1  1 1  7 2020.00000 202120.000 2022-66.66 2023.00000 2024.00000                    685
                    TJ     45  2         2025.00000 2026.00000                                                     686
                    *                                                                                              687
 TRAJECTORY         TJ     46  1  1 1  3 20203.0133 20213.0087 20223.0000                                          688
                    *                                                                                              689
 TRAJECTORY         TJ     47  1  1 1  6 2020-15.60 2021-7.534 20225.5555 20235.6140 20243.9867                    690
                    TJ     47  2         20253.0000                                                                691
                    *                                                                                              692
 TRAJECTORY         TJ     48  1  1 1  1 20203.0000                                                                693
                    *                                                                                              694
 TRAJECTORY         TJ     49  1  1 1  1 2020.00000                                                                695
                    *                                                                                              696
 TRAJECTORY         TJ     50  1  1 1  6 2020-13.54 2021-8.208 20226.0975 20236.1302 20244.3321                    697
                    TJ     50  2         20253.0000                                                                698
                    *                                                                                              699
 TRAJECTORY         TJ     51  1  1 1  1 20213.0000                                                                700
                    *                                                                                              701
 TRAJECTORY         TJ     52  1  1 1  3 2021.00000 2022.00000 2023.00000                                          702

                                1          2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
```

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RECORD DESCRIPTION TYP  REF  SQ                            DATA FIELDS                                                      NUM
---------------------- ----- -- -------------------------------------------------------------------------------------   ----
                                 1          2          3          4          5          6          7          8          9
         COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

                   *                                                                                                    703
TRAJECTORY         TJ     53  1  1 1  1 2020.00000                                                                      704
                   *                                                                                                    705
TRAJECTORY         TJ     54  1  1 1  1 20213.0000                                                                      706
                   *                                                                                                    707
TRAJECTORY         TJ     56  1  1 1  1 20213.0000                                                                      708
                   *                                                                                                    709
TRAJECTORY         TJ     58  1  1 1  1 20213.0000                                                                      710
                   *                                                                                                    711
TRAJECTORY         TJ     59  1  1 1  1 20213.0000                                                                      712
                   *                                                                                                    713
TRAJECTORY         TJ     60  1  1 1  1 20213.0000                                                                      714
                   *                                                                                                    715
TRAJECTORY         TJ     61  1  1 1  1 20213.0000                                                                      716
                   *                                                                                                    717
TRAJECTORY         TJ     62  1  1 1  1 20213.0000                                                                      718
                   *                                                                                                    719
TRAJECTORY         TJ     63  1  1 1  1 20213.0000                                                                      720
                   *                                                                                                    721
TRAJECTORY         TJ     69  1  1 1  1 20213.0000                                                                      722
                   *                                                                                                    723
                   *            == LOADING BLOCKS ==                                                                    724
                   *              -A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-                                            725
                   *            N     1       2       3       4       5                                                 726
                   *            - ++++++++--------++++++++--------++++++++                                              727
                   *                                                                                                    728
LOADING BLOCK      LBA     1    5 0.2325580.2093020.1860470.1860470.186047                                              729
                   LBB     1      1.8436370.7766110.6303580.7719000.794509                                              730
                   LBC     1      1.0000000.0000000.0000000.0000000.000000                                              731
                   *                                                                                                    732
LOADING BLOCK      LBA     2    5 0.0946750.2130180.2011830.3076920.183432                                              733
                   LBB     2      3.2613650.8753020.6785150.6585090.903074                                              734
                   LBC     2      1.0000000.0000000.0000000.0000000.000000                                              735
                   *                                                                                                    736
LOADING BLOCK      LBA     3    5 0.0873940.1966630.1857260.2841110.246106                                              737
                   LBB     3      3.0457110.8174080.6336880.6219161.132123                                              738
                   LBC     3      1.0000000.0000000.0000000.0000000.000000                                              739
                   *                                                                                                    740
LOADING BLOCK      LBA     4    5 0.0946330.2129470.2011220.2171920.274106                                              741
                   LBB     4      2.9498470.7916370.6136950.6402401.057082                                              742
                   LBC     4      1.0000000.0000000.0000000.0000000.000000                                              743
                   *                                                                                                    744
LOADING BLOCK      LBA     5    5 0.2535210.1690140.1690140.2253520.183099                                              745
                   LBB     5      1.6222220.7421580.7319290.7941840.877250                                              746
                   LBC     5      1.0000000.0000000.0000000.0000000.000000                                              747
                   *                                                                                                    748
LOADING BLOCK      LBA     6    5 0.2000000.2000000.2000000.2000000.200000                                              749

                                 1          2          3          4          5          6          7          8          9
         COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
```

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RECORD DESCRIPTION TYP  REF  SQ                           DATA FIELDS                                                  NUM
---------------------- ----- -- ---------------------------------------------------------------------------------    ----
                                1         2         3         4         5         6         7         8         9
         COLUMNS       123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

LOADING BLOCK          LBB     6      1.0000001.0000001.0000001.0000001.000000                                         750
                       LBC     6      1.0000000.0000000.0000000.0000000.000000                                         751
                       *                                                                                               752
LOADING BLOCK          LBA     7    5 0.2000000.2000000.2000000.2000000.200000                                         753
                       LBB     7      1.0000001.0000001.0000001.0000001.000000                                         754
                       LBC     7      1.0000000.0000000.0000000.0000000.000000                                         755
                       *                                                                                               756
LOADING BLOCK          LBA     8    5 0.0953370.2145080.2025910.3098450.177720                                         757
                       LBB     8      3.2591500.8747070.6780540.6580620.902461                                         758
                       LBC     8      1.0000000.0000000.0000000.0000000.000000                                         759
                       *                                                                                               760
LOADING BLOCK          LBA    10    5 0.2325580.2093020.1860470.1860470.186047                                         761
                       LBB    10      1.8436370.7766110.6303580.7719000.794509                                         762
                       LBC    10      1.0000000.0000000.0000000.0000000.000000                                         763
                       *                                                                                               764
LOADING BLOCK          LBA    11    5 0.1891890.2432430.2162160.2162160.135135                                         765
                       LBB    11      1.2000461.1529430.8809440.8645150.851903                                         766
                       LBC    11      1.0000000.0000000.0000000.0000000.000000                                         767
                       *                                                                                               768
LOADING BLOCK          LBA    12    5 0.2777780.1587300.2380950.1190480.206349                                         769
                       LBB    12      1.6629090.1229151.1262310.7842410.761127                                         770
                       LBC    12      0.7885320.0841890.1095830.1287550.227864                                         771
                       *                                                                                               772
LOADING BLOCK          LBA    13    5 0.2309470.2078520.1847570.1847570.191686                                         773
                       LBB    13      1.8148470.7642730.6209910.7594000.871078                                         774
                       LBC    13      1.0000000.0000000.0000000.0000000.000000                                         775
                       *                                                                                               776
LOADING BLOCK          LBA    14    5 0.2226030.1883560.2054790.2054790.178082                                         777
                       LBB    14      1.1014360.6004480.5689500.9914581.803029                                         778
                       LBC    14      0.5990180.0967090.3117780.2505240.258642                                         779
                       *                                                                                               780
LOADING BLOCK          LBA    15    5 0.3927610.1970510.1340480.1340480.142091                                         781
                       LBB    15      1.0653170.9015531.1667870.9644570.832163                                         782
                       LBC    15      0.6892410.1361860.3041380.2250420.289710                                         783
                       *                                                                                               784
LOADING BLOCK          LBA    16    5 0.3632890.1147230.1147230.1720840.235182                                         785
                       LBB    16      1.1031060.9346200.9345930.9345930.952387                                         786
                       LBC    16      0.6857320.1000710.0984190.2329840.443454                                         787
                       *                                                                                               788
LOADING BLOCK          LBA    17    5 0.3158040.1515490.1515490.2274160.153682                                         789
                       LBB    17      1.1555420.8683480.9024050.9451990.987560                                         790
                       LBC    17      1.0000000.0000000.0000000.0000000.000000                                         791
                       *                                                                                               792
LOADING BLOCK          LBA    18    5 0.4215460.1405150.1405150.1405150.156909                                         793
                       LBB    18      1.1057930.9092560.9184120.9267520.935703                                         794
                       LBC    18      1.0000000.0000000.0000000.0000000.000000                                         795
                       *                                                                                               796

                                1         2         3         4         5         6         7         8         9
         COLUMNS       123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
```

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 ****************************************************************************************************************************

 RECORD DESCRIPTION TYP  REF  SQ                          DATA FIELDS                                                        NUM
 ---------------------- ----- -- --------------------------------------------------------------------------------   ----
                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 LOADING BLOCK      LBA    19    5 0.2325580.2093020.1860470.1860470.186047                                         797
                    LBB    19      1.8436370.7766110.6303580.7719000.794509                                         798
                    LBC    19      1.0000000.0000000.0000000.0000000.000000                                         799
                    *                                                                                               800
                    *            == ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ==                                 801
                    *            YEAR OPT   RATE                                                                    802
                    *            ---- +    ------                                                                   803
 A. F. U. D. C.     ZA      1    2021 1    10.500                                                                   804
                    *                                                                                               805
                    *-- ----- -- ------------------------------------------------------------------               806
                    *            == EXPENDITURE PATTERNS - CONSTRUCTION COST AND CAPITAL EXPENSES ==                807
                    *                          COST PERCENTAGES FOR YEARS BEFORE ON-LINE                            808
                    *            YR          1    2    3    4    5    6    7    8    9   10                         809
                    *ZC A        --        +++++-----+++++-----+++++-----+++++-----+++++-----                       810
                    *                      ANNUAL EXPENDITURES FOR YEARS OF OPERATING LIFE                          811
                    *            YR F   TJ      1         2         3         4         5                           812
                    *ZC B        -- +----- ++++++++++----------++++++++++----------++++++++++                       813
                    *-- ----- -- ------------------------------------------------------------------               814
                    *                                                                                               815
 CONSTRUCTION EXPEN ZCA    31  1  4        13.7035.1034.8016.50                                                     816
                    *                                                                                               817
 CONSTRUCTION EXPEN ZCA    37  1  3        69.0027.004.000                                                          818
                    *                                                                                               819
 CONSTRUCTION EXPEN ZCA    38  1  1        100.0                                                                    820
                    *                                                                                               821
                    *            == RETURN ON RATE BASE ==                                                          822
                    *                --CAPITAL STRUC-- -RATES OF RETURN- INCOME  PROP                               823
                    *            YEAR COMM  PREF  DEBT  COMM  PREF  DEBT  TAX    TAX                                824
                    *            ----+++++------+++++------+++++------+++++------                                   825
 RETURN ON RATEBASE ZR      1  1 202150.0000.000050.0009.6500       4.7024.0001.1770                                826
                    *                                                                                               827
                    *            == TAX DEPRECIATION TABLES ==                                                      828
                    *                              DEPRECIATION PERCENTAGES FOR YEARS                               829
                    *            YR          1    2    3    4    5    6    7    8    9   10                         830
                    *            --        +++++-----+++++-----+++++-----+++++-----+++++-----                       831
                    *                                                                                               832
 TAX DEPRECIATION   ZT     20  1 21        3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464                       833
                    ZT     20  2           4.4624.4624.4624.4624.4624.4624.4624.4624.4624.462                       834
                    ZT     20  3           2.224                                                                    835
                    *                                                                                               836
 TAX DEPRECIATION   ZT     21  1 20        3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464                       837
                    ZT     21  2           4.4624.4624.4624.4624.4624.4624.4624.4624.4626.686                       838
                    *                                                                                               839

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
```

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*****************************************************
*****************************************************
**                                                 **
**                                                 **
**              DIAGNOSTIC SUMMARY                 **
**                                                 **
**                                                 **
**         TERMINAL ERRORS             0           **
**         FATAL ERRORS                0           **
**         WARNING MESSAGES            0           **
**         DEFAULTS                    0           **
**                                                 **
**                                                 **
**     HIGHEST ERROR LEVEL FOUND IS NONE           **
**                                                 **
**                                                 **
**     DATA BASE HAS BEEN SUCCESSFULLY CREATED     **
**                                                 **
**                                                 **
*****************************************************
*****************************************************
```

SOURCE FILE HEADERS	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
	2021	1	0	5/26/21	10:14:58	2021 IRP	1300

FILE CONTENTS

LOAD FORMAT	2	SUBPERIOD
COST ANALYSIS FORMAT	1	NO CONSTRUCTION COSTS, LEVELIZED FIXED CHARGES
NUMBER OF LOAD AREAS	1	
LOAD MODIFICATION OPTION	1	
NUMBER OF LOAD COMPONENTS	1	
NUMBER OF NON-DISPATCHABLE TECHNOLOGIES	6	
NUMBER OF YEARS	21	
FIRST CALENDAR YEAR	2020	
LAST CALENDAR YEAR	2040	
NUMBER OF DAYS PER YEAR	364	
NUMBER OF CUMULANTS	8	
NUMBER OF SEGMENTS PER YEAR	4	
NUMBER OF SUBWEEKS PER SEGMENT	3	
NUMBER OF CONTRACTS	0	
DAY OF WEEK OPTION	0	- DETERMINED BY CALENDAR YEAR IN COLUMNS 5-6
TIME INTERVAL OPTION	0	ONE HOUR

SOURCE FILE HEADERS	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
ORTHOGONALIZED LOAD	2021	1	0	5/26/21	10:14:56	2021 IRP	1300
HOURLY LOADS							
SYSTEM A	HOURLOAD	1	0				
HOURLY NDT							
TECHNOLOGY 1	windDWcf	1	0				
TECHNOLOGY 2	windCHcf	1	0				
TECHNOLOGY 3	windTScf	1	0				
TECHNOLOGY 4	wind46cf	1	0				
TECHNOLOGY 5	slr16cf	1	0				
TECHNOLOGY 6	slr20cf	1	0				

ADDITIONAL HOURLY FILE PARAMETERS

SOURCE FILE	HEADER RECORD OPTION	DUPLICATE RECORD OPTION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
HOURLY LOADS																																
SYSTEM A	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
HOURLY NDT																																
TECHNOLOGY 1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
TECHNOLOGY 2	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
TECHNOLOGY 3	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
TECHNOLOGY 4	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
TECHNOLOGY 5	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
TECHNOLOGY 6	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									

GENERAL DATA

BASE YEAR 2020
ALL DATA BASE COSTS
ARE IN 2020 DOLLARS

SYSTEM DISCOUNT RATE (PERCENT) 6.59
CUSTOMER DISCOUNT RATE (PERCENT) 6.59
INFLATION RATE (PERCENT) 3.00

NUMBER OF DAYS PER YEAR 364
NUMBER OF HOURS PER YEAR 8736
STORAGE GENERATION SUBWEEK 1

NUMBER OF CUMULANTS 8
USED IN REPRESENTING PLANT
OUTAGES AND LOAD CURVES

UNSERVED ENERGY COST . . . . . 130.00 $/MWH
YEARLY ESCALATION TRAJECTORY 31
CAPITAL STRUCTURE FOR NON-EGEAS ASSETS . 1

BENCHMARK YEAR 2020
BENCHMARK PEAK . . . . . 485. MW

SERVICE AREAS AND NAMES IDENTIFYING SYSTEMS

SYSTEM A - SYSA SYSA

GENERATING COMPANIES

SYSTEM	COMPANY	CODE	NAME
A	1	NDAK	NDAK
	2	MONT	MONT
	3	SDAK	SDAK
	4	MISO	MISO

SYSTEM DEMAND

IN BASE YEAR 2020 -
PEAK LOAD . . . . 484.9 MW
ENERGY . . . . 3169.1 GWH

YEARLY ESCALATION TRAJECTORIES
PEAK LOAD 1
ENERGY 2

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
1	2020	INITIAL LOAD	484.9	295.0	3169.1	0.74811978	0.60840499	SUNDAY
		LOAD AFTER CONTRACTS	484.9	295.0	3169.1	0.74811978	0.60840499	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
0.996873492276267	0.979785943806632	0.907430742848859	0.838621423711708	0.768036444940141
0.648368033220770	0.522980561703447	0.397033329814500	0.294110970183055	0.206231479674343
0.137639825394167	0.088336007342527	0.052157048262966	0.030700757073826	0.019173707020086
0.010728145594573	0.005135814380383	0.002168454960608	0.000570646042268	0.000000000000000

CUMULANTS

0.748119779990848D+00	0.421162822164375D-02	0.118553227417888D-03	0.296190372550703D-08
-0.353236392281644D-06	-0.783756680666098D-07	-0.154810157871838D-07	-0.324879128792147D-09

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
2	2021	INITIAL LOAD	485.2	327.1	3350.6	0.79047689	0.67425700	SUNDAY
		LOAD AFTER CONTRACTS	485.2	327.1	3350.6	0.79047689	0.67425700	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.996192583863684	0.983131514566138
0.894876045410901	0.816074038608437	0.698892511656838	0.556076501987582	0.398596845804493
0.277460611505638	0.176078579599140	0.108680625879522	0.058274711253345	0.030676902792858
0.017448201216757	0.008210918219652	0.002622932209058	0.000684243184974	0.000000000000000

CUMULANTS

0.790476891626905D+00	0.291424444148678D-02	0.682381502804688D-04	0.141742407258351D-08
-0.140687486534807D-06	-0.259662537288032D-07	-0.426642653596643D-08	-0.744920741536206D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
3	2022	INITIAL LOAD	492.8	335.0	3418.2	0.79398840	0.67971634	SUNDAY
		LOAD AFTER CONTRACTS	492.8	335.0	3418.2	0.79398840	0.67971634	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.995575757899084	0.991138740593186
0.915916492776697	0.831225069041446	0.736463014916128	0.587917100402572	0.421662347207098
0.293682126689918	0.186443135143465	0.115330350100971	0.062565575301813	0.031567694642264
0.018120084650254	0.008661172537230	0.002621144320480	0.000683776779258	0.000000000000000

CUMULANTS

0.793988401267307D+00	0.281737998287637D-02	0.648644149436768D-04	0.132523837998249D-08
-0.129286925909594D-06	-0.234621638652741D-07	-0.379037755725356D-08	-0.650643913016839D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
4	2023	INITIAL LOAD	498.9	340.1	3466.2	0.79529363	0.68174556	SUNDAY
		LOAD AFTER CONTRACTS	498.9	340.1	3466.2	0.79529363	0.68174556	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.991254699450710
0.924632847374343	0.836779266018025	0.745039419772208	0.595949061498746	0.435140935524128
0.298362848573292	0.193901713946946	0.117433432390405	0.063723567963787	0.032089368153195
0.018661902046540	0.008648198509374	0.002617217969945	0.000682752513901	0.000000000000000

CUMULANTS

0.795293625846762D+00	0.278179378997764D-02	0.636393469639693D-04	0.129068744464948D-08
-0.125242998478774D-06	-0.225842636829483D-07	-0.362544868945111D-08	-0.618272322483716D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
5	2024	INITIAL LOAD	505.8	346.8	3525.5	0.79786474	0.68574285	SUNDAY
		LOAD AFTER CONTRACTS	505.8	346.8	3525.5	0.79786474	0.68574285	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.994160171562634
0.945553313737399	0.851861786034789	0.759173721538541	0.615518263368365	0.455146369433752
0.315618265690923	0.201831673332486	0.123468134250800	0.066745688810858	0.033031142926877
0.019021382306169	0.008998138935255	0.002619711335583	0.000683402957111	0.000000000000000

CUMULANTS

0.797864740084652D+00	0.271235262477047D-02	0.612713715829631D-04	0.122814143559321D-08
-0.117572655458927D-06	-0.209348613714372D-07	-0.331843944129225D-08	-0.559047784491679D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
6	2025	INITIAL LOAD	512.4	352.7	3579.1	0.79956186	0.68838136	SUNDAY
		LOAD AFTER CONTRACTS	512.4	352.7	3579.1	0.79956186	0.68838136	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.995002545979378
0.957261669091012	0.861449659600310	0.774187118332122	0.628795066616659	0.465757244487934
0.324936316359978	0.210661728243199	0.125326068722294	0.068815405007516	0.034065904134517
0.019140708677590	0.009456421549049	0.002734386953944	0.000683596738489	0.000000000000000

CUMULANTS

0.799561862205484D+00	0.266699795019964D-02	0.597409844330542D-04	0.118734895506826D-08
-0.112719141393056D-06	-0.199021428697120D-07	-0.312824192891656D-08	-0.522700985080286D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
7	2026	INITIAL LOAD	516.9	354.6	3603.4	0.79798233	0.68592566	SUNDAY
		LOAD AFTER CONTRACTS	516.9	354.6	3603.4	0.79798233	0.68592566	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.994775188704668
0.946135332204044	0.852343631037276	0.762309686137080	0.615866423602814	0.455403817305117
0.315796791229350	0.201945836903072	0.123537972462151	0.066783442677880	0.033049826581205
0.019032141514006	0.009003228620400	0.002621193142650	0.000683789515477	0.000000000000000

CUMULANTS

0.797982326131623D+00	0.270919751865759D-02	0.611644847037833D-04	0.122528213829774D-08
-0.117230921388372D-06	-0.208618745129117D-07	-0.330495832200297D-08	-0.556276671005818D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
8	2027	INITIAL LOAD	521.5	356.8	3630.5	0.79689208	0.68423067	SUNDAY
		LOAD AFTER CONTRACTS	521.5	356.8	3630.5	0.79689208	0.68423067	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.991854151296824
0.936408896830148	0.844215101116138	0.757885112867568	0.609471742717544	0.448220200800104
0.309274212627166	0.198413051850885	0.120184868656956	0.064697436391494	0.032974088846282
0.018988527025274	0.008982596616748	0.002615186356777	0.000682222527857	0.000000000000000

CUMULANTS

0.796892080462782D+00	0.273851911635190D-02	0.621601529803223D-04	0.125196168302459D-08
-0.120428890304862D-06	-0.215465941892156D-07	-0.343185994351879D-08	-0.580731530549623D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
9	2028	INITIAL LOAD	526.0	358.9	3655.9	0.79560210	0.68222516	SUNDAY
		LOAD AFTER CONTRACTS	526.0	358.9	3655.9	0.79560210	0.68222516	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.992253715833759
0.928230994406419	0.837194144101391	0.749481586745652	0.601092515427357	0.435437496441219
0.298566191336004	0.194033863476947	0.117513466612800	0.063766997386792	0.032111237969779
0.018674620663277	0.008654092502496	0.002619001678389	0.000683217829148	0.000000000000000

CUMULANTS

0.795602095050897D+00	0.277341490928671D-02	0.633520344726382D-04	0.128375260043667D-08
-0.124301941174772D-06	-0.223808168730334D-07	-0.358737199615756D-08	-0.610919185688287D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
10	2029	INITIAL LOAD	530.7	361.1	3683.1	0.79442300	0.68039201	SUNDAY
		LOAD AFTER CONTRACTS	530.7	361.1	3683.1	0.79442300	0.68039201	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	0.990279804727834
0.919052262721579	0.830675096892774	0.741016307891260	0.588327152154210	0.427445990096703
0.293271649754847	0.190279471629844	0.115169153881223	0.063729966574591	0.031523572752076
0.018663775925418	0.008649066892269	0.002617480770031	0.000682821070445	0.000000000000000

CUMULANTS

0.794422999893530D+00	0.280550572969090D-02	0.644547823476808D-04	0.131405921440092D-08
-0.127928946975321D-06	-0.231667178081655D-07	-0.373478025525042D-08	-0.639427573419031D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
11	2030	INITIAL LOAD	535.4	363.3	3710.4	0.79328586	0.67862410	SUNDAY
		LOAD AFTER CONTRACTS	535.4	363.3	3710.4	0.79328586	0.67862410	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.995455524686448	0.989902382481819
0.911865321412026	0.826596624063675	0.730711499890932	0.582721694019045	0.414779667988942
0.290003916217545	0.186422949678549	0.112583052739858	0.062558801573060	0.030766623724458
0.018118122859960	0.008660234826146	0.002620860539494	0.000683702749436	0.000000000000000

CUMULANTS

0.793285858916467D+00	0.283662831442850D-02	0.655302805965555D-04	0.134185283704490D-08
-0.131506674898288D-06	-0.239463312215656D-07	-0.388178126847843D-08	-0.668670000955928D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
12	2031	INITIAL LOAD	540.1	365.6	3737.7	0.79216866	0.67688720	SUNDAY
		LOAD AFTER CONTRACTS	540.1	365.6	3737.7	0.79216866	0.67688720	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.996314984366918	0.988372952041202
0.903695825907540	0.822422545302749	0.720432264080757	0.570342798006987	0.407162458290227
0.286724487434632	0.182139620697339	0.110743626610594	0.059762780992742	0.030793799366491
0.018134126293602	0.008211679831067	0.002623175501593	0.000684306652592	0.000000000000000

CUMULANTS

0.792168661596389D+00	0.286737277500880D-02	0.665985256054647D-04	0.137257578007844D-08
-0.135098790460881D-06	-0.247334068596438D-07	-0.403106113530145D-08	-0.697867553139693D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
13	2032	INITIAL LOAD	544.8	367.9	3765.2	0.79111263	0.67524546	SUNDAY
		LOAD AFTER CONTRACTS	544.8	367.9	3765.2	0.79111263	0.67524546	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.995270966327453	0.984390693822134
0.897683922976531	0.818158173739621	0.703719379995306	0.565544538231969	0.401388559543893
0.282441736903013	0.178762035175809	0.110629659755075	0.058220140200664	0.030648175565518
0.017431861938753	0.008203229147650	0.002620475977724	0.000683602428974	0.000000000000000

CUMULANTS

0.791112630174929D+00	0.289658503986218D-02	0.676188464829992D-04	0.140100004600140D-08
-0.138565800107299D-06	-0.254970551987152D-07	-0.417662663668609D-08	-0.726938942102749D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
14	2033	INITIAL LOAD	549.6	370.1	3792.8	0.78995187	0.67344080	SUNDAY
		LOAD AFTER CONTRACTS	549.6	370.1	3792.8	0.78995187	0.67344080	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.993899391757155	0.978805454781151
0.890255661869083	0.810562148678590	0.696753501123155	0.553571877491273	0.395382294589853
0.276824495751688	0.175674895783234	0.108431460933565	0.058141108643288	0.030606571868973
0.017408198869715	0.008192093585750	0.002616918784339	0.000682674465482	0.000000000000000

CUMULANTS

0.789951869229059D+00	0.292886785858542D-02	0.687524244158659D-04	0.143189202537394D-08
-0.142459111286118D-06	-0.263590877464767D-07	-0.434185082021376D-08	-0.759573992326829D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
15	2034	INITIAL LOAD	554.2	372.5	3820.4	0.78909568	0.67210972	SUNDAY
		LOAD AFTER CONTRACTS	554.2	372.5	3820.4	0.78909568	0.67210972	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.995119392275268	0.976391837892311
0.885959967029674	0.807924403519924	0.686712958885802	0.543728577545176	0.391317022855464
0.272839670957450	0.173500968212192	0.106629616708216	0.056276742151560	0.030416781689205
0.017088079600679	0.008088357677656	0.002278410613427	0.000683523184030	0.000000000000000

CUMULANTS

0.789095682367831D+00	0.295279260479943D-02	0.695965599163836D-04	0.145624590138628D-08
-0.145386072710340D-06	-0.270103326921837D-07	-0.446723911475258D-08	-0.784950055553611D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
16	2035	INITIAL LOAD	558.9	374.8	3848.2	0.78815364	0.67064507	SUNDAY
		LOAD AFTER CONTRACTS	558.9	374.8	3848.2	0.78815364	0.67064507	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.993952466755783	0.970503495941639
0.880533053483069	0.802606406546721	0.683388758192390	0.540392585764125	0.383247118172060
0.266953010460705	0.169775742373135	0.103321966538076	0.054733332494291	0.030382120116375
0.017068606806954	0.008079140555293	0.002275814240930	0.000682744272281	0.000000000000000

CUMULANTS

0.788153639028787D+00	0.297923040967643D-02	0.705333493180629D-04	0.148169951980206D-08
-0.148662451459366D-06	-0.277423834542949D-07	-0.460879822548761D-08	-0.813523415877995D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
17	2036	INITIAL LOAD	563.6	377.2	3876.0	0.78722736	0.66920503	SUNDAY
		LOAD AFTER CONTRACTS	563.6	377.2	3876.0	0.78722736	0.66920503	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
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1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.994339599234018	0.966117667766980
0.877595510889272	0.796318680466599	0.673593642024057	0.531537187036866	0.377838699137764
0.262631479033090	0.166549568194804	0.103367742939770	0.054757581887699	0.029371010659100
0.016506963354922	0.008082719987584	0.002276822531716	0.000683046759517	0.000000000000000

CUMULANTS

0.787227362210167D+00	0.300533993655139D-02	0.714625903577946D-04	0.150736787458277D-08
-0.151940997698900D-06	-0.284781771367090D-07	-0.475172841041870D-08	-0.842350826194913D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
18	2037	INITIAL LOAD	568.4	379.5	3903.9	0.78619803	0.66760474	SUNDAY
		LOAD AFTER CONTRACTS	568.4	379.5	3903.9	0.78619803	0.66760474	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
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1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.995468553323602	0.961751916086995
0.871066004624998	0.792790635105352	0.665465381415535	0.518247615924277	0.372856673965438
0.258412130810043	0.162319750451480	0.100879901088175	0.054030591091295	0.029409055910453
0.016528345376032	0.007865212627217	0.002279771776007	0.000683931532805	0.000000000000000

CUMULANTS

0.786198028842925D+00	0.303448747051225D-02	0.725047294260935D-04	0.153602714274588D-08
-0.155651885452954D-06	-0.293148154269942D-07	-0.491499305854969D-08	-0.875420084479868D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
19	2038	INITIAL LOAD	573.2	381.8	3932.0	0.78522604	0.66609362	SUNDAY
		LOAD AFTER CONTRACTS	573.2	381.8	3932.0	0.78522604	0.66609362	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.994594921554463	0.954775237030166
0.866589918929923	0.785519644752889	0.659365973883160	0.507711365748202	0.367504255657755
0.254154368993321	0.162221345336841	0.098882112185660	0.053997835456226	0.028821629473472
0.016518325192308	0.007860444401859	0.002278389681701	0.000683516904513	0.000000000000000

CUMULANTS

0.785226036544658D+00	0.306214127004170D-02	0.734981019009601D-04	0.156457127745745D-08
-0.159222225970056D-06	-0.301235868955994D-07	-0.507355759028583D-08	-0.907798795783498D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
20	2039	INITIAL LOAD	577.9	384.2	3960.3	0.78444544	0.66488004	SUNDAY
		LOAD AFTER CONTRACTS	577.9	384.2	3960.3	0.78444544	0.66488004	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.995062591623636	0.950327712046638
0.863833873841628	0.780612830997300	0.654174312802332	0.500576786080941	0.362194155680150
0.250246186232334	0.158584257425594	0.098958400751558	0.052101369980949	0.028843865656851
0.016189047127562	0.007866508815507	0.002166140108620	0.000684044244830	0.000000000000000

CUMULANTS

0.784445442995080D+00	0.308444059184665D-02	0.743024245813684D-04	0.158791330501900D-08
-0.162137027134335D-06	-0.307865351948215D-07	-0.520404659108564D-08	-0.934587794277597D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
21	2040	INITIAL LOAD	582.7	386.6	3988.8	0.78358231	0.66353813	SUNDAY
		LOAD AFTER CONTRACTS	582.7	386.6	3988.8	0.78358231	0.66353813	

LOAD DURATION CURVE (50 POINTS)

1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000	1.000000000000000
1.000000000000000	1.000000000000000	1.000000000000000	0.994306074076797	0.945120262267935
0.856469327903866	0.780192217425712	0.647509200679110	0.491683596221826	0.356378289452628
0.250181780582760	0.154668189635903	0.096083481107641	0.052087960695365	0.027696661813949
0.016184880566177	0.007864484218778	0.002165582610970	0.000683868192940	0.000000000000000

CUMULANTS

0.783582307209667D+00	0.310919281213640D-02	0.751986204375772D-04	0.161472980119699D-08
-0.165409297530749D-06	-0.315336862076862D-07	-0.535167901391657D-08	-0.965222854363938D-10

BASIC PLANT TYPES - 1

DATA SET REF. NO.	1	2	3	4	5
NAME	STORAGE1	ENERGY	CAPACITY	SOLAR PPA	SOLAR QF
TYPE / LOADING / STATUS /AVD	STOR P G	THRM B C	THRM P C	NDT B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	PURC MDU MISO	PURC MDU MISO	SOLR MDU NDAK	SOLR MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE		1/ 1/2021	1/ 1/2021		
OPERATING/BOOK LIVES, YEARS	30 25	6 6	6 6	20 20	20 20
RATED CAPACITY, MW	1.000	30.000	75.000	50.000	20.000
- RESERVE	0.9500	0.0000	1.0000	0.5000	0.5000
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	1.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0000	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	10500.	1.	0.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.800000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	2500.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	2500.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	1	1
LEVEL. CARRYING CHARGE, PCT	10.16	0.00	0.00	10.16	10.16
FIXED O+M COST, $/KW-YR	60.00	0.00	12.00	0.00	51.24
VARIABLE O+M COST, $/MWH	0.00	21.00	1000.00	51.45	24.77
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	0	0	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 0	0 0 42	0 21 23	0 0 52	0 53 53
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	28	45	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	1	2	3	4	5
MAINTENANCE REQUIREMENTS	0	7	7	9	11
FUEL 1 / FUEL 2	0 0	8 0	8 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 0	6 0	0 0	0 6	0 6
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	0.00	0.00	0.00	2558.00	2558.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	2558.00	2558.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	30 38	30 38
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	24	26	27	80	90
NAME	STORAGE10	AC CYCLE	STORAGE	MISO - On peak	MISO - Off peak
TYPE / LOADING / STATUS /AVD	STOR P G	DTHR P G	STOR P G	HYDR P E	HYDR P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	PURC MDU MISO	STRG MDU NDAK	PURC MDU MISO	PURC MDU MISO
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE				1/ 1/2014	1/ 1/2014
OPERATING/BOOK LIVES, YEARS	30 25	30 30	30 25	50 50	50 50
RATED CAPACITY, MW	10.000	2.000	10.000	250.000	250.000
- RESERVE	0.9500	1.1000	0.9500	0.0000	0.0000
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	1.0000	0.0000	1.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0000	0.0010	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	1.	0.	10500.	10500.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	8.000000	0.000000	8.000000	1000.000000	1000.000000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	95.00	0.00	0.00
INSTALLATION COST 1, $/KW	1720.00	0.00	1720.00	0.00	0.00
INSTALLATION COST 2, $/KW	1720.00	0.00	1720.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	2
LEVEL. CARRYING CHARGE, PCT	10.16	0.00	9.50	0.00	0.00
FIXED O+M COST, $/KW-YR	35.00	363.71	35.00	0.00	0.00
VARIABLE O+M COST, $/MWH	0.00	100.00	0.00	25.89	23.23
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	0	1	0	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 0	0 48 49	51 22 0	0 0 29	0 0 46
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	41 0	0 0
RATED CAPACITY	0	26	0	41	41
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

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                                                    BASIC PLANT TYPES - 2
                                                    ---------------------

 DATA SET REF. NO.                    24                26                27                80                90
 -----------------                 -------           -------           -------           -------           -------
 MAINTENANCE REQUIREMENTS             0                39                 0                 0                 0
 FUEL 1 / FUEL 2                 0    0            8    0            0    0            8    0            8    0
 LOADING BLOCKS / NDT NO.             0    0            0    0            0    0            7    0            7    0
 EMISSIONS / SITE / TAX DEPR.    0    0    0       0    0    0       0    0    0       0    0    0       0    0    0

 MUST RUN  / 1ST YR / LAST YR
 SPIN RSV  / 1ST YR / LAST YR
 DISPATCH MODIFIER, $/MWH             0.00              0.00              0.00              0.00              0.00
 TJ-DISP MODIF / SM-MUST-RUN          0    0            0    0            0    0            0    0            0    0

 CONSTRUCTION COST 1, $/KW            0.00              0.00              0.00              0.00              0.00
 CONSTRUCTION COST 2, $/KW            0.00              0.00              0.00              0.00              0.00
 TRAJECTORY / EXPEND. PATTERN         0    0            0    0            0    0            0    0            0    0
 PERCENT CWIP IN RATE BASE            0.00              0.00              0.00              0.00              0.00

 STARTING VALUE OF CWIP, $/KW         0.00              0.00              0.00              0.00              0.00
   EQUITY AFUDC, $/KW                 0.00              0.00              0.00              0.00              0.00
   DEBT AFUDC, $/KW                   0.00              0.00              0.00              0.00              0.00

 DSM CUSTOMER COST / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
   BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
   LEV.CARRYING CHARGE, PCT        0.00              0.00              0.00              0.00              0.00
   EXPENDITURE PATTERN                0                 0                 0                 0                 0
 REBOUND BENEFITS  / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
   BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
   LEV.CARRYING CHARGE, PCT        0.00              0.00              0.00              0.00              0.00
   EXPENDITURE PATTERN                0                 0                 0                 0                 0
 CUSTOMER BENEFITS / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
   BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
   LEV.CARRYING CHARGE, PCT        0.00              0.00              0.00              0.00              0.00
   EXPENDITURE PATTERN                0                 0                 0                 0                 0
 TRANS/DISTR COSTS / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
   BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
   LEV.CARRYING CHARGE, PCT        0.00              0.00              0.00              0.00              0.00
   EXPENDITURE PATTERN                0                 0                 0                 0                 0
 OTHER COSTS       / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
   BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
   LEV.CARRYING CHARGE, PCT        0.00              0.00              0.00              0.00              0.00
   EXPENDITURE PATTERN                0                 0                 0                 0                 0

 PERCENTAGE FOR 2ND FUEL
   MINIMUM / TRAJ / SEG MULT    0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0
   MAXIMUM / TRAJ / SEG MULT  100.00      0    0 100.00      0    0 100.00      0    0 100.00      0    0 100.00      0    0
   TARGET  / TRAJ / SEG MULT    0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0

 BID MULTIPLIERS                   1.00              1.00              1.00              1.00              1.00
   TRAJECTORY / SEG MULT               0    0            0    0            0    0            0    0            0    0
 NDT REVENUES                         0.00              0.00              0.00              0.00              0.00
   TRAJECTORY                                0                 0                 0                 0                 0
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BASIC PLANT TYPES - 1

DATA SET REF. NO.	100	110	120	130	132
NAME	INTERRUPTIBLES	COMMERCIAL DSM	MILES CITY C.T.	GLENDIVE CT #1	GLENDIVE CT #2
TYPE / LOADING / STATUS /AVD	DTHR P E	DTHR P E	THRM P E	THRM P E	THRM P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MDU MISO	PURC MDU MISO	GAS MDU MONT	GAS MDU MONT	GAS MDU MONT
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2012	1/ 1/2013	1/ 1/1972	1/ 1/1979	1/ 1/2003
OPERATING/BOOK LIVES, YEARS	30 30	30 30	99 30	99 30	99 30
RATED CAPACITY, MW	15.200	25.000	25.200	35.500	43.300
- RESERVE	0.9474	1.1000	0.8333	0.8535	0.8915
CAPACITY - OPERATING	1.0000	1.0000	0.8571	0.8451	0.9238
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.0000	0.5000	0.5000	0.5000
FULL LOAD HEAT RATE, BTU/KWH	1.	1.	14459.	12465.	9322.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	1	2	2	2	2
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	50.04	50.04	7.06	5.90	7.07
VARIABLE O+M COST, $/MWH	300.00	300.00	4.20	4.20	4.20
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	0	0	0	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 48 49	0 48 49	0 3 5	0 3 6	0 3 7
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	16	4	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

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DATA SET REF. NO.                      100               110               120               130               132
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MAINTENANCE REQUIREMENTS              14                14                 2                 3                 4
FUEL 1 / FUEL 2                   8    0            8    0            1    0            1    0            1    0
LOADING BLOCKS / NDT NO.               0    0            0    0           12    0            5    0           13    0
EMISSIONS / SITE / TAX DEPR.      0    0    0       0    0    0       0    0    0       0    0    0       0    0    0

MUST RUN  / 1ST YR / LAST YR
SPIN RSV  / 1ST YR / LAST YR
DISPATCH MODIFIER, $/MWH               0.00              0.00              0.00              0.00              0.00
TJ-DISP MODIF / SM-MUST-RUN            0    0            0    0            0    0            0    0            0    0

CONSTRUCTION COST 1, $/KW              0.00              0.00              0.00              0.00              0.00
CONSTRUCTION COST 2, $/KW              0.00              0.00              0.00              0.00              0.00
TRAJECTORY / EXPEND. PATTERN           0    0            0    0            0    0            0    0            0    0
PERCENT CWIP IN RATE BASE              0.00              0.00              0.00              0.00              0.00

STARTING VALUE OF CWIP, $/KW           0.00              0.00              0.00              0.00              0.00
  EQUITY AFUDC, $/KW                   0.00              0.00              0.00              0.00              0.00
  DEBT AFUDC, $/KW                     0.00              0.00              0.00              0.00              0.00

DSM CUSTOMER COST / OPT / TJ        0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR     0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT           0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                  0                 0                 0                 0                 0
REBOUND BENEFITS  / OPT / TJ        0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR     0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT           0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                  0                 0                 0                 0                 0
CUSTOMER BENEFITS / OPT / TJ        0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR     0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT           0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                  0                 0                 0                 0                 0
TRANS/DISTR COSTS / OPT / TJ        0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR     0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT           0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                  0                 0                 0                 0                 0
OTHER COSTS       / OPT / TJ        0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR     0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT           0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                  0                 0                 0                 0                 0

PERCENTAGE FOR 2ND FUEL
  MINIMUM / TRAJ / SEG MULT     0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0
  MAXIMUM / TRAJ / SEG MULT   100.00     0    0 100.00     0    0 100.00     0    0 100.00     0    0 100.00     0    0
  TARGET  / TRAJ / SEG MULT     0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0

BID MULTIPLIERS                    1.00              1.00              1.00              1.00              1.00
  TRAJECTORY / SEG MULT                 0     0           0     0           0     0           0     0           0     0
NDT REVENUES                           0.00              0.00              0.00              0.00              0.00
  TRAJECTORY                                  0                 0                 0                 0                 0
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BASIC PLANT TYPES - 1

DATA SET REF. NO.	136	138	140	150	152
NAME	DIESEL 2	DIESEL 3	HESKETT #1	HESKETT #2	HESKETT #3
TYPE / LOADING / STATUS /AVD	THRM P E	THRM P E	THRM B E	THRM B E	THRM P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	GAS MDU NDAK	COAL MDU NDAK	COAL MDU NDAK	GAS MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2012	1/ 1/2012	1/ 1/1954	1/ 1/1963	1/ 1/2014
OPERATING/BOOK LIVES, YEARS	99 30	99 30	69 30	60 30	40 25
RATED CAPACITY, MW	2.000	2.000	29.200	74.600	88.000
- RESERVE	0.9048	0.9048	0.7192	0.8727	0.8057
CAPACITY - OPERATING	1.0000	1.0000	0.7534	0.9383	0.9545
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.5000	0.5000	0.0323	0.0631	0.5000
FULL LOAD HEAT RATE, BTU/KWH	8687.	8687.	18731.	12447.	11482.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	1
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	28.00	28.00	85.88	56.28	31.13
VARIABLE O+M COST, $/MWH	4.20	4.20	15.73	7.29	2.68
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	0	0	0	0	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 8	0 3 8	0 3 9	0 3 10	0 3 15
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 27 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

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                                              BASIC PLANT TYPES - 2
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DATA SET REF. NO.                  136               138               140               150               152
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MAINTENANCE REQUIREMENTS          23                23                 5                 6                17
FUEL 1 / FUEL 2                2   0             2   0             3   0             4   0            13   0
LOADING BLOCKS / NDT NO.           0    0            0    0           14    0           15    0            2    0
EMISSIONS / SITE / TAX DEPR.   0   0    0        0   0    0        0   0    0        0   0    0        0   0    0

MUST RUN  / 1ST YR / LAST YR                                       M 1980 2080       M 1980 2080
SPIN RSV  / 1ST YR / LAST YR
DISPATCH MODIFIER, $/MWH           0.00              0.00              0.00              0.00              0.00
TJ-DISP MODIF / SM-MUST-RUN        0    0            0    0            0    0            0    0            0    0

CONSTRUCTION COST 1, $/KW          0.00              0.00              0.00              0.00              0.00
CONSTRUCTION COST 2, $/KW          0.00              0.00              0.00              0.00              0.00
TRAJECTORY / EXPEND. PATTERN       0    0            0    0            0    0            0    0            0    0
PERCENT CWIP IN RATE BASE          0.00              0.00              0.00              0.00              0.00

STARTING VALUE OF CWIP, $/KW       0.00              0.00              0.00              0.00              0.00
  EQUITY AFUDC, $/KW               0.00              0.00              0.00              0.00              0.00
  DEBT AFUDC, $/KW                 0.00              0.00              0.00              0.00              0.00

DSM CUSTOMER COST / OPT / TJ    0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR  0   0    0        0   0    0        0   0    0        0   0    0        0   0    0
  LEV.CARRYING CHARGE, PCT       0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN              0                 0                 0                 0                 0
REBOUND BENEFITS  / OPT / TJ    0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR  0   0    0        0   0    0        0   0    0        0   0    0        0   0    0
  LEV.CARRYING CHARGE, PCT       0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN              0                 0                 0                 0                 0
CUSTOMER BENEFITS / OPT / TJ    0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR  0   0    0        0   0    0        0   0    0        0   0    0        0   0    0
  LEV.CARRYING CHARGE, PCT       0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN              0                 0                 0                 0                 0
TRANS/DISTR COSTS / OPT / TJ    0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR  0   0    0        0   0    0        0   0    0        0   0    0        0   0    0
  LEV.CARRYING CHARGE, PCT       0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN              0                 0                 0                 0                 0
OTHER COSTS       / OPT / TJ    0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR  0   0    0        0   0    0        0   0    0        0   0    0        0   0    0
  LEV.CARRYING CHARGE, PCT       0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN              0                 0                 0                 0                 0

PERCENTAGE FOR 2ND FUEL
  MINIMUM / TRAJ / SEG MULT   0.00     0    0  0.00     0    0  0.00     0    0  0.00     0    0  0.00     0    0
  MAXIMUM / TRAJ / SEG MULT 100.00     0    0 100.00    0    0 100.00    0    0 100.00    0    0 100.00    0    0
  TARGET  / TRAJ / SEG MULT   0.00     0    0  0.00     0    0  0.00     0    0  0.00     0    0  0.00     0    0

BID MULTIPLIERS                 1.00              1.00              1.00              1.00              1.00
  TRAJECTORY / SEG MULT             0     0           0     0           0     0           0     0           0     0
NDT REVENUES                       0.00              0.00              0.00              0.00              0.00
  TRAJECTORY                              0                 0                 0                 0                 0
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BASIC PLANT TYPES - 1

DATA SET REF. NO.	154	160	162	170	180
NAME	HESKETT #4	LEWIS & CLARK1	LEWIS & CLARK2	BIG STONE	COYOTE
TYPE / LOADING / STATUS /AVD	THRM P C	THRM B E	THRM P E	THRM B E	THRM B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	COAL MDU NDAK	GAS MDU NDAK	COAL MDU SDAK	COAL MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2023	1/ 1/1958	1/ 1/2015	1/ 1/1975	1/ 1/1981
OPERATING/BOOK LIVES, YEARS	40 35	64 30	40 25	99 30	99 30
RATED CAPACITY, MW	78.300	52.300	18.600	107.800	106.700
- RESERVE	0.9515	0.6807	0.9785	0.9879	0.8806
CAPACITY - OPERATING	0.8864	0.8604	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.5000	0.1730	0.5000	0.0191	0.1201
FULL LOAD HEAT RATE, BTU/KWH	11770.	12909.	8643.	10158.	11031.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	878.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	878.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	1	2	1	2	2
LEVEL. CARRYING CHARGE, PCT	8.73	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	13.77	85.02	29.17	25.51	28.77
VARIABLE O+M COST, $/MWH	0.90	7.22	3.60	2.31	3.86
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	0	1	0	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 60	0 3 11	0 3 20	0 3 12	0 3 13
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	154	160	162	170	180
MAINTENANCE REQUIREMENTS	37	18	19	8	22
FUEL 1 / FUEL 2	13 0	5 0	11 0	6 0	7 0
LOADING BLOCKS / NDT NO.	8 0	16 0	11 0	17 0	18 0
EMISSIONS / SITE / TAX DEPR.	0 0 20	0 0 0	0 0 0	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR		M 1980 2080		M 1980 2080	M 1980 2080
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	857.00	0.00	0.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	857.00	0.00	0.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	30 37	0 0	0 0	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	190	200	210	220	230
NAME	DIAMOND WILLOW	GLEN ULLIN ORMAT	CEDAR HILLS	THUNDER SPIRIT	WAPA PUR-FT PECK
TYPE / LOADING / STATUS /AVD	NDT B E	THRM B E	NDT B E	NDT B E	HYDR B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	WIND MDU MONT	PURC MDU NDAK	WIND MDU MONT	WIND MDU NDAK	HYDR MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2008	1/ 1/2009	1/ 1/2010	1/ 1/2015	1/ 1/2001
OPERATING/BOOK LIVES, YEARS	28 25	35 20	26 25	25 25	50 30
RATED CAPACITY, MW	30.000	7.500	19.500	150.000	2.800
- RESERVE	0.1700	0.4533	0.1897	0.1480	0.0000
CAPACITY - OPERATING	1.0000	0.6667	1.0000	1.0000	0.8929
MULTIPLIERS - EMERGENCY	0.3810	0.6667	0.3810	0.4186	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.1058	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	1.	0.	0.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	14.350000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	2
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	21.57	81.83	26.48	21.82	0.00
VARIABLE O+M COST, $/MWH	0.00	7.77	0.00	-35.38	24.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 0	0 44 18	0 3 0	0 3 32	0 0 14
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	40	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

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                                                   BASIC PLANT TYPES - 2
                                                   ---------------------

DATA SET REF. NO.                    190               200               210               220               230
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MAINTENANCE REQUIREMENTS            10                15                10                13                 0
FUEL 1 / FUEL 2                 0    0            8    0            0    0            0    0            0    0
LOADING BLOCKS / NDT NO.             0    1            0    0            0    2            0    3            0    0
EMISSIONS / SITE / TAX DEPR.    0    0    0       0    0    0       0    0    0       0    0    0       0    0    0

MUST RUN  / 1ST YR / LAST YR                      M 1980 2080                                           M 1980 2080
SPIN RSV  / 1ST YR / LAST YR
DISPATCH MODIFIER, $/MWH             0.00              0.00              0.00              0.00              0.00
TJ-DISP MODIF / SM-MUST-RUN          0    0            0    0            0    0            0    0            0    0

CONSTRUCTION COST 1, $/KW            0.00              0.00              0.00              0.00              0.00
CONSTRUCTION COST 2, $/KW            0.00              0.00              0.00              0.00              0.00
TRAJECTORY / EXPEND. PATTERN         0    0            0    0            0    0            0    0            0    0
PERCENT CWIP IN RATE BASE            0.00              0.00              0.00              0.00              0.00

STARTING VALUE OF CWIP, $/KW         0.00              0.00              0.00              0.00              0.00
  EQUITY AFUDC, $/KW                 0.00              0.00              0.00              0.00              0.00
  DEBT AFUDC, $/KW                   0.00              0.00              0.00              0.00              0.00

DSM CUSTOMER COST / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN               0                 0                 0                 0                 0
REBOUND BENEFITS  / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN               0                 0                 0                 0                 0
CUSTOMER BENEFITS / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN               0                 0                 0                 0                 0
TRANS/DISTR COSTS / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN               0                 0                 0                 0                 0
OTHER COSTS       / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0       0    0    0       0    0    0       0    0    0       0    0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN               0                 0                 0                 0                 0

PERCENTAGE FOR 2ND FUEL
  MINIMUM / TRAJ / SEG MULT   0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0
  MAXIMUM / TRAJ / SEG MULT 100.00      0    0 100.00      0    0 100.00      0    0 100.00      0    0 100.00      0    0
  TARGET  / TRAJ / SEG MULT   0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0   0.00      0    0

BID MULTIPLIERS                   1.00              1.00              1.00              1.00              1.00
  TRAJECTORY / SEG MULT               0    0            0    0            0    0            0    0            0    0
NDT REVENUES                         0.00              0.00              0.00              0.00              0.00
  TRAJECTORY                                0                 0                 0                 0                 0
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BASIC PLANT TYPES - 1

DATA SET REF. NO.	310	320	330	340	370
NAME	PURCHASE POWER	GE 7EA	GE LMS100PB	GE LM6000PH	GE 7EA 2x1 ADD
TYPE / LOADING / STATUS /AVD	THRM P G	THRM P G	THRM P G	THRM P G	THRM I G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MDU MISO	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE					
OPERATING/BOOK LIVES, YEARS	1 1	40 35	40 35	40 35	50 50
RATED CAPACITY, MW	10.000	78.300	90.700	45.300	329.800
- RESERVE	1.0000	0.9521	0.9519	0.9450	0.9448
CAPACITY - OPERATING	1.0000	0.9195	0.9041	0.9272	0.9096
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.5000	0.5000	0.5000	0.0552
FULL LOAD HEAT RATE, BTU/KWH	1.	11770.	9050.	9510.	9990.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	0.00	1590.00	1760.00	2320.00	862.00
INSTALLATION COST 2, $/KW	0.00	1590.00	1760.00	2320.00	862.00
MULTI-UNIT CAPITAL COST OPT.	2	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	0.00	9.22	9.22	9.22	8.70
FIXED O+M COST, $/KW-YR	12.00	19.41	16.22	32.08	20.03
VARIABLE O+M COST, $/MWH	1000.00	1.50	1.70	1.60	4.10
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	0	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 21 23	30 22 60	30 22 24	30 22 62	59 59 59
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

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                                                     BASIC PLANT TYPES - 2
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DATA SET REF. NO.                    310               320               330               340               370
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MAINTENANCE REQUIREMENTS             0                 28                28                28                21
FUEL 1 / FUEL 2                 8    0           13    0           13    0           13    0           13    0
LOADING BLOCKS / NDT NO.             0    0             2    0            13    0            13    0             4    0
EMISSIONS / SITE / TAX DEPR.    0    0    0      0     0   20      0     0   20      0     0   20      0     0   20

MUST RUN  / 1ST YR / LAST YR
SPIN RSV  / 1ST YR / LAST YR
DISPATCH MODIFIER, $/MWH             0.00              0.00              0.00              0.00              0.00
TJ-DISP MODIF / SM-MUST-RUN          0    0            0    0            0    0            0    0            0    0

CONSTRUCTION COST 1, $/KW            0.00            857.00            857.00            850.00            750.00
CONSTRUCTION COST 2, $/KW            0.00            857.00            857.00            850.00            750.00
TRAJECTORY / EXPEND. PATTERN         0    0           30   37           30   37           30   37           30   37
PERCENT CWIP IN RATE BASE            0.00              0.00              0.00              0.00              0.00

STARTING VALUE OF CWIP, $/KW         0.00              0.00              0.00              0.00              0.00
  EQUITY AFUDC, $/KW                 0.00              0.00              0.00              0.00              0.00
  DEBT AFUDC, $/KW                   0.00              0.00              0.00              0.00              0.00

DSM CUSTOMER COST / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0      0     0    0      0     0    0      0     0    0      0     0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                0                 0                 0                 0                 0
REBOUND BENEFITS  / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0      0     0    0      0     0    0      0     0    0      0     0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                0                 0                 0                 0                 0
CUSTOMER BENEFITS / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0      0     0    0      0     0    0      0     0    0      0     0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                0                 0                 0                 0                 0
TRANS/DISTR COSTS / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0      0     0    0      0     0    0      0     0    0      0     0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                0                 0                 0                 0                 0
OTHER COSTS       / OPT / TJ      0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0       0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0    0    0      0     0    0      0     0    0      0     0    0      0     0    0
  LEV.CARRYING CHARGE, PCT         0.00              0.00              0.00              0.00              0.00
  EXPENDITURE PATTERN                0                 0                 0                 0                 0

PERCENTAGE FOR 2ND FUEL
  MINIMUM / TRAJ / SEG MULT     0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0
  MAXIMUM / TRAJ / SEG MULT   100.00     0    0 100.00     0    0 100.00     0    0 100.00     0    0 100.00     0    0
  TARGET  / TRAJ / SEG MULT     0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0   0.00     0    0

BID MULTIPLIERS                   1.00              1.00              1.00              1.00              1.00
  TRAJECTORY / SEG MULT               0    0            0    0            0    0            0    0            0    0
NDT REVENUES                         0.00              0.00              0.00              0.00              0.00
  TRAJECTORY                                0                 0                 0                 0                 0
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BASIC PLANT TYPES - 1

DATA SET REF. NO.	380	400	410	420	430
NAME	GE 7FA.05 1x1	SMN SGT-800 2x1	WRTSLA 18V50SG	WRTSLA 20V34SG	BIOMASS
TYPE / LOADING / STATUS /AVD	THRM I G	THRM I G	THRM P G	THRM P G	THRM B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK	GAS MDU NDAK	BMP MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE					
OPERATING/BOOK LIVES, YEARS	50 50	50 50	40 25	40 25	40 25
RATED CAPACITY, MW	329.200	173.900	55.000	36.500	25.000
- RESERVE	0.9447	0.9451	0.9455	0.9463	0.9072
CAPACITY - OPERATING	0.8571	0.8571	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	1.0000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0552	0.0552	0.5000	0.5000	0.0928
FULL LOAD HEAT RATE, BTU/KWH	6530.	7180.	8310.	8470.	12300.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	1520.00	2180.00	2180.00	2710.00	7980.00
INSTALLATION COST 2, $/KW	1520.00	2180.00	2180.00	2710.00	7980.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	8.70	8.70	9.22	9.22	9.22
FIXED O+M COST, $/KW-YR	16.42	37.59	23.16	32.78	252.00
VARIABLE O+M COST, $/MWH	3.00	4.00	4.60	4.40	5.60
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 54	30 22 69	30 22 56	30 22 56	30 22 58
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	380	400	410	420	430
MAINTENANCE REQUIREMENTS	24	25	1	28	28
FUEL 1 / FUEL 2	13 0	13 0	13 0	13 0	10 0
LOADING BLOCKS / NDT NO.	2 0	3 0	1 0	10 0	19 0
EMISSIONS / SITE / TAX DEPR.	0 0 20	0 0 20	0 0 20	0 0 20	0 0 20
MUST RUN / 1ST YR / LAST YR					
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	750.00	750.00	857.00	857.00	857.00
CONSTRUCTION COST 2, $/KW	750.00	750.00	857.00	857.00	857.00
TRAJECTORY / EXPEND. PATTERN	30 37	30 37	30 37	30 37	30 37
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	450	460	490	500	510
NAME	PV SOLAR50	PV SOLAR5	CFBC	CFBC CO2	WIND20
TYPE / LOADING / STATUS /AVD	NDT B G	NDT B G	THRM B G	THRM B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	SOLR MDU NDAK	SOLR MDU NDAK	LIGN MDU NDAK	COAL MDU NDAK	WIND MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE					
OPERATING/BOOK LIVES, YEARS	30 25	30 25	50 50	50 50	25 25
RATED CAPACITY, MW	50.000	5.000	30.000	30.000	20.000
- RESERVE	0.5000	0.5000	0.9143	0.9143	0.1690
CAPACITY - OPERATING	1.0000	1.0000	0.9500	0.9500	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	1.0000	0.3810
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.0000	0.0936	0.0936	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	10000.	13800.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	1390.00	2500.00	5880.00	10400.00	1630.00
INSTALLATION COST 2, $/KW	1390.00	2500.00	5880.00	10400.00	1630.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	10.16	10.16	8.70	8.70	10.16
FIXED O+M COST, $/KW-YR	13.20	14.40	168.72	267.48	50.40
VARIABLE O+M COST, $/MWH	0.00	0.00	14.06	22.29	0.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 0	30 22 0	30 22 61	30 22 25	30 22 0
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

DATA SET REF. NO.	450	460	490	500	510
MAINTENANCE REQUIREMENTS	10	10	33	33	10
FUEL 1 / FUEL 2	0 0	0 0	12 0	12 0	0 0
LOADING BLOCKS / NDT NO.	0 6	0 6	0 0	0 0	0 4
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 20	0 0 20	0 0 21
MUST RUN / 1ST YR / LAST YR			M 1980 2080	M 1980 2080	
SPIN RSV / 1ST YR / LAST YR					
DISPATCH MODIFIER, $/MWH	0.00	0.00	0.00	0.00	0.00
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	2558.00	2558.00	3900.00	3900.00	2400.00
CONSTRUCTION COST 2, $/KW	2558.00	2558.00	3900.00	3900.00	2400.00
TRAJECTORY / EXPEND. PATTERN	30 38	30 38	30 31	30 31	30 38
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	0.00	0.00	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
REBOUND BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
TRANS/DISTR COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
OTHER COSTS / OPT / TJ	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0	0
PERCENTAGE FOR 2ND FUEL					
MINIMUM / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
MAXIMUM / TRAJ / SEG MULT	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0	100.00 0 0
TARGET / TRAJ / SEG MULT	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0	0.00 0 0
BID MULTIPLIERS	1.00	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	520
NAME	WIND50
TYPE / LOADING / STATUS /AVD	NDT B G
LOAD COMPONENT FOR DSM	
CLASS / AREA / GENERATING CO.	WIND MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1
INSTALLATION DATE	
OPERATING/BOOK LIVES, YEARS	25 25
RATED CAPACITY, MW	50.000
- RESERVE	0.1690
CAPACITY - OPERATING	1.0000
MULTIPLIERS - EMERGENCY	0.3810
- CHARGING	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.
HEAT RATE MULT. - 2ND FUEL	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000
STORAGE EFFICIENCY, PERCENT	0.00
INSTALLATION COST 1, $/KW	1580.00
INSTALLATION COST 2, $/KW	1580.00
MULTI-UNIT CAPITAL COST OPT.	1
LEVEL. CARRYING CHARGE, PCT	10.16
FIXED O+M COST, $/KW-YR	50.40
VARIABLE O+M COST, $/MWH	0.00
DEFAULT AFUDC, PCT. OF GBV	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00
CAPITAL STRUCTURE	1
YEARLY TRAJECTORIES	
COSTS-CAPITAL/FIX OM/VAR OM	30 22 0
F.O.R./RESERVE CAP/OPER CAP	0 0 0
ENERGY / HEAT RATE	0 0
RATED CAPACITY	0
SEGMENT MULT. - CAP / ENERGY	0 0
SUBWEEK ENERGY ALLOCATION	0

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDT=NON-DISPATCHABLE TECHNOLOGY
B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

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DATA SET REF. NO.                   520
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MAINTENANCE REQUIREMENTS           10
FUEL 1 / FUEL 2               0     0
LOADING BLOCKS / NDT NO.            0    4
EMISSIONS / SITE / TAX DEPR.  0     0   21

MUST RUN  / 1ST YR / LAST YR
SPIN RSV  / 1ST YR / LAST YR
DISPATCH MODIFIER, $/MWH            0.00
TJ-DISP MODIF / SM-MUST-RUN         0    0

CONSTRUCTION COST 1, $/KW        2400.00
CONSTRUCTION COST 2, $/KW        2400.00
TRAJECTORY / EXPEND. PATTERN       30   38
PERCENT CWIP IN RATE BASE           0.00

STARTING VALUE OF CWIP, $/KW        0.00
  EQUITY AFUDC, $/KW                0.00
  DEBT AFUDC, $/KW                  0.00

DSM CUSTOMER COST / OPT / TJ        0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0     0    0
  LEV.CARRYING CHARGE, PCT        0.00
  EXPENDITURE PATTERN               0
REBOUND BENEFITS  / OPT / TJ        0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0     0    0
  LEV.CARRYING CHARGE, PCT        0.00
  EXPENDITURE PATTERN               0
CUSTOMER BENEFITS / OPT / TJ        0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0     0    0
  LEV.CARRYING CHARGE, PCT        0.00
  EXPENDITURE PATTERN               0
TRANS/DISTR COSTS / OPT / TJ        0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0     0    0
  LEV.CARRYING CHARGE, PCT        0.00
  EXPENDITURE PATTERN               0
OTHER COSTS       / OPT / TJ        0.00 0    0
  BK LIFE/CAP STRUCT/TAX DEPR   0     0    0
  LEV.CARRYING CHARGE, PCT        0.00
  EXPENDITURE PATTERN               0

PERCENTAGE FOR 2ND FUEL
  MINIMUM / TRAJ / SEG MULT     0.00     0    0
  MAXIMUM / TRAJ / SEG MULT   100.00     0    0
  TARGET  / TRAJ / SEG MULT     0.00     0    0

BID MULTIPLIERS                 1.00
  TRAJECTORY / SEG MULT                0     0
NDT REVENUES                        0.00
  TRAJECTORY                                 0
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MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	START WEEK	..SECOND PERIOD.. NO. OF WEEKS	START WEEK
1	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
2	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	1	20		
					2	1	13		
					3	1	19		
					4	2	16		
					5	1	16		
					6	1	16		
					7	1	19		
					8	1	17		
					9	2	21		
					10	1	16		
3	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	1	22		
					2	2	16		
					3	1	18		
					4	1	16		
					5	1	16		
					6	1	19		
					7	2	38		
					8	1	16		
					9	1	17		
					10	1	18		
4	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	1	20		
					2	11	33		
					3	1	20		
					4	1	20		
					5	1	16		
					6	1	20		
					7	2	20		
					8	1	20		
					9	1	20		
					10	1	20		
5	3	3	2 - BASE YEAR=1	2 - TWO PERIODS	1	1	25	1	43
					2	1	16	1	41
					3	39	14	0	0
6	3	3	2 - BASE YEAR=1	2 - TWO PERIODS	1	4	35	0	0
					2	2	18	2	42
					3	39	14	0	0
7	6	1	0 - INSTALLATION	1 - START WEEKS	1	23	1		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	29	23		

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	START WEEK	..SECOND PERIOD.. NO. OF WEEKS	START WEEK
8	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	4	40		
					2	8	38		
					3	3	41		
					4	4	40		
					5	8	38		
					6	3	41		
					7	3	42		
					8	8	38		
					9	3	42		
					10	3	42		
9	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
10	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
11	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
13	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
14	1	1	0 - INSTALLATION	0 - NO. WEEKS ONLY	1	1			
15	1	1	2 - BASE YEAR=1	0 - NO. WEEKS ONLY	1	1			
17	10	10	1 - BASE YEAR=0	1 - START WEEKS	1	0	0		
					2	0	0		
					3	0	0		
					4	0	0		
					5	0	0		
					6	2	38		
					7	0	0		
					8	0	0		
					9	0	0		
					10	0	0		
18	2	2	2 - BASE YEAR=1	1 - START WEEKS	1	2	34		
					2	39	14		
19	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	0	0		
					2	0	0		
					3	0	0		
					4	0	0		
					5	2	19		
					6	0	0		
					7	0	0		
					8	0	0		
					9	0	0		
					10	0	0		
21	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	START WEEK	..SECOND PERIOD.. NO. OF WEEKS	START WEEK
22	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	1	22	1	44
					2	2	23	1	38
					3	8	14	1	49
					4	1	22	1	50
					5	1	22	1	50
					6	7	13	1	50
					7	1	22	1	50
					8	1	23	1	50
					9	7	14	1	50
					10	1	24	1	50
23	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
24	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
25	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
28	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
33	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	3			
37	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
39	1	1	0 - INSTALLATION	0 - NO. WEEKS ONLY	1	1			

FUEL TYPES

DATA SET REF. NO.	NAME	MASS UNIT	HEAT CONTENT MBTU/MASS UNIT	..MASS UNITS AVAILABLE.. MAXIMUM	MINIMUM	FUEL COST $/MBTU	..TRAJECTORIES.. MAX.	MIN.	COST	..SEGMENT MULT.. MAX.	MIN.	COST
1	GAS	DKT	1.14	-1.00	0.00	3.090000	0	0	33	0	0	0
2	OIL2	GAL	39.17	-1.00	0.00	15.690000	0	0	34	0	0	0
3	COAL	TON	14.27	-1.00	0.00	2.700000	0	0	35	0	0	0
4	COAL	TON	14.27	-1.00	0.00	2.700000	0	0	36	0	0	0
5	COAL	TON	13.22	-1.00	0.00	2.420000	0	0	37	0	0	0
6	COAL	TON	16.48	-1.00	0.00	1.800000	0	0	38	0	0	0
7	COAL	TON	13.68	-1.00	0.00	1.930000	0	0	39	0	0	0
8	PURC	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
10	BMP	TON	14.90	-1.00	0.00	6.750000	0	0	63	0	0	0
11	GAS	DKT	1.14	-1.00	0.00	3.460000	0	0	47	0	0	0
12	COAL	TON	14.07	-1.00	0.00	2.880000	0	0	43	0	0	0
13	GAS	DKT	1.14	-1.00	0.00	3.100000	0	0	50	0	0	0

CAPACITY PLANNING ALTERNATIVES

DATA SET REF. NO.	NAME	BASIC PLANT INSTALLED	GENERIC SITE	-AVAILABLE- FIRST YEAR	LAST YEAR	TYPE	BASIC PLANT RETIRED	PREREQUISITE PLANNING ALTERNATIVE PLAN. ALT.	DEPENDENCY MULTIPLIER NO.	FLAG	RETIRE. OPTION	LAG YEAR MIN	MAX	REQUIRED OPTION
1	GE 7EA	320	0	2024	2040	0	0	0	0	0	0 - NO	0	-1	0
2	WRTSLA 18V50SG	410	0	2024	2040	0	0	0	0	0	0 - NO	0	-1	0
3	STORAGE1	1	0	2023	2040	0	0	12	1	0	0 - NO	0	-1	0
4	SOLAR PPA	4	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0
5	CFBC	490	0	2027	2040	0	0	0	0	0	0 - NO	0	-1	0
6	GE LM6000PH	340	0	2024	2040	0	0	0	0	0	0 - NO	0	-1	0
7	PURCHASE POWER	310	0	2021	2040	1	0	0	0	0	0 - NO	0	-1	0
8	GE 7EA 2x1 ADD	370	0	2026	2040	0	152	0	0	0	0 - NO	0	-1	0
9	GE 7FA.05 1x1	380	0	2026	2040	0	0	0	0	0	0 - NO	0	-1	0
10	BIOMASS	430	0	2024	2040	0	0	0	0	0	0 - NO	0	-1	0
11	CFBC CO2	500	0	2027	2040	0	0	0	0	0	0 - NO	0	-1	0
12	PV SOLAR5	460	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0
13	SOLAR QF	5	0	2023	2024	0	0	0	0	0	0 - NO	0	-1	0
14	GE LMS100PB	330	0	2024	2040	0	0	0	0	0	0 - NO	0	-1	0
16	PV SOLAR50	450	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0
19	SMN SGT-800 2x1	400	0	2026	2040	0	0	0	0	0	0 - NO	0	-1	0
20	WIND20	510	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0
22	WIND50	520	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0
23	WRTSLA 20V34SG	420	0	2024	2040	0	0	0	0	0	0 - NO	0	-1	0
40	STORAGE10	24	0	2023	2040	0	0	16	1	0	0 - NO	0	-1	0
42	AC CYCLE	26	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0
43	STORAGE	27	0	2023	2040	0	0	0	0	0	0 - NO	0	-1	0

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
1	1 - RATE	2020	0.06	2021	1.57	2022	1.24	2023	1.38	2024	1.30
		2025	0.88	2026	0.89	2027	0.86	2028	0.89	2029	0.89
		2030	0.88	2031	0.87	2032	0.88	2033	0.84	2034	0.85
		2035	0.84	2036	0.85	2037	0.84	2038	0.82	2039	0.83
		2040	1.37								
2	1 - RATE	2020	5.73	2021	2.02	2022	1.40	2023	1.71	2024	1.52
		2025	0.68	2026	0.75	2027	0.70	2028	0.74	2029	0.74
		2030	0.74	2031	0.74	2032	0.73	2033	0.73	2034	0.73
		2035	0.72	2036	0.72	2037	0.72	2038	0.72	2039	0.72
		2040	1.56								
3	1 - RATE	2020	3.00								
4	1 - RATE	2020	0.00	2021	40.00	2022	28.57	2023	0.00		
5	1 - RATE	2020	3.00								
6	1 - RATE	2020	3.00								
7	1 - RATE	2020	3.00								
8	1 - RATE	2020	3.00								
9	1 - RATE	2020	3.00								
10	1 - RATE	2020	3.00								
11	1 - RATE	2020	3.00								
12	1 - RATE	2020	3.00								
13	1 - RATE	2020	3.00								
14	1 - RATE	2020	0.00								
15	1 - RATE	2020	3.00								
16	1 - RATE	2020	0.00	2021	15.79	2022	13.64	2023	0.00		
18	1 - RATE	2020	1.54	2021	1.52	2022	1.50	2023	1.48	2024	1.45
		2025	1.50								
20	1 - RATE	2020	3.00								
21	1 - RATE	2020	0.00	2021	25.00	2022	60.00	2023	25.00	2024	20.00
		2025	3.00								
22	1 - RATE	2021	3.00								

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
23	1 - RATE	2020	3.00								
24	1 - RATE	2021	3.00								
25	1 - RATE	2021	3.00								
26	1 - RATE	2020	0.00	2021	0.00	2022	100.00	2023	50.00	2024	33.33
		2025	25.00	2026	0.00	2027	0.00				
27	1 - RATE	2020	0.00	2021	4.23	2022	4.06	2023	0.00		
28	1 - RATE	2020	0.00	2021	150.00	2022	0.00	2023	0.00	2024	0.00
		2025	0.00	2026	0.00						
29	1 - RATE	2020	3.01	2021	3.00	2022	2.98	2023	3.00	2024	3.00
		2025	3.00								
30	1 - RATE	2021	3.00								
31	1 - RATE	2020	3.00								
32	1 - RATE	2020	0.00	2021	0.00	2022	0.00	2023	0.00	2024	0.00
		2025	-66.70	2026	0.00	2027	-100.00	2028	0.00		
33	1 - RATE	2020	29.77	2021	-6.48	2022	3.73	2023	5.91	2024	3.64
		2025	3.00								
34	1 - RATE	2020	3.19	2021	68.50	2022	4.22	2023	0.00	2024	0.00
		2025	3.00								
35	1 - RATE	2020	0.00	2021	0.00	2022	0.00				
36	1 - RATE	2020	-0.37	2021	0.00	2022	0.00				
37	1 - RATE	2020	0.00	2021	0.00						
38	1 - RATE	2020	4.44	2021	2.66	2022	0.00	2023	0.00	2024	0.00
		2025	3.00								
39	1 - RATE	2020	10.36	2021	8.45	2022	-8.23	2023	1.42	2024	0.00
		2025	3.00								
40	1 - RATE	2020	0.00	2021	0.00	2022	0.00	2023	0.00	2024	0.00
		2025	0.00	2026	0.00	2027	0.00	2028	0.00	2029	0.00
		2030	0.00	2031	0.00	2032	0.00	2033	-65.00	2034	0.00
		2035	0.00	2036	0.00						
41	1 - RATE	2020	20.00	2021	33.33	2022	-25.00	2023	0.00		

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
42	1 - RATE	2020	0.00	2021	2.76	2022	4.63	2023	4.43	2024	4.24
		2025	1.71	2026	0.00						
43	1 - RATE	2021	3.00								
44	1 - RATE	2020	3.00								
45	1 - RATE	2020	0.00	2021	20.00	2022	-66.66	2023	0.00	2024	0.00
		2025	0.00	2026	0.00						
46	1 - RATE	2020	3.01	2021	3.01	2022	3.00				
47	1 - RATE	2020	-15.60	2021	-7.53	2022	5.56	2023	5.61	2024	3.99
		2025	3.00								
48	1 - RATE	2020	3.00								
49	1 - RATE	2020	0.00								
50	1 - RATE	2020	-13.54	2021	-8.21	2022	6.10	2023	6.13	2024	4.33
		2025	3.00								
51	1 - RATE	2021	3.00								
52	1 - RATE	2021	0.00	2022	0.00	2023	0.00				
53	1 - RATE	2020	0.00								
54	1 - RATE	2021	3.00								
56	1 - RATE	2021	3.00								
58	1 - RATE	2021	3.00								
59	1 - RATE	2021	3.00								
60	1 - RATE	2021	3.00								
61	1 - RATE	2021	3.00								
62	1 - RATE	2021	3.00								
63	1 - RATE	2021	3.00								
69	1 - RATE	2021	3.00								

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
1	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000
2	5	1	0.094675	3.261365	1.000000
		2	0.213018	0.875302	0.000000
		3	0.201183	0.678515	0.000000
		4	0.307692	0.658509	0.000000
		5	0.183432	0.903074	0.000000
3	5	1	0.087394	3.045711	1.000000
		2	0.196663	0.817408	0.000000
		3	0.185726	0.633688	0.000000
		4	0.284111	0.621916	0.000000
		5	0.246106	1.132123	0.000000
4	5	1	0.094633	2.949847	1.000000
		2	0.212947	0.791637	0.000000
		3	0.201122	0.613695	0.000000
		4	0.217192	0.640240	0.000000
		5	0.274106	1.057082	0.000000
5	5	1	0.253521	1.622222	1.000000
		2	0.169014	0.742158	0.000000
		3	0.169014	0.731929	0.000000
		4	0.225352	0.794184	0.000000
		5	0.183099	0.877250	0.000000
6	5	1	0.200000	1.000000	1.000000
		2	0.200000	1.000000	0.000000
		3	0.200000	1.000000	0.000000
		4	0.200000	1.000000	0.000000
		5	0.200000	1.000000	0.000000
7	5	1	0.200000	1.000000	1.000000
		2	0.200000	1.000000	0.000000
		3	0.200000	1.000000	0.000000
		4	0.200000	1.000000	0.000000
		5	0.200000	1.000000	0.000000
8	5	1	0.095337	3.259150	1.000000
		2	0.214508	0.874707	0.000000
		3	0.202591	0.678054	0.000000
		4	0.309845	0.658062	0.000000
		5	0.177720	0.902461	0.000000

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
10	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000
11	5	1	0.189189	1.200046	1.000000
		2	0.243243	1.152943	0.000000
		3	0.216216	0.880944	0.000000
		4	0.216216	0.864515	0.000000
		5	0.135135	0.851903	0.000000
12	5	1	0.277778	1.662909	0.788532
		2	0.158730	0.122915	0.084189
		3	0.238095	1.126231	0.109583
		4	0.119048	0.784241	0.128755
		5	0.206349	0.761127	0.227864
13	5	1	0.230947	1.814847	1.000000
		2	0.207852	0.764273	0.000000
		3	0.184757	0.620991	0.000000
		4	0.184757	0.759400	0.000000
		5	0.191686	0.871078	0.000000
14	5	1	0.222603	1.101436	0.599018
		2	0.188356	0.600448	0.096709
		3	0.205479	0.568950	0.311778
		4	0.205479	0.991458	0.250524
		5	0.178082	1.803029	0.258642
15	5	1	0.392761	1.065317	0.689241
		2	0.197051	0.901553	0.136186
		3	0.134048	1.166787	0.304138
		4	0.134048	0.964457	0.225042
		5	0.142091	0.832163	0.289710
16	5	1	0.363289	1.103106	0.685732
		2	0.114723	0.934620	0.100071
		3	0.114723	0.934593	0.098419
		4	0.172084	0.934593	0.232984
		5	0.235182	0.952387	0.443454
17	5	1	0.315804	1.155542	1.000000
		2	0.151549	0.868348	0.000000
		3	0.151549	0.902405	0.000000
		4	0.227416	0.945199	0.000000
		5	0.153682	0.987560	0.000000

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
18	5	1	0.421546	1.105793	1.000000
		2	0.140515	0.909256	0.000000
		3	0.140515	0.918412	0.000000
		4	0.140515	0.926752	0.000000
		5	0.156909	0.935703	0.000000
19	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

DATA SET REF. NO.	CALENDAR YEAR	COMPOUNDING OPTION	AFUDC RATE
1	2021	1 - COMPOUND	10.50

CONSTRUCTION COST EXPENDITURE PATTERN

DATA SET REF. NO.	NUMBER OF YEARS	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST	YEAR BEFORE ON-LINE	PERCENT OF COST
31	4	1	13.70	2	35.10	3	34.80	4	16.50		
37	3	1	69.00	2	27.00	3	4.00				
38	1	1	100.00								

RETURN ON RATE BASE

DATA SET REFERENCE NUMBER 1 (DEFAULT)

CALENDAR YEAR	CAPITAL STRUCTURE: COMMON STOCK PERCENT	CAPITAL STRUCTURE: PREFERRED STOCK PERCENT	CAPITAL STRUCTURE: DEBT PERCENT	RETURN ALLOWED ON EQUITY PERCENT	COST OF PREFERRED STOCK PERCENT	DEBT INTEREST RATE PERCENT	ANNUAL INCOME TAX RATE PERCENT	PROPERTY TAX RATE PERCENT	CALCULATED RETURN ON RATE BASE PERCENT
2021	50.00	0.00	50.00	9.65	0.00	4.70	24.00	1.18	8.70

TAX DEPRECIATION TABLE

DATA SET REF. NO.	TAX LIFE YEARS	DEPRECIATION YEAR	DEPRECIATION PERCENT	DEPRECIATION YEAR	DEPRECIATION PERCENT	DEPRECIATION YEAR	DEPRECIATION PERCENT	DEPRECIATION YEAR	DEPRECIATION PERCENT	DEPRECIATION YEAR	DEPRECIATION PERCENT
20	21	1	3.75	2	7.22	3	6.68	4	6.18	5	5.71
		6	5.28	7	4.89	8	4.52	9	4.46	10	4.46
		11	4.46	12	4.46	13	4.46	14	4.46	15	4.46
		16	4.46	17	4.46	18	4.46	19	4.46	20	4.46
		21	2.22								
21	20	1	3.75	2	7.22	3	6.68	4	6.18	5	5.71
		6	5.28	7	4.89	8	4.52	9	4.46	10	4.46
		11	4.46	12	4.46	13	4.46	14	4.46	15	4.46
		16	4.46	17	4.46	18	4.46	19	4.46	20	6.69

SUBPERIOD DEFINITION

SEGMENT	WEEKS	HOURS
1	13	2184
2	13	2184
3	13	2184
4	13	2184
	52	8736

SEGMENT	SUBWEEK	HOURS	TIME FRAME	HOURS
ALL	1	60	1	60
	2	60	2	60
	3	48	3	48

SUBWEEK DEFINITION

DAY HOUR--	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SUNDAY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
MONDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
TUESDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
WEDNESDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
THURSDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
FRIDAY	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
SATURDAY	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Appendix B

EGEAS OUTPUT REPORT FOR THE BASE CASE

```
EEEEEEEE     GGGGGG     EEEEEEEE     AAAAAA      SSSSSS
EEEEEEEE    GGGGGGGG    EEEEEEEE    AAAAAAAA    SSSSSSSS
EE          GG    GG    EE          AA    AA    SS
EEEEEEE     GG          EEEEEEE     AAAAAAAA    SSSSSSS
EEEEEEE     GG   GGG    EEEEEEE     AAAAAAAA     SSSSSSS
EE          GG    GG    EE          AA    AA          SS
EEEEEEEE    GGGGGGGG    EEEEEEEE    AA    AA    SSSSSSSS
EEEEEEEE     GGGGGG     EEEEEEEE    AA    AA     SSSSSS
```

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

REPORT PROGRAM

Montana-Dakota Utilities Co.
2021 Model
Base Case Run
-- Data updated for the 2021 Model

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3420 HILLVIEW AVENUE
PALO ALTO, CALIFORNIA 94304

REPORT FILE OPTION 0 - STANDARD

REPORT OPTIONS

CONTROL	1 - GENERATE
MIRROR IMAGE	1 - GENERATE
ERROR	3 - ALL MESSAGES
REPORT SELECTION	1 - GENERATE

INPUT FILES	NAME	VERSION	UPDATE	RUN	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
EGEAS DATA BASE	2021	1	0		5/11/21	8:20: 6	2021 IRP	1300
EXPANSION PLAN	2021	1	0	1	5/11/21	8:20: 8	2021 IRP	1300
SUBPERIOD REPORT	2021	1	0	1	5/11/21	8:20: 8	2021 IRP	1300
UNIT REPORT	2021	1	0	1	5/11/21	8:20: 8	2021 IRP	1300
UNIT CAPITAL COST REPORT	2021	1	0	1	5/11/21	8:20: 8	2021 IRP	1300

```
--------------------------------------------------------------------------------------------------------------------------------
 EGEAS   REPORT                                                 MIRROR IMAGE REPORT                                PAGE      2
 *******************************************************************************************************************************

 HEADER RECORD        PROGRAM   VERSION   DATE & TIME MODIFIED                                                                  NUM
                      REPORT    13        05/11/21  08:20:00                                                                      1


 RECORD DESCRIPTION   TYP  REF  SQ                          DATA FIELDS                                                         NUM
 -------------------- --- ----- -- ------------------------------------------------------------------------------- ----
                                 1          2         3         4         5         6         7         8         9
           COLUMNS    123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
                      *            Montana-Dakota Utilities Co.                                                                  2
                      *            2021 Model                                                                                    3
                      *            Base Case Run                                                                                 4
                      *              -- Data updated for the 2021 Model                                                          5
                      *                                                                                                          6
                      *            CONTROL RECORD                                                                                7
                      *             SbUnUcc                                                                                      8
                      *                                                                                                          9
                      *                       C M E S   F                                                                       10
                      *                       T I R E   I                                                                       11
                      *                       L R R L   L       DESCRIPTIVE INFORMATION                                         12
                      *                       + - + -   +       --------------------------------                                13
 CONTROL RECORD       CC                      1 1 3 1   0       2021 IRP                                                        14
                      *                                                                                                         15
                      *            --INPUT FILES---                                                                             16
                      *            NAME     V U RUN                                                                             17
                      *            --------++--++++                                                                             18
 FILE IDENTIFICATION  FF           2021     1 0  1                                                                              19
                      *                                                                                                         20
                      *            == PLAN SELECTION ==                                                                         21
                      *               PLANS C O   C E M                                                                         22
                      *            DR  1  L P M   S N O                   --AREAS TO INCLUDE--                                  23
                      *             -+++--- + -   + - +                   --++--++--++--++--++                                  24
 PLAN SELECTION       RA            1  1  1 0 1   3 2 0                                                                         25
                      *                                                                                                         26
                      *            == TIME PERIODS ==                                                                           27
                      *            --YEARS-- -SG- -SW-                                                                          28
                      *             1ST LAST  1 L 1 L                                                                           29
                      *            ---- ++++ --++ - +                                                                           30
 TIME PERIOD          RB           2021 2040  113 1 3                                                                           31
                      *                                                                                                         32
                      *            == REPORT SELECTION ==                                                                       33
                      *                 -PROD-  MNT -STORAGE--   -FL -EM-    -ECON INT- -COST -EM RED  CAP                      34
                      *             S S S  UOBRRSU DOSPD  -PJ-     SU SSU GCF TSTU  CUT  UCTCA RR    I   TU N                   35
                      *             Y U YAFNRLEEYN EPWRS C 1 L     YN YIN E+M RYIN  OFF  NOOOS AU    N   ON D                   36

                                 1          2         3         4         5         6         7         8         9
           COLUMNS    123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
```

```
 RECORD DESCRIPTION   TYP  REF  SQ                          DATA FIELDS                                                 NUM
 -------------------- --- ----- -- ------------------------------------------------------------------------------- ----
                                 1          2         3         4         5         6         7         8         9
            COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0

                      *             S M SRLTDKLSST TRKDP E 1 L    ST STT NRT NSET  PCT. TNTVT TN    C   TI U          37
                      *             - + -+-+-+-+-+ +-+-+ -++--    +- +-+ -+- +-+-++++++ -+-+- +-    +   -+ -          38
 REPORT SELECTION     RC            1 2 0111101100 00000 0        10 000 001 00000.0000 00000 00    0   00 0          39
                      *                                                                                               40

                                 1          2         3         4         5         6         7         8         9
            COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
```

```
****************************************************
****************************************************
**                                                **
**                                                **
**               DIAGNOSTIC SUMMARY               **
**                                                **
**                                                **
**          TERMINAL ERRORS            0          **
**          FATAL ERRORS               0          **
**          WARNING MESSAGES           0          **
**          DEFAULTS                   0          **
**                                                **
**                                                **
**      HIGHEST ERROR LEVEL FOUND IS NONE         **
**                                                **
**                                                **
**      REPORT PROGRAM INPUT SUCCEEDED            **
**                                                **
**                                                **
****************************************************
****************************************************
```

```
RA      EXPANSION PLAN DIRECTORY      =  1 - YES

        FIRST EXPANSION PLAN          =  1                CAPACITY OPTION  =  0 - RATED
        LAST  EXPANSION PLAN          =  1                FIXED O+M OPTION =  1 - SEPARATE ITEM IN PRODUCTION COST

        COST SCALING OPTION           =  3 - 0.001 M$
        ENERGY SCALING OPTION         =  2 - 0.010 GWH
        MONTHLY OUTPUT OPTION         =  0 - NO

RB      FIRST YEAR = 2021         FIRST SEGMENT =  1      FIRST SUBWEEK =  1
        LAST  YEAR = 2040         LAST  SEGMENT = 13      LAST  SUBWEEK =  3

RC      SYSTEM/DISPATCH OPTION        =  1 - SYSTEM A,  INDEPENDENT DISPATCH

        EXPANSION PLAN SUMMARY        =  2 - YES, WITH RESERVE CAPACITY

        PRODUCTION COST REPORTS
           SYSTEM                     =  0 - NO           UNIT ORDER OPTION    =  1 - CAPACITY FACTOR
           SERVICE AREAS              =  1 - ANNUAL       LOADING BLOCK OPTION =  0 - UNIT
           FUEL CLASSES               =  1 - ANNUAL
           UNITS                      =  1 - ANNUAL
           DETAILED COSTS BY UNITS    =  0 - NO
           NDT UTILIZTION             =  0 - NO

        RELIABILITY REPORTS
           RELIABILITY                =  1 - ANNUAL
           RESERVE                    =  1 - ANNUAL

        FUEL USAGE REPORTS
           SYSTEM                     =  1 - ANNUAL
           UNITS                      =  0 - NO
```

PLAN 1

NEW UNITS ADDED

YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2021	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2022	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2023	0	0.	0.	0.	0.	0.	0	0	0.	0	0	0	0	0.	0.
2024	0	0.	0	0	0	0.	0	0	0	0	0	0	0	0	0
2025	0	0.	0	0	0	0.	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	2+	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	2+	0	0	0	0	0	1+	0	0	0	0	0	0	0	0

PLAN 1

NEW UNITS ADDED

YEAR	16	17	18
2021	0.	0.	0.
2022	0.	0.	0.
2023	0	0	0
2024	0	0	1+
2025	0	0	0+
2026	0	0	0+
2027	0	0	0+
2028	0	0	0+
2029	0	0	0+
2030	0	0	0+
2031	0	0	0+
2032	0	0	0+
2033	0	0	0+
2034	0	1+	0+
2035	0	0+	0+
2036	0	0+	0+
2037	1	0+	0+
2038	0	0+	0+
2039	1	0+	0+
2040	0	0+	0+

TOTAL COST, M$
--W/O EXT 1233.581
--WITH EXT 2320.682

UNIT TYPES

1 PA	7 PURCHASE POWER	10.000 MW	2 PA	8 GE 7EA 2x1 ADD	329.800 MW	3 PA	1 GE 7EA	78.300 MW
4 PA	6 GE LM6000PH	45.300 MW	5 PA	14 GE LMS100PB	90.700 MW	6 PA	9 GE 7FA.05 1x1	329.200 MW
7 PA	16 PV SOLAR50	50.000 MW	8 PA	12 PV SOLAR5	5.000 MW	9 PA	10 BIOMASS	25.000 MW
10 PA	3 STORAGE1	1.000 MW	11 PA	40 STORAGE10	10.000 MW	12 PA	20 WIND20	20.000 MW
13 PA	22 WIND50	50.000 MW	14 PA	2 WRTSLA 18V50SG	55.000 MW	15 PA	23 WRTSLA 20V34SG	36.500 MW
16 PA	43 STORAGE	10.000 MW	17 PA	4 SOLAR PPA	50.000 MW	18 PA	13 SOLAR QF	20.000 MW

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2020.
W/O EXT = COST FOR STUDY PERIOD ONLY.
WITH EXT = TOTAL COST FOR STUDY AND EXTENSION PERIODS.
\+ MEANS CUMULATIVE NUMBER OF UNITS IS AT AN UPPER BOUND.
. MEANS LOWER AND UPPER BOUNDS ARE EQUAL.

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	1	2	3	4	5	6	7	8	9	10
2021	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2022	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2023	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00	0.00	0.00 .	0.00
2024	0.00	0.00 .	0.00	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00
2025	0.00	0.00 .	0.00	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	2.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	2.00 +	0.00	0.00	0.00	0.00	0.00	1.00 +	0.00	0.00	0.00
TOTAL	18.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00

NOTE: + MEANS CUMULATIVE NUMBER OF UNITS IS AT AN UPPER BOUND
. MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1 PA	7 PURCHASE POWER	10.000 MW	2 PA	8 GE 7EA 2x1 ADD	329.800 MW	3 PA	1 GE 7EA	78.300 MW
4 PA	6 GE LM6000PH	45.300 MW	5 PA	14 GE LMS100PB	90.700 MW	6 PA	9 GE 7FA.05 1x1	329.200 MW
7 PA	16 PV SOLAR50	50.000 MW	8 PA	12 PV SOLAR5	5.000 MW	9 PA	10 BIOMASS	25.000 MW
10 PA	3 STORAGE1	1.000 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14	15	16	17	18
2021	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2022	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2023	0.00	0.00	0.00	0.00 .	0.00 .	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00 +
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +
2034	0.00	0.00	0.00	0.00	0.00	0.00	1.00 +	0.00 +
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +	0.00 +
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +	0.00 +
2037	0.00	0.00	0.00	0.00	0.00	1.00	0.00 +	0.00 +
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +	0.00 +
2039	0.00	0.00	0.00	0.00	0.00	1.00	0.00 +	0.00 +
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00 +	0.00 +
TOTAL	0.00	0.00	0.00	0.00	0.00	2.00	1.00	1.00

NOTE: + MEANS CUMULATIVE NUMBER OF UNITS IS AT AN UPPER BOUND
. MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

11 PA	40 STORAGE10	10.000 MW	12 PA	20 WIND20	20.000 MW	13 PA	22 WIND50	50.000 MW
14 PA	2 WRTSLA 18V50SG	55.000 MW	15 PA	23 WRTSLA 20V34SG	36.500 MW	16 PA	43 STORAGE	10.000 MW
17 PA	4 SOLAR PPA	50.000 MW	18 PA	13 SOLAR QF	20.000 MW			

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2031	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2032	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2033	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2040	20.000	0.000	0.000	0.000	0.000	0.000	50.000	0.000	0.000	0.000
TOTAL	180.000	0.000	0.000	0.000	0.000	0.000	50.000	0.000	0.000	0.000

NOTE: + MEANS CUMULATIVE NUMBER OF UNITS IS AT AN UPPER BOUND
. MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1 PA	7 PURCHASE POWER	10.000 MW	2 PA	8 GE 7EA 2x1 ADD	329.800 MW	3 PA	1 GE 7EA	78.300 MW
4 PA	6 GE LM6000PH	45.300 MW	5 PA	14 GE LMS100PB	90.700 MW	6 PA	9 GE 7FA.05 1x1	329.200 MW
7 PA	16 PV SOLAR50	50.000 MW	8 PA	12 PV SOLAR5	5.000 MW	9 PA	10 BIOMASS	25.000 MW
10 PA	3 STORAGE1	1.000 MW						

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14	15	16	17	18
2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	20.000
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	50.000	0.000
2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	10.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	10.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	20.000	50.000	20.000

UNIT TYPES

11 PA	40 STORAGE10	10.000 MW	12 PA	20 WIND20	20.000 MW	13 PA	22 WIND50	50.000 MW
14 PA	2 WRTSLA 18V50SG	55.000 MW	15 PA	23 WRTSLA 20V34SG	36.500 MW	16 PA	43 STORAGE	10.000 MW
17 PA	4 SOLAR PPA	50.000 MW	18 PA	13 SOLAR QF	20.000 MW			

PLAN 1

YEAR	PEAK LOAD,MW	ENERGY GWH	..........RATED CAPACITY, MW.......... INSTALLED	RETIRED	CHANGED	TOTAL	RESERVE CAPACITY	RESERVE PERCENT	RELATIVE RELIABILITY	.CAPITAL COSTS, M$ NEW UNITS	CHANGES
BENCH	484.9	3169.10				1335.2	581.1	21.71	1.0000		
2021	485.2	3350.60	105.0	0.0	100.0	1540.2	656.1	38.55	1.0000	0.000	0.000
2022	492.8	3418.20	0.0	52.3	272.4	1760.3	651.8	36.32	1.0000	0.000	0.000
2023	498.9	3466.20	78.3	103.8	-247.6	1487.2	596.4	22.66	1.0000	72.934	0.000
2024	505.8	3525.49	20.0	0.0	0.0	1507.2	606.4	23.01	1.0000	0.000	0.000
2025	512.4	3579.09	0.0	0.0	0.0	1507.2	606.4	21.18	1.0000	0.000	0.000
2026	516.9	3603.39	0.0	0.0	0.0	1507.2	606.4	19.96	1.0000	0.000	0.000
2027	521.5	3630.49	0.0	105.0	0.0	1402.2	576.4	12.12	1.0000	0.000	0.000
2028	526.0	3655.89	0.0	0.0	0.0	1402.2	576.4	11.02	1.0000	0.000	0.000
2029	530.7	3683.09	0.0	0.0	0.0	1402.2	576.4	9.89	1.0000	0.000	0.000
2030	535.4	3710.39	10.0	0.0	0.0	1412.2	586.4	10.93	1.0000	0.000	0.000
2031	540.1	3737.69	10.0	10.0	0.0	1412.2	586.4	9.82	1.0000	0.000	0.000
2032	544.8	3765.19	20.0	10.0	0.0	1422.2	596.4	10.84	1.0000	0.000	0.000
2033	549.6	3792.79	20.0	20.0	0.0	1422.2	596.4	9.73	1.0000	0.000	0.000
2034	554.2	3820.39	60.0	20.0	-19.5	1442.7	608.1	11.10	1.0000	0.000	0.000
2035	558.9	3848.19	10.0	10.0	0.0	1442.7	608.1	10.03	1.0000	0.000	0.000
2036	563.6	3875.99	20.0	40.0	0.0	1422.7	612.6	9.90	1.0000	0.000	0.000
2037	568.4	3903.89	30.0	20.0	0.0	1432.7	622.1	10.75	1.0000	27.601	0.000
2038	573.2	3931.99	20.0	20.0	0.0	1432.7	622.1	9.69	1.0000	0.000	0.000
2039	577.9	3960.29	30.0	20.0	0.0	1442.7	631.6	10.55	1.0000	29.282	0.000
2040	582.7	3988.79	70.0	170.0	0.0	1342.7	634.4	10.06	1.0000	121.869	0.000

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	..................COST SUMMARY.................. ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2021	77.360	0.000	77.360	77.360	72.577	72.577
2022	71.393	0.000	71.393	148.753	62.838	135.415
2023	66.604	6.366	72.971	221.724	60.256	195.671
2024	71.708	6.366	78.075	299.798	60.485	256.156
2025	74.729	6.366	81.095	380.893	58.940	315.096
2026	93.227	6.366	99.593	480.487	67.910	383.005
2027	97.505	6.366	103.871	584.358	66.448	449.453
2028	107.744	6.366	114.110	698.468	68.485	517.938
2029	111.633	6.366	118.000	816.468	66.440	584.378
2030	116.436	6.366	122.802	939.270	64.870	649.248
2031	121.522	6.366	127.888	1067.158	63.380	712.628
2032	125.920	6.366	132.286	1199.445	61.506	774.134
2033	130.596	6.366	136.963	1336.407	59.743	833.877
2034	138.516	6.366	144.882	1481.289	59.290	893.167
2035	142.893	6.366	149.260	1630.549	57.305	950.473
2036	150.956	6.366	157.322	1787.871	56.667	1007.139
2037	158.037	8.989	167.025	1954.897	56.442	1063.581
2038	163.056	8.989	172.045	2126.941	54.544	1118.125
2039	169.383	11.770	181.153	2308.095	53.881	1172.006
2040	196.507	24.158	220.665	2528.760	61.575	1233.581
EXT.	999.275	87.826			1087.101	2320.682

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS. PRESENT WORTH COSTS ARE SHOWN FOR THE EXTENSION PERIOD.
- PRESENT WORTH COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2020.
- CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES. SEE RESERVE REPORT FOR DETAILS.

PLAN 1

YEAR	......TOTAL SYSTEM..... ENERGY, GWH	COST, M$	..SERVICE AREA - MDU .. ENERGY, GWH	COST, M$
2021	3350.60	77.360	3350.60	77.360
2022	3418.20	71.393	3418.20	71.393
2023	3466.20	66.604	3466.20	66.604
2024	3525.49	71.708	3525.49	71.708
2025	3579.09	74.729	3579.09	74.729
2026	3603.39	93.227	3603.39	93.227
2027	3630.49	97.505	3630.49	97.505
2028	3655.89	107.744	3655.89	107.744
2029	3683.09	111.633	3683.09	111.633
2030	3710.39	116.436	3710.39	116.436
2031	3737.69	121.522	3737.69	121.522
2032	3765.19	125.920	3765.19	125.920
2033	3792.79	130.596	3792.79	130.596
2034	3820.39	138.516	3820.39	138.516
2035	3848.19	142.893	3848.19	142.893
2036	3875.99	150.956	3875.99	150.956
2037	3912.31	158.037	3912.31	158.037
2038	3940.41	163.056	3940.41	163.056
2039	3977.13	169.383	3977.13	169.383
2040	4005.57	196.491	4005.57	196.491
EXT.	4005.57	999.194	4005.57	999.194

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2020.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1

	......TOTAL SYSTEM.....		..FUEL CLASS - STRG..		..FUEL CLASS - PURC..		..FUEL CLASS - SOLR..	
YEAR	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$
2021	3350.60	77.360	0.00	0.000	1171.24	30.628	0.00	0.000
2022	3418.20	71.393	0.00	0.000	1456.62	38.095	0.00	0.000
2023	3466.20	66.604	0.00	0.000	1529.86	41.326	0.00	0.000
2024	3525.49	71.708	0.00	0.000	1427.84	40.247	33.92	1.865
2025	3579.09	74.729	0.00	0.000	1288.23	38.021	33.92	1.865
2026	3603.39	93.227	0.00	0.000	1195.99	37.673	33.92	1.865
2027	3630.49	97.505	0.00	0.000	1277.64	41.282	33.92	1.865
2028	3655.89	107.744	0.00	0.000	1307.48	43.494	33.92	1.865
2029	3683.09	111.633	0.00	0.000	1240.93	42.546	33.92	1.865
2030	3710.39	116.436	0.00	0.000	1285.60	45.789	33.92	1.865
2031	3737.69	121.522	0.00	0.000	1398.82	51.215	33.92	1.865
2032	3765.19	125.920	0.00	0.000	1431.76	54.404	33.92	1.865
2033	3792.79	130.596	0.00	0.000	1367.12	53.574	33.92	1.865
2034	3820.39	138.516	0.00	0.000	1440.55	57.582	118.71	6.228
2035	3848.19	142.893	0.00	0.000	1473.71	60.640	118.71	6.228
2036	3875.99	150.956	0.00	0.000	1497.16	63.927	118.71	6.228
2037	3912.31	158.037	8.00	0.562	1614.20	70.848	118.71	6.228
2038	3940.41	163.056	8.00	0.578	1648.22	74.467	118.71	6.228
2039	3977.13	169.383	16.00	1.192	1582.32	73.703	118.71	6.228
2040	4005.57	196.491	16.00	1.227	2055.37	98.554	203.50	7.385
EXT.	4005.57	999.194	16.00	6.311	2055.37	505.710	203.50	28.433

	..FUEL CLASS - GAS ..		..FUEL CLASS - COAL..		..FUEL CLASS - WIND..		..FUEL CLASS - HYDR..	
YEAR	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$
2021	0.00	4.210	1428.31	58.364	736.70	-16.186	14.35	0.344
2022	0.00	4.336	1210.53	44.666	736.70	-16.049	14.35	0.344
2023	0.00	5.610	1185.29	35.232	736.70	-15.908	14.35	0.344
2024	0.00	5.779	1312.69	39.236	736.70	-15.762	14.35	0.344
2025	0.00	5.952	1505.90	44.159	736.70	-15.613	14.35	0.344
2026	0.00	6.131	1622.43	48.828	736.70	-1.614	14.35	0.344
2027	0.00	6.315	1567.89	49.155	736.70	-1.455	14.35	0.344
2028	0.00	6.504	1563.44	49.916	736.70	5.620	14.35	0.344
2029	0.00	6.699	1657.20	54.390	736.70	5.789	14.35	0.344
2030	0.00	6.900	1639.82	55.575	736.70	5.962	14.35	0.344
2031	0.00	7.107	1553.90	54.850	736.70	6.141	14.35	0.344
2032	0.00	7.320	1548.46	55.661	736.70	6.325	14.35	0.344
2033	0.00	7.540	1640.70	60.758	736.70	6.515	14.35	0.344
2034	0.11	7.773	1569.63	60.515	677.04	6.074	14.35	0.344
2035	0.00	7.999	1564.39	61.425	677.04	6.257	14.35	0.344
2036	0.05	8.242	1659.07	66.962	586.65	5.252	14.35	0.344
2037	0.14	8.496	1570.26	66.150	586.65	5.410	14.35	0.344
2038	0.07	8.746	1564.41	67.122	586.65	5.572	14.35	0.344
2039	0.05	9.006	1659.05	73.171	586.65	5.739	14.35	0.344
2040	75.01	14.229	1641.33	74.751	0.00	0.000	14.35	0.344
EXT.	75.01	73.159	1641.33	384.337	0.00	0.000	14.35	1.243

PLAN 1

YEAR	..FUEL CLASS - ENERGY, GWH	BMP .. COST, M$
2021	0.00	0.000
2022	0.00	0.000
2023	0.00	0.000
2024	0.00	0.000
2025	0.00	0.000
2026	0.00	0.000
2027	0.00	0.000
2028	0.00	0.000
2029	0.00	0.000
2030	0.00	0.000
2031	0.00	0.000
2032	0.00	0.000
2033	0.00	0.000
2034	0.00	0.000
2035	0.00	0.000
2036	0.00	0.000
2037	0.00	0.000
2038	0.00	0.000
2039	0.00	0.000
2040	0.00	0.000
EXT.	0.00	0.000

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2020.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

EGEAS REPORT PRODUCTION COST - ANNUAL BY UNITS REPORT PAGE 16

PLAN 1 YEAR 2021 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	667.	667.	7.26
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	532.	532.	9.13
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3371.	-17385.	-29.63
BIG STONE		MUST	107.800	10159.	1.880	82.62	778.05	14860.	1851.	2832.	19544.	25.12
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	302.	632.	934.	24.39
ENERGY			30.000	10500.	0.000	55.58	145.67	0.	3059.	0.	3059.	21.00
COYOTE		MUST	106.700	11966.	2.130	39.31	366.40	9339.	1457.	3162.	13957.	38.09
MISO - Off peak		HYDR	300.000	10500.	0.000	37.14	973.46	0.	23295.	0.	23295.	23.93
HESKETT #2		MUST	74.600	13260.	2.690	32.54	212.05	7564.	1592.	4324.	13481.	63.57
HESKETT #1		MUST	29.200	20631.	2.700	15.81	40.34	2247.	654.	2583.	5484.	135.93
LEWIS & CLARK1		MUST	52.300	14240.	2.420	6.89	31.47	1084.	234.	4580.	5898.	187.44
MISO - On peak		HYDR	300.000	10500.	0.000	0.53	13.79	0.	368.	0.	368.	26.67
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	58.	58.	0.00
CAPACITY			75.000	0.	0.000	0.00	0.00	0.	0.	900.	900.	0.00
INTERRUPTIBLES		D	15.200	0.	0.000	0.00	0.00	0.	0.	783.	783.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	2822.	2822.	0.00
COMMERCIAL DSM		D	25.000	0.	0.000	0.00	0.00	0.	0.	1289.	1289.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	559.	559.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	183.	183.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	216.	216.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	315.	315.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	58.	58.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2022 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	687.	687.	7.48
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	548.	548.	9.40
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3472.	-17283.	-29.46
ENERGY			75.000	10500.	0.000	97.77	640.61	0.	13824.	0.	13824.	21.58
BIG STONE		MUST	107.800	10160.	1.930	90.97	856.71	16799.	2100.	2917.	21816.	25.47
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	307.	651.	958.	25.01
COYOTE		MUST	106.700	12198.	2.310	30.67	285.90	8056.	1171.	3257.	12483.	43.66
MISO - Off peak		HYDR	399.999	10500.	0.000	22.26	777.69	0.	19170.	0.	19170.	24.65
HESKETT #2		MUST	74.600	13260.	2.690	8.81	57.43	2049.	444.	4454.	6947.	120.96
HESKETT #1		MUST	29.200	20631.	2.700	4.11	10.49	584.	175.	2660.	3420.	326.05
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	325.	325.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	59.	59.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	59.	59.	0.00
MISO - On peak		HYDR	399.999	0.	0.000	0.00	0.00	0.	0.	0.	0.	0.00
CAPACITY			90.000	0.	0.000	0.00	0.00	0.	0.	1350.	1350.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	2906.	2906.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	576.	576.	0.00
INTERRUPTIBLES		D	17.600	0.	0.000	0.00	0.00	0.	0.	934.	934.	0.00
COMMERCIAL DSM		D	35.000	0.	0.000	0.00	0.00	0.	0.	1858.	1858.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	189.	189.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	222.	222.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2023 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	707.	707.	7.70
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	564.	564.	9.69
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3576.	-17179.	-29.28
ENERGY			75.000	10500.	0.000	97.84	641.02	0.	14474.	0.	14474.	22.58
BIG STONE		MUST	107.800	10158.	1.930	90.54	852.70	16717.	2152.	3005.	21874.	25.65
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	311.	671.	982.	25.64
COYOTE		MUST	106.700	12197.	2.120	35.68	332.59	8600.	1403.	3354.	13357.	40.16
MISO - Off peak		HYDR	299.999	10500.	0.000	32.45	850.38	0.	21591.	0.	21591.	25.39
MISO - On peak		HYDR	299.999	10500.	0.000	0.01	0.14	0.	4.	0.	4.	28.29
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	229.	229.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	335.	335.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	61.	61.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	61.	61.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	2993.	2993.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1144.	1144.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	593.	593.	0.00
CAPACITY			30.006	0.	0.000	0.00	0.00	0.	0.	720.	720.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1094.	1094.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2461.	2461.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	194.	194.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2024 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	728.	728.	7.93
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	581.	581.	9.98
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3684.	-17072.	-29.10
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
ENERGY			75.000	10500.	0.000	98.50	645.37	0.	15218.	0.	15218.	23.58
BIG STONE		MUST	107.800	10158.	1.930	83.00	781.64	15324.	2032.	3095.	20451.	26.16
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	316.	691.	1007.	26.28
COYOTE		MUST	106.700	11406.	2.150	56.97	531.05	13022.	2307.	3455.	18785.	35.37
MISO - Off peak		HYDR	299.999	10500.	0.000	28.38	743.91	0.	19454.	0.	19454.	26.15
MISO - On peak		HYDR	299.999	10500.	0.000	0.01	0.25	0.	7.	0.	7.	29.14
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	236.	236.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	345.	345.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	63.	63.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	63.	63.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3083.	3083.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1178.	1178.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	611.	611.	0.00
CAPACITY			30.006	0.	0.000	0.00	0.00	0.	0.	900.	900.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1126.	1126.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2534.	2534.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	200.	200.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2025 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	750.	750.	8.17
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	599.	599.	10.28
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3794.	-16961.	-28.91
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
ENERGY			75.000	10500.	0.000	99.11	649.37	0.	15962.	0.	15962.	24.58
BIG STONE		MUST	107.800	10158.	1.930	92.43	870.46	17065.	2331.	3188.	22584.	25.95
COYOTE		MUST	106.700	11105.	2.150	68.17	635.44	15172.	2843.	3559.	21574.	33.95
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	321.	711.	1032.	26.94
MISO - Off peak		HYDR	299.999	10500.	0.000	22.91	600.31	0.	16170.	0.	16170.	26.94
MISO - On peak		HYDR	299.999	10500.	0.000	0.01	0.23	0.	7.	0.	7.	30.01
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	243.	243.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	355.	355.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	65.	65.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	65.	65.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3176.	3176.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1214.	1214.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	629.	629.	0.00
CAPACITY			30.006	0.	0.000	0.00	0.00	0.	0.	1080.	1080.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1160.	1160.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2610.	2610.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	206.	206.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2026 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	773.	773.	8.42
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	617.	617.	10.58
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-6912.	3908.	-3004.	-5.12
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	1.988	92.43	870.46	17577.	2401.	3284.	23262.	26.72
COYOTE		MUST	106.700	11070.	2.214	80.67	751.97	18435.	3466.	3665.	25566.	34.00
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	325.	733.	1058.	27.62
ENERGY			75.000	10500.	0.000	43.74	286.59	0.	7165.	0.	7165.	25.00
MISO - Off peak		HYDR	299.999	10500.	0.000	29.79	780.75	0.	21661.	0.	21661.	27.74
MISO - On peak		HYDR	299.999	10500.	0.000	3.45	90.34	0.	2793.	0.	2793.	30.91
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	250.	250.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	366.	366.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	67.	67.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	67.	67.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3271.	3271.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1250.	1250.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	648.	648.	0.00
CAPACITY			30.006	0.	0.000	0.00	0.00	0.	0.	1113.	1113.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1195.	1195.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2689.	2689.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	212.	212.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2027 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	796.	796.	8.67
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	635.	635.	10.90
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-6912.	4025.	-2886.	-4.92
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
COYOTE		MUST	106.700	11033.	2.281	84.35	786.25	19787.	3733.	3775.	27295.	34.72
BIG STONE		MUST	107.800	10158.	2.048	83.00	781.64	16257.	2221.	3382.	21860.	27.97
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	330.	755.	1085.	28.33
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	28576.	0.	28576.	28.58
MISO - On peak		HYDR	299.999	10500.	0.000	9.13	239.33	0.	7620.	0.	7620.	31.84
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	219.	219.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	258.	258.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	377.	377.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	69.	69.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	69.	69.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3369.	3369.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1287.	1287.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	667.	667.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1231.	1231.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2769.	2769.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2028 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	820.	820.	8.93
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	654.	654.	11.23
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4146.	4146.	7.07
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.109	92.43	870.46	18648.	2547.	3484.	24679.	28.35
COYOTE		MUST	106.700	11032.	2.349	74.34	692.98	17961.	3388.	3889.	25238.	36.42
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	335.	777.	1113.	29.05
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	29433.	0.	29433.	29.43
MISO - On peak		HYDR	299.999	10500.	0.000	10.27	269.17	0.	8828.	0.	8828.	32.80
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	225.	225.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	265.	265.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	388.	388.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	71.	71.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	71.	71.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3470.	3470.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1326.	1326.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	687.	687.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1268.	1268.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2853.	2853.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2029 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	844.	844.	9.20
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	674.	674.	11.56
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4271.	4271.	7.28
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.172	92.43	870.46	19207.	2624.	3588.	25419.	29.20
COYOTE		MUST	106.700	11033.	2.420	84.40	786.74	21004.	3962.	4005.	28972.	36.82
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	340.	801.	1141.	29.79
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	30316.	0.	30316.	30.32
MISO - On peak		HYDR	299.999	10500.	0.000	7.73	202.62	0.	6844.	0.	6844.	33.78
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	232.	232.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	273.	273.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	399.	399.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	73.	73.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	73.	73.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3574.	3574.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1366.	1366.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	708.	708.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1306.	1306.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	2938.	2938.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2030 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	870.	870.	9.47
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	694.	694.	11.91
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4399.	4399.	7.50
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.237	90.54	852.70	19380.	2647.	3696.	25723.	30.17
COYOTE		MUST	106.700	11032.	2.492	84.44	787.13	21644.	4083.	4125.	29853.	37.93
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	345.	825.	1170.	30.55
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	31226.	0.	31226.	31.23
MISO - On peak		HYDR	299.999	10500.	0.000	9.44	247.29	0.	8604.	0.	8604.	34.79
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	239.	239.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	281.	281.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	411.	411.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	75.	75.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	75.	75.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3682.	3682.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1407.	1407.	0.00
LEWIS & CLARK2			18.600	0.	0.000	0.00	0.00	0.	0.	729.	729.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1345.	1345.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3026.	3026.	0.00
PURCHASE POWER	2030		10.000	0.	0.000	0.00	0.00	0.	0.	417.	417.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2031 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	896.	896.	9.76
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	715.	715.	12.27
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4531.	4531.	7.72
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.305	83.00	781.64	18298.	2499.	3807.	24604.	31.48
COYOTE		MUST	106.700	11032.	2.567	82.85	772.27	21871.	4126.	4249.	30246.	39.17
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	351.	850.	1200.	31.33
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	32163.	0.	32163.	32.16
MISO - On peak		HYDR	299.999	10500.	0.000	13.76	360.51	0.	12920.	0.	12920.	35.84
LEWIS & CLARK2			18.600	10372.	3.738	0.00	0.00	0.	0.	751.	751.	*********
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	290.	290.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	424.	424.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	78.	78.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	78.	78.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3792.	3792.	0.00
HESKETT #4			78.300	0.	0.000	0.00	0.00	0.	0.	1449.	1449.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1385.	1385.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3117.	3117.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	246.	246.	0.00
PURCHASE POWER	2031		10.000	0.	0.000	0.00	0.00	0.	0.	430.	430.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

EGEAS REPORT PRODUCTION COST - ANNUAL BY UNITS REPORT

PLAN 1 YEAR 2032 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	923.	923.	10.05
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	736.	736.	12.64
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4667.	4667.	7.95
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.374	92.43	870.46	20988.	2867.	3921.	27776.	31.91
COYOTE		MUST	106.700	11031.	2.644	72.74	678.00	19777.	3731.	4377.	27885.	41.13
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	356.	875.	1231.	32.13
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	33127.	0.	33127.	33.13
MISO - On peak		HYDR	299.999	10500.	0.000	15.01	393.45	0.	14523.	0.	14523.	36.91
LEWIS & CLARK2			18.600	9303.	3.850	0.00	0.00	0.	0.	774.	774.	*********
HESKETT #4			78.300	25499.	3.555	0.00	0.00	0.	0.	1492.	1492.	*********
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	436.	436.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	80.	80.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	80.	80.	0.00
HESKETT #3			88.000	0.	0.000	0.00	0.00	0.	0.	3906.	3906.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1427.	1427.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3211.	3211.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	254.	254.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	299.	299.	0.00
PURCHASE POWER	2032		10.000	0.	0.000	0.00	0.00	0.	0.	443.	443.	0.00
PURCHASE POWER	2032		10.000	0.	0.000	0.00	0.00	0.	0.	443.	443.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2033 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	35.02	91.79	0.	0.	950.	950.	10.35
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	758.	758.	13.02
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4807.	4807.	8.19
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.445	90.54	852.70	21177.	2893.	4038.	28108.	32.96
COYOTE		MUST	106.700	11032.	2.724	84.54	788.01	23676.	4467.	4508.	32650.	41.43
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	361.	901.	1262.	32.95
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	34121.	0.	34121.	34.12
MISO - On peak		HYDR	299.999	10500.	0.000	12.55	328.81	0.	12501.	0.	12501.	38.02
LEWIS & CLARK2			18.600	9225.	3.965	0.00	0.00	0.	0.	797.	797.	*********
HESKETT #4			78.300	23286.	3.661	0.00	0.00	0.	0.	1537.	1537.	*********
HESKETT #3			88.000	37447.	3.661	0.00	0.00	0.	0.	4023.	4023.	*********
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	82.	82.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	82.	82.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1470.	1470.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3307.	3307.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	261.	261.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	308.	308.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	450.	450.	0.00
PURCHASE POWER	2033		10.000	0.	0.000	0.00	0.00	0.	0.	456.	456.	0.00
PURCHASE POWER	2033		10.000	0.	0.000	0.00	0.00	0.	0.	456.	456.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2034 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	10.500	0.	0.000	35.02	32.13	0.	0.	343.	343.	10.66
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	781.	781.	13.41
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4951.	4951.	8.44
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
COYOTE		MUST	106.700	11032.	2.805	84.54	788.02	24386.	4601.	4643.	33631.	42.68
BIG STONE		MUST	107.800	10158.	2.518	83.00	781.61	19994.	2731.	4160.	26884.	34.40
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	367.	928.	1295.	33.80
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	35145.	0.	35145.	35.14
MISO - On peak		HYDR	299.999	10500.	0.000	15.35	402.24	0.	15752.	0.	15752.	39.16
LEWIS & CLARK2			18.600	8879.	4.084	0.02	0.04	1.	0.	821.	822.	23304.95
HESKETT #4			78.300	16946.	3.771	0.01	0.04	3.	0.	1583.	1586.	36695.43
HESKETT #3			88.000	18325.	3.771	0.00	0.02	1.	0.	4144.	4145.	218825.67
GLENDIVE CT #2			43.300	11067.	5.571	0.00	0.01	0.	0.	463.	464.	61258.93
GLENDIVE CT #1			35.500	13940.	5.571	0.00	0.00	0.	0.	317.	317.	86208.00
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	1.	1514.	1514.	738951.81
MILES CITY C.T.			25.200	16298.	5.571	0.00	0.00	0.	0.	269.	269.	138515.67
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3406.	3406.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	85.	85.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	85.	85.	0.00
PURCHASE POWER	2034		10.000	0.	0.000	0.00	0.00	0.	0.	470.	470.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2035 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
DIAMOND WILLOW		NDT	10.500	0.	0.000	35.02	32.13	0.	0.	353.	353.	10.98
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	804.	804.	13.81
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5099.	5099.	8.69
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.594	92.43	870.43	22934.	3133.	4284.	30351.	34.87
COYOTE		MUST	106.700	11031.	2.889	74.45	693.96	22119.	4173.	4783.	31074.	44.78
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	372.	956.	1328.	34.67
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	36199.	0.	36199.	36.20
MISO - On peak		HYDR	299.999	10500.	0.000	16.61	435.40	0.	17562.	0.	17562.	40.33
LEWIS & CLARK2			18.600	9002.	4.207	0.00	0.00	0.	0.	845.	845.	*********
HESKETT #4			78.300	15952.	3.884	0.00	0.00	0.	0.	1631.	1631.	*********
HESKETT #3			88.000	15908.	3.884	0.00	0.00	0.	0.	4268.	4268.	*********
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	87.	87.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	87.	87.	0.00
INTERRUPTIBLES		D	20.000	0.	0.000	0.00	0.00	0.	0.	1559.	1559.	0.00
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3508.	3508.	0.00
MILES CITY C.T.			25.200	0.	0.000	0.00	0.00	0.	0.	277.	277.	0.00
GLENDIVE CT #1			35.500	0.	0.000	0.00	0.00	0.	0.	326.	326.	0.00
GLENDIVE CT #2			43.300	0.	0.000	0.00	0.00	0.	0.	477.	477.	0.00
PURCHASE POWER	2035		10.000	0.	0.000	0.00	0.00	0.	0.	484.	484.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2036 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5252.	5252.	8.95
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.672	92.43	870.46	23622.	3227.	4413.	31262.	35.91
COYOTE		MUST	106.700	11031.	2.976	84.60	788.61	25889.	4885.	4926.	35700.	45.27
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	378.	985.	1363.	35.57
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	37285.	0.	37285.	37.29
MISO - On peak		HYDR	299.999	10500.	0.000	17.51	458.85	0.	19063.	0.	19063.	41.54
LEWIS & CLARK2			18.600	8958.	4.333	0.01	0.02	1.	0.	871.	871.	47486.29
HESKETT #4			78.300	19305.	4.001	0.00	0.02	1.	0.	1680.	1681.	97428.48
HESKETT #3			88.000	19814.	4.001	0.00	0.01	1.	0.	4396.	4397.	549048.88
GLENDIVE CT #2			43.300	11223.	5.911	0.00	0.00	0.	0.	491.	492.	133043.11
GLENDIVE CT #1			35.500	14199.	5.911	0.00	0.00	0.	0.	336.	336.	185821.64
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	0.	1606.	1606.	*********
MILES CITY C.T.			25.200	16504.	5.911	0.00	0.00	0.	0.	285.	286.	304364.59
COMMERCIAL DSM		D	45.000	0.	0.000	0.00	0.00	0.	0.	3613.	3613.	0.00
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	90.	90.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	90.	90.	0.00
PURCHASE POWER	2036		10.000	0.	0.000	0.00	0.00	0.	0.	498.	498.	0.00
PURCHASE POWER	2036		10.000	0.	0.000	0.00	0.00	0.	0.	498.	498.	0.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2037 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5410.	5410.	9.22
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
COYOTE		MUST	106.700	11031.	3.065	84.60	788.62	26667.	5031.	5074.	36772.	46.63
BIG STONE		MUST	107.800	10158.	2.752	83.00	781.64	21848.	2984.	4545.	29378.	37.59
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	383.	1014.	1398.	36.49
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	38404.	0.	38404.	38.40
MISO - On peak		HYDR	299.999	10500.	0.000	21.97	575.88	0.	24643.	0.	24643.	42.79
LEWIS & CLARK2			18.600	8919.	4.463	0.03	0.05	2.	0.	897.	899.	19391.21
HESKETT #4			78.300	17882.	4.121	0.01	0.05	4.	0.	1730.	1734.	34219.80
HESKETT #3			88.000	19183.	4.121	0.00	0.02	2.	0.	4528.	4530.	188214.66
GLENDIVE CT #2			43.300	11078.	6.088	0.00	0.01	1.	0.	506.	507.	46435.33
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	1.	1654.	1655.	518812.28
GLENDIVE CT #1			35.500	14001.	6.088	0.00	0.01	0.	0.	346.	347.	63837.07
MILES CITY C.T.			25.200	16331.	6.088	0.00	0.00	0.	0.	294.	294.	102148.95
COMMERCIAL DSM		D	45.000	1.	0.000	0.00	0.00	0.	0.	3722.	3722.	*********
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	93.	93.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	93.	93.	0.00
PURCHASE POWER	2037		10.000	0.	0.000	0.00	0.00	0.	0.	513.	513.	0.00
PURCHASE POWER	2037		10.000	0.	0.000	0.00	0.00	0.	0.	513.	513.	0.00
STORAGE	2037	CHRG	10.000				-8.42					
STORAGE	2037	STOR	10.000	0.	0.000	9.16	8.00	0.	0.	562.	562.	70.21

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2038 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5572.	5572.	9.50
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.834	92.43	870.46	25061.	3423.	4682.	33166.	38.10
COYOTE		MUST	106.700	11031.	3.157	74.45	693.95	24169.	4560.	5226.	33956.	48.93
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	389.	1045.	1434.	37.43
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	39556.	0.	39556.	39.56
MISO - On peak		HYDR	299.999	10500.	0.000	23.27	609.91	0.	26881.	0.	26881.	44.07
LEWIS & CLARK2			18.600	8973.	4.597	0.02	0.03	1.	0.	924.	925.	36067.40
HESKETT #4			78.300	19060.	4.245	0.00	0.02	2.	0.	1782.	1784.	71966.06
HESKETT #3			88.000	19070.	4.245	0.00	0.01	1.	0.	4664.	4665.	404569.88
GLENDIVE CT #2			43.300	11044.	6.271	0.00	0.01	0.	0.	521.	522.	95378.39
GLENDIVE CT #1			35.500	14207.	6.271	0.00	0.00	0.	0.	357.	357.	120420.85
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	0.	1704.	1704.	*********
MILES CITY C.T.			25.200	16484.	6.271	0.00	0.00	0.	0.	303.	303.	195767.75
COMMERCIAL DSM		D	45.000	1.	0.000	0.00	0.00	0.	0.	3834.	3834.	*********
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	95.	95.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	95.	95.	0.00
PURCHASE POWER	2038		10.000	0.	0.000	0.00	0.00	0.	0.	529.	529.	0.00
PURCHASE POWER	2038		10.000	0.	0.000	0.00	0.00	0.	0.	529.	529.	0.00
STORAGE	2037	CHRG	10.000				-8.42					
STORAGE	2037	STOR	10.000	0.	0.000	9.16	8.00	0.	0.	578.	578.	72.31

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2020.

PLAN 1 YEAR 2039 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5739.	5739.	9.78
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	2.919	92.43	870.46	25813.	3526.	4822.	34161.	39.24
COYOTE		MUST	106.700	11031.	3.252	84.60	788.59	28290.	5338.	5383.	39010.	49.47
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	395.	1076.	1471.	38.40
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	40743.	0.	40743.	40.74
MISO - On peak		HYDR	299.999	10500.	0.000	20.76	544.01	0.	24697.	0.	24697.	45.40
LEWIS & CLARK2			18.600	8974.	4.735	0.01	0.02	1.	0.	951.	952.	55955.34
HESKETT #4			78.300	19210.	4.372	0.00	0.02	1.	0.	1836.	1837.	113330.81
HESKETT #3			88.000	19427.	4.372	0.00	0.01	1.	0.	4804.	4804.	627834.69
GLENDIVE CT #2			43.300	11222.	6.459	0.00	0.00	0.	0.	537.	537.	152977.44
GLENDIVE CT #1			35.500	14309.	6.459	0.00	0.00	0.	0.	367.	367.	207173.27
MILES CITY C.T.			25.200	16588.	6.459	0.00	0.00	0.	0.	312.	312.	340114.06
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	0.	1755.	1755.	*********
COMMERCIAL DSM		D	45.000	1.	0.000	0.00	0.00	0.	0.	3949.	3949.	*********
DIESEL 2			2.000	0.	0.000	0.00	0.00	0.	0.	98.	98.	0.00
DIESEL 3			2.000	0.	0.000	0.00	0.00	0.	0.	98.	98.	0.00
PURCHASE POWER	2039		10.000	0.	0.000	0.00	0.00	0.	0.	545.	545.	0.00
PURCHASE POWER	2039		10.000	0.	0.000	0.00	0.00	0.	0.	545.	545.	0.00
STORAGE	2037	CHRG	10.000				-8.42					
STORAGE	2037	STOR	10.000	0.	0.000	9.16	8.00	0.	0.	596.	596.	74.48
STORAGE	2039	CHRG	10.000				-8.42					
STORAGE	2039	STOR	10.000	0.	0.000	9.16	8.00	0.	0.	596.	596.	74.48

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
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PLAN 1 YEAR 2040 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST $/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K$	VAR. O + M K$	FIXED O + M K$	PRODUCTION COST K$	PRODUCTION COST $/MWH
PV SOLAR50	2040	NDT	50.000	0.	0.000	19.41	84.79	0.	0.	1157.	1157.	13.65
SOLAR PPA	2034	NDT	50.000	0.	0.000	19.41	84.79	0.	4363.	0.	4363.	51.45
SOLAR QF	2024	NDT	20.000	0.	0.000	19.41	33.92	0.	840.	1025.	1865.	54.98
BIG STONE		MUST	107.800	10158.	3.007	90.54	852.70	26045.	3558.	4967.	34569.	40.54
COYOTE		MUST	106.700	11031.	3.350	84.61	788.64	29140.	5498.	5544.	40182.	50.95
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	344.	0.	344.	24.00
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	401.	1108.	1509.	39.40
MISO - On peak		HYDR	299.999	10500.	0.000	38.75	1015.52	0.	47485.	0.	47485.	46.76
MISO - Off peak		HYDR	299.999	10500.	0.000	38.16	1000.00	0.	41965.	0.	41965.	41.96
LEWIS & CLARK2			18.600	8646.	4.877	12.45	20.23	853.	132.	980.	1964.	97.10
HESKETT #4			78.300	14069.	4.503	6.26	42.83	2713.	68.	1891.	4671.	109.08
HESKETT #3			88.000	21858.	4.503	1.15	8.84	870.	43.	4948.	5861.	662.86
INTERRUPTIBLES		D	20.000	1.	0.000	0.43	0.76	0.	228.	1808.	2035.	2682.51
GLENDIVE CT #2			43.300	10247.	6.653	0.43	1.64	112.	12.	553.	677.	412.81
GLENDIVE CT #1			35.500	13221.	6.653	0.30	0.92	81.	7.	378.	466.	507.46
MILES CITY C.T.			25.200	15689.	6.653	0.25	0.54	56.	4.	321.	382.	705.89
COMMERCIAL DSM		D	45.000	1.	0.000	0.18	0.69	0.	207.	4067.	4274.	6183.12
PURCHASE POWER	2040		10.000	1.	0.000	0.06	0.05	0.	97.	561.	658.	12268.89
PURCHASE POWER	2040		10.000	1.	0.000	0.04	0.04	0.	67.	561.	628.	16883.17
DIESEL 2			2.000	8687.	44.293	0.04	0.01	3.	0.	101.	104.	15814.48
DIESEL 3			2.000	8687.	44.293	0.04	0.01	2.	0.	101.	104.	16290.16
STORAGE	2037	CHRG	10.000				-8.42					
STORAGE	2037	STOR	10.000	0.	0.000	9.16	8.00	0.	0.	614.	614.	76.72
STORAGE	2039	CHRG	10.000				-8.42					
STORAGE	2039	STOR	10.000	0.	0.000	9.16	8.00	0.	0.	614.	614.	76.72

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PLAN 1

YEAR	PEAK LOAD MW	ENERGY GWH	RESERVE CAPACITY MW	RESERVE MARGIN PCT.	EMERGENCY CAPACITY MW	---LOSS OF LOAD--- HOURS	PROB.	OPERATING CAPACITY MW	--UNSERVED ENERGY-- GWH	PCT.
2021	485.2	3350.60	656.1	38.55	1537.7	0.00	0.000000	1501.9	0.00	0.00
2022	492.8	3418.20	651.8	36.32	1757.8	0.00	0.000000	1729.3	0.00	0.00
2023	498.9	3466.20	596.4	22.66	1484.7	0.00	0.000000	1459.1	0.00	0.00
2024	505.8	3525.49	606.4	23.01	1504.7	0.00	0.000000	1479.1	0.00	0.00
2025	512.4	3579.09	606.4	21.18	1504.7	0.00	0.000000	1479.1	0.00	0.00
2026	516.9	3603.39	606.4	19.96	1504.7	0.00	0.000000	1479.1	0.00	0.00
2027	521.5	3630.49	576.4	12.12	1399.7	0.00	0.000000	1374.1	0.00	0.00
2028	526.0	3655.89	576.4	11.02	1399.7	0.00	0.000000	1374.1	0.00	0.00
2029	530.7	3683.09	576.4	9.89	1399.7	0.00	0.000000	1374.1	0.00	0.00
2030	535.4	3710.39	586.4	10.93	1409.7	0.00	0.000000	1384.1	0.00	0.00
2031	540.1	3737.69	586.4	9.82	1409.7	0.00	0.000000	1384.1	0.00	0.00
2032	544.8	3765.19	596.4	10.84	1419.7	0.00	0.000000	1394.1	0.00	0.00
2033	549.6	3792.79	596.4	9.73	1419.7	0.00	0.000000	1394.1	0.00	0.00
2034	554.2	3820.39	608.1	11.10	1440.2	0.00	0.000000	1414.6	0.00	0.00
2035	558.9	3848.19	608.1	10.03	1440.2	0.00	0.000000	1414.6	0.00	0.00
2036	563.6	3875.99	612.6	9.90	1420.2	0.00	0.000000	1394.6	0.00	0.00
2037	568.4	3903.89	622.1	10.75	1430.2	0.00	0.000000	1404.6	0.00	0.00
2038	573.2	3931.99	622.1	9.69	1430.2	0.00	0.000000	1404.6	0.00	0.00
2039	577.9	3960.29	631.6	10.55	1440.2	0.00	0.000000	1414.6	0.00	0.00
2040	582.7	3988.79	634.4	10.06	1340.2	0.00	0.000000	1314.6	0.07	0.00
EXT.	582.7	3988.79	634.4	10.06	1340.2	0.00	0.000000	1314.6	0.07	0.00

NOTE - RESERVE MARGIN: ANNUAL CALCULATION, CAPACITIES NOT DERATED FOR MAINTENANCE. SEE RESERVE REPORT FOR DETAIL.
- LOSS OF LOAD: ANNUAL CALCULATION, CAPACITIES DERATED FOR MAINTENANCE.
- RESERVE, EMERGENCY AND OPERATING CAPACITIES SHOWN ABOVE ARE NOT DERATED FOR MAINTENANCE.
- CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES.

PLAN 1

	LOADS				RESOURCES				RESERVE
YEAR	PEAK LOAD MW	PURCH./SALE CONTRACTS	DEMAND-SIDE MANAGEMENT	NET LOADS MW	CAPACITY MW	RESERVE SHARING	PURCH./SALE CONTRACTS	NET RESOURCES MW	MARGIN PCT.
2021	485.2	0.0	-41.9	443.3	614.2	0.0	0.0	614.2	38.55
2022	492.8	0.0	-55.2	437.6	596.6	0.0	0.0	596.6	36.32
2023	498.9	0.0	-68.4	430.5	528.0	0.0	0.0	528.0	22.66
2024	505.8	0.0	-68.4	437.4	538.0	0.0	0.0	538.0	23.01
2025	512.4	0.0	-68.4	444.0	538.0	0.0	0.0	538.0	21.18
2026	516.9	0.0	-68.4	448.5	538.0	0.0	0.0	538.0	19.96
2027	521.5	0.0	-68.4	453.1	508.0	0.0	0.0	508.0	12.12
2028	526.0	0.0	-68.4	457.6	508.0	0.0	0.0	508.0	11.02
2029	530.7	0.0	-68.4	462.3	508.0	0.0	0.0	508.0	9.89
2030	535.4	0.0	-68.4	467.0	518.0	0.0	0.0	518.0	10.93
2031	540.1	0.0	-68.4	471.7	518.0	0.0	0.0	518.0	9.82
2032	544.8	0.0	-68.4	476.4	528.0	0.0	0.0	528.0	10.84
2033	549.6	0.0	-68.4	481.2	528.0	0.0	0.0	528.0	9.73
2034	554.2	0.0	-68.4	485.8	539.7	0.0	0.0	539.7	11.10
2035	558.9	0.0	-68.4	490.5	539.7	0.0	0.0	539.7	10.03
2036	563.6	0.0	-68.4	495.2	544.2	0.0	0.0	544.2	9.90
2037	568.4	0.0	-68.4	500.0	553.7	0.0	0.0	553.7	10.75
2038	573.2	0.0	-68.4	504.8	553.7	0.0	0.0	553.7	9.69
2039	577.9	0.0	-68.4	509.5	563.2	0.0	0.0	563.2	10.55
2040	582.7	0.0	-68.4	514.3	566.0	0.0	0.0	566.0	10.06
EXT.	582.7	0.0	-68.4	514.3	566.0	0.0	0.0	566.0	10.06

PLAN 1 YEAR 2021

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	40.34	20631.	TON	14.27	5.83217E+04				2.70	2247.	55.70
COAL	212.05	13260.	TON	14.27	1.97046E+05				2.69	7564.	35.67
COAL	31.47	14240.	TON	13.22	3.38956E+04				2.42	1084.	34.46
COAL	778.05	10159.	TON	16.48	4.79625E+05				1.88	14860.	19.10
COAL	366.40	11966.	TON	13.68	3.20501E+05				2.13	9339.	25.49
PURC	1171.24	10157.	NONE	0.01	1.18958E+09				0.00	0.	0.00

PLAN 1 YEAR 2022

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	10.49	20631.	TON	14.27	1.51636E+04				2.70	584.	55.70
COAL	57.43	13260.	TON	14.27	5.33667E+04				2.69	2049.	35.67
COAL	856.71	10160.	TON	16.48	5.28168E+05				1.93	16799.	19.61
COAL	285.90	12198.	TON	13.68	2.54931E+05				2.31	8056.	28.18
PURC	1456.62	10224.	NONE	0.01	1.48923E+09				0.00	0.	0.00

PLAN 1 YEAR 2023

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	852.70	10158.	TON	16.48	5.25590E+05				1.93	16717.	19.60
COAL	332.59	12197.	TON	13.68	2.96541E+05				2.12	8600.	25.86
PURC	1529.86	10237.	NONE	0.01	1.56613E+09				0.00	0.	0.00

PLAN 1 YEAR 2024

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	781.64	10158.	TON	16.48	4.81791E+05				1.93	15324.	19.60
COAL	531.05	11406.	TON	13.68	4.42763E+05				2.15	13022.	24.52
PURC	1427.84	10218.	NONE	0.01	1.45901E+09				0.00	0.	0.00

PLAN 1 YEAR 2025

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	870.46	10158.	TON	16.48	5.36540E+05				1.93	17065.	19.60
COAL	635.44	11105.	TON	13.68	5.15847E+05				2.15	15172.	23.88
PURC	1288.23	10188.	NONE	0.01	1.31242E+09				0.00	0.	0.00

PLAN 1 YEAR 2026

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	870.46	10158.	TON	16.48	5.36540E+05				1.99	17577.	20.19
COAL	751.97	11070.	TON	13.68	6.08524E+05				2.21	18435.	24.52
PURC	1195.99	10164.	NONE	0.01	1.21557E+09				0.00	0.	0.00

PLAN 1 YEAR 2027

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	781.64	10158.	TON	16.48	4.81791E+05				2.05	16257.	20.80
COAL	786.25	11033.	TON	13.68	6.34127E+05				2.28	19787.	25.17
PURC	1277.64	10185.	NONE	0.01	1.30130E+09				0.00	0.	0.00

PLAN 1 YEAR 2028

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	870.46	10158.	TON	16.48	5.36540E+05				2.11	18648.	21.42
COAL	692.98	11032.	TON	13.68	5.58844E+05				2.35	17961.	25.92
PURC	1307.48	10192.	NONE	0.01	1.33264E+09				0.00	0.	0.00

PLAN 1 YEAR 2029

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	870.46	10158.	TON	16.48	5.36540E+05				2.17	19207.	22.07
COAL	786.74	11033.	TON	13.68	6.34494E+05				2.42	21004.	26.70
PURC	1240.93	10176.	NONE	0.01	1.26275E+09				0.00	0.	0.00

PLAN 1 YEAR 2030

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	852.70	10158.	TON	16.48	5.25590E+05				2.24	19380.	22.73
COAL	787.13	11032.	TON	13.68	6.34788E+05				2.49	21644.	27.50
PURC	1285.60	10187.	NONE	0.01	1.30966E+09				0.00	0.	0.00

PLAN 1 YEAR 2031

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	781.64	10158.	TON	16.48	4.81791E+05				2.30	18298.	23.41
COAL	772.27	11032.	TON	13.68	6.22756E+05				2.57	21871.	28.32
PURC	1398.82	10212.	NONE	0.01	1.42854E+09				0.00	0.	0.00
GAS	0.00	10372.	DKT	1.14	2.35953E-01				3.74	0.	38.77

PLAN 1 YEAR 2032

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	870.46	10158.	TON	16.48	5.36540E+05				2.37	20988.	24.11
COAL	678.00	11031.	TON	13.68	5.46724E+05				2.64	19777.	29.17
PURC	1431.76	10219.	NONE	0.01	1.46313E+09				0.00	0.	0.00
GAS	0.00	9303.	DKT	1.14	1.02001E+00				3.85	0.	35.81
GAS	0.00	25499.	DKT	1.14	1.65046E+00				3.55	0.	90.64

PLAN 1 YEAR 2033

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	852.70	10158.	TON	16.48	5.25590E+05				2.44	21177.	24.84
COAL	788.01	11032.	TON	13.68	6.35449E+05				2.72	23676.	30.04
PURC	1367.12	10206.	NONE	0.01	1.39526E+09				0.00	0.	0.00
GAS	0.00	9225.	DKT	1.14	1.59482E+00				3.97	0.	36.58
GAS	0.00	26509.	DKT	1.14	4.11794E+00				3.66	0.	97.06

PLAN 1 YEAR 2034

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.01	12639.	DKT	1.14	1.46239E+02				5.57	1.	70.42
COAL	781.61	10158.	TON	16.48	4.81774E+05				2.52	19994.	25.58
COAL	788.02	11032.	TON	13.68	6.35461E+05				2.81	24386.	30.95
PURC	1440.55	10221.	NONE	0.01	1.47236E+09				0.00	0.	0.00
GAS	0.04	8879.	DKT	1.14	2.74762E+02				4.08	1.	36.26
GAS	0.06	17366.	DKT	1.14	9.47010E+02				3.77	4.	65.49

PLAN 1 YEAR 2035

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
COAL	870.43	10158.	TON	16.48	5.36523E+05				2.59	22934.	26.35
COAL	693.96	11031.	TON	13.68	5.59581E+05				2.89	22119.	31.87
PURC	1473.71	10227.	NONE	0.01	1.50717E+09				0.00	0.	0.00
GAS	0.00	9002.	DKT	1.14	1.75079E+00				4.21	0.	37.87
GAS	0.00	15939.	DKT	1.14	6.33553E+00				3.88	0.	61.91

PLAN 1 YEAR 2036

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.01	12828.	DKT	1.14	7.24923E+01				5.91	0.	75.82
COAL	870.46	10158.	TON	16.48	5.36540E+05				2.67	23622.	27.14
COAL	788.61	11031.	TON	13.68	6.35902E+05				2.98	25889.	32.83
PURC	1497.16	10231.	NONE	0.01	1.53180E+09				0.00	0.	0.00
GAS	0.02	8958.	DKT	1.14	1.44203E+02				4.33	1.	38.81
GAS	0.03	19467.	DKT	1.14	4.31390E+02				4.00	2.	77.88

PLAN 1 YEAR 2037

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.02	12691.	DKT	1.14	2.14044E+02				6.09	1.	77.26
COAL	781.64	10158.	TON	16.48	4.81791E+05				2.75	21848.	27.95
COAL	788.62	11031.	TON	13.68	6.35916E+05				3.07	26667.	33.81
PURC	1614.20	10251.	NONE	0.01	1.65468E+09				0.00	0.	0.00
GAS	0.05	8919.	DKT	1.14	3.62678E+02				4.46	2.	39.81
GAS	0.07	18301.	DKT	1.14	1.19984E+03				4.12	6.	75.42

PLAN 1 YEAR 2038

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	0.01	12827.	DKT	1.14	1.12294E+02				6.27	1.	80.43
COAL	870.46	10158.	TON	16.48	5.36540E+05				2.83	25061.	28.79
COAL	693.95	11031.	TON	13.68	5.59576E+05				3.16	24169.	34.83
PURC	1648.22	10256.	NONE	0.01	1.69041E+09				0.00	0.	0.00
GAS	0.03	8973.	DKT	1.14	2.01848E+02				4.60	1.	41.25
GAS	0.04	19063.	DKT	1.14	6.07368E+02				4.24	3.	80.91

PLAN 1 YEAR 2039

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	FUEL CONSUMPTION, MASS UNITS TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.01	12899.	DKT	1.14	7.01735E+01				6.46	1.	83.31
COAL	870.46	10158.	TON	16.48	5.36540E+05				2.92	25813.	29.65
COAL	788.59	11031.	TON	13.68	6.35891E+05				3.25	28290.	35.87
PURC	1582.32	10246.	NONE	0.01	1.62122E+09				0.00	0.	0.00
GAS	0.02	8974.	DKT	1.14	1.33966E+02				4.73	1.	42.49
GAS	0.02	19280.	DKT	1.14	4.03533E+02				4.37	2.	84.29

PLAN 1 YEAR 2040

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	3.10	12078.	DKT	1.14	3.28412E+04				6.65	249.	80.35
OIL2	0.01	8687.	GAL	39.17	2.86542E+00				44.29	5.	384.77
COAL	852.70	10158.	TON	16.48	5.25590E+05				3.01	26045.	30.54
COAL	788.64	11031.	TON	13.68	6.35925E+05				3.35	29140.	36.95
PURC	2055.37	10296.	NONE	0.01	2.11630E+09				0.00	0.	0.00
GAS	20.23	8646.	DKT	1.14	1.53430E+05				4.88	853.	42.16
GAS	51.67	15402.	DKT	1.14	6.98028E+05				4.50	3583.	69.35

PLAN 1 EXTENSION PERIOD

FUEL TYPE	ENERGY GENERATED GWH	AVERAGE HT. RATE BTU/KWH	UNIT OF MASS	HEAT CONTENT MBTU/ MASS UNIT	.......FUEL CONSUMPTION, MASS UNITS....... TOTAL	NOT USED	MINIMUM	MAXIMUM	FUEL COST $/MBTU	TOTAL FUEL COST K$	$/MWH
GAS	3.10	12078.	DKT	1.14	3.28412E+04				34.20	1281.	413.12
OIL2	0.01	8687.	GAL	39.17	2.86542E+00				227.73	26.	1978.33
COAL	852.70	10158.	TON	16.48	5.25590E+05				15.46	133910.	157.04
COAL	788.64	11031.	TON	13.68	6.35925E+05				17.22	149824.	189.98
PURC	2055.37	10296.	NONE	0.01	2.11630E+09				0.00	0.	0.00
GAS	20.23	8646.	DKT	1.14	1.53430E+05				25.07	4386.	216.78
GAS	51.67	15402.	DKT	1.14	6.98028E+05				23.15	18424.	356.59

Attachment D

PUBLIC ADVISORY GROUP DOCUMENTATION

ATTACHMENT D
PUBLIC ADVISORY GROUP DOCUMENTATION

This Attachment is comprised of the official Public Advisory Group roster as well as the description of the meetings and the topics discussed at each meeting. No minutes of the meetings were taken.

MONTANA-DAKOTA UTILITIES CO. INTEGRATED RESOURCE PLANNING
2020-2021 PUBLIC ADVISORY GROUP ROSTER

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In addition to the PAG members and Montana-Dakota personnel included on the roster, the following Montana-Dakota personnel and invited guests participated in one or more of the Public Advisory Group meetings as presenters:

Abbie Krebsbach	Director of Environmental
Cory Fong	Director of Communications & Public Affairs
Jacob Hein	Engineer – Power Production
Jay Skabo	VP Electric Supply

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

November 2, 2020 Meeting Agenda

2019 IRP Action Plan Updates	Darcy Neigum
2020 RFP	Brian Giggee
Coyote Regional Haze	Abbie Krebsbach
Request for Proposals	Brian Giggee
2021 Supply Side Overview	Brian Giggee
Wrap-up	Group Discussion
Meeting Logistics	
Discussion Topics for Future Meetings	

March 23, 2021 Meeting Agenda

2021 Cold Weather	Jay Skabo
Load Forecast	Joanne Mahrer
Resource Alternatives/Heskett 4	Jake Hein
2021 IRP Modeling	Brian Giggee
Wrap-up	
Meeting Logistics	
Discussion Topics for Future Meetings	

June 14, 2021 Meeting Agenda

Legislative Session Recap	Cory Fong
Environmental Update	Abbie Krebsbach
Demand Side Update	Larry Oswald
Supply-Side Analysis	Brian Giggee
Two-year Action Plan	Darcy Neigum

Wrap-up

IRP Filing Timeline

Feedback from the PAG members

Future PAG membership for 2021 IRP

Attachment E

SUPPLY-SIDE RESOURCES STUDY

2021 Renewables and Storage Technology Assessment

MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

Montana-Dakota Utilities Co.

2021 Renewables and Storage Technology Assessment
Project No. 127909

Revision 3
December 2020

2021 Renewables and Storage Technology Assessment

prepared for

Montana-Dakota Utilities Co.
2021 Renewables and Storage Technology Assessment
Bismarck, North Dakota

Project No. 127909

Revision 3
December 2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

Page No.

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BMcD	Burns & McDonnell Engineering Company, Inc.
CAES	Compressed Air Energy Storage
CO	Carbon Monoxide
COD	Commercial Operating Date
DOE	Department of Energy
EpCM	Engineer, Procurement-Assistance, Construction Management
FAA	Federal Aviation Administration
GCF	Gross Capacity Factor
GSU	Generator Step-Up Transformer
ILR	Inverter Loading Ratio
ITC	Investment Tax Credit
LAES	Liquid Air Energy Storage
MCFC	Molten-Carbonate Fuel Cell
MDU	Montana-Dakota Utilities Co.
NCF	Net Capacity Factor
NOx	Nitrous Oxides
NREL	National Renewable Energy Laboratory
PM	Particulate Matter
PEM	Polymer Electrolyte Membrane
PPA	Power Purchase Agreement
PTC	Production Tax Credit

Abbreviation	Term/Phrase/Name
PV	Photovoltaic
TES	Thermal Energy Storage
SCR	Selective Catalytic Reduction
SOFC	Solid Oxide Fuel Cell

1.0 INTRODUCTION

Montana-Dakota Utilities Co. (Montana-Dakota, MDU, or Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various power generation technologies in support of its power supply planning efforts. The 2021 IRP Technology Assessment (Assessment) is screening-level in nature and includes a comparison of technical features, cost, performance, and emissions characteristics of the generation technologies listed below. Information provided in this Assessment is preliminary in nature and is intended to highlight indicative, differential costs associated with each technology. Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. The basis for all estimates and projections is included in this report in Section 2.0.

It is the understanding of BMcD that this Assessment will be used for preliminary information in support of the Owner's long-term power supply planning process and should not be used for construction purposes. Any technologies of interest to the Owner should be followed by additional detailed studies to further investigate each technology and its direct application within the Owner's long-term plans.

1.1 Evaluated Technologies

- Wind Generation
  - 20 MW – 8 x GE 2.82-127
  - 50 MW – 18 x GE 2.82-127
- Solar PV
  - 5 MW_{AC}
    - Single axis tracking
    - Add-On Cost for 1 MW / 4 MWh co-located Li-Ion battery energy storage
  - 50 MW_{AC}
    - Single axis tracking
    - Add-On Cost for 10 MW / 40 MWh co-located Li-Ion battery energy storage

1.2 Assessment Approach

This report accompanies the 2021 IRP Technology Assessment spreadsheet file (Summary Table) provided by BMcD in Appendix B.

This report compiles the assumptions and methodologies used by BMcD during the Assessment. Its purpose is to articulate that the delivered information is in alignment with Montana-Dakota's intent to advance its resource planning initiatives. Appendix A includes a scope assumptions matrix that was sent to Montana-Dakota and incorporates comments from Montana-Dakota.

1.3 Statement of Limitations

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

2.0 STUDY BASIS AND ASSUMPTIONS

2.1 Scope Basis and Assumptions Matrix

Scope and economic assumptions used in developing the Assessment are presented below. A spreadsheet-based scope matrix was delivered to MDU at the start of the project. An updated matrix is included for reference in Appendix A.

2.2 General Assumptions

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M estimates are stated in 2021 US dollars (USD). Escalation is excluded.
- Estimates assume an EpCM philosophy for project execution. This philosophy assumes that the contractor will provide engineering services, aid in procurement activities like specification development and bid analysis and provide construction management services.
- Unless stated otherwise, all options are based on a generic site with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material.
- Sites are assumed to be flat, with minimal rock and with soils suitable for spread footings.
- Costs and performances are based on North Dakota siting.
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- Interconnection allowances for transmission are listed in the Summary Table and general assumptions are discussed in the Owner Cost section of this report.
- Piling is included under heavily loaded foundations.
- EpCM electrical scope is assumed to end at the high side of the generator step up transformer (GSU) at 115 kV except for the 5 MW_{AC} PV option, which is assumed to interconnect at 34.5 kV. Allowances for equipment after the high side of the GSU and network upgrades are discussed in subsection 2.4.
- Demolition or removal of hazardous materials is not included.

2.3 EPC Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing (where applicable)
- Construction/startup technical service
- Engineering and construction management
- Freight
- Startup spare parts

2.4 Owner Costs

Allowances for the following Owner's costs are included in the pricing estimates:

- Owner's project development
- Owner's operational personnel prior to COD
- Owner's project management
- Owner's legal costs
- Owner's Start-up Engineering
- No land allowances are included, as wind and PV options are assumed to be located onto leased land.
- Permitting and licensing fees
- Construction power, temporary utilities
- Site security
- Operating spare parts
- Switchyard (assumes 115 kV for transmission voltage, except for the 5 MW_{AC} PV option)
- MISO Queue Fees and Network Upgrades are presented as allowances as provided by Montana-Dakota.
- Political concessions / area development fees for greenfield projects as applicable.
- Permanent plant equipment and furnishings.
- Builder's risk insurance at 0.45% of construction cost.
- Owner project contingency at 10% of total costs for screening purposes.

2.5 Project Capital Cost Estimate Exclusions

The following costs are excluded from all Project Capital Cost estimates:

- Financing fees
- Escalation
- Sales tax

- Property tax and property insurance. Included in O&M with rates provided by MDU.
- Off-site infrastructure
- Utility demand costs
- Decommissioning costs
- Salvage values

2.6 Loaded Costs

Interest During Construction (IDC) is presented in the Summary Table as determined by Montana-Dakota based on cash flows provided by BMcD.

2.7 Operating and Maintenance Assumptions

Operations and maintenance (O&M) estimates are based on the following assumptions:

- O&M costs are based on a greenfield facility with new and clean equipment.
- O&M costs are in 2021 USD.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by MDU.
- Land lease allowance included for PV and onshore wind options.
- Where applicable, fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Personnel counts for each technology are included in the scope matrix in Appendix A.
- Where applicable, variable O&M costs include routine maintenance, capacity augmentation, and other consumables.
- Where applicable, major maintenance costs are shown separately from variable O&M costs.

3.0 RENEWABLE TECHNOLOGY – ONSHORE WIND

3.1 Wind Energy General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, which can be used to generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW operate are horizontal-axis. Subsystems for either configuration typically include the following: a blade/rotor assembly to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital. According to the Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), Class 3 wind areas (wind speeds of 14.5 mph) are generally considered to have suitable wind resources for wind generation development.

Locations were selected for their proximity to relatively high wind speeds in accordance with NREL wind maps, but they are otherwise arbitrary. They were not selected with respect to actual, expected, or preferred locations for current or future wind development. They were not selected with respect to actual, expected, or preferred locations for current or future wind development. Instead, they were intended to represent the average expected wind speeds available if the project were to be built within each service area.

3.2 Wind Energy Emission Controls

No emission controls are necessary for a wind energy installation.

3.3 Wind Performance

This Assessment includes 20 MW and 50 MW onshore wind generating facilities in the North Dakota service area. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization.

The GE 2.82-127 wind turbine model was assumed for this analysis, with a nameplate capacity of 2.8 MW. The maximum tip height of this package is expected to be ~500 feet, which means that a permitting process through the Federal Aviation Administration (FAA) may be required since the tip height could reach altitudes available for general aircraft. A generic power curve at standard atmospheric conditions (i.e., sea level air density, normal turbulence intensity) was utilized for the GE 2.82-127. Note that this turbine is intended only to be representative of a typical wind turbine utilized for utility scale projects. Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition. Actual turbine selection requires further site-specific analysis.

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated for an 89 m hub height for the GE 2.82-127 to determine a representative wind speed. Using a Rayleigh distribution and power curve for the turbine technology described above, a gross annual capacity factor (GCF) was subsequently estimated for each site.

Annual losses for a wind energy facility were estimated at approximately 15 percent, which is a common assumption for screening level estimates in the wind industry. This loss factor was applied to the gross capacity factor estimates to derive a net annual capacity factor (NCF) for each potential site. Ideally, a utility-scale generation project should have an NCF of 30 percent or better.

3.4 Wind Cost Estimate

The wind energy cost estimate is shown in the Summary Tables. The cost estimate assumes a two-contract approach with the Owner awarding a turbine supply contract and a separate BOP contract. Typical Owner's costs are also shown. Costs are based on 20 MW and 50 MW plants with 2.8 MW turbines (8 and 18 total turbines, respectively).

- The EPC scope includes a GSU transformer for interconnection at 115 kV.
- Land costs are excluded from the EPC and Owner's cost. For the 2021 Study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate.
- Cost estimates also exclude escalation, interest during construction, financing fees, off-site infrastructure, and transmission.

3.5 Wind Energy O&M Estimates

O&M costs in the Summary Tables are derived from in-house information based on BMcD project experience and vendor information. Wind O&M costs are modeled as fixed O&M, including all typical operating expenses with the following breakdown:

- Labor costs
- Turbine O&M
- BOP O&M and other fixed costs (G&A, insurance, environmental costs, etc.)
- Property taxes
- Land lease payments

An allowance for capital replacement costs is not included within the annual O&M estimate in the Summary Table. A capital expenditures budget for a wind farm is generally a reserve that is funded over the life of the project that is dedicated to major component failures. An adequate capital expenditures budget is important for the long-term viability of the project, as major component failures are expected to occur, particularly as the facility ages.

If a capital replacement allowance is desired for planning purposes, the table below shows indicative budget expectations as a percentage of the total operating cost. As with operating expenses, however, these costs can vary with the type, size, or age of the facility, and project-specific considerations may justify deviations in the budgeted amounts.

Table 3-1: Summary of Indicative Capital Expenditures Budget by Year

Operational Years	Capital Expenditure Budget
0 – 2	None (warranty)
3 – 5	3% – 5%
6 – 10	5% – 10%
11 – 20	10% – 15%
21 – 30	15% – 20%
31 – 40	20% – 25%

3.6 Wind Energy Production Tax Credit

Tax credits such as the production tax credit (PTC) and investment tax credit (ITC) are not factored into the cost or O&M estimates in this Assessment, but an overview of the PTC is included below for reference.

To incentivize wind energy development, the PTC for wind was first included in the Energy Policy Act of 1992. It began as a $15/MWh production credit and has since been adjusted for inflation. In December 2019, Congress passed extensions of the PTC for wind through 2020. Wind projects will qualify if developers begin construction before the end of 2020. The value of the PTC for each year is summarized below.

The PTC is awarded annually for the first 10 years of a wind facility's operation. Unlike the ITC that is common in the solar industry, there is no upfront incentive to offset capital costs. The PTC value is calculated by multiplying the $/MWh credit times the total energy sold during a given tax year. At the end of the tax year, the total value of the PTC is applied to reduce or eliminate taxes that the owners would normally owe. If the PTC value is greater than the annual tax bill, the excess credits can potentially go unused unless the owner has a suitable tax equity partner.

Since 1992, the changing PTC expiration/phaseout schedules have directly impacted market fluctuations, driving wind industry expansions and contractions. The PTC is currently available for projects that begin construction by the end of 2020, but with a phaseout schedule that began in 2017. Projects that started construction after 2016 will receive reduced credits. Projects have four years from commencing construction to begin producing electricity. Guidance from the Department of Energy estimates the following allowable tax credits per unit of energy production:

- 2019: 1 ¢/kWh
- 2020: 1.5 ¢/kWh
- 2021: PTC Expires

To avoid receiving a reduction in the PTC, a "Safe Harbor" clause allow developers to avoid the reduction through an upfront investment in wind turbines before the phase out of the PTC. The Safe Harbor clause allows for wind projects to be considered as having begun construction by the end of the year if a minimum of 5% of the project's total capital cost was incurred before January 1st of the applicable year.

Many wind farms were planned for construction and operation when it was assumed that they would receive 100% of the PTC. However, with the reduction in the PTC some of these projects are no longer financially viable for developers to operate. This may result in renegotiated or canceled PPAs, or transfers to utilities for operation.

4.0 RENEWABLE TECHNOLOGY – SOLAR PHOTOVOLTAIC

This Assessment includes single axis tracking photovoltaic (PV) options at 5 MW_{AC} and 50 MW_{AC}. Each of these options are solar-plus-storage options with 1 MW | 4 MWh and 10 MW | 40 MWh lithium ion batteries included respectively.

4.1 PV General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 2% in the first year and 0.5% per year thereafter. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80% of its initial efficiency.

4.2 PV Emission Controls

No emission controls are necessary for a PV system.

4.3 PV Performance

BMcD ran simulations of each PV option using PVsyst software. The resultant capacity factors for fixed tilt (60° angle) and single axis tracking systems are shown in the Summary Table. An Inverter Loading Ratio (ILR) of 1.25 for each system was assumed, which is within a range of typical utility systems design. Depending on the application and requirements for firmer solar generation, ILR values can commonly range from just greater than 1 to 1.4. This value will also depend on expected interconnection type, AC capacity ratio between the PV facility to the interconnection limit, and potential use cases when paired with an energy storage system. A larger ILR value will typically yield greater capacity factors at greater overall cost of installation of the PV facility to install greater DC capacity.

Capacity factors are better for single axis tracking systems, but costs are higher for similar ILR ratios. Single axis tracking systems tend to perform better in the summer, when they are able to make better use of longer days and higher sun heights. However, they also can underperform when compared to fixed tilt systems in the winter at high latitude sites since single axis tracking systems lay flat on their racking structures and are not tilted to the equator. Further analysis would be required to select which mounting system is best suited for a given site.

Panel technologies may also exhibit different performance characteristics depending on the site. Thin film technologies are typically cheaper per panel, but they are also less energy dense, so it's likely that more panels would be required to achieve the same output. In addition, the two technologies respond differently to shaded conditions and ambient and PV cell temperature effects.

Additional assumptions are listed in the scope matrix in Appendix A.

4.4 PV Cost Estimates

Cost estimates were developed using in-house information based on BMcD project experience. Cost estimates assume an EPC project plus typical Owner's costs.

PV cost estimates for the fixed tilt and single axis tracking systems with 1,500V central inverters are included in the Summary Tables. The project scope for the 5 MW option assumes a medium voltage interconnection and the Owner's costs include an allowance for interconnection downstream of the 34.5 kV circuit breaker. The 50 MW option scope includes interconnection at 115 kV.

PV installed costs have steadily declined for years. The main drivers of cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. However, also impacting PV prices are US tariffs on PV panels and steel imports. The panel tariffs only impact crystalline solar modules, however the availability of CdTe is limited for the next couple years, so it is prudent to assume similar cost increases for thin film panels until the impacts of the tariff are clearer.

The 2021 Assessment excludes land costs from capital and Owner costs. It is assumed that all PV projects will be on leased land with allowances provided in the O&M costs.

4.5 PV O&M Cost Estimate

O&M costs for the PV options are shown in the Summary Tables. O&M costs are derived from BMcD project experience and vendor information. The 2021 Assessment includes allowances for land lease and property tax costs.

The following assumptions and clarifications apply to PV O&M:

- O&M costs assume that the system is remotely operated and that all O&M activities are performed through a third-party contract. Therefore, all O&M costs are modeled as fixed costs, shown in terms of $MM per year.
- Land lease and property tax allowances are based on input from Duke.
- Equipment O&M costs account for inverter maintenance and other routine equipment inspections.
- BOP costs account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs.
- The capital replacement allowance is a sinking fund for inverter replacements, assuming they will be replaced once during the project life. It is a 15-year levelized cost based on the current inverter capital cost.

5.0 EMERGING TECHNOLOGIES

5.1 General Description

To support Montana-Dakota's integrated resource planning, the following emerging technologies are described below:

- Flow batteries
- Liquid Air Energy Storage (LAES)
- Fuel Cells
- Compressed Air Energy Storage (CAES)
- Hydrogen Generation and Applications

These technologies have begun to see commercial applications and are beginning to accrue operating hours in some installations.

5.1.1 Flow Batteries

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Depending on the technology and design, some flow battery technologies are able to scale power and energy independently, such that the storage duration can be increased by adding electrolyte volume. Other technologies may also need to add surface area to the electrode cell stack in addition to adding electrolyte volume. Round trip efficiencies for flow battery technologies are generally in the 65% - 75% range, depending on the technology type and system losses.

Flow battery technology is generally believed to be better suited for long duration (>6 hours) storage than other leading battery technologies such as lithium ion. The demand for long duration storage is expected to increase as renewable energy penetration increases, and therefore manufacturers are rapidly developing products to meet potential future demand.

Operation and maintenance for flow batteries differs from lithium ion storage technology because there is more mechanical equipment, but there is generally no performance degradation. Lithium ion battery performance degrades over time regardless of operation, and degradation increases with each charge/discharge cycle. So, while there may be routine maintenance requirements for pumps, tanks, valves, and electrolyte chemistry, flow batteries do not require regular augmentation to maintain guaranteed system performance.

There are several flow battery manufacturers offering products in various stages of commercial development, and some with utility scale, multi-MW installations installed or planned. It is recommended that Montana-Dakota monitor flow battery market and product development in the coming years.

5.1.2 Liquid Air Energy Storage

Liquid air energy storage (LAES) uses electricity to drive a compression/refrigeration system that cools ambient air to approximately -320 °F, at which point it becomes a liquid. Liquefying air is advantageous because it achieves a volume reduction of approximately 700:1, meaning that large quantities of air can be stored in a significantly smaller volume. The liquid air is stored until it is ready for use. Energy is then recaptured by re-vaporizing the liquid air and generating power as the heated air travels through a series of heat exchangers and expanders. The overall system is optimized by taking advantage of waste heat and "waste cold" in the process to reduce the amount of power required to liquefy the air.

LAES is a relatively new application in the energy storage market, however, the major equipment components and technologies used to liquefy, store, and re-vaporize the air have been widely used in many other industry applications for decades. Highview Power is one of the major LAES technology licensors in the market, having completed a LAES pilot plant in Heathrow, UK in 2011. This operational facility uses 350 kW to liquefy the air and provides 2.5 MWh of energy storage.

One of the major similarities between LAES and CAES is that the LAES technology also offers the ability to take advantage of off-peak power to charge the system that can then be later discharged during peak demand hours as described in Section 5.1.4.

Another similarity LAES shares with adiabatic CAES is a zero emissions process. When coupled with a renewable energy source to provide power for the system, LAES is considered a completely green technology, meaning that it does not have any emissions associated with the process. The system utilizes motor-driven equipment, as opposed to a gas turbine, for the main air compressors and other auxiliary equipment, so there are no emissions generated from combustion. Additionally, there are no hydrocarbons used in the process at all – only air – so fugitive emissions are also non-existent.

The LAES technology can be broken down into three (3) major systems; system charging (air liquefaction), energy storage (liquid air storage), and system discharge (power generation). Each of these systems are relatively independent of one another and therefore can be designed for different amounts of capacity, depending on the specific application and use case. For example, the charging section of the facility (air liquefaction) could be designed to produce liquid air at a rate sufficient enough to utilize any excess energy generated from renewable sources that otherwise would need to be curtailed due to transmission constraints. However, the discharge system could be designed to generate power at the rate required to meet the demand during peak times; this rate may or may not be the same as the charging rate. The number of hours of available storage can be easily modified by adding additional liquid air storage tanks.

Ambient air is used as the source of air for the process. The air is sent through a series of compressors and heat exchangers to increase the pressure from atmospheric to approximately 850 psig. This initial air compression requires the largest amount of power usage for the entire process; there are other users within the process, but they are significantly smaller the main air compressor.

Contaminants in the air such as carbon dioxide, water, and particulates must be removed prior to the liquefaction process. Carbon dioxide and water will freeze at the cryogenic temperatures and could clog the piping, valves, or equipment. The air flows through a set of molecular-sieve beds that adsorb the water and CO_2 from the air – this technology is very similar to the process used in liquefied natural gas (LNG) facilities. Once saturated, the molecular-sieve is regenerated with dry air and ready to be used again.

A common process used to liquefy air is the Claude cycle. In the Claude cycle, the air acts as the process fluid to be cooled as well as the refrigerant. The high pressure air is let-down across an expander and/or valve to low pressure. This rapid reduction in pressure creates a cooling effect, known the Joule-

Thompson (JT) effect, and a portion of the air becomes the liquid air product. Any air that is not liquefied is used as a refrigerant to further cool the system and is recycled to go through the process again. This is a well-known and widely industry-recognized process for liquefying air.

Once the air is liquefied, it must be stored until ready for use. A benefit that LAES provides over CAES is that a specialized storage site, such as a salt cavern, is not required. Liquid air is stored in field-erected, insulated, cryogenic, storage tanks. These tanks are very similar to the storage tanks used to store other cryogenic liquids (such as liquid nitrogen or liquefied natural gas) and are widely utilized the in the oil, gas, and chemicals industry. By not depending on the geological formations of the site for storage, LAES facilities can be built in any location in which sufficient space is available.

Although the tanks are very well insulated, there will be some amount of the liquid air that "boils-off" as the system sits stagnant. Fortunately, since the contents of the storage system are only air (nitrogen, oxygen, argon, etc.), this "boil-off" vapor can be vented directly to atmosphere with no additional handling equipment required.

Depending on the amount of storage duration desired (i.e. hours of storage), the volume and quantities of storage tanks can be modified. Additional storage duration requires additional storage volume. When determining the size/capacity of the charging system, it is important to consider how long it will take to fill the storage tanks. If the charging duration is too long, it may be advantageous to increase the charging system capacity.

When ready to use to generate power, the liquid air is pumped from the storage tanks to a heat exchanger in which it is re-vaporized. The warm air then flows through series of heat exchangers and expanders, similar to CAES, in order to generate power via the expander. The rate in which power is generated is determined by the pumping capacity and the expander capacity. The higher discharge rate required, the larger the expander required. Once the air is fully expanded, it is released back into the atmosphere.

The industry in general in investigating the potential of LAES systems but there are limited manufacturers offering products in various stages of commercial development. It is recommended that Montana-Dakota monitor the LAES systems market and product development in the coming years.

5.1.3 Fuel Cells

Fuel cells consist of an electrolyte material held between a negatively charged anode and a positively charged cathode, and then placed between two flow field plates. Via the flow plates, hydrogen fuel is forced through the anode while oxygen (air) flows through the cathode. The resultant chemical reaction splits the hydrogen into particles by charge. The electrolyte is impermeable to the negatively charged particles, which are then forced through a circuit, generating current. Positively charged particles pass through the electrolyte and recombine with oxygen and the negatively charged particles at the anode to form water and carbon dioxide byproducts. This process also yields heat which can be recuperated to generate high temperature steam used in the reformation of natural gas to produce the hydrogen fuel.

As fuel cell technology matures and installations accrue more operating hours, research and development continues in both private and government funded institutions to optimize operating efficiency and reduce costs. Many states offer financial incentives that can reduce the installed cost of fuel cells.

Molten-carbonate fuel cells (MCFCs) utilize a high temperature salt (typically sodium or magnesium) based electrolyte core. The electrolyte compound is held in molten state, operating at 1,100°F to 1,300°F. While this yields relatively high thermal efficiencies in the range of 50 percent to 60 percent, the elevated temperatures also result in increased corrosiveness of the liquid electrolyte. MCFCs are currently being marketed as commercially available technology for megawatt-scale generation needs, however this is still a developing generation technology with limited operational experience compared to simple cycle turbine and engine technologies. Research and development efforts are focused on increased size and reliability while reducing the cost of manufacture.

Solid Oxide fuel cells (SOFCs) utilize a solid ceramic and metal oxide based electrolyte but operate at even higher temperatures than the MCFC, in the range of 1,200°F to 1,800°F at similar thermal efficiencies. Elevated operating temperatures yield the possibility of internal gas reformation and can limit cell component life. However, elevated temperatures can provide benefits in steam co-generation applications. SOFCs are commercially available, but like MCFCs, they are a relatively recent development in fuel cell technology with limited operating experience in the utility market.

Due to the configuration of the cell and electrolyte core, MCFCs are more commonly scalable and are commercially available in modular units approaching 3,000 kW output. This scalability lends the MCFC to better suitability for distributed generation applications at the utility scale, particularly in excess of 1 to 2 MW of output. Recent domestic SOFC installations have trended more towards single consumer use at large company headquarters, rather than for the sole purpose of power generation and sale to the grid. In addition, manufacture of SOFCs is limited, which has led to high cell cost and concern over product value. There are technologies including phosphoric acid fuel cells and polymer electrolyte membrane fuel cells, but these are better suited for residential, commercial, or transportation applications.

Fuel cells do not rely on fuel combustion and therefore NO_x, CO, and PM emissions are inherently low compared to most generation technologies. CO_2 emission rates are comparable to natural gas combustion technologies. No external emission control technologies are expected for fuel cell technologies. Fuel cell heat rates are generally in line with modern combined cycle plant heat rates. Fuel cell costs are generally declining as the technology matures, and installations are increasing in areas with high electricity costs (i.e. California) and/or prominent incentives (i.e. Connecticut). The two leading fuel cell manufacturers in the utility space commonly offer full turnkey solutions, in which they engineer, construct, own, and operate their facilities, selling electricity directly to their customer. It is recommended that Montana-Dakota monitor the market and technology development for fuel cell systems in the coming years.

5.1.4 Compressed Air Energy Storage

Compressed air energy storage (CAES) offers a way of storing off peak generation that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, either a salt cavern or mined hard-rock cavern. Salt caverns are the most preferred due to the low cavern construction costs, however mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it, and generating power as the heated air travels through an expander.

The difference between diabatic and adiabatic compressed air energy storage is in the method that the air is heated during generation. Diabatic CAES uses natural gas firing during generation via a gas turbine expansion train. Expansion train technology is also currently allowing for 30% H2 co-firing today and there are plans to develop the technology to support 100% H2. Round-trip efficiencies for diabatic CAES plants account for the energy input of the compressors as well as the energy input of the gas turbine. The energy input of the compressors is a design choice that will be made to balance cost and benefit. The round-trip efficiencies represented in this technology assessment are the efficiencies that can be reached at the cost that is shown. The heat input of the gas turbine during generation takes into account the heat rate of the turbine. The total energy output of the CAES plant is divided by the combination of these two figures (compressor energy and natural gas heat input) to calculate the round-trip efficiency. There have been two commercial CAES plants built and operated in the world. The first plant began commercial operations in 1978 and was installed near Huntorf, Germany. This 290 MW facility included major equipment by Brown, Boveri, and Company (BBC). The second is located near McIntosh, Alabama and is currently owned and operated by PowerSouth (originally by Alabama Electric Cooperative). This 110 MW facility began commercial operations in 1991 and employs Dresser Rand (DR) equipment. BMcD served as the Owner's engineer for this project. In new projects, however, diabatic CAES is not as popular due to a shift in focus from developers to adiabatic CAES, which offers zero emissions storage.

Adiabatic CAES does not require natural gas or hydrogen firing during expansion/discharge. Heat is recovered in a Thermal Energy Storage (TES) system while air is being compressed and this energy is released to heat the air during expansion and generation. During compression, air temperatures can reach up to 1000°F. The use of a TES (with oil, molten salt, etc..) to capture and release this heat allows the adiabatic CAES technology to work free of any fuel. This trait can decrease operating and construction costs. The absence of a gas turbine makes the calculation for round-trip efficiency the total energy output of the plant divided by the energy input of the compressors. Again, the size and energy requirements of the compressors is a design choice and the efficiencies represented in the technology assessment table are in conjunction with the costs also represented for each option. This technology is currently in service or in construction at 3 plants in Canada and Australia that total 25 MWh of storage capacity.

A Selective Catalytic Reduction (SCR) system is utilized in the diabatic CAES design along with demineralized water injection in the combustor to achieve NOx emissions of 2 parts per million, volumetric dry (ppmvd). A carbon monoxide (CO) catalyst is also used to control CO emissions to 2 ppmvd at the exit of the stack.

The use of an SCR and a CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with the exhaust gas to strip out NOx. This requires onsite ammonia storage and provisions for ammonia unloading and transfer. Adiabatic CAES is an emissions-free operation and does not require an emissions control system. It is recommended that Montana-Dakota monitor the market and technology development of CAES in the coming years.

5.1.5 Hydrogen Generation and Applications

Hydrogen production can play a part in enabling carbon emission reduction targets and has been proposed as a part of an overarching hydrogen economy since the early 1970s. High hydrogen fuel blends or 100% hydrogen combustion is an attractive avenue due to the potential of retrofitting existing units and to experience in compression and storage of other gases. Low carbon sources of hydrogen include fuel stock gasification, methane reforming (potentially paired with carbon capture and sequestration), and water electrolysis. Industry has colorful monikers for each of these options. Gasification of biomass and solid fossil fuels takes place in a sub-stoichiometric partial combustion in hot air, oxygen, or steam and is sometimes called "white" hydrogen when paired with carbon capture technology. Methane reforming requires superheated steam to form hydrogen from a natural gas stream. This process also results in carbon monoxide that requires sequestration to limit the carbon emissions from the process. This hydrogen generation and carbon capture combination is generally called "blue" hydrogen.

Water electrolysis has seen limited deployment to date. Electrolysis generates hydrogen through the decomposition of water into its formative atoms in a polymer electrolyte membrane (PEM) or alkaline water process using an electrical current. PEM technology is generally more compact, simple to operate and exhibit higher initial efficiencies compared to alkaline water options. However, PEM technology also typically degrades at a greater rate, is more expensive, and has had fewer large-scale installations. Both solutions have commercially available options and manufacturers. In addition to the electrolysis equipment, these hydrogen generating technologies also require balance of plant equipment and tie-ins like feed water storage, a demineralized water feed, nitrogen purge systems, medium and low voltage power feeds, and alkali reagent storage and unloading for alkaline electrolyzers. Electrolysis has been touted as a potential source of hydrogen in the future thanks to potential utilization of curtailed energy from renewable sources allowing for "green" hydrogen. However, this mode of operation is not yet widespread and might require firmer power to maintain economic viability. Due to these potential issues in these facets of the supply chain, in addition to storage and transport of the hydrogen, there are significant developments required for widespread use of hydrogen as a fuel source. Hydrogen leaks much easier than other commonly stored gases due to its small molecule size, making leak detection, ventilation, and continuous monitoring of storage container conditions for embrittlement of high importance. Hydrogen storage in compressed form would likely require high pressure rating tubing and tanks with potential metal and plastic lining that is available commercially. Metal hydride and adsorption storage, liquid storage, and geological storage might also serve as potential storage solutions.

In the following sections, discussion is provided about hydrogen combustion specific performance and cost concerns for simple cycle and combined cycle gas turbine applications. While reciprocating engines have some capabilities of burning hydrogen fuels, there are limitations on the maximum capability by volume that is expected to be lower than that of combustion turbine options.

5.1.5.1 Simple Cycle Gas Turbine

To combust high hydrogen fuels, available aeroderivative & frame gas turbines models typically require either steam injection or water injection methods in order to control emissions. This requirement for water can greatly influence the viability of these technologies depending on project siting and conditions. Plants firing high hydrogen fuels would accordingly be expected to have variable O&M impacts to acquire water of the quality necessary to meet these needs.

Frame engines capable of firing high hydrogen fuel are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Solar. Historically, due to the large amount of volume of hydrogen rich fuels necessary to fully meet the heat input requirements for larger frame turbines, smaller frame engines have had greater experience in hydrogen combustion applications. Industrial and aero turbines are largely capable to operate on hydrogen at 65-100% capability by volume. For high hydrogen content fuels, water or steam injection may be required that might require exhaust energy recuperation to supply these engines with this mass flow.

Turbine suppliers offer a range of NO_x emissions levels based on their combustor technologies and control systems including water and steam injection. Depending on the planned operating profile of the turbines, selective catalytic reduction might be required to meet NO_x limits. Due to the lower carbon content of high hydrogen fuels, CO and CO_2 control equipment would not be anticipated for simple cycle turbine applications but will depend on project specific requirements. Supplemental natural gas as required for turbine operation is expected to be the main driver for other potential emissions like sulfur dioxide and particulate matter.

In addition to these performance concerns, costs for simple cycle applications is impacted by potential requirement of on-site hydrogen compression and modifications to the turbine enclosure and fuel conditioning packages.

5.1.5.2 Combined Cycle Gas Turbine

Combined cycle high hydrogen fuel combustion applications share similar performance and cost considerations as the simple cycle details described previously. An area of specific concern is the feasibility of duct firing in combined cycle applications. Safety concerns related to the characteristics of hydrogen gas combustion in duct burners like flame speed are a potential concern. For example, during a flame-out event of the turbine, unburned fuel could be ignited by the duct burner causing the duct burner flame to propagate back and cause a pressure rise that cannot be contained by the exhaust ducting. This is a serious safety concern for which mitigation measures require further detailed field testing. One method that could be used to mitigate this risk is to dilute the gas turbine exhaust with fresh air to increase the velocity of the gas flow. However, this will reduce the exhaust temperature of the gas turbine which has a negative effect on the steam cycle efficiency.

6.0 CONCLUSIONS

This Assessment provides information to support Montana-Dakota's power supply planning efforts. Information provided in this Assessment is preliminary in nature and is intended to highlight indicative, differential costs associated with each technology. Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD recommends that Montana-Dakota use this information to update production cost models for comparison of generation alternatives and their applicability to future resource plans. Montana-Dakota should pursue additional engineering studies to define project scope, budget, and timeline for technologies of interest.

Of all technologies evaluated, the 50 MW Solar PV option exhibits the lowest capital cost per kW generated. PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals. PV capital costs have steadily declined for years, but recent import tariffs on PV panels and foreign steel may impact market trends.

Wind energy generation is a proven technology and turbine costs have dropped considerably over the past few years.

In addition to the technologies included in the Summary Table of the Assessment, flow batteries, liquid air energy storage, fuel cells, compressed air energy storage, and hydrogen generation and storage were discussed as emerging technologies for informational purposes. It is recommended that Montana-Dakota Utilities monitor the development of these technologies and their economic viability in the coming years.

APPENDIX A – SCOPE MATRIX

2021 MDU RENEWABLE & STORAGE TECHNOLOGY ASSESSMENT ASSUMPTIONS

	Wind	PV	PV + Storage
Project Description			
Plant Size(s):	20 MW	50 MW - Single Axis Tracking	Co-Located w/50 MW PV 10 MW / 40 MWh Storage
	50 MW	5 MW Single Axis Tracking PV	Co-Located w/5 MW PV 1 MW / 4 MWh Storage
Fuel:	N/A	N/A	N/A
Project Location:	North Dakota		
Contract Philosophy:	Multiple Contract Approach (EpCM)		
Project COD:	Shown in 2021 (i.e. no escalation)		
Labor Type:	Union		
Labor Incentives:	50 hrs / week & $80 per day per diem		
Site Description:	Greenfield		
Scope Basis / Assumptions:			
Redundancy:	Reflective of typical utility service. Redundant installed components (2 x 100%, 3 x 50%) where component failure could cause outage of the plant. No spare GSU.		
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and coal plant stacks.		
Site Elevation:	1690 ft ASML		
Water Supply:	No fresh water supply expected to be required.		
Waste Water Disposal:	N/A	N/A	N/A
Interconnection:			
Switchyard / Interconnection:	Included with position for generators & 2 outgoing lines at 115 kV.	PV scope for EPC includes 34.5 kV collector bus and circuit breaker. Owner Costs include allowance for interconnection at 34.5 kV for 5 MW option and 115 kV for 50 MW option.	
MISO Queue Fees:	Included.		
Network Upgrades:	Included as provided by MDU.		
Miscellaneous Contract Costs:			
Startup Spare Parts:	Allowance included.		
Construction Indirects:	Construction Mgmt, Engineering, Performance testing and start-up, initial fills and consumables, startup, surveys, and site security Included.		
Performance Bonds:	Excluded		
Indirect / Owner's Indirect Costs:			
Project Development	Allowance included.		
Owner Operations Personnel Prior to COD	Allowance included.		
Owner's Project Management	Allowance included.		
Owner Engineering	Excluded.		
Owner Legal Council	Allowance included.		
Operator Training	Allowance included.		
Permitting & License Fees	Allowance included.		
Land	Excluded - represented as a lease in O&M costs.		
Labor Camp	Excluded - assumed to not be required and that plant has local towns / housing.		
Temporary Utilities	Allowance included.		
Builder's Risk Insurance	Allowance included.		
Operating Spare Parts	Allowance included.		
Owner's Contingency:	Allowance included.		
Interest During Construction	Provided by MDU		
Sales Tax:	Excluded		

2021 MDU RENEWABLE & STORAGE TECHNOLOGY ASSESSMENT
OPERATING ASSUMPTIONS

	Wind	PV / PV + Storage
General		
Staffing:		
Number of Personnel:	2	2
Labor Cost:	O&M costs associated with labor are expected to be representative of tasks required to maintain assets through contractors or internal employees.	
Operating Hours Considered:	N/A	
Standby Power:	Connection to grid for night-time or non-generating hours.	
Standby Power Cost:	$21/MWh	
Property Insurance:	Included, rate provided by MDU (0.15% of Total Loaded Project Cost)	
Property Tax:	Included, rate provided by MDU (0.42% of Total Loaded Project Cost)	
Maintenance Considerations		
Maintenance Basis	Storage augmentation and overbuild assumptions included in summary table. Other capital maintenance measures described in summary table notes.	
Scope Basis / Assumptions		
Water Supply Cost:	No fresh water supply expected to be required.	

APPENDIX B – 2021 RENEWABLES & STORAGE TECHNOLOGY ASSESSMENT SUMMARY TABLE

MONTANA-DAKOTA UTILITIES CO. 2021 RENEWABLES & STORAGE TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
November 2020 - Rev 1

PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
BASE PLANT DESCRIPTION				
Nominal Output, MW	20	50	50 MW PV Opt: 10 MW / 40 MWh Storage	5 MW PV Opt: 1 MW / 4 MWh Storage
Representative Technology	GE 2.82-127	GE 2.82-127	PV: Single Axis Tracking Storage: Li-Ion Batteries	PV: Single Axis Tracking Storage: Li-Ion Batteries
Number of Turbines	8	18	N/A	N/A
Capacity Factor (%) (Notes 1, 2)	44.9%	44.9%	22.3%	22.4%
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	1.25	1.25
PV Degradation (%/yr) (Note 3)	N/A	N/A	0.50%	0.50%
Equivalent Availability Factor (%) (Note 4)	95%	95%	99%	99%
ESTIMATED PERFORMANCE				
Base Load Performance				
Net Plant Output, kW	20,000	50,000	50,000	5,000
Net Plant Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	N/A
Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	N/A
ESTIMATED CAPITAL AND O&M COSTS (Note 6)				
Project Capital Costs, 2021 MM$ (w/o Owner's Costs)	**$25.2**	**$61.0**	**$53.1**	**$9.30**
Project Cost Per kW, 2021 $/kW	**$1,260**	**$1,220**	**$1,060**	**$1,860**
Owner's Costs, 2021 MM$	**$7.4**	**$18**	**$16**	**$3.2**
Owner's Project Development	$0.2	$0.3	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$0	$0	$0	$0
Owner's Engineer	$0	$0	$0	$0
Owner's Project Management	Included	Included	$0.2	$0.1
Owner's Legal Costs	Included	Included	$0.0	$0.0
Owner's Start-up Engineering	$0	$0	$0	$0
Land (Note 5)	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Temporary Utilities	Included	Included	$0.3	$0.1
Permitting and Licensing Fees	Included	Included	$0.5	$0.4
Switchyard / Interconnection (Notes 7, 8)	Included	Included	$2.0	$0.2
MISO Queue Fees (Note 9)	$0.1	$0.2	$0.2	$0.1
Network Upgrades	$2.3	$5.6	$5.6	$0.6
Site Security	Included	Included	$0.1	$0.1
Operating Spare Parts	Included	Included	$0.4	$0.1
Permanent Plant Equipment and Furnishings (Note 10)	Included	Included	$0.3	$0.3
Political Concessions & Area Development Fees	$0	$0	$0.0	$0.0
Builder's Risk Insurance (0.45% Project Cost)	$0.1	$0.3	$0.2	$0.0
Owner's Contingency (10% for Screening Purposes)	$2.5	$6.1	$6.3	$1.1
Total Project Costs, 2021 MM$ (Unloaded)	**$33**	**$79**	**$70**	**$13**
Total Cost Per kW, 2021 $/kW (Unloaded)	**$1,630**	**$1,580**	**$1,390**	**$2,500**
Loaded Costs				
Interest During Construction, 2021 MM$ (Note 13)	**$1.1**	**$2.2**	**$1.8**	**$0.5**
Total Project Costs, 2021 MM$ (Loaded)	**$34**	**$81**	**$71**	**$13**
Total Cost Per kW, 2021 $/kW (Loaded)	**$1,680**	**$1,620**	**$1,430**	**$2,600**
FIXED O&M COST				
Fixed O&M Cost, 2021$/kW-mo (Note 10)	$4.20	$4.20	$1.10	$1.20
Property Tax, 2021 $/kW-mo (Note 11)	$0.60	$0.60	$0.50	$0.90
Property Insurance, 2021 $/kW-mo (Note 12)	$0.20	$0.20	$0.20	$0.30
NON-FUEL VARIABLE & MAINTENANCE COST				
Major Maintenance Cost, 2021$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Variable O&M Cost, 2021$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Co-Located Energy Storage			**10 MW | 40 MWh**	**1 MW | 4 MWh**
Add-On Costs				
Capital Costs, 2021 MM$	N/A	N/A	$15.7	$2.1
Owner's Costs, 2021 MM$	N/A	N/A	$1.50	$0.40
Incremental O&M Cost, 2021 MM$/Yr	N/A	N/A	$0.35	$0.06
Loaded Costs, Interest During Construction, 2021 MM$	N/A	N/A	**$0.60**	**$0.32**

MONTANA-DAKOTA UTILITIES CO. 2021 RENEWABLES & STORAGE TECHNOLOGY ASSESSMENT SUMMARY TABLE
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Representative Technology	GE 2.82-127	GE 2.82-127	PV: Single Axis Tracking Storage: Li-Ion Batteries	PV: Single Axis Tracking Storage: Li-Ion Batteries

Notes:
Note 1: Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on GE 2.82-127 turbines with 89 meter hub height and 8.5 m/s average wind speed.
Note 2: Solar capacity factor accounts for typical losses.
Note 3: PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each remaining year.
Note 4: Availability estimates are based on vendor correspondence and industry publications.
Note 5: Wind and PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Land lease and property tax allowances are included in the the Fixed O&M. Wind assumes one acre per turbine. PV assumes eight acres per MW for single axis tracking options.
Note 6: Estimated Costs exclude decommisioning costs and salvage values.
Note 8: PV scope for EPC includes 34.5 kV collector bus and circuit breaker. Owner costs include allowance for interconnection at 115 kV for the 50 MW option only.
Note 9: MISO Queue Fees Owner's Costs includes application fee and Study Funding Deposit. Milestone payments are not included as those would be expected to be utilized for Network Upgrades which are shown separately as provided by MDU.
Note 10: Renewable options include an administrative building for storage and monitoring functions.
Note 11: Property tax rate provided by MDU.
Note 12: Property Insurance rate provided by MDU.
Note 13: Interest During Construction costs are estimated based on previous work performed for MDU for similar scale projects.

CREATE AMAZING.

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Attachment F

January 17, 2020 Request for Proposal for Capacity and Energy Supply

2020 RFP for Capacity and Energy

Overview

Montana-Dakota issued a Request for Proposal (RFP) on January 17, 2020, for capacity and energy totaling at least 10 MW and no more than 200 MW for the period beginning June 1, 2023.

Process

Once the RFP was issued, companies had until January 31, 2020, to submit a Notice of Intent to Bid (NOIB). Seventeen companies submitted a NOIB. The companies then had until February 28, 2020, to submit their final proposals. This resulted in twelve companies submitting final bids with several companies submitting multiple proposals.

The date for a shortlist was March 27, 2020, and ultimately three projects were shortlisted from the list of proposals that included a demand response program, solar, and small storage. The final selection process was April 30, 2020, which was delayed, and resulted in only the demand response program being selected.

The full RFP issued by Montana-Dakota can be seen in Appendix A of this attachment.

A redacted version of the Company's RFP evaluation spreadsheet can be found in Appendix B of this attachment. Appendix B is redacted to remove confidential information.

Summary of bids

The list below shows the types of responses, and numbers of each, that were received:

- Wind – 3
- Solar – 2
- Distributed Solar/Battery – 1
- Demand Response - 2
- Capacity and Energy – 5
- Solar/ Battery Storage – 2
- Wind/Solar/Battery - 1

Analysis Results

All but three of the proposals received in the RFP failed to meet the minimum bid requests. The reason that many of the proposals did not meet the minimum bid requirements is that projects did not have a final interconnection agreement and the costs of their network interconnection upgrades were unknown or did not directly tie to MDU's system. With MISO's interconnection queue being backed up and projects dropping out of the queue with high interconnection costs it makes difficult to move forward with projects. Then once the magnitude of network upgrade costs are known, these additional costs would be passed along as an additional charge to Montana-Dakota and its customers. Two of the proposals were greater than the maximum request of 100 MW, ranging from 150 MW to 450 MW in size in which if we were to take smaller amounts the project would be contingent on finding additional partners.

In the final analysis only the demand response program was selected which was an expansion of our current Commercial Demand Response Program to grow from 25 MW up to 50 MW. The solar project was not selected with uncertainty of potential network upgrades costs and location of the project not being on Montana-Dakota's system, and the small storage was tabled for later discussion. The Company will issue a new request for proposal before the start of the next integrated resource plan.

Appendix A

2020 RFP MATRIX

2020 RFP Evaluation Matrix

Bidders / Proposals	1 - Located in MISO LRZ 1	2 - Price	3 - Term	4 - Cost Adders/Adjustment *	5 - Project Size *	6 - Resource Type	7 - Interconnects to MDU *	8 - Location	9 - GIA Status	10 - Met RFP Requirements	11 - Risk of Curtailments	12 - Comments
1 [redacted]												
Proposal	Yes	[redacted]	25 Years (2023)	Network Upgrades	150-170MW	Solar, Battery	No	Minnesota	Queue	No	Low	Network Upgrade costs unknown and assigned to off-taker.
2 [redacted]												
Proposal	Yes	[redacted]	N/A years (2021)	None	10-30 MW	Distributed Solar and/or Battery	Yes	North Dakota	N/A	Yes	None	
3 [redacted]												
Wind Proposal 1	Yes	[redacted]	20 Years (Q4 2022)	Network Upgrades	54 MW	Wind	Yes	South Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Wind Proposal 2	Yes		20 Years(Q4 2021)	Network Upgrades	100 MW	Wind	No	Minnesota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
4 [redacted]												
Hybrid 1	Yes	[redacted]	20 Years (Q4 2024)	Network Upgrades	Up to 450 MW	Wind, Solar, Battery	No	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
5 [redacted]												
Solar Proposal 1	Yes	[redacted]	20 Years(Q4 2022)	Network Upgrades	Up to 100 MW	Solar	No	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Solar Proposal 2	Yes		20 Years(Q4 2022)	Network Upgrades	52 MW	Solar	Yes	Montana	Not studied	No	Medium	GIA not filed. Network Upgrade costs unknown and assigned to off-taker.
6 [redacted]												
Demand Response 1	Yes	[redacted]	N/A (2021)	None	25 MW	Demand Response	Yes	Interconnected System	N/A	Yes	None	
Demand Response 2	Yes		N/A (2021)	None	2.1 MW	Demand Response	Yes	Interconnected System	N/A	Yes	None	
7 [redacted]												
Proposal	Yes	[redacted]	20 Years (Q4 2022)	Network Upgrades	45-55 MW	Solar, Battery	No	Minnesota	Queue	No	Low	Network Upgrade costs unknown and assigned to off-taker.
8 [redacted]												
Proposal	Yes	[redacted]	20 Years (2022)	Network Upgrades	100 MW	Wind	Yes	North Dakota	Queue	No	Low	Network Upgrade costs unknown and assigned to off-taker.
9 [redacted]												
Proposal	Yes	[redacted]	2 Years (2023)	None	25 to 50 MW	Capacity & Energy	No	Western Interconnect	N/A	No	None	Unkown transmission issues across DC tie
10 [redacted]												
Proposal	Yes	[redacted]	2 or 5 Years (2023)	None	20 to 50 MW	Energy	No	Minnesota Hub	N/A	Yes	None	Only energy
11 [redacted]												
Proposal	Yes	[redacted]	2 or 5 Years (2023)	None	20 or 100 MW	Capacity & Energy	No	Minnesota Hub	N/A	Yes	None	
12 [redacted]												
Proposal	Yes	[redacted]	10 Years (2023)	None	50 to 100 MW	Capacity & Energy	No	Minnesota	N/A	Yes	None	

* to be determined network upgrade costs assigned to PPA

* several projects larger than RFP request

* Interconnections to MDU's transmission system provide other benefits including
  1. Local Reliability
  2. SPP Membership Transferability (otherwise stranded MISO resource)

Appendix B

2020 REQUEST FOR PROPOSAL FOR CAPACITY AND ENERGY

Montana-Dakota Utilities Co.

Request for Proposal for

Capacity and Energy Supply

January 17, 2020

Table of Contents

1. INTRODUCTION

1.1. Purpose

Montana-Dakota Utilities Co., a Subsidiary of MDU Resources Group, Inc. ("Montana-Dakota"), is a public utility with retail electric load in parts of North Dakota, South Dakota, Montana, and Wyoming. During the normal course of its business operations, Montana-Dakota continuously evaluates alternatives to fulfill its need to maintain reliable and cost-efficient capacity and energy resources for its customers.

In this Request for Proposal ("RFP"), Montana-Dakota requests competitive proposals ("Proposals") for capacity and energy resources totaling at least 10 megawatts (MW) and no more than 100 MW beginning June 1, 2023. Persons or entities responding to this RFP are referred to as "Respondents."

1.2. Product Description and Requirements

Montana-Dakota is seeking Proposals involving the purchase of capacity and energy resources beginning June 1, 2023 totaling at least 10 megawatts (MW) and no more than 100 MW. Company's most recent load forecast shows a need for 25 MWs of MISO Zone 1 accredited capacity for the 2023-2024 MISO Planning Year growing to 50 MWs for the 2027-2028 MISO Planning Year.

All capacity and energy offered in a Proposal must be deliverable to Montana-Dakota's integrated system, which consists of its service territories in North Dakota, South Dakota and Montana, in order to serve Montana-Dakota retail load customers. Bid pricing should reflect the capacity and energy at the designated delivery point and include all costs to deliver the capacity and energy to such delivery point.

Montana-Dakota's entire customer load under this RFP is located within the Midcontinent ISO (MISO) Local Resource Zone #1.

Montana-Dakota will consider all Proposals that meet the aforementioned requirements. Montana-Dakota will evaluate the reliability, cost, and customer rate impacts of all Proposals.

If a Proposal involves a generating unit not yet fully operational, in addition to the other requirements outlined in this section, the Respondent must provide Montana-Dakota with sufficient data to establish that the proposed generating unit(s) will achieve the commercial operation date designated in the Proposal, and at that date will be fully capable of producing the capacity and energy stated in the Proposal. The Proposal must provide an overview and detailed description of the proposed generating unit, including status of any and all necessary permits and regulatory approvals, in a separate attachment as part of the Respondent's response package.

Montana-Dakota is particularly interested in proposals for energy storage, customer demand side management, and energy efficiency programs.

Montana-Dakota reserves the right to require additional information not identified in this RFP to fully evaluate the costs, impacts, and viability of any Proposal.

1.3. Changes to RFP, Schedules, and Addenda

Montana-Dakota reserves the right to unilaterally revise or suspend the schedule, or terminate this RFP process at its sole discretion without liability to any Respondent.

2. BID SUBMITTAL

2.1. General Instructions

Montana-Dakota's Official Contact for this RFP is:

Mr. Brian Giggee
Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND 58501
701-222-7907 OFFICE
701-222-7872 FAX
E-mail: brian.giggee@mdu.com

Respondents should meet all the terms and conditions of the RFP to be eligible to compete in the RFP process. Respondents should follow all instructions contained in the RFP and submit all relevant documents. It is the Respondent's responsibility to advise the Official Contact of any conflicting requirements, omissions of information, or the need for clarification before Proposals are due. Respondents should clearly organize and identify all information submitted in their Proposals to facilitate review and evaluation. **Failure to provide all the information requested in the RFP process or failure to demonstrate that the Proposal satisfies all of the Montana-Dakota requirements may be grounds for disqualification.** Prior to the short-listing of Proposals, all correspondence and communications from the Respondent to Montana-Dakota must be made in writing through the Official Contact.

2.2. Respondent's Qualifications

Montana-Dakota will consider Proposals from any qualified Respondent, including electric utilities (e.g., investor-owned, municipal, cooperative, or tribal), independent power producers, qualified developers of generation (including renewable resources generation, distributed generation, demand side management (DSM)), and power marketers**.**

Each Respondent shall respond fully and accurately to the Statement of Financial Conditions and Creditworthiness Qualifications included in Exhibit A to the RFP. In addition to that information, during the Proposal review process, Montana-Dakota may require each Respondent to provide further credit and financial information in order to assist Montana-Dakota in addressing and weighing the creditworthiness of each Respondent.

Montana-Dakota invites Proposals from all potential suppliers who are capable of meeting the conditions of the RFP, and Montana-Dakota will evaluate all responsive bids.

2.3. RFP Communications

Prior to the Proposal submission deadline, all communications should be directed to the Official Contact's e-mail. Based upon the nature and frequency of questions received, Montana-Dakota may respond to questions individually or to all bidders.

2.4. Schedule

The following schedule and deadlines apply to this RFP:

ACTIVITY	**DATE***
Issue RFP	January 17, 2020
Bidder's Conference	None
Notice of Intent to Bid Due	January 31, 2020
RFP Responses Due	February 28, 2020
Shortlist Notification	March 27, 2020
Selection Process Complete	April 30, 2020

* Dates may be advanced or delayed at Montana-Dakota's sole discretion.

2.5. Bidder's Conference

Montana-Dakota does not plan to hold a Bidder's Conference for this RFP. Questions regarding this RFP should be sent directly to the Company's Official Contact.

2.6. Notice of Intent to Bid

In order to identify persons or entities interested in submitting a Proposal, and to assure that all those having such an interest receive any subsequent information distributed in the RFP process, interested parties are requested to submit via e-mail or FAX, a non-binding notice of intent to bid (NOIB) on or before 5:00 P.M. CDT on January 31, 2020. The form for the NOIB is included in Exhibit B to this RFP.

2.7. Proposal Content and Submission Instructions

2.7.1 In addition to the information described elsewhere in this RFP, all Respondents must include as part of their Proposal all relevant information requested in the response package. Proposals that do not contain all required information or do not fully reflect the bid requirements may not be considered at Montana-Dakota's sole discretion. In addition to the required information, Respondents should include with their Proposals any other information that may be needed for a thorough understanding or evaluation of their Proposals.

2.7.2 Complete Proposals, including all exhibits, must be received on or before 5:00 p.m. CDT on February 28, 2020 by Montana-Dakota's Official Contact. Respondents shall submit one hard copy of the original Proposal as well as one electronic version of their response package on a compact disc or DVD. **Montana-Dakota will not accept late Proposals or Proposals delivered by**

e-mail, FAX or other electronic means. Only sealed Proposals will be accepted. On the envelope, Respondent shall indicate **"Response to Montana-Dakota 2020 RFP re. Capacity and Energy Supply Resources."** Any Proposals received after the scheduled date and time will be disqualified and a notice will be sent to the Respondent.

2.7.3 All Proposal terms, conditions, and pricing should be valid through the completion of the selection process, currently planned for the close of business (5:00 p.m. CST) on April 30, 2020. Any accepted Proposal will become binding in accordance with the executed definitive agreement (see Section 4.3), including through the Regulatory Approval Process described in Section 4.4.

2.7.4 Respondents will be notified by March 27, 2020 if their bid has been selected for the short list and further negotiation. This date may be advanced or delayed at Montana-Dakota's sole discretion. Respondents will be notified if the date is changed. Respondents with Proposals not selected for the short list will be notified. None of the material received by Montana-Dakota from Respondents in response to this RFP will be returned. All Proposals and exhibits will become the property of Montana-Dakota, subject to the confidentiality provisions of Section 2.8.

2.7.5 Prices and dollar figures must be stated in U.S. Dollars.

2.8. Confidentiality

With each Respondent's Proposal, Montana-Dakota will require all parties to sign the Confidentiality Agreement, contained in Exhibit C to this RFP. Montana-Dakota will sign and execute the Confidentiality Agreement upon receipt from each Respondent. Montana-Dakota will use commercially reasonable efforts, in a manner consistent with the Confidentiality Agreement, to protect any claimed proprietary and confidential information contained in a Proposal, provided that such information is clearly identified by the Respondent as "PROPRIETARY AND CONFIDENTIAL" on the page on which proprietary and confidential material appears.

2.9. Requirements of the Proposals

2.9.1 Proposals should be provided in the format outlined in Section 2.9. Montana-Dakota requests that all exhibits, documents, schedules, etc. submitted as a part of a proposal be clearly labeled and organized in a fashion that facilitates easy location and review.

2.9.2 All proposals must conform, as applicable, to the requirements within this RFP.

2.9.3 Proposals must be for the sale to, and purchase by Montana-Dakota, of a firm, unit-contingent supply of capacity and energy, and/or system participation capacity and energy. The proposals must identify the resource and location supplying the capacity and any special regulatory status that may be claimed.

2.9.4 A single Respondent may submit more than one proposal.

2.9.5 The pricing, as set forth in Section 2.9.11.5, contained in each proposal shall reflect all present applicable local, state, and federal environmental regulations and requirements. Montana-Dakota reserves the right to estimate the impacts of future environmental regulations on the Respondent's proposal. Montana-Dakota will not be responsible for any "stranded costs" that the Respondent may incur, but are not identified in the proposal. Any exit fees must be explicitly stated in the Respondent's proposal.

2.9.6 Proposals that rely upon supply resources located outside of the Montana-Dakota system must provide for the delivery of the full capacity amount to Montana-Dakota's system.

2.9.7 Transmission service that the Respondent acquires for the purpose of delivering said capacity should be Firm, Point-to-Point, or Network service. Said transmission service shall be continuously reserved for the duration of the capacity transaction. If Firm, Point-to-Point, or Network Transmission service is not obtained prior to the time the Respondent submits his proposal, the burden will be on the Respondent to identify all known fixed and variable costs for delivery to Montana-Dakota's system as well as any known transmission constraints.

2.9.8 The Respondent shall be responsible for the providing and contracting of all transmission related services for delivery to the Montana-Dakota system. At some point during the evaluation process, Montana-Dakota, in its sole discretion, will require a Respondent to demonstrate the ability to acquire transmission services if necessary. If the Respondent is unable or fails to demonstrate such ability to obtain transmission services, or if obtaining such service requires system upgrade or interconnection costs that Montana-Dakota, in its sole discretion, determines to be excessive, Montana-Dakota may terminate further consideration of the Respondent's proposal.

2.9.9 Proposals should address any contractual and operational constraints such as cycling, minimum load, minimum run time, minimum down time, start-up fees, etc., that the Respondent intends to impose under its proposal.

2.9.10 Respondents are advised that prior to Montana-Dakota signing a power purchase agreement, the Respondent will be required to provide substantial evidence of credit assurance as detailed in Section 2.9.11.9 of this RFP. Montana-Dakota will approve all forms of credit assurance before entering into the agreement.

2.9.11 All Proposals must include the following minimum components in the order provided:

2.9.11.1 "Executive summary" which indicates the highlights and special features of the Proposal including a description of the source for the capacity and energy.

2.9.11.2 Statement from the Respondent which clearly indicates the time period during which the proposal will remain effective. Montana-Dakota requires that proposals remain effective at least until April 30, 2020.

2.9.11.3 Comprehensive listing and description, including a rationale if warranted, of all material contract terms and conditions that the Respondent would seek during contract negotiations.

2.9.11.4 Listing of any economic, operational, or system conditions (including sensitivities to anticipated dispatch levels) that might affect the Respondent's ability to deliver capacity and energy, as proposed.

2.9.11.5 Information on the cost of the capacity and energy shall be provided including:

2.9.11.5.1 Designated delivery point including applicable MISO Local Resource Zone.

2.9.11.5.2 Firm price bid. The capacity price must be fixed for the time period(s) quoted and the energy price must be either fixed or based on known and easily measurable indices.

2.9.11.5.3 In addition to a firm price bid, the Respondent may submit alternative non-firm price bids. However, these bids must specifically describe the risks that the Respondent is passing on to Montana-Dakota and its customers.

2.9.11.5.4 The Respondent should specify the basis (i.e. annually, quarterly, monthly, etc.) and type of all payments it expects to receive. In the case of a fully dispatchable generating resource, such payments might include start-up payments ($/start) or spinning and supplemental reserve payments ($/operating hour).

2.9.11.5.5 As applicable, the Respondent's proposal should include all formulas that will be used to calculate the full capacity and energy rate, or any other rate that the Respondent may specify, with all its respective components well defined. A sample calculation illustrating the application of each formula is also required.

2.9.11.5.6 The Respondent must provide a printed schedule projecting for each contract year, quarter, or month, as appropriate, depending upon how frequently the Respondent's rate(s) or its respective components will be updated, for the full term of the proposed contract of the following:

a. Full capacity rate and all components ($/kW-month, etc.).
b. Contract capacity amount in MW.
c. Capacity payment ($/month).
d. Total energy rate and all its components ($/MWh).
e. Projected values of any independent variables (e.g. fuel price, heat rates, operating hours, and number of starts) that are to be used in the calculation of payments.
f. Sufficient information to allow Montana-Dakota to replicate the proposed contract term data.
g. Any proposed revisions to the pricing scheme if the Respondent intends to offer a contract extension option.

2.9.11.6 Information on the makeup of the Respondent and its parent organization, if any, shall be provided along with the more recent financial report, the current audited annual financial report, and if Respondent or its parent organization is publicly traded, SEC Form 10-K.

2.9.11.7 Site locations of the proposed generating units and other drawings that are helpful in describing proposed generation resources shall be included.

2.9.11.8 The Respondent must certify that any identified generating unit is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.

2.9.11.9 Montana-Dakota requires secure and reliable physical delivery of the capacity and associated energy corresponding to all proposals. Security and reliability of physical delivery will be guaranteed by either (1) contractual credit assurance by a third party, (2) corporation commitment accompanied by an investment level credit rating from a major rating agency, or (3) combinations of 1 and 2. All forms of credit assurance will be approved by Montana-Dakota before entering into a power purchase agreement. (Credit Assurances shall include a letter of credit or performance bonds for an amount equal to the costs associated with one year of the contract or as mutually agreed.)

2.9.11.10 The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit. The Respondent shall provide a description of the resource's ability to comply with all presently applicable and anticipated environmental regulations and requirements (including, but not limited to, EPA Greenhouse Gas Clean Air Act permitting requirements for New Source Performance Standards, New Source Review and Prevention of Significant Deterioration, and the Affordable Clean Energy Rule or replacement rule) and any additional environmental benefits that the resource would, or presently does, afford; a listing of expected emissions (as applicable) and the status of all permit applications; and a listing of any and all potential and known environmental liabilities that may be associated with the generating unit or its sites. If the Respondent is unable or fails to obtain permits, or if obtaining a permit or certification requires costs or fees that Montana-Dakota, in its sole discretion, determines to be excessive, Montana-Dakota may terminate further consideration of the Respondent's proposal.

2.9.11.11 Montana-Dakota prefers proposals offering full dispatchability of energy for all hours during the term of the contract. This would permit Montana-Dakota to schedule quantities of energy, from a minimum of zero to a maximum equal to the quantity stated in the Respondent's proposal. Montana-Dakota prefers to have the option of connecting any generating units whose output may be offered as part of this solicitation to its automatic generation control system. However, full dispatchability is not a requirement for any proposals.

2.9.12 Montana-Dakota encourages Respondents to provide Proposals for year-round capacity and energy.

2.9.13 Proposals for variable capacity resources such as DSM, wind, solar, run-of-river hydro, and landfill gas should include, for each calendar month, a schedule of expected capacity factors, maximum capacity, and hourly capacity (for each hour of the month).

2.9.14 Montana-Dakota will entertain proposals which contain the provision for an asset sale or option for an asset sale from the Respondent to Montana-Dakota as part of the Respondent’s bid.

3. EVALUATION PROCESS

3.1. Proposal Review

3.1.1. Respondents are advised that price will be a major factor in Montana-Dakota’s evaluation, with due consideration given to dispatchability, operational performance, reliability, deliverability, credit, environmental impacts, contract considerations and other criteria. Respondents shall include sufficient detail to evaluate all costs associated with the Proposal(s). To ensure that Proposals will provide customer benefits, Montana-Dakota will compare Proposals with the benefits, including costs and reliability, of alternative resource scenarios. Proposals also will be compared and evaluated in terms of other non-price characteristics; therefore, the lowest price submittal may not necessarily be selected. The evaluation of Proposals will be based on the information provided by the Respondent and available industry information, with special emphasis on Montana-Dakota being able to provide reliable service and maximize the economic value to its customers. Montana-Dakota shall evaluate all Proposals in terms of price and non-price attributes and may reject any Proposal that, in Montana-Dakota's sole discretion:

a) Does not meet the minimum requirements set forth in the RFP;

b) Is not economically competitive with other Proposals or resource alternatives;

c) Is submitted by Respondents who are determined by Montana-Dakota to have insufficient creditworthiness, insufficient financial resources and/or insufficient technical qualifications to provide dependable or reliable service; or

d) Fails to meet the resource and reliability needs of Montana-Dakota.

In order to assess the feasibility and viability of the Proposals, the evaluation will determine the technical, physical and operational capability of the applicable generating unit(s) to meet the operating parameters specified in the Proposal. Such technical analysis will include, but not be limited to, a review of transmission access (including existing transmission contracts), fuel access and transportation (including existing fuel contracts), environmental conditions, certification and permit conditions and/or restrictions, unit location, maintenance history and schedules, and operational flexibility and history.

3.1.2. Montana-Dakota shall evaluate responsive Proposals and select for further review and negotiation a Proposal or Proposals, if any, that Montana-Dakota believes provides the greatest value to its customers. In the event negotiations with a Respondent or Respondents do not produce a final and fully executed contract satisfactory to Montana-Dakota, Montana-Dakota reserves the right to pursue any and all other resource options available to it.

3.1.3. Montana-Dakota reserves the right to accept or reject any or all Proposals for any reason at any time after submittal without explanation to the Respondent, or to make an award at any time to a Respondent who, in the sole opinion and discretion of Montana-Dakota, provides a Proposal Montana-Dakota deems favorable. Montana-Dakota also reserves the right to make an award to other than the lowest price Respondent, if Montana-Dakota determines that to do so would result in the greatest value to its customers.

3.1.4. All Proposals related to renewable resources, energy storage, distributed generation and DSM are invited to participate in this RFP process and will be evaluated in a consistent manner with all other bids, with consideration given to projections as to life-cycle costs, operational compatibility, reliability and availability of the resource(s).

3.1.5. Those Respondents who submit Proposals do so without legal recourse against Montana-Dakota or its directors, management, employees, agents or contractors based on Montana-Dakota's rejection, in whole or in part, of their Proposal or for failure to execute any agreement tendered by Montana-Dakota. Montana-Dakota shall not be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to Montana-Dakota's acts or omissions arising out of or in connection with the RFP.

3.1.6. If a selected Proposal involves a generating unit not yet operational, the Respondent must provide Montana-Dakota with a full financial guarantee, including performance bonds and/or letters of credit, up to the level of product commitments and in an amount and at a level determined by Montana-Dakota in its sole discretion, expressly including replacement capacity and energy costs and any related penalty fees, in the event the generating unit does not become commercially operational as scheduled.

3.1.7. In reviewing and considering Proposals, Montana-Dakota will analyze potential credit and risk concerns in any comparison of Proposals. As part of its detailed evaluation phase, Montana-Dakota will specifically weigh the credit- and risk-related factors and costs underlying each of the Proposals. To assist Montana-Dakota in this review, Montana-Dakota requires that each Respondent include with its response package a detailed description of the proposed credit support. The pricing provided shall expressly include the costs of such credit support. Montana-Dakota will review and assess the sufficiency and adequacy of the proposed credit support, and if Montana-Dakota, in its sole discretion, determines such credit support is insufficient, it shall assess additional costs and/or expenses to any such Proposal.

3.1.8. Selection and elimination of Proposals and subsequent notification of Respondents at all stages of the evaluation will remain entirely at Montana-Dakota's discretion.

3.1.9. Montana-Dakota reserves the right to award multiple contracts if combinations of proposals provide the lowest overall cost, highest level of reliability, and greatest value to its customers.

3.2. Proposal Threshold Requirements

The Respondent should provide complete and accurate information to ensure that its Proposal satisfies the Threshold Requirements listed below. Montana-Dakota, at its sole discretion, may reject a Proposal for further consideration if the Proposal fails to meet the Threshold Requirements or provides incomplete and/or inaccurate responses. Montana-Dakota may seek clarification and/or remedy of a Respondent's Proposal.

3.2.1. General Threshold Requirements

a. The Proposal is received on time and complies with the submission instructions.

b. The Proposal is bona fide, and the Respondent (or its guarantor) has sufficient financial capacity to support the Proposal.

c. Complete and accurate answers are provided to all questions in the RFP.

d. Capacity and energy must be available for delivery no later than June 1, 2023 and fully deliverable to Montana-Dakota's system.

g. The project size is at least 10 MW and no more than 100 MW.

h. PPA's of a term shorter than twenty years will be considered in this RFP. Preference will be given to Proposals with an initial term of twenty years or longer.

3.2.2. Operating Performance Thresholds

a. The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit.

b. The Respondent must certify that any identified generating unit is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.

c. If a PPA, the Respondent must be willing to coordinate the generating unit's maintenance scheduling with Montana-Dakota.

3.2.3. Transmission Threshold

a. Deliverability to Montana-Dakota's integrated system, which consists of its service territories in Montana, North Dakota, and South Dakota, will be taken into account.

b. Preference will be given to generating unit(s) which connect to Montana-Dakota's integrated system. If the generating unit(s) is or will be located outside of Montana-Dakota's integrated system, the Respondent must provide a transmission plan for deliverability to wheel the generating unit's power to Montana-Dakota's integrated system. Transmission costs to deliver to Montana-Dakota's integrated system are the responsibility of the Respondent.

c. If the generating unit is not yet in-service, but has a completed Generator Interconnection Study, a copy of this study must accompany the Respondent's Proposal.

d. If the generating unit is not yet in-service and will be interconnected to Montana-Dakota's transmission system, the Respondent must complete an Application for Generator Interconnection Request with MISO. A copy of this application must accompany the Respondent's Proposal.

e. For an unfinished resource, the final agreement between Montana-Dakota and the Respondent will require the Interconnection Study to be completed, or will be contingent upon such a study being completed.

3.3. Screening Process

On or before March 27, 2020, Montana-Dakota intends to select Proposals that will be included on a short list. This date may be advanced or delayed at Montana-Dakota's sole discretion. Through the short-listing process, those Proposals that are inferior to other Proposals in terms of overall cost and level of reliability, in Montana-Dakota's sole discretion, will be eliminated from further consideration. Montana-Dakota will notify all short-listed Respondents that they have been included on the short list. Similarly, Montana-Dakota intends to notify Respondents of those Proposals that are eliminated from further consideration within a reasonable amount of time.

Montana-Dakota plans to analyze the short-listed Proposals in detail by assessing their impact on its customer electric service rates, comparing their costs to those of other resource alternatives, and examining their compatibility with Montana-Dakota's resource needs.

Montana-Dakota may elect to schedule meetings or conference calls with each short-listed Respondent to review and clarify its Proposal. After the selection of the short-listed Proposals, Montana-Dakota will begin contract negotiations with such Respondent(s).

Montana-Dakota may select a final Respondent(s) based on the detailed evaluation of the short-listed Proposals. This selection will not automatically be based on the lowest price alternatives available amongst the Proposals. The price and non-price attributes described in part in this RFP solicitation document will be considered in their totality for each Proposal. Montana-Dakota will use its sole discretion, judgment and analyses in making the final selection(s) in the RFP process. Montana-Dakota's objective is to select resources that have the potential to offer the maximum reliability and value, based on cost and non-cost attributes.

4. CONTRACTS AND REGULATORY APPROVAL

4.1. General

The Respondent(s) whose Proposal is selected, if any, will be responsible for acquiring and verifying that they are in compliance with all necessary licenses, permits, certifications, reporting requirements and approvals required by federal, state and local government laws, regulations and policies, including if applicable, for the design, construction and operation of the generating unit. In addition, the Respondent shall fully support the regulatory approval process associated with any potential acquisition or power supply arrangement.

The Respondent shall be liable for all, and Montana-Dakota shall not be responsible for any, of the costs that the Respondent incurs to prepare and submit its Proposal, negotiate any subsequent contract, and any related activity including applicable permitting and governmental approvals.

4.2. Contract Modifications

It is anticipated that the contract format for an award in response to this RFP will be based on the North American Energy Markets Association (NAEMA) Capacity and Energy Tariff which can be found at https://www.naema.com. Respondents may expressly identify and include proposed changes to the NAEMA Capacity and Energy Tariff in their response packages. Such proposed revisions will allow Montana-Dakota to assess in its evaluation process the significance and impact to any Proposal of the changes requested by Respondents. Montana-Dakota reserves the right to utilize a different contract format, based on its sole discretion, for power purchase agreements under this RFP.

4.3. Definitive Agreement

As soon as practicable after Montana-Dakota completes negotiations, Montana-Dakota expects the selected Respondent(s), if any, to execute a definitive agreement. Failure of the Respondent(s) to promptly execute a definitive written agreement after notification of an award will result in rejection of the Proposal.

4.4. Regulatory Approval Process

At Montana-Dakota’s sole discretion, any final negotiated contract may be conditioned upon regulatory actions and approvals by regulatory authorities. All consents and approvals of governmental authorities required for the consummation of the contemplated transactions shall have terms and conditions acceptable to Montana-Dakota.

4.5. Collusion

By submitting a Proposal to Montana-Dakota in response to this RFP, the Respondent certifies that the Respondent has not divulged, discussed or compared its Proposal with any other Respondents and has not colluded whatsoever with any other Respondents with respect to this Proposals.

Exhibit A – Form of Statement of Financial Conditions and Creditworthiness

The following information shall be completed as appropriate and will be used to assess the applicant's financial conditions and creditworthiness.

1. Company Information

Type of Business

____ Corporation
____ Limited Liability Company
____ Partnership
____ Other (describe)

Applicant Organization

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

Applicant Credit Contact

Name:

Title:

Phone Number:

Email Address:

For Corporation/Limited Liability Companies

Date and State of Incorporation/Registration:

Street Address:

City, State, Zip Code:

For General Partnerships

Name of General Partner:

Address of General Partner/Registered Agent:

City, State, Zip Code:

2. Guarantor

Guarantor Company

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

3. Credit Information

The company and/or company's guarantor (if applicable) is required to submit the most recent 2 years of audited financial statements and accompanying notes. Indicate below what statements are being submitted.

____ 10K

____ 8Ks to the extent they address any information set forth in the 10Ks or 10Qs

____ 10Q

____ Other (describe)

All submitted information must be in the English language, and financial data denominated in United States currency, and conform to generally accepted accounting principles (GAAP) in the United States. If the offering entity's financial information is consolidated with other entities, then it is the offering entity's responsibility to extract and submit as separate documents all data and information related solely to the offering entity. This must include all financial information, associated notes and all other information that would comprise a full financial report conforming to GAAP.

Has the offering entity or predecessor company declared bankruptcy in the last 5 years?

____ Yes

____No

Are there any pending bankruptcies or other similar state or federal proceedings, outstanding judgments or pending claims or lawsuits that could affect the solvency of the offering entity?

____ Yes

____No

If the answer is "Yes" to either of the above questions, please provide an addendum to this application describing the situation and how it affects the offering entity's ability to meet or not meet it credit obligations.

Respondent/Guarantor Credit Rating

Standard & Poor's

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Moody's

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Fitch

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

In the event the above information is inadequate or fails to completely meet Montana-Dakota's need for financial security for a given bid, the entity must provide evidence of its capability to provide collateral instruments.

Please detail all credit related issues and concerns that Montana-Dakota should be aware of prior to negotiation of a formal power purchase agreement document:

Bank Reference Information

Bank Name:

Street Address:

City, State, Zip Code:

Contact Name:

Phone Number:

Fax Number:

Account Number:

4. Project-specific Information

For project-specific supply proposals, please provide the following information:

Owners and percentage of ownership in generation unit(s):

Amount and source(s) of equity financing:

Amount and terms of financing, including:

- Amount of loan(s)
- Term of loan(s)
- List of conditions
- Amortization schedule

5. Authorization

The Offering Entity hereby represents and warrants that all statements and representations made herein, including any supporting documents, are true to the best of Offering Entity's knowledge and belief. The undersigned authorized official of the Offering Entity warrants that the Offering Entity agrees to be bound by these representations. The Offering Entity authorizes the above listed entities to release data requested by Montana-Dakota necessary to perform a credit check in connection with Offering Entity's interest to bid on this RFP.

Offering Entity's Company Name:________________________________

Signature of Authorized Official:_________________________________

Name of Authorized Official (print):______________________________

Title of Authorized Official (print):_______________________________

Date Signed:____

Exhibit B – Form of Notice of Intent to Bid

Date: ____

Our organization intends to submit a proposal in response to the Montana-Dakota Utilities Co. Request for Proposals for Capacity and Energy Supply.

Contact Name: ____

Name of Firm: ____

Address: ____

____

Phone: ____

E-mail: ____

Alternate Contact: ____

Address: ____

____

Phone: ____

E-mail: ____

Project Description: ____

____

____

____

____

Signature: ____

Exhibit C – Form of Confidentiality Agreement

MUTUAL CONFIDENTIALITY AGREEMENT

Montana-Dakota Utilities Co., a Subsidiary of MDU Resources Group, Inc., having its principal place of business at 400 North 4th Street, Bismarck, ND 58501 ("Montana-Dakota") and ____________________, having its principal place of business at ______________________________ ("Respondent"), are discussing details related to the Respondent's reply to a Request for Proposal ("RFP") that Montana-Dakota has issued regarding the purchases of capacity and energy dated January 17, 2020. In the course of the discussions about the RFP each party may disclose certain confidential or proprietary information ("Proprietary Information") to the other party.

For purposes of this Mutual Confidentiality Agreement, Proprietary Information shall mean all information, technical data or know-how, whether written, oral, visual, electronic or in any other form (which may include, without limitation, strategic project development plans, financial information, business plans and records, and project information and records,) disclosed, acquired, or generated as a result of or in connection with the RFP process. Proprietary Information shall also include this Mutual Confidentiality Agreement and the terms and conditions set forth herein.

A. In consideration of Montana-Dakota and Respondent agreeing to supply each other Proprietary Information relating to the RFP process and in consideration of both parties entering into the exchange of information and/or discussions relating to the RFP process, Montana-Dakota and Respondent each agree that it, its corporate affiliates, and each of their respective directors, officers, employees, lenders, and professional advisors (each individually "Representatives"):

1. Will keep secret and confidential the Proprietary Information supplied to the other party and any discussions and negotiations about the RFP process except as herein provided and in a manner no less restrictive than the manner that the receiving party protects its own confidential information;

2. Will use the Proprietary Information only for the purpose of participating in, evaluating and negotiating the RFP process;

3. Will disclose the Proprietary Information only to its Representatives who need to know the Proprietary Information for the purpose of participating in, evaluating and negotiating the RFP process;

4. Will not, whether or not the Parties enter into definitive agreements, disclose to any third party (other than its Representatives) any of the

Proprietary Information, other than the Proprietary Information which is in, or independently comes into, the public domain;

5. Will not, engage in any transactions of any kind or description whatsoever with regard to or using the Proprietary Information during the term of this Agreement without the written consent of the other party;

6. Will, if requested in writing, promptly destroy or return any of the Proprietary Information provided without keeping any copies, except portion of the Proprietary Information that is found in analyses, compilations, studies or other documents prepared by Montana-Dakota and its employees, representatives, consultants and counsel may be held by Montana-Dakota and kept subject to the terms of this Agreement, or destroyed; and

7. Will promptly notify the other party if any of the Proprietary Information conveyed to it is required to be disclosed by reason of law or legal process and will cooperate with the other party regarding any action which the other party (at the other party's sole cost and expense) may elect to take to challenge the legality or validity of such requirement.

B. Montana-Dakota and Respondent also acknowledge and agree:

1. Proprietary Information which is provided will not be considered to be Proprietary information if that information is (I) in the other party's possession prior to disclosure, (ii) is in the public domain prior to disclosure, or (iii) lawfully enters the public domain through no violation of this Mutual Confidentiality Agreement.

2. No agreement for a power purchase agreement or other transaction shall be deemed to exist unless and until a Definitive Transaction Agreement has been executed and delivered by the parties. The term "Definitive Transaction Agreement" does not include this Mutual Confidentiality Agreement, a letter of interest or any other preliminary written agreement, nor does it include any verbal agreement;

3. Neither party makes any representation or warranty regarding the completeness or accuracy of any information provided to the other; any and all such representations and warranties shall be made in a written, executed agreement and will then be subject to the provisions thereof;

4. Money damages would not be a sufficient remedy for a breach of this Mutual Confidentiality Agreement and the injured party is entitled to specific performance and injunctive or other equitable relief and remedies for any breach; such remedies shall not be the exclusive

remedies but shall be in addition to all other remedies available at law or in equity;

5. Neither party will make any announcement of the status of the Respondent's reply to the RFP or of any negotiations with respect to a possible power purchase agreement without the prior written consent of the other;

6. This Mutual Confidentiality Agreement is governed by the laws of the state of North Dakota; and

7. The obligations under this Mutual Confidentiality Agreement shall be continuing and shall survive the termination of the RFP process and any discussion or negotiations between the parties, but that all obligations of the parties hereunder will expire two years from the date of this Mutual Confidentiality Agreement.

The parties have executed this Mutual Confidentiality Agreement as of ___________________, 2020.

_____________________________	MONTANA-DAKOTA UTILITIES CO. a Subsidiary of MDU Resources Group, Inc.
By:___________________________	By:__________________________ Jay Skabo
Title:_________________________	Title: Vice President Electric Supply

Attachment G

TRANSMISSION SERVICE CHARGE IMPACTS

TRANSMISSION SERVICE CHARGE IMPACTS

Montana-Dakota's electric service customers in the Interconnected System will continue to see increased transmission service charges resulting from (1) the termination of the Transmission Services Agreement (TSA) with Western Area Power Administration (WAPA) on December 31, 2015; (2) WAPA and Basin Electric Power Cooperative (BEPC) joining Southwest Power Pool (SPP) as a transmission owning member on October 1, 2015; (3) revenue credits provided to BEPC for facilities used by Montana-Dakota's customers; (4) the Midcontinent Independent System Operator, Inc. (MISO) allocation of cost sharing for baseline reliability and market efficiency projects under Regional Economic Criteria Benefit (RECB) I and II criteria; (5) the allocation of MISO Multi-Value Projects (MVP); and (6) allocation of Long-Range Transmission Plan (LRTP) projects.

Transmission Services Agreement with Western Area Power Administration

Montana-Dakota and WAPA had a long history of sharing transmission facilities and providing service across each other's systems using a reciprocal wheeling arrangement. This arrangement expired on December 31, 2015. On October 1, 2015, WAPA and BEPC joined Southwest Power Pool (SPP) as a transmission owning member and, as such, transmission service across their facilities are now covered under the SPP Tariff. As part of a Federal Energy Regulatory Commission (FERC) settlement that Montana-Dakota entered into with SPP, WAPA, and BEPC regarding WAPA and BEPC's integration into the SPP footprint, Montana-Dakota agreed to take Network Integrated Transmission Service (NITS) under the SPP Tariff for service that was historically provided under the WAPA TSA, which basically covers Montana-Dakota's customer load west of Beulah, ND and west of Glenham, SD. Montana-Dakota has only a single 115kV transmission path west of Beulah to provide a connection back to the rest of Montana-Dakota's interconnected service territory and MISO. In return for taking NITS service under the SPP Tariff, Montana-Dakota is eligible for Facility Credits under Section 30.9 of the SPP Tariff for transmission facilities that WAPA and BEPC require service from Montana-Dakota which were previously provided under the WAPA TSA and BEPC Interconnection and Common Use Agreement (ICCUA). The impacts of the SPP NITS service is reduced by the Section 30.9 Facility Credit arrangement whereby Montana-Dakota is able to net a significant portion of its SPP transmission bill. BEPC is required to take MISO NITS service in areas that Montana-Dakota does not rely on SPP transmission facilities to serve its customer load providing additional offsets to the SPP NITS payments. Montana-Dakota received approval from FERC in 2021 for a Settlement

Agreement in docket ER20-108 and an Amendment to a Partial Settlement Agreement in ER21-169 which provides for addition future Section 30.9 Credits to Montana-Dakota.

Montana-Dakota continues to see greater value in remaining a MISO transmission owning member as compared to exiting MISO and joining SPP as a full member. The greater MISO membership value is largely related to a difference in resource adequacy requirements between MISO and SPP. SPP requires each load serving entity to carry capacity resources for their full forecasted customer load plus a planning reserve margin while MISO includes a diversity factor reduction as not all MISO customer load experiences their peak at the same time. Montana-Dakota receives a significant benefit from being the western most transmission owning member in MISO As such, Montana-Dakota's customers currently only need to supply 81.1% of their full capacity requirements which provides 120 MWs of capacity savings. If Montana-Dakota were to join SPP, Montana-Dakota would have to add approximately 75 MW of additional capacity resources to its generation portfolio as SPP has a lower planning reserve margin than MISO. Using the MISO Cost of New Entry (CONE)[1] value of $254.27 per MW-day for 2021/2022, the resource adequacy diversity value that Montana-Dakota receives in MISO is equal to $11.1 million versus having to carry one hundred percent non-coincident peak requirements. The monetary value of MISO's resource adequacy requirements versus SPP's resource adequacy requirements is $7.0 million per year if Montana-Dakota would exit MISO and join SPP as a transmission owning member and move all its load and generation into SPP's energy market.

To verify that the current netting arrangement is in the best interest of serving its customer obligations, Montana-Dakota annually calculates the cost differential of the two options: 1) continuing to take both SPP and MISO NITS service, versus, 2) withdrawing from MISO membership and switching to SPP.

Based on Montana-Dakota's 2021 load forecast, the estimated cost of taking MISO transmission service is $8.2 million per year. Using the company's Plexos modeling software and removing the MISO market energy purchase option, the increased cost for Montana-Dakota to self-schedule its own generation without access to the MISO energy market is $6.1 million. This value is used as a rough estimate of MISO market benefits that the Company receives versus the self-scheduling of only resources owned by the Company. Additional MISO membership benefits include reliability oversight through Reliability Coordinator services, resource adequacy diversification ($11.1

[1] 2020/2021 Planning Resource Auction (PRA) Results. Page 9. PowerPoint Presentation (misoenergy.org)

million benefit as calculated above), tariff management, coordinated transmission planning studies, and generator interconnection queue management.

In 2020, the total net cost of taking both MISO and SPP transmission services is estimated at $15.4 million or $9.1 million above MISO only tariff costs. This estimate includes the SPP Section 30.9 Facility Credits provided under the SPP Tariff as well as the payments from Basin Electric for Transmission Service taken from MISO and the Basin Electric Facility Sharing Agreement. Montana-Dakota also received an additional $2.1 million in market revenues from SPP in 2020 for real-time asset losses, congestion, and auction revenue rights associated with the SPP network transmission service reservation. For Montana-Dakota to have its load and generation in MISO's resource adequacy requirements versus SPP, provides a net savings of $7.0 million using the current MISO CONE value for capacity resources calculated above. The FERC approval of dockets ER20-108 and ER21-169 will provide Montana-Dakota an additional $2.5 million in Section 30.9 Credits from SPP in 2021. If Montana-Dakota would exit MISO and join SPP as a transmission owning member, it would continue to make annual transmission investment payments of $6.2 million (2020 amount) to MISO for Schedule 26 and 26a projects that it has on-going cost responsibility to make under the MISO Tariff.

MISO Allocation of Cost Sharing under RECB I Criteria

The MISO RECB I cost allocations allow for the cost sharing of approved network transmission facilities with the benefiting transmission owners or with the entire MISO footprint. Contained in MISO's FERC Order 1000 compliance filing was the removal of the requirement to cost share future MISO RECB I projects, also referred to as baseline reliability projects, from the MISO Tariff beginning with MTEP 2014. Previously approved MISO RECB I projects will continue to be cost shared as before. Schedule 26 allocations are directly assigned revenue requirements for approved projects to an individual Transmission Owner or all MISO load through a system-wide postage-stamp rate. The CapX2020 Alexandria to Fargo 345 kV transmission line was approved in 2008 as a baseline reliability project eligible for cost sharing under the MISO Tariff and was placed into service in 2015. As defined in RECB I, eighty percent (80%) of the revenue requirements for these projects are allocated under a line outage distribution factor (LODF) calculation to determine beneficiaries, and the remaining twenty percent (20%) are allocated to all MISO load through a postage-stamp rate. Montana-Dakota's allocated investment share of the Alexandria to Fargo 345 kV line is $6.6 million. Annual revenue requirements for all RECB I projects allocated to Montana-Dakota's transmission pricing zone in MISO are forecasted to equal $1.3 million dollars in 2021, which includes the cost of the Mandan 230 kV Junction Substation. Montana-Dakota also receives RECB I (MISO Schedule 26) revenues from Otter Tail Power for the reliability benefits they are assigned for the Mandan 230kV Junction Substation.[2] The MISO NITS transmission service that BEPC takes for its customer load in Montana-Dakota's transmission pricing zone is allocated a load ratio portion of the Montana-Dakota RECB I cost responsibilities. Montana-Dakota also receives Schedule 26 revenues as part of its ownership of the Twin Brooks 345 kV substation in South Dakota which is located on the Ellendale 345kV substation to Big Stone South substation transmission line. The Twin Brooks Substation was the cost allocation responsibility of the interconnecting generator and because the voltage of the network upgrade is 345 kV, ten percent of the project cost is allocated to the MISO system wide postage allocation for which Montana-Dakota receives Schedule 26 revenues.

MISO Allocation of Cost Sharing under RECB II Criteria

The MISO RECB II cost allocation allows for the cost sharing of approved market efficiency projects (MEPs) with the benefiting transmission owners or with the entire MISO footprint.

To qualify as a MEP, network transmission upgrades must be shown to have regional economic benefits as demonstrated through multi-future and multi-year planning. MEP's currently involve transmission facilities operating at voltages of 345kV and higher. Project costs must be at least $5 million or more with at least 50% of the project cost associated with 345kV or above facilities. MEPs must have a benefit-cost ratio of 1.25 or higher with annual benefits calculated using 100% adjusted production cost savings for multiple future scenarios with the present value of benefits and costs calculated over the first 20 years after the in-service date, but not to exceed 25 years from the project's approval year.

Revenue requirements for MEP's are allocated 80% to all load within the MISO Local Resource Zone that receives benefits with the remaining 20% allocated to the MISO footprint wide postage stamp.

On February 25, 2019, MISO filed FERC Docket No. ER19-1124-000 to modify cost allocation for MEP's using existing and newly adopted metrics that allow for added precision in allocating costs and facilitate 100% allocation of MEP costs to benefitting Transmission Pricing Zones (eliminating the 20% allocation to all of MISO on a postage stamp basis). The filing also provides an expanded framework for the designation of MEPs at lower voltages, including lowering the

[2] MISO Indicative Annual charges for approved Baseline Reliability Projects (Schedule 26). Schedule 26 and 26A Indicative Reports (misoenergy.org)

voltage threshold from 345 kV to 230 kV and the creation of a new local economic project category between 230kV and 100kV.

MISO continues to engage stakeholders through the RECB Task Force to review the MEP metrics and potential additional benefit calculations for things like (1) reduced planning reserve margin, (2) reduction in transmission losses, (3) avoided costs by deferring or eliminating future baseline reliability transmission investments, and (4) avoidance of market-to-market settlement payments. Montana-Dakota believes the current cost allocation for MEPs is sufficient and no changes are needed. If changes to voltage threshold or additional benefit criteria are implemented, then MISO should also look to allocate the costs for MEPs to local transmission pricing zones which benefit directly from the MEPs.

Allocation of MISO Multi-Value Projects

On December 17, 2010, the FERC approved a joint application filing by MISO and various MISO Transmission Owners to create a new cost allocation methodology for qualifying multi-value high-voltage transmission facilities called Multi-Value Projects (MVPs). MVPs are one or more network transmission upgrades that, when considered as part of a portfolio, provide widespread regional benefits, respond to documented public policy requirements, and/or provide multiple benefits such as reliability and economic value. Network transmission projects classified as MVPs will be cost-shared on a one hundred percent (100%) basis to all MISO load and system exports to PJM.

MVP Eligibility Criteria

To be eligible as an MVP, the project must meet at least one of the following:

- A project that enables the transmission system to deliver energy in support of documented energy policy mandates or laws that have been adopted through state or federal legislation or regulatory requirement and deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
- A project that provides multiple types of economic value across multiple pricing zones with a total project benefit-to-cost ratio of 1.0 or higher.
- A project that addresses at least one transmission issue associated with a projected reliability violation and at least one economic-based transmission issue, and that provides economic value across multiple pricing zones and generates financially quantifiable benefits in excess of the total project cost.

2011 MVP Portfolio

MTEP 2011 approved $5.6 billion for 17 Multi-Value Projects that were selected as part of a regional portfolio to improve reliability of the transmission system, meet public policy targets, and distribute economic benefits across the entire MISO footprint.[3] The MTEP 2011 Report identified potential benefits of at least 1.8 to 3.0 times their cost for all MISO Local Resource Zones. The MTEP 2014 MVP Triennial Review Report calculates potential benefits from the 2011 MVP Portfolio of at least 2.6 to 3.9 times their cost for all MISO Local Resource Zones. The MTEP17 results provide benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.2 to 3.4; an increase from the 1.8 to 3.0 range calculated in MTEP11.[4]

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[3] MISO Transmission Expansion Plan 2011.
https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf
[3] MTEP17 MVP Triennial Review.
https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

One of the 2011 MVP Portfolio projects is a 345 kV transmission line from Big Stone, SD to Ellendale, ND. Montana-Dakota completed this project in partnership with Otter Tail Power Company in February 2019 with a constructed cost of $247 million.

The 2021 forecasted MISO Schedule 26-A (MVP Cost Adder) charge is $1.67 per MWh.[5] Assuming a 2021 Total Energy Requirements of 3,350,642 MWh, this would result in a total charge of $5,595,572 to Montana-Dakota's customers.

Montana-Dakota's cost allocation share of all MVP investments is less than one percent.

Long-Range Transmission Planning

A key part of MISO's Reliability Imperative is the need for additional high voltage electric transmission across the MISO footprint as plant retirements and increasing renewables continue to transform the grid. MISO is responding to this need with the Long-Range Transmission Planning (LRTP) effort. LRTP provides as a road map for investment decisions as the grid evolves.

LRTP is designed to assess the region's future transmission needs holistically, in concert with utility and state plans on where to site and build new generation resources.

The model building process used for LRTP is representative of the MTEP process but has a different data set and time frame of study. Load and renewable availability are dependent on time of day that is accounted for in the reliability base model set. The dispatch method for LRTP captures the ability to realize the target renewable energy levels with the various MISO Futures.

MISO is working with the Organization of MISO States (OMS) and stakeholders to develop and/or adjust cost-allocation methodologies that may be needed to support projects identified by LRTP. MISO is moving through a multi-phase approach of LRTP with the first phase only targeted towards MISO MTEP Future One. The estimated investment associated with MISO Future One is approximately $30 billion with the first phase of LRTP projects included in the MISO MTEP21 study approved by the MISO Board of Directors in December 2021. The total cost of all LRTP projects associated with all three MTEP futures could be in the range of $100 billion.

[5] MISO Indicative Annual charges for approved Multi-Value Projects (Schedule 26-A). Schedule 26 and 26A Indicative Reports (misoenergy.org)

Attachment H

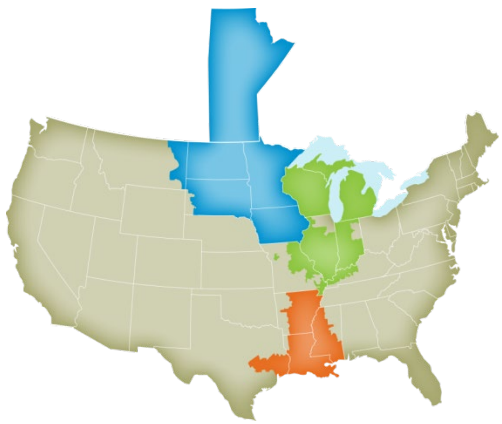
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO)

REGIONAL TRANSMISSION ORGANIZATION (RTO)

MISO OVERVIEW

Formed in 2002, the Midcontinent Independent System Operator (MISO) is a not-for-profit, member based organization. MISO ensures the reliable delivery of electricity, at the lowest cost, across high-voltage power lines in 15 U.S. States and the Canadian province of Manitoba. MISO also conducts transmission planning and manages the buying and selling of wholesale electricity in one the world's largest energy markets.

MISO Footprint



MISO Scope of Operations[1]

1. Generation Capacity
    - 184,287 MW (market)
    - 198,933 MW (reliability)
2. Generation Fuel Mix
    - 42% Gas
    - 29% Coal
    - 19% Renewables (22,082 MW of in-service wind generation)
    - 8% Nuclear
    - 2% Other
3. Historic Summer Peak Load (set July 20, 2011)
    - 127,125 MW (market)
    - 130,917 MW (reliability)
4. Historic Winter Peak Load (set January 6, 2014)
    - 109,336 MW (market)
    - 117,903 MW (reliability)
5. Transmission

[1] **MISO Fact Sheet Updated January 2021** Corporate Fact Sheet (misoenergy.org)

- 65,800 miles

6. Balancing Authorities
   - 38 Local Balancing Authorities in MISO
7. Network Model
   - 294,467 SCADA data points
   - 6,726 generating units

MISO has four main areas of services that it provides to its members[2]

1. Tariff Administration

As a Regional Transmission Organization (RTO), MISO is responsible for administering its Open Access Transmission, Energy and Operating Reserve Markets Tariff and rate. Administration of the tariff includes:

- Calculating available transfer capability (ATC)
- Evaluating and approving all requests for transmission service
- Performing transmission system impact studies
- Communicating with transmission customers
- Coordinating use and administration with other transmission providers in the region

2. Reliability Assurance

MISO's State Estimator and Contingency Analysis tools are the foundation for reliability and market operations. With these tools, MISO's reliability coordinators see actual flows, voltages against limits, breaker changes and alarms.

Solving every 60 seconds or less, MISO's State Estimator processes more than 294,000 real-time measurements, giving their reliability coordinators a continuous assessment of the transmission system including all flows, voltages, and angles.

MISO's real-time Contingency Analysis runs more than 11,500 "what-if" scenarios every four minutes providing MISO system operators and engineers the information they need to reliably operate the system and feed system status information to the energy markets.

3. Competitive Markets

The Day-Ahead Energy and Operating Reserve Market is a forward market that simultaneously clears energy and operating reserves on a co-optimized basis for each hour of the next Operating

[2] MISO Website. "What We Do." https://www.misoenergy.org/WHATWEDO/Pages/WhatWeDo.aspx

Day. Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) computer programs satisfy the Energy Demand Bids and Operating Reserve requirements of the Day-Ahead Energy and Operating Reserve Market to ensure scheduling of adequate resources to meet the next day's anticipated load.

MISO's Real-Time and Operating Reserves Market continuously balances supply and demand at the least-possible cost while also recognizing current system conditions. MISO uses the SCED algorithm that simultaneously:

- Balance injections and withdrawals
- Meet operating reserve requirements
- Manage congestion of the transmission system
- Produce real-time Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs)

The primary function of MISO's FTR Market is the allocation of Auction Revenue Rights (ARRs) and the auction of Financial Transmission Rights (FTRs). ARRs/ FTRs get issued based on transmission capacity and as a means to provide a financial hedging mechanism to the Load Serving Entities (LSEs) and other Market Participants against congestion charges in MISO's Day-Ahead Market. An ARR is a Market Participant's entitlement to a share of revenue generated in annual FTR auctions. A Market Participant's firm historical usage of MISO's transmission system determines its share, and depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge. MISO facilitates annual and monthly FTR Auctions.

4. Transmission and Resource Planning

The transmission system expansion plans produced through the MISO planning process must ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enable competition among wholesale capacity and energy suppliers in the MISO markets, and allow for competition among transmission developers in the assignment of transmission projects.

Projects listed in Appendix A of the MTEP Report constitute the transmission projects recommended to the MISO Board of Directors for review and approval. In aggregate, these projects will:

- Ensure the reliability of the transmission system
- Provide economic benefits such as increased market efficiency
- Facilitate public policy objectives such as integrating renewable energy
- Address other issues or goals identified through the stakeholder process

MISO Generation Interconnection Studies

As part of its tariff, MISO manages generator interconnection requests and studies for those transmission facilities which functional and non-functional control has been turned over to MISO.

Generator interconnection are studied in groups under MISO's Definitive Planning Process (DPP) which are scheduled bi-annually. Due to the high number of interconnection requests for wind and solar projects associated with the expiration of the Federal tax credits for renewable energy, study times to complete group interconnection requests are running 24 to 36 months to complete.

MISO's generation interconnection queue currently consists of 557 projects totaling 83.3 GW of generation. By comparison, MISO all-time peak system load is 130 GW. A breakdown of the interconnection requests by local planning regions[3] can be found in Figure 1. Montana-Dakota's service territory is contained within the West Region.

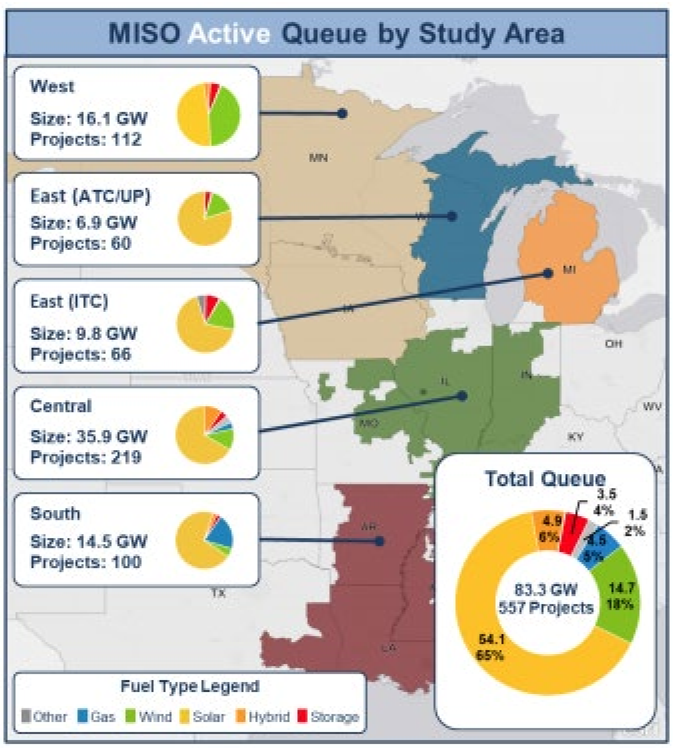


Figure 1 – MISO Generation Queue Summary

MISO has made changes to their tariff and interconnection study process to ensure projects meet higher milestone requirements before they are studied to reduce uncertainty and the need for

[3] MISO Website. Generation Interconnection Queue Summary updated 4/1/2021. GIQ Web Overview272899.pdf (misoenergy.org)

restudies if speculative projects with approved interconnection agreements are ultimately not constructed.

The delay in completing interconnection studies and assignment of network upgrade costs creates many uncertainties in all future new generation resource projects. The potential magnitude of assigned network upgrades costs can run from several hundreds of dollars per installed kW to almost a thousand dollars per kW which essentially doubles the capital cost of a wind, solar, or natural gas-fired generation project that want to locate in Montana-Dakota's service territory in Montana, North Dakota and South Dakota.

FERC recently approved a generator replacement process under its tariff whereby an existing generator can be retired and its interconnection rights transferred to new generator projects following an 180 day system impact study and does not have to go through the interconnection queue. The new generator must commence operation within three years of the retirement of the existing generator. Montana-Dakota is utilizing this new generator replacement process for the retirement of Heskett 1 and Heskett 2 and the construction of Heskett 4. The use of MISO's generator replacement process will provide certainty in the interconnection timing and costs for Heskett 4.

MISO Generation Shifts

As part of the annual MISO transmission expansion planning (MTEP) process, MISO looks at different future generation portfolios within the MISO footprint to ensure the transmission system meets the future needs of its members.

MISO future MTEP 2020 studies analyzed the following scenarios: Limited Fleet Change, Continued Fleet Change, Accelerated Fleet Change, and Distributed & Emerging Technologies. A breakdown of the MTEP 2020 Futures[4] is illustrated in Figure 2.

[4] MISO Website. MTEP 2020 Full Report. MTEP20 Full Report485662.pdf (misoenergy.org)

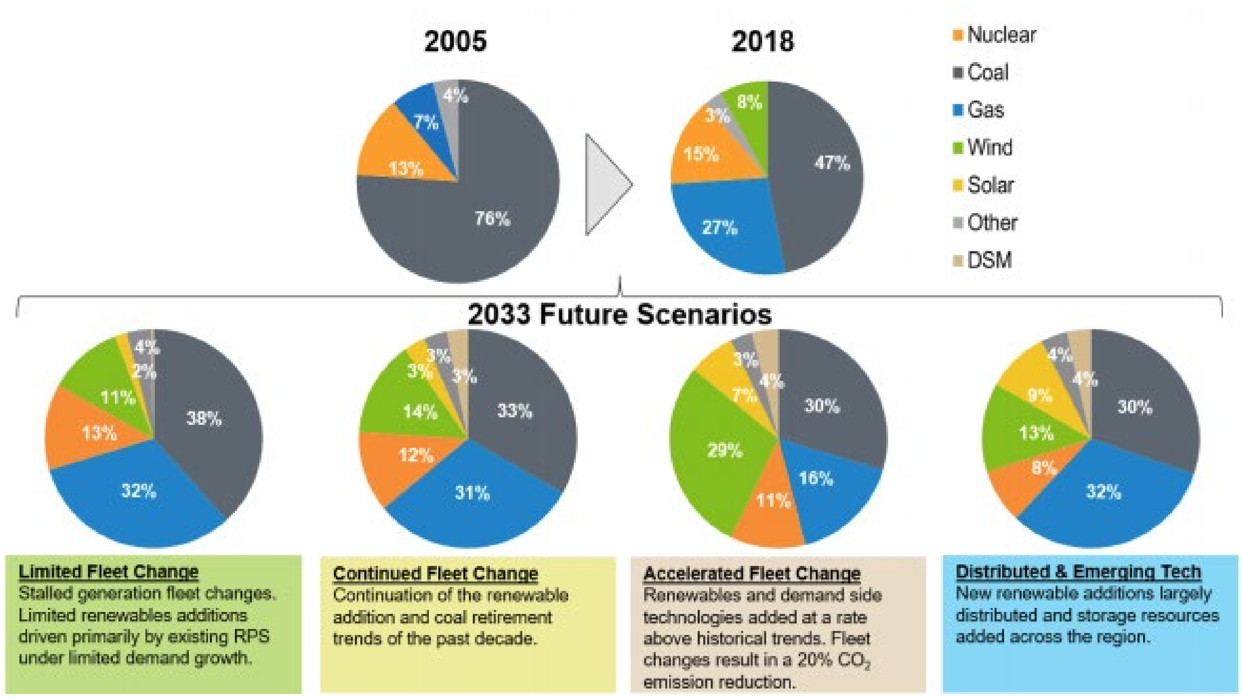


Figure 2 – MTEP 2020 Futures

Though most new generation resources additions in MISO are natural gas-fired, wind, or solar; nuclear, coal, and hydro (other) still make up a significant portion of the MISO generation fleet.

MISO has updated the MTEP 2021 future methodology and the MISO Futures Report[5] published in April 2021, captures an eighteen-month collaboration between MISO and stakeholders to develop three Future scenarios that bookend the uncertainty over the next twenty years. When carried forward into the transmission planning models, this set of Futures will enable the diverse goals and policies of MISO's states and utilities.

A. FUTURE 1

This future reflects substantial achievement of state and utility announcements and includes a 40% carbon dioxide reduction trajectory. While Future 1 incorporates 100% of utility integrated resource plan (IRP) announcements, state and utility goals that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these announced goals and respective timelines. Future 1 assumes that demand and energy growth are driven by exiting economic factors, with small increases in EV adoption,

[5] MISO Website. MISO Futures Report. https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

resulting in an annual energy growth rate of 0.5%. Modeling Future 1 results in the retirement of 77 GW and the addition of 121 GW of resources in the MISO footprint.

B. FUTURE 2

This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including a 60% carbon dioxide reduction. Future 2 introduces an increase in electrification, driving an approximate 1.1% annual energy growth rate. Modeling of Future 2 results in the retirement of 80 GW and addition of 160 GW of resources to the MISO footprint.

C. FUTURE 3

This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction. Future 3 requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.7% annual energy growth rate. Modeling of Future 3 results in the retirement of 112 GW and addition of 330 GW of resources to the MISO footprint.

A breakdown of the generation shift in the MTEP 2021 Futures is illustrated in Figure 3[6].

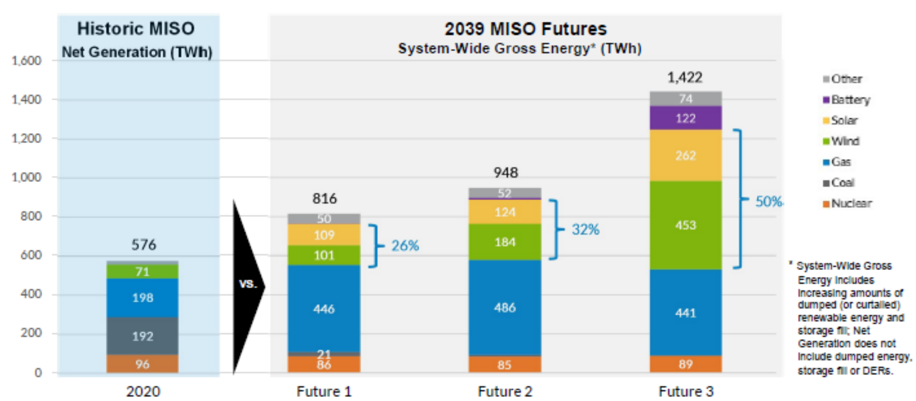


Figure 3 – Summary of MTEP 2021 Future generation shift.

[6] MISO Long-Range Transmission Plan Roadmap.
https://www.eenews.net/assets/2021/04/16/document_ew_02.pdf

Value Proposition

As a means of providing a measurement of value related services to its members, MISO annually updates its Value Proposition. The 2020 MISO Value Proposition consists of the following benefits:

A. IMPROVED RELIABILITY

MISO's broad regional view and state-of-the-art reliability tool set enable improved reliability for the region as measured by transmission system availability.

B. DISPATCH OF ENERGY

MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.

C. REGULATION

With MISO's regulation market, the amount of regulation required within the MISO footprint dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than several non-coordinated regulation targets.

D. SPINNING RESERVES

Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement declined, freeing low cost capacity to meet energy requirements.

E. WIND INTEGRATION

MISO's regional planning enables more economic placement of wind resources in the region. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.

F. COMPLIANCE

Before MISO, utilities in the MISO footprint managed FERC and NERC compliance. With MISO, many of these compliance responsibilities have been consolidated. As a result, member responsibilities decreased, saving them time and money.

G. FOOTPRINT DIVERSITY

MISO's large footprint increases the load diversity allowing for a decrease in regional planning reserve margins. This decrease delays the need to construct new capacity.

H. DEMAND RESPONSE

MISO enables demand response through transparent market prices and market platforms. MISO-enabled demand response delays the need to construct additional capacity.

I. MISO COST STRUCTURE

MISO expects administrative costs to remain relatively flat and to represent a small percentage of the benefits.

The 2020 Value Proposition study indicates that MISO provides approximately $3.5 billion in annual economic benefits to its members and the surrounding region.

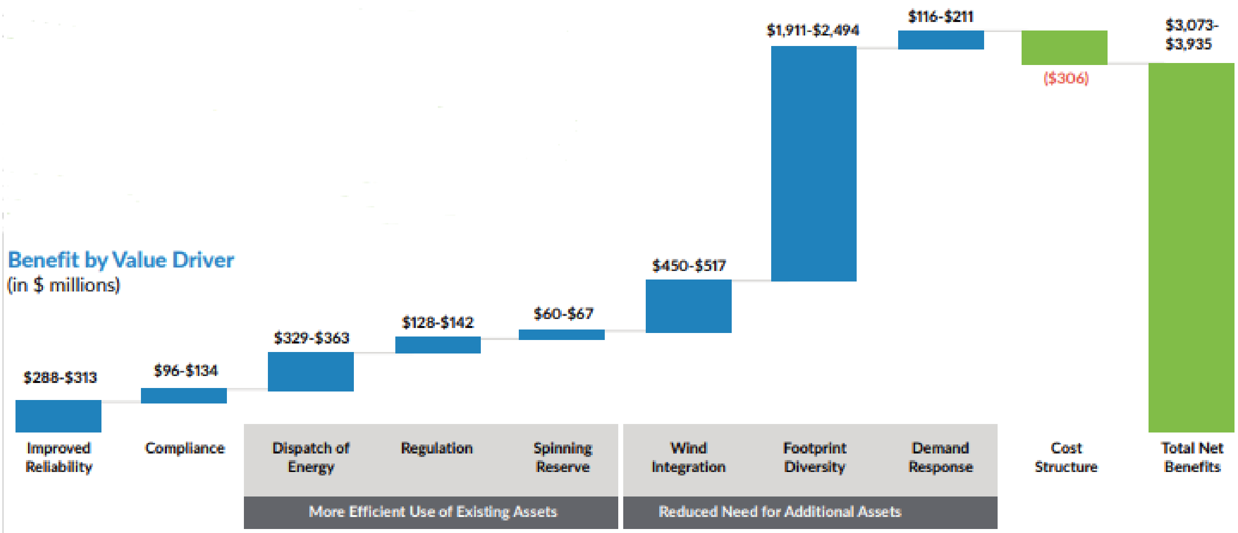


Figure 4 – MISO 2020 Value Proposition

Attachment I

Responses to Montana Public Service Commission Comments Regarding Montana-Dakota’s 2019 IRP

Service Date: October 28, 2020

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF Montana-Dakota Utilities' 2019 Integrated Resource Plan	)))	REGULATORY DIVISION DOCKET NO. 2019.07.043

MONTANA PUBLIC SERVICE COMMISSION COMMENTS IN RESPONSE TO MONTANA-DAKOTA UTILITIES COMPANY 2019 INTEGRATED RESOURCE PLAN

BACKGROUND

1. Montana-Dakota Utilities Company ("MDU") was required to file an Integrated Resource Plan ("IRP") with the Montana Public Service Commission ("Commission") by September 15, 2019, pursuant to Commission rules that provide utilities guidelines to be used in preparing an IRP. Mont. Admin. R. 38.5.2012(1) (2020); Mont. Code Ann. § 69-3-1204 (2019).

2. An IRP must demonstrate a utility's plan for meeting the service requirements of its customers in the most cost-effective manner consistent with its obligation to serve. Mont. Code Ann. § 69-3-1204. An IRP must minimally include an evaluation of the full range of cost-effective means of meeting the service requirements of its customers, including energy efficiency and other demand-side resources. *Id*.

3. Under the Commission's guidelines, an IRP should outline a strategy for meeting customer needs for adequate, reliable, and efficient energy services at the lowest long-term total societal cost. Mont. Admin. R. 38.5.2001. The Commission's guidelines encourage utilities to actively pursue all cost-effective demand-side resources. *Id*. In addition, an IRP should analyze uncertainty and risk associated with forecasting customer needs and estimating the costs of alternatives for meeting the needs. Mont. Admin. R. 38.5.2004.

4. The Commission's guidelines encourage utilities to thoroughly document resource decisions so that they can be reasonably understood by the Commission and interested parties. Mont. Admin. R. 38.5.2001.

5. According to the Commission's guidelines, competitive solicitations are important to the least cost planning process, as they can provide important cost information

regarding available resources. The guidelines encourage utilities to thoroughly test the market for cost-effective alternatives before acquiring any new resources. Mont. Admin. R. 38.5.2010.

6. IRPs do not bind the Commission in its review of utility resource plans in conjunction with a rate case or in setting rates. Mont. Admin. R. 38.5.2012. An IRP must be accompanied by an action plan that illustrates how the plan will be implemented over the near-term under various load and resource scenarios. *Id.*

7. MDU filed its 2019 IRP on July 12, 2019. On November 13, 2019, the Commission issued a Notice of Public Meeting to receive public comment on the IRP on January 28, 2020, in Helena, Montana. The Notice of Public Meeting also set a deadline of December 23, 2019, to submit written comments on MDU's 2019 IRP. The Commission received written comments from Montana Department of Environmental Quality ("DEQ") and Denbury Onshore, LLC ("Denbury"). The Commission issued a second Notice of Public Meeting on February 5, 2020, which announced another opportunity for public comment in Sydney, Montana, on February 25, 2020. On March 23, 2020, MDU filed a written response to the oral and written comments the Commission received from the public and interested stakeholders.

2019 IRP SUMMARY

8. MDU provides electric service through an integrated system to customers in Montana, North Dakota, South Dakota, and Wyoming. MDU's service territory in Montana includes about 20,268 residential customers, 5,460 small commercial and industrial ("SC&I") customers, 264 large commercial and industrial ("LC&I") customers, 36 street lighting customers, and 100 miscellaneous customers, all located in ten counties on the eastern side of Montana. Although the 2019 IRP is tailored to Montana, MDU's long-term planning process and resource acquisition decisions are based on the load obligation for its entire four-state service territory.

9. The 2019 IRP forecasts MDU's load over a 20-year period (2019-2038), and considers potential supply- and demand-side resource options that are available to meet expected loads. MDU uses the Electric Generation Expansion Analysis System ("EGEAS"), a model developed by the Electric Power Research Institute, to identify the least-cost resource portfolio for meeting forecast loads under a number of potential future scenarios.

10. MDU uses econometric models to forecast load growth and energy sales over the planning period for its residential, SC&I, and LC&I customer classes. There are also four LC&I

customers whose load growth MDU forecasts individually, in order to account for known changes to their operations. MDU expects energy sales across its integrated system to increase by about 1.32% per year over the planning horizon, net of expected energy savings from demand-side management ("DSM") programs. MDU expects net energy sales in Montana to increase by about 1.18% per year over the same time period.

11. MDU develops a peak demand forecast for its integrated system as a whole – peak demand is not disaggregated on a state-by-state basis. An econometric model is used to forecast peak load separately in the summer and winter seasons. The model examines the historical relationship between peak day/hour temperatures, annual degree days, annual sales, and a time-trend variable. Peak loads are then forecast based on MDU's sales forecast and expected normal weather. MDU's base case peak load forecast assumes normal temperatures during system peak, which means there is a 50% chance temperatures will be higher or lower than average. Based on studies conducted by MDU, the utility expects the system peak will increase by about 6.9 megawatts ("MW") for every one degree increase in temperature at the time of system peak. MDU expects the summer peak to increase by about 1.7% annually, with its summer peak load reaching 763.9 MW by 2038, net of the load reductions MDU expects to receive through its DSM programs. The winter peak is expected to increase by about 1.4% per year, reaching 716.1 MW by 2038, net the load reductions MDU expects to receive through DSM.

12. The offset to its load obligation that MDU expects to receive through DSM programs include both energy efficiency ("EE") programs and Demand Response ("DR") programs. EE programs in Montana are funded through the Universal System Benefits ("USB") charge. The amount of load reduction MDU expects to achieve through EE programs stems from an EE potential study conducted by Navigant Consulting, LLC ("Navigant") in 2012, and an EE program planning study conducted by Navigant in 2013. MDU uses the Total Resource Cost ("TRC") to determine which programs are economically feasible in the 2019 IRP. Under the TRC, benefits are based on avoided energy and capacity that the measure avoids, and the costs include all costs for both the utility and the participant (DSM measure costs, program administration costs, etc.). If the benefit/cost ratio of a program is greater than one (1.00) under the TRC, MDU will evaluate the program for potential implementation. Navigant's EE potential study found that the achievable EE potential in Montana is lower than MDU's system-wide

average due to MDU's small rural customer base and limited contractor networks. Navigant found in its program planning study that program delivery mechanisms and marketing will be key to increased participation. One residential and 35 commercial customers participated in EE programs in Montana in 2018. In the 2019 IRP, MDU reports it offers the following EE programs:

- *Residential LED Lighting Program*: Residential customers receive a rebate of 50% of the bulb cost, up to $7/bulb, for purchasing LED lighting.
- *Commercial Lighting Program*: The commercial lighting program offers prescriptive rebate levels individually designed to maximize customer participation, and includes rebates for lighting controls and occupancy sensors.
- *Commercial Partnership Program*: Commercial and industrial customers receive rebates for installing energy conservation measures that are not eligible for MDU's other energy efficiency rebates. Rebate levels are based on the amount of estimated energy savings and are project-specific.

13. In addition to the above EE programs, MDU began implementing an LED conversion program for company-owned street lights in 2018. MDU completed the conversion of 5,600 street lights in Montana in 2018, with an estimated energy savings of 3.08 million kilowatt hours ("kWh") per year, or the equivalent of serving 410 homes for a year.

14. MDU offers the following DR programs to commercial and industrial customers:

- *Commercial Demand Response Resources ("DRR") Program*: The Commercial DRR program is administered by CPower. MDU directly pays CPower for capacity provided (up to 25 MW per month per contract), plus an avoided energy payment during an actual DR event. CPower contracts directly with participating customers and pays customers directly. The Commercial DRR program is available to customers with a demand equal to or greater than 50 kilowatts ("kW"), but is focused mainly on customers with a demand of 150 kW or greater.
- *Rate 38/39 ("Interruptible Customers")*: Rate 38/39 is available to customers with loads equal to or greater than 500 kW. Interruptible customers receive a discount to their demand charge in exchange for shedding load during DR events. Participants agree to be interrupted up to 100 hours per year. 15.4 MW of load currently

participates in the program, and MDU plans to increase participation to 20 MW by the Summer of 2021.

15. MDU estimates the amount of achievable annual energy reduction that can be acquired through EE and DR programs across its integrated system is equal to about 0.35% of annual energy sales will reduce peak demand by about 1.7% in 2037. MDU estimates the amount of achievable, cost-effective EE in the Montana service territory is equal to about 0.26% of energy sales to Montana customers over the planning horizon.

16. MDU is a member of the Midcontinent Independent System Operator ("MISO"). MISO is a regional trading organization ("RTO") that coordinates the operation of the regional transmission system and operates a day-ahead and real-time energy market to facilitate the economic dispatch of resources required to meet loads across the entire MISO footprint. MISO assigns Zonal Resource Credits ("ZRCs") to all resources of MISO participants in the MISO RTO footprint. The ZRC is a measure of the capacity each resource can provide to the system. As a member of MISO, MDU is required to carry enough resources to meet its projected Planning Reserve Margin Requirement ("PRMR"), which is the sum of MDU's native load at a time coincident with the MISO peak summer demand, plus a 1.9% adder for MISO losses, and a reserve margin of 7.8%. MDU's current native load that is coincident with the MISO summer peak is about 80% of the peak load that MDU experiences on its own integrated system.

17. MDU's existing supply-side resources include baseload coal-fired generation (361.8 MW), natural gas-fired peaking units (197.5 MW), wind generation (157 MW), portable diesel units (4.2 MW), and a waste heat generating unit (7.5 MW). MISO has assigned MDU's existing portfolio of supply- and demand-side resources 590.1 MW ZRCs. MDU currently meets the MISO PRMR, but expects to become resource deficient by 2022, based on the modeling assumptions included in the 2019 IRP. A significant contributor to the 2022 resource deficiency is MDU's decision to retire the Lewis and Clark coal plant (47 MW) at the end of 2022, and the Heskett Unit I (26.1 MW) and Heskett Unit II (73.1 MW) coal plants at the end of 2021. The 2019 IRP states the main reasons for retiring those coal plants include age (all are about 60 years old), an abundance of low-cost natural gas, low power prices in the MISO market, rising coal supply costs, and rising plant O&M costs. MDU also conducted a per kWh comparison of the fuel and O&M costs associated with the coal-fired units and determined they are no longer cost competitive when compared with other resource options. MDU modeled the retirement date of

the coal plants in 2021, 2024, and 2029, and found customers would receive the greatest benefit with a retirement date in 2021. The 2021 retirement date also coincides with the expiration of coal supply agreements for the plants. In the 2019 IRP, MDU provided EGEAS with an option to re-select any of the coal plants back into the portfolio as a 5-year resource at zero capital investment following their retirement date; however, EGEAS did not select any of the retired coal plants for inclusion in the least-cost portfolio – in either the base scenario or any alternative sensitivity cases.

18. MDU uses EGEAS to develop a least-cost integrated resource expansion plan under the base case scenario in the 2019 IRP, as well as to model the least-cost expansion plan under other sensitivity cases. The supply-side resources that EGEAS was allowed to select in an expansion plan include simple cycle aeroderivative and frame natural gas units, simple cycle reciprocating internal combustion engine ("RICE") natural gas units, combined cycle combustion natural gas turbines, coal units with and without carbon sequestration technology, wind resources, solar resources plus storage, and biomass resources. The full list of supply-side resources included in the EGEAS model for future selection, as well as their corresponding cost profiles, are contained in Table 2-5 of Appendix C of the 2019 IRP.

19. MDU issued a request for proposal ("RFP") in August 2018; however, none of the offered projects were short-listed. MDU did not pursue any future wind, solar, or natural gas-fired generation from the 2018 RFP due to project size, uncertainties in final costs associated with network upgrades, and location of resources. Some of the projects from the 2018 RFP were included in the 2019 IRP modeling to show the potential need to reevaluate projects in the future.

20. The MISO energy market provides a source of energy available to MDU when market prices are lower than MDU's generation costs, or when energy is required due to planned maintenance or forced outages. The EGEAS model includes a 200 MW block of energy from the MISO market for on-peak and off-peak periods as an alternative to meet load. MDU's base case forecasts MISO market prices using the mid- price between the one- and five-year historical average for the first year of the forecast. Prices are escalated annually at a rate of 3% beyond year one.

21. The natural gas price forecast MDU uses to estimate fuel costs for natural gas-fired units is calculated using a combination of forward index prices at Henry Hub and MDU's

knowledge of natural gas prices. The forecast is escalated at a rate of 3% annually in years beyond 2023.

22. MDU's designated least-cost plan in the 2019 IRP reflects its base case scenario. The least-cost plan acquires an 88 MW natural gas-fired simple cycle combustion turbine to be online in 2022 or early 2023. The plan also acquires wind, solar, and natural gas-fired generation from the 2018 RFP in years 2022-2025; however, MDU's action plan does not include pursuing those resources at this time because of uncertainties surrounding their final cost associated with unknown transmission upgrades. The base case portfolio in the 2019 IRP has a net-present value ("NPV") of $2,860,370,000.

23. In addition to the base case, MDU modeled sensitivity cases to account for uncertainty surrounding assumptions made for carbon taxes, natural gas prices, load growth, MISO resource adequacy requirements, combustion turbine capital costs, the market price of electricity, and market energy availability. The following describes each sensitivity case modeled by MDU in the 2019 IRP and provides the NPV of each portfolio:

- *Carbon Tax*: No carbon tax was modeled in the base case. In the carbon tax sensitivity case, MDU modeled a $30 carbon tax on all carbon emissions from its existing coal-fired and natural gas generation, energy purchases from the MISO market, and new generating units added to the resource plan starting in 2025. The NPV of the portfolio is $3,916 million.
- *High and Low Gas Price*: MDU's base case delivered natural gas price is $3.04/MBTU in 2019, decreasing to $2.67/MMBtu in 2023, and escalating at 3% annually thereafter. The high gas price sensitivity cases increase base case prices by $2/MMBtu and $5/MMBtu The low gas price sensitivity case decreases base case prices by $1/MMBTu. The NPV of the high gas $2/MMBtu portfolio is $3,036.76 million, the NPV of the high gas $5/MMBtu portfolio is $3,297.51 million, and the NPV of the low gas $1/MMBtu is $2,719 million.
- *90% Coincident Factor for MISO Resource Adequacy*: This sensitivity case uses a 90% coincident factor to establish MDU's PRMR, rather than the 81.5% factor utilized in the base case. The NPV for the 90% coincident portfolio is $3,081 million.
- *High and Low Load Growth*: The base case load growth forecast assumes an average increase in loads of 2.42% for the first five years of the planning horizon, followed by an average increase of 1.3% per year through 2038. The low-growth sensitivity case, derived from the historically low growth period of 1985–1993, uses a 0.5% annual growth rate over the planning horizon. The high-growth sensitivity case, derived from the historical period of 1977–1985, assumes an annual load growth rate of 4.4% over the planning horizon. The NPV of the low-growth sensitivity case is $2,219.07 million. The NPV of the high-growth sensitivity case is $5,014 million.

- *High Combustion Turbine and Internal Combustion Engine Costs*: This sensitivity case adds 20% to the capital costs of combustion turbines and internal combustion engines, to assess the sensitivity of base case results to higher resource costs. The NPV of this portfolio is $2,884 million.
- *High and Low MISO Market Prices*: The high market price adds $5/MWh and $10/MWh to the on-peak and off-peak market prices of the base year. The low market price sensitivity case reduces base year on- and off-peak prices by $3/MWh. The NPV of the high market $5/MWh portfolio is $3,029.88 million, the NPV of the high market $10/MWh portfolio is $3,135.75 million, and the NPV of the low market portfolio is $2,749 million.
- *High Natural Gas and MISO Purchases*: This sensitivity case assumes both natural gas and MISO energy market purchases increase from the base year by $5/MMBtu and $25/MMBtu. The NPV of this portfolio is $4,214 million.

24. The Environmental Protection Agency's ("EPA") 111(d) Rule, the "Clean Power Plan", established carbon dioxide limits for existing fossil-fired electric generation units. On October 16, 2017, the EPA proposed to repeal the Clean Power Plan and replace it with the Affordable Clean Energy ("ACE") Rule. MDU is reviewing the preliminary ACE Rule and will incorporate changes as needed into the evaluation of supply-side resources.

25. In 2017, MDU as a company set an internal target to reduce the carbon dioxide emission intensity of its generation fleet by 45 percent by 2030, compared to carbon dioxide emission intensity in 2005. MDU will monitor all federal environmental rules that could potentially impact its generating fleet, including:

- *The Regional Haze ("RH") Rule* was promulgated in 1999 by the EPA to address visibility impairment in Class I areas of the United States. Round one of the RH rule was finalized in 2012 and required MDU to install pollution controls on three of its generating units: the Big Stone Plant, Heskett II, and Coyote Station. States are required to submit RH Rule round two State Implementation Plans ("SIPs") to EPA by July 31, 2021. The DEQ requested MDU to provide analysis with regard to Lewis & Clark I compliance with the round two of the RH Rule, but since MDU plans to retire Lewis & Clark I prior to the July 31, 2028 compliance date of round two of the RH Rule, MDU will not need to install additional pollution controls on the unit. Similarly, because Heskett I and Heskett II will retire prior to July 31, 2028, MDU will not need to install additional pollution controls on either unit. MDU expects it will likely need to install nitrous oxide and sulfur dioxide controls at Coyote Station to comply with round two of the RH rule; however, actual costs are unknown at this time as compliance measures are still being evaluated.
- *The Coal Combustion Residual ("CCR") Rule* was promulgated by the EPA in 2015 and established requirements for the management and disposal of coal ash. The rule requires landfills of existing units that do not meet the specified criteria to be closed and replaced with new landfills, and requires new groundwater monitoring. On

December 16, 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was signed into law, which provided the EPA and states the authority to administer and enforce the CCR Rule requirements. Lewis & Clark 1 completed a retrofit to scrubber ponds in 2018 at a cost of $5.4 million, and would have been forced to close by April 17, 2019, without the retrofit. Big Stone and Coyote Station also require retrofits, and MDU's ownership shares are expected to be $2 million for Big Stone and $2.5 million for Coyote Station.

- *The Aquatic Species Protection 316(b) Rule* was published by the EPA in 2014 and is intended to reduce impingement of fish and other aquatic organisms at cooling intake structures. Due to planned retirement dates for Lewis & Clark I, Heskett I, and Heskett II, MDU does not anticipate any controls will be required.

26. Up until 2015, MDU and the Western Area Power Administration ("WAPA") had a history of sharing transmission facilities and wheeling power across each other's systems through a Transmission Services Agreement ("TSA"). On October 1, 2015, WAPA joined the Southwest Power Pool ("SPP") as a transmission-owning member, and on December 15, 2015, MDU's TSA with WAPA expired. MDU currently takes Network Integrated Transmission Service ("NITS") under the SPP tariff for service it previously received under its TSA with WAPA. MDU receives Section 30.9 facilities credits from SPP to offset a portion of its SPP transmission bill. MDU continues to see a greater value in remaining a MISO member rather than joining SPP as a full member. The greater value comes largely from the resource adequacy requirements set in MISO and SPP. MISO includes a diversity factor reduction to account for MISO customer loads peaking at different times, whereas SPP requires each load serving entity to carry capacity resources for their full forecasted load plus a planning reserve margin. If MDU were to join SPP, it would need to add 105 MW of additional capacity to meet the SPP resource adequacy requirement. MDU evaluates the benefits of remaining a member of MISO compared to joining SPP each year, and continues to find that remaining a member of MISO provides the greatest value to customers.

27. Based on its analysis of the resource expansion model results and consideration of other factors such as customer impacts, environmental regulations, and the balance of its generation mix, MDU identified the following two-year plan action items.

- Retire Lewis & Clark I by the end of 2020, and Heskett I and Heskett II by the end of 2021, and submit regulatory filings to address the retirements;
- Continue the design and engineering work on a natural gas-fired simple cycle combustion turbine resource to be online in 2022 or early 2023;
- Issue a new RFP prior to the next IRP;

- Continue to study the need to install local generation projects, including community solar;
- Continue to monitor the availability and price of energy and short-term capacity in the MISO market or through bi-lateral agreements;
- Continue to monitor the development of and impacts to the Coyote Station associated with the next round of regional haze reductions and other changes of environmental rules;
- Continue to monitor new RTO resource adequacy requirements in MISO associated with the changing fleet fuel mix, including seasonal variations and reserve margins;
- Continue to evaluate solar and battery storage technologies;
- Continue to monitor the impacts and benefits of its RTO transmission agreements with MISO and SPP; and
- Maintain the IRP Public Advisory Group to provide input to and review MDU's future resource plans.[1]

PUBLIC COMMENT SUMMARY

28. DEQ, which is statutorily required to review and comment on IRPs, submitted its written comments on December 23, 2019. Mont. Code Ann. § 69-3-1205. DEQ supports MDU's decision to rely on MISO purchases for the next several years, with the option to increase the dispatch of Big Stone, Coyote, and other natural gas-fired units if MISO energy prices increase more than forecasted. DEQ concurs with MDU that modeling in the 2019 IRP indicates the coal plants scheduled for closure are no longer cost-competitive in MISO, and encourages MDU to work with local communities affected by the retirements to ease the transition period.

29. DEQ is concerned that MDU does not include a carbon cost in its base case, and points to other members of MISO (Minnesota Power and Xcel Energy) that do include carbon pricing in their base scenario. DEQ states that MDU's high carbon scenario is too moderate. It recommended that MDU use, in part, Minnesota Power's assumption of carbon costs as guidance in its next IRP.

30. DEQ believes MDU's high-gas cost scenario is too moderate. It suggests that MDU should model a high gas scenario where natural gas market prices increase by $9/MBTU above the base scenario, rather than the $5/MBTU above the base scenario that is included in the

[1] The IRP Public Advisory Group consists of two Montana members (Kevin Thompson of Action for Eastern Montana and Garett Martin with the Montana DEQ), five North Dakota members, and one South Dakota member. A representative from the North Dakota Public Service Commission also participates as an observer. The group held three meetings during this IRP planning period.

2019 IRP. DEQ also recommends MDU analyze the costs of carbon capture, utilization, and sequestration in order to better understand carbon sequestration as a tool to mitigate the cost of carbon regulation or pricing.

31. DEQ states that MDU should include a scenario that assumes distributed generation increases to meet 3-5% of retail sales in 10 years. DEQ also states that MDU should consider hybrid renewable energy plus energy storage systems in future supply-side analysis, and fully evaluate storage systems as resources that could assist MDU to mitigate transmission constraints, defer grid infrastructure investments, and provide ancillary services.

32. DEQ supports the expansion of MDU's cost-effective DSM programs, and recommends MDU not to rely so heavily on a single interruptible customer for DR. DEQ suggests that MDU should treat DSM resources more similarly to supply side resources, and should model different quantities of energy efficiency and demand response. DEQ recommends that MDU continue to look at expanding its demand response offerings within the residential and commercial sectors, including the continued evaluation of a residential A/C demand response program.

33. Denbury submitted comments on December 23, 2019. Denbury suggests that the Commission evaluate how PacifiCorp and NorthWestern are addressing coal-fired generation risks in their resource plans to inform its assessment of MDU's IRP. Denbury states that the economics of retirements and building new generation should be thoroughly vetted, and include consideration of impacts to service reliability. Denbury acknowledges that some concerns about reliability are alleviated by MDU's plans to replace its coal-fired generation in part with natural gas-fired generation. Denbury is concerned about MDU's reliance on MISO energy purchases for short-term needs, as NorthWestern and PacifiCorp have expressed concerns about increased price and volatility in the regional market due to significant coal retirements.

34. Denbury is supportive of MDU expanding its DR programs. Denbury plans to continue to evaluate its ability to increase its participation in MDU's DR programs, and supports MDU's effort to take full advantage of DSM programs prior to investing in new generation resources. Denbury also states that it looks forward to working with MDU on a potential future distributed generation project.

35. MDU submitted a response to DEQ and Denbury comments on March 23, 2020. MDU states it has already reached out to local government officials in Sydney, Montana, to

discuss the impacts of retiring the Lewis and Clark I plant, and MDU is willing to work with local governments on options for mitigating those impacts.

36. MDU states that it did not include carbon costs in the base case for the 2019 IRP because the plan was prepared for its interconnected system in Montana, North Dakota, and South Dakota, and must conform to the regulatory requirements in each of those states. North Dakota does not allow MDU to include external costs in its analysis while Montana statute and Commission rules require MDU to consider externalities like carbon. MDU believes it satisfies the requirements for both states through its carbon sensitivity case.

37. MDU disagrees with DEQ that it did not adequately analyze solar plus storage and DSM. MDU states solar plus storage was a resource option available for EGEAS to select and its current DR programs, which provide 40 MW of capacity to the portfolio, have been successful. MDU states it plans to expand its analysis of potential new DR programs as part of its 2021 IRP. It also notes that its 2020 RFP solicited proposals for energy storage, DSM, and EE programs.

38. MDU believes it adequately analyzed the risks associated with natural gas resource options. It included a sensitivity in which natural gas prices increase by $5/MMBTU and MISO energy prices increase by $25/MWh. MDU states the sensitivity case did not materially change future resource selections by the model, therefore, higher natural gas prices do not support continued operation of MDU’s smaller coal plants. Furthermore, if natural gas prices or MISO energy prices rise beyond a level projected even in the sensitivity case, MDU could still dispatch its remaining coal-fired generation before the need for natural-gas fired generation to meet customer energy requirements. MDU also has the option to construct additional renewable generation or convert Heskett 3 & 4 into a combined cycle generator to capture higher efficiencies from combusting natural gas, should natural gas prices rise beyond what MDU expects.

39. MDU is not clear what risks related to coal-fired generation Denbury refers to in its comments recommending that MDU examine the IRPs of PacifiCorp and NorthWestern Energy. MDU points out that it provides electricity to customers on the Eastern Interconnection Grid, which is fairly isolated from the Western Interconnection Grid where PacifiCorp and NorthWestern Energy provide electric service. MDU also notes that, as a member of MISO, it has access to more stable energy pricing than is seen in the Western Interconnection Grid.

40. MDU agrees with Denbury's comment that the Commission and MDU should consider reliability impacts as MDU transitions away from coal-fired generation. MDU states that the reliability benefits of natural gas-fired generation coupled with low market energy prices were key drivers in its decision to retire its uneconomic coal units.

41. MDU also addressed oral comments from the general public, Richland County, and the City of Sydney that were provided during the Commission's Public Meeting held in Sydney, Montana, on February 25, 2020.

42. Generally, comments provided at the Public Meeting reflect community concerns over MDU's decision to shut down the Lewis & Clark 1 coal-fired generating station in Sydney. In response, MDU emphasizes that the decision to shut down its smaller coal plants is strictly an economic decision. MDU reiterates that modeling in the 2019 IRP shows that the total cost of its supply portfolio over the planning horizon is less if the company shuts down its smaller coal plants, because there are less costly alternatives available. MDU states the variable costs (fuel plus O&M costs) of generating energy at Lewis & Clark I were about $10.00/MWh higher than the cost of purchasing energy from the MISO market in 2018.

43. MDU rejects the notion made by some commenters that the company is building wind generation to replace coal-fired generation, and the notion that wind generation was the cause of MDU's most recent two rate cases. MDU states that wind did not drive its decision to retire its smaller coal plants. Rather, as shown in the 2019 IRP, energy from coal generation is replaced with purchases from the MISO market and coal generation capacity is replaced with a natural gas turbine at the Heskett generating station. MDU states that if its next RFP identifies resources more economic than relying on the MISO market, the resources will be selected regardless of generation type. MDU explains that, while wind generation costs were part of its recent rate cases, those costs were not the sole driver of either rate case. A variety of factors contributed to MDU's decision to file its recent rate cases, including transmission investments, environmental control upgrades at existing facilities, increased O&M costs, and construction of new generating facilities.

44. MDU similarly rejects the notion that the decision to retire the Lewis & Clark 1 plant is driven by a carbon tax or a desire to move away from coal. MDU points out that it will still have coal plants in its portfolio even after the smaller coal plants are retired. MDU did not

include a carbon cost in its base case portfolio, and therefore a carbon tax did not drive resource selection in the 2019 IRP.

45. Commenters questioned why MDU would recently install costly environmental controls at the Lewis & Clark 1 Station if it was going to shut down the plant. MDU explains that it installed new environmental control equipment and ash tanks at Lewis & Clark 1 because, at the time, those controls were needed to comply with federal environmental rules. Had MDU not installed the environmental upgrades, the coal plants would have been required to retire as early as 2015.

46. Commenters asked MDU if it would be willing to sell Lewis & Clark to another party. MDU explains that it contacted five utilities in its operating region to see if one would be interested in purchasing the plant, but none were interested. MDU has not been approached by any other party that would like to purchase the Lewis & Clark plant. MDU states it would be interested in selling the plant to another party, but it would have to ensure its customers are protected from future clean-up and environmental liability costs.

47. MDU continues to analyze comments made at the Public Meeting on February 25, 2020, about community transition needs, but at this point no data or analysis has been provided which would undermine the conclusion reached in the 2019 IRP to retire the Lewis & Clark 1 plant. MDU states it is sensitive to the communities' concerns regarding the plant closure, but MDU is obligated to provide electricity to its customers with a least-cost resource mix. MDU states that absent an acquisition by an appropriate buyer, MDU is obligated to move forward with closure and decommissioning of the Lewis & Clark 1, Heskett I, and Heskett II plants because the plants are no longer economic compared to other alternatives.

COMMISSION COMMENTS

48. Commission rules provide utilities guidelines for developing plans to provide adequate, reliable, and efficient energy services at the lowest long-term total cost while remaining financially sound. Mont. Admin. R. 38.5.2001. MDU's 2019 IRP reasonably adheres to those guidelines. The Commission appreciates the analyses and other work MDU performed in compiling the 2019 IRP, and its effort to engage the public to discuss its results. The Commission offers the following comments on MDU's 2019 IRP.

49. A significant conclusion in the 2019 IRP is that the Lewis & Clark I and Heskett I & II coal-fired generating plants should be retired in 2020 and 2021, respectively. MDU has

contemplated an appropriate retirement date for these plants since at least its 2015 IRP. Commission rules dictate that, should an IRP demonstrate that previously rate-based resources should be abandoned and replaced by new resources, the Commission will open separate proceedings to determine recovery of a rate-based asset. Mont. Admin. R. 38.5.2001(5). Therefore, neither the 2019 IRP nor Commission comments in response to the 2019 IRP dictate in itself any decision made by the Commission with regard to cost-recovery of any resource, whether that be a resource that has already been acquired or not.

50. In response to MDU's 2017 IRP, the Commission stated MDU should proactively estimate the amount of capital investment that would likely be required to keep its coal units in service. While the revenue requirement portion of the retirement analysis provided in Volume IV of the 2019 IRP appears to account for at least some of that necessary capital investment, a description of the upgrade-related capital investments MDU expects it would avoid is lacking in that section of the IRP. The main volume of the 2019 IRP assumes the Lewis & Clark and Heskett plants will retire in 2021, and therefore, does not address the cost of potential upgrades at all. MDU should provide a detailed discussion on all costs it expects to avoid by retiring the aforementioned coal plants in 2021 rather than 2024.

51. MDU should use EGEAS to endogenously model the optimal retirement date(s) of its resources, rather than deterministically selecting retirement dates for the units and testing those dates within the model. Importantly, and related to this analysis, it appears MDU did not include the cost of retiring the coal units (or any other unit) in the EGEAS model within the 2019 IRP. The cost of shutting down a plant can be significant, and the timing and cost of retiring a plant should be considered by MDU. While the Commission recognizes MDU did include the cost of retirement in its revenue requirement analysis for the year 2023, provided in Volume IV of the 2019 IRP, one purpose of the planning exercise is to measure the impact to the NPV of the supply portfolio over the entire planning horizon, rather than a single year. To the extent possible, MDU should forecast both required capital expenditures and retirement costs for its resources, include those costs as an input to the EGEAS model, and allow the model to endogenously select the optimal retirement date for its resources. If it is not possible to conduct this type of analysis within the EGEAS model, MDU should clearly explain why.

52. In its most recent electric rate case in front of the Commission, MDU testified that the environmental upgrades made to the Heskett and Lewis & Clark plants would keep the units

in service until at least 2025. *In re the Application of Montana-Dakota Utilities for Authority to Increase Rates,* Dkt. 2018.09.060, Test. Nicole Kivisto 5 (Sept. 28, 2018). Furthermore, in both the 2015 and 2017 IRPs, MDU projected a retirement for those resources at the end of 2024. In the 2019 IRP, MDU examined various potential retirement dates for the units and found the NPV cost of its portfolio would be less if the units were retired in 2021 rather than 2024. However, the NPV of the portfolio with a 2021 retirement date is $6 million, or a mere 0.21%, less than the NPV cost of the portfolio with a 2024 retirement date. It is not clear that such minimal savings, which are identified in a model that is dependent on uncertain information, justifies the significant change in course of action in moving the retirement date up to 2021. In any future proceeding in which MDU seeks cost recovery for this transition, the Commission will be paying particular attention to this issue.

53. The Commission appreciates MDU's effort in the 2019 IRP to address the inconsistent escalation factors that had been used in the natural gas and electricity market price forecasts in past IRPs. MDU generally explains how it derived the natural gas and electricity market prices forecasts used in the 2019 IRP, but it does not provide the forecasts in the main report of the 2019 IRP. The electricity market price forecast is provided in graphical form in Volume I of the 2019 IRP, but the actual prices are only located in the EGEAS output files in Volume IV. MDU should provide the year-by-year values for its natural gas and electricity market price forecasts in the main volume of its next IRP, so they can be easily located and understood by any reader of the document. MDU should also compare its own MISO electricity market price forecast with the MISO electricity market price forecast of other utilities in the MISO footprint.

54. The MISO capacity market could be an inexpensive source of short-term capacity for MDU. In the next IRP, MDU should more thoroughly discuss to what extent it believes it can rely on the MISO capacity market to meet its annual PRMR.

55. The Commission agrees with DEQ's assessment that MDU should fully evaluate storage systems as resources that could assist MDU to mitigate transmission constraints, defer grid infrastructure investments, and provide ancillary services. The Commission recognizes that MDU modeled a 50 MW solar project plus a 10 MW battery, as well as a 5 MW solar project plus a 1 MW battery in the 2019 IRP; however, MDU should also model wind plus storage resources, as well as stand-alone storage resources, like a battery, that are not coupled with

renewable projects. MDU should analyze what the costs and benefits are of coupling a renewable project with storage compared to a stand-alone storage resource that could be charged when MISO prices are low, in order to see which configuration provides greater benefits to MDU's system. MDU should also model storage resources at a scale larger than 10 MW.

56. MDU states in the 2019 IRP that customer participation in Montana in its DSM programs continues to be low. Navigant found in its program planning study in 2013 that program delivery mechanisms and marketing are key to increased participation. In its next IRP, MDU should discuss what program delivery mechanisms and marketing efforts are currently in place to support customer participation in its DSM programs, as well as any potential or recently made changes that have occurred through delivery/marketing in order to encourage increased participation in DSM programs. Furthermore, the 2012 EE potential study and the 2013 program planning study are significantly outdated at this point. MDU should conduct new EE potential and program planning studies, and incorporate the results into future IRPs as soon as possible.

57. MDU conducted an RFP in 2018 but did not short-list any projects. However, MDU states it selected a group of projects that responded to the 2018 RFP to be included in modeling analysis in the 2019 IRP. MDU does not specify what criteria were used to determine which respondents to the 2018 RFP should be analyzed in the 2019 IRP, and which projects should not. In this type of situation, MDU should clearly explain how it selected certain projects from an RFP to be analyzed further in the context of an IRP.

DONE AND DATED on this 28th day of October, 2020, by Order of the Commission.

BY THE MONTANA PUBLIC SERVICE COMMISSION

BOB LAKE, Chairman
BRAD JOHNSON, Vice Chairman
ROGER KOOPMAN, Commissioner
TONY O'DONNELL, Commissioner
RANDALL PINOCCI, Commissioner

CERTIFICATE OF SERVICE

I certify that on the 28th day of October, 2020, a true and accurate copy of the foregoing document was served by email to the following:

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For Applicant Montana-Dakota Utilities Company

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By:_/s/ Susie Osborne____________
Susie Osborne
Compliance Spec./Administrative Asst.
Montana Public Service Commission

Attachment J

Responses to Montana Department of Environmental Quality Comments Regarding Montana-Dakota's 2019 IRP

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF Montana-Dakota Utilities' 2019 Integrated Resource Plan	REGULATORY DIVISION Docket No. 2019.07.043

COMMENTS OF THE
MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY

I. Introduction

The Montana Department of Environmental Quality ("DEQ") appreciates the opportunity to comment on Montana-Dakota Utilities' 2019 Integrated Resource Plan ("2019 Plan"). DEQ is an executive agency established under 2-15-3501, Montana Code Annotated ("MCA") and is home to the Montana Energy Office. DEQ houses multiple functions on behalf of the state including regulation of certain energy development projects pursuant to the Montana Major Facilities Siting Act, analyzing emerging energy issues and providing recommendations for appropriate state action, financing energy efficiency and renewable energy projects, and supporting energy emergency planning and response. DEQ analyzes energy policy and regularly participates in state, regional, and national forums regarding energy issues including supply planning, and regional market coordination, all of which are relevant to the 2019 Plan.

DEQ is required to comment on integrated least-cost plans submitted to the Public Service Commission ("Commission"). Montana statute requires DEQ to "review a plan and comment on the need for new resources, the alternatives evaluated to meet the need, the environmental implications of the resource choices, and other related issues that it considers important."[1] DEQ is also an active member of the Montana-Dakota Utilities ("MDU") Public Advisory Group. DEQ is committed to participating in energy planning processes that will help guide future energy resource decisions. Consistent with the mission and responsibilities of DEQ, the following general comments are provided in response to the Commission Notice for Opportunity to Comment on the 2019 Plan.

II. Transparency of modelling and planning process allows for appropriate stakeholder engagement

DEQ is pleased that MDU continues to increase the discussion and data made available in the utility's biennial IRP submission to the Commission. The additional discussion and data provided improves the transparency of MDU's demand and supply side planning efforts, allowing both regulators and the public to better understand the costs and risks that the utility and its customers will face in the future.

III. Market purchases

MDU is a member of the Midcontinent Independent System Operator ("MISO"), a regional transmission organization that serves utilities spanning from Manitoba, Canada south to Louisiana. DEQ supports MDU's decision to rely further on MISO purchases for the next several years, taking advantage of MDU's geographic non-coincident peak demand within the ISO footprint while additional resources are developed. MDU states that, "If MISO energy prices increase higher than forecasted, Big Stone, Coyote, and Montana-Dakota's natural gas-fired units could be dispatched to offset forecasted MISO energy purchases and provide pricing protection

[1] 69-3-1205, MCA

for customers."[2]

IV. Lewis & Clark Station 1 retirement was carefully analyzed and deserves continued MDU's attention through transition

DEQ appreciates MDU's analysis showing the economic rationale behind the decision to retire the coal-fired Lewis & Clark Station 1 in Sidney by the end of 2020 and coal-fired Heskett 1 and 2, located in central North Dakota, by the end of 2021. MDU notes that their plan to replace the output of these plants with a combination of a new gas-fired power plant and market purchases is a significantly lower-cost option for customers. The 2019 Plan states, "[t]he total cost of a new simple cycle combustion turbine coupled with MISO market purchases is expected to be about half the total cost of continuing to run the Heskett and Lewis & Clark coal-fired units."[3] The modelling provided in the 2019 Plan showed that the units are uneconomical under various modeling scenarios. Their closure would also reduce the impact of a future price on greenhouse gas emissions by lowering the carbon-intensity of MDU's supply mix.

While not explicitly required to be addressed in the supply planning process, the closure of Lewis & Clark 1 will impact local jobs, income, and taxes. DEQ encourages MDU to continue working with the local communities affected by the closure. The meeting in Sidney in July of 2019 was a start to this process but DEQ encourages MDU to listen to local concerns and work with the community to mitigate negative impacts to the greatest extent possible.

[2] 2019 Plan, Volume IV, page 19
[3] 2019 Plan, Volume 1, page 50

V. 2019 Plan should mitigate risks of future carbon pricing by using a carbon cost in 2019 Plan's base case analysis

MDU's modelling does not include a future price on greenhouse gas emissions in the 2019 Plan. DEQ acknowledges that MDU includes a carbon cost modelling scenario in the 2019 Plan but finds it concerning that the base case includes no projected cost on greenhouse gas emissions. MDU has chosen to omit carbon costs from their base case analysis at a time when regional peer utilities, including Minnestoa Power, Xcel Energy, and other utilities who are members of MISO are taking into account future carbon pricing as a likely factor in their decisions to significantly reduce the carbon intensity of their supply portfolio. DEQ acknowledges that MDU has announced its intent to reduce the carbon intensity of its supply portfolio forty-five percent below 2005 levels by 2030,[4] and that the decisions to accelerate the retirement of Lewis & Clark 1 and Heskett 1 & 2 will likely help MDU to reach that target sooner.

The carbon cost portfolio analyzed by MDU falls short of the high-cost scenarios modelled by peer utility Minnesota Power. Its approach to evaluating carbon regulation impacts for the 2015 Plan includes using a $21.50/ton regulation penalty in its base case and comparing the short and long-term action plans with other plausible carbon alternatives, including a delayed carbon regulation penalty to 2025 and a zero carbon regulation penalty. This affected the plan in that additional wind power was selected with the $21.50 penalty modeled.[5] Xcel Minnesota's plan contains carbon emissions cost assumptions starting at around $46/ton in 2020 and moderating in the $20-30 range from 2024 through 2044.[6]

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[4] 2019 Plan, Volume 1, page 2

[5] https://www.mnpower.com/Content/Documents/Environment/2015-resource-plan.pdf, page 40

[6] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf, page 104.

By leaving carbon costs out of its base case and by using a relatively moderate cost for its carbon modelling scenario, MDU does not adequately plan for and mitigate the risks to its customers of future carbon pricing or regulation.

VI. 2019 Plan should more fully analyze solar and storage options

DEQ commends MDU for analyzing options to integrate storage as a tool to increase grid reliability in certain areas, and to potentially reduce MISO transmission charges. DEQ recommends that MDU continue to evaluate and accurately assign value to energy storage technologies where appropriate for their potential value in mitigating transmission constraints, deferring grid infrastructure investments, and as a potential resource that can provide additional ancillary services. These additional benefits would improve the stability of MDU's service territory as well as providing value to the larger MISO region.

Innovative distributed storage has the potential to be part of the solution to help serve MDU's capacity needs. Improved economies of scale with the production of lithium ion batteries and other storage technologies will create more potential for increased deployment of storage solutions. The 2019 Plan should analyze the costs of customer-owned, grid-connected battery back-up systems that MDU would be able to use as a "distributed power plant." By sharing costs of battery storage systems with customers who also want the reliability of a back-up power supply, the relatively high cost of distributed storage systems may be sufficiently mitigated to provide a cost-competitive, flexible capacity resource, as well as a new service to interested customers. Green Mountain Power, a Vermont investor-owned utility, has successfully piloted this model.[7]

[7] https://greenmountainpower.com/news/gmp-pioneers-patent-pending-system/

Based on promising recent requests for proposal (RFP) results in other western states, DEQ encourages MDU to continue to explore hybrid renewable energy plus energy storage systems in their future supply-side analyses. As generation and capacity costs for wind and solar energy and energy storage systems continue to drop, the potential to combine renewable energy resources with energy storage has the potential to dramatically change future utility supply plans. Because these technologies are still, in many cases, emerging technologies, they may transition from being less economically optimal resource options to market-leading, least cost resources within the span of one or two IRP biennial periods. As such, DEQ recommends MDU evaluate not only the submissions they receive within their own supply RFP processes, but also the reported public bids that other western and midwestern utilities receive for combined renewable energy and energy storage projects.

VII. 2019 Plan should more fully analyze demand side management options

DEQ encourages MDU to expand its demand side programs to not rely so heavily on a single interruptible customer for most of its demand side peak reductions.

On page 17, MDU states that "DSM analysis is completed on a state by state approach versus an Integrated System approach." DEQ encourages MDU to treat demand side resources more similarly to supply side resources and conduct a more robust analysis of opportunities to expand and diversify current Energy Efficiency and Demand Response programs. This analysis should include inputting different quantities of energy efficiency and demand response into the model and then comparing those model runs against supply side resources. The assumption that energy efficiency only serves as a "load modifying" resource constrains the analysis, and this can result in undervaluing energy efficiency and demand response.

MDU's estimated achievable energy reduction of 0.35% of annual energy sales and 1.70% of demand over the IRP planning period uses estimates from the 2013 Nexant Energy Efficiency Potential Study. These estimates are based on Total Resource Cost test analysis. DEQ recommends that MDU evaluate the achievable energy efficiency potential under additional scenarios; including but not limited to a high-natural gas cost scenario. The IRP should include the ranges of energy efficiency potential under different scenarios.

On page 19 of Volume 1, MDU states: "Interruptible Demand Response Rate has been available for several years and is available to commercial and industrial electric customers with loads of 500 kW or higher. This program currently has 15.4 MW enrolled and Montana-Dakota's goal is to increase participation by 2.1 MW or to a total enrollment of 20 MW by the summer of 2021." This math does not add up. MDU should clarify if there was another customer missing that was not mentioned for the 20 MW total.

DEQ understands the financial reasons for MDU suspending its Wi-Fi Thermostat Demand Response program; however, it is unfortunate to see MDU relinquish the opportunity presented in the residential program. This new area of demand response has the potential to deliver direct benefits to MDU and to its customers. One benefit of this type of program is that it has the potential to reduce the utility bills of residential customers with air conditioners for four months out of the year. DEQ recommends MDU continue to look closely at expanding its demand response programmatic offerings within the residential and commercial sectors and consider sector diversity as a key benefit when selecting its demand response programs. On its current demand response development trajectory, MDU may become overly dependent on a single market sector for meeting a majority of MDU's demand response obligations. If that market sector were to experience conditions that diminished its capability to provide demand response capacity to MDU, the utility may find itself in a capacity deficit that could be difficult or expensive to meet.

DEQ supports MDU's move to create a new Residential LED Lighting Program and the LED conversion project of its company-owned streetlights. In recent years, LED technology has rapidly progressed, in terms of price, lighting quality, and durability. Promoting and incentivizing the increased use of LEDs will assist MDU customers in lowering their overall energy usage and utility bills more quickly, and may help dampen peak loads.

VIII. 2019 Plan should include analysis of high-growth distributed generation scenario

DEQ recommends that MDU include within its future integration and risk analysis a scenario for high growth in distributed generation (e.g., distributed generation growing to meet 3-5% of MDU retail sales 10 years into the future). DEQ believes these results may generate distinctly different results from the low-growth scenario forecast because distributed generation typically does not generate electricity and reduce system load uniformly across the day, month, and year.

IX. Risks of reliance on natural gas costs is not fully analyzed

The Base-Case least cost plan consists of a plan to install an 88 MW natural gas-fired Simple Cycle Combustion Turbine unit expected to be online in 2022-2023. DEQ recommends that MDU consider the impact that additional reliance on gas resources in the near term will have on their customers' exposure to longer-term natural gas volatility. The high gas scenario, which increased the gas price by $5/MMBtu from the base case is still less than the $3 to $9 million/

MMBtu spread in EIA's Henry Hub spot price range forecasted for 2030. DEQ suggests running a high gas scenario of $9/MMBtu.

DEQ recommends that MDU also analyze the costs of including carbon capture, utilization, and sequestration (CCUS) capabilities on new gas generation to better understand the potential for using CCUS as a tool to mitigate the risk of carbon pricing or regulation.

This concludes DEQ's comments.

Respectfully submitted on this 20th day of December, 2019.

Laura Rennick
Montana Department of Environmental Quality