Integrated Resource Plan 2019

Submitted to the North Dakota Public Service Commission July 1, 2019

Volume IV: Attachments C-I

Montana-Dakota Utilities Co.

2019 Integrated Resource Plan

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Attachments C – I

MONTANA-DAKOTA UTILITIES CO.

A Subsidiary of MDU Resources Group, Inc.

Attachment C

SUPPLY-SIDE AND INTEGRATION ANALYSIS DOCUMENTATION

Supply Side and Integration Analysis

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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 7.9 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 percent adder for MISO losses, plus 7.9 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 81.5 percent coincident factor for the 2019-2020 Planning Year in MISO based on MDU's analysis of Montana-Dakota's peak at the time of the MISO system-wide peak.

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 81.5 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:

$$UCAP = ICAP – (1\text{-}XEFORd).$$

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 2021 when the unit retirements for Lewis Clark 1 and Heskett 1/2 are modeled to occur. The capacity deficit in 2022 will be 92.0 ZRC and grow to 146.1 ZRC in 2030. As shown in Figure 1-2, under the low-growth forecast, a capacity deficit occurs in 2022 at 51.8 ZRC and grows to 66.8 ZRC by 2030. With the high-growth forecast, as shown in Figure 1-3, a capacity deficit of 140.9 ZRC will occur in 2022 and grow to 389.1 ZRC in 2030.

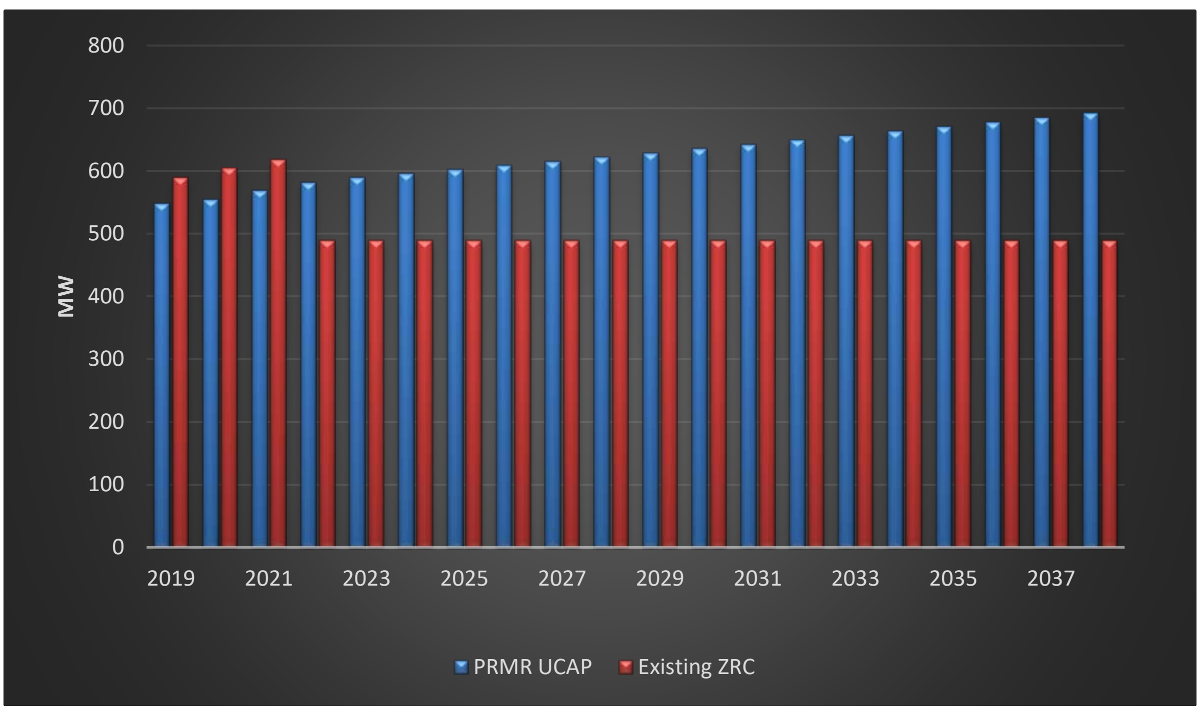

Figure 1-1: Zonal Resource Credit and Planning Reserve Margin Requirement
Base Forecast

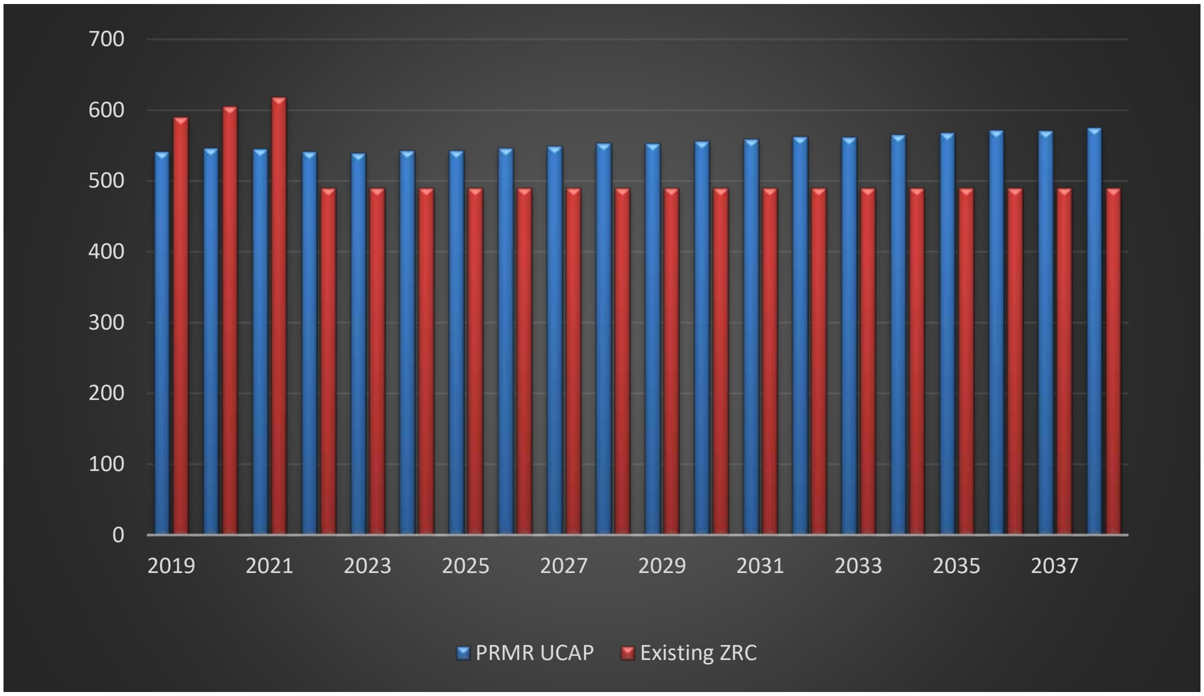

Figure 1-2: Zonal Resource Credit and Planning Reserve Margin Requirement
Low Growth Forecast

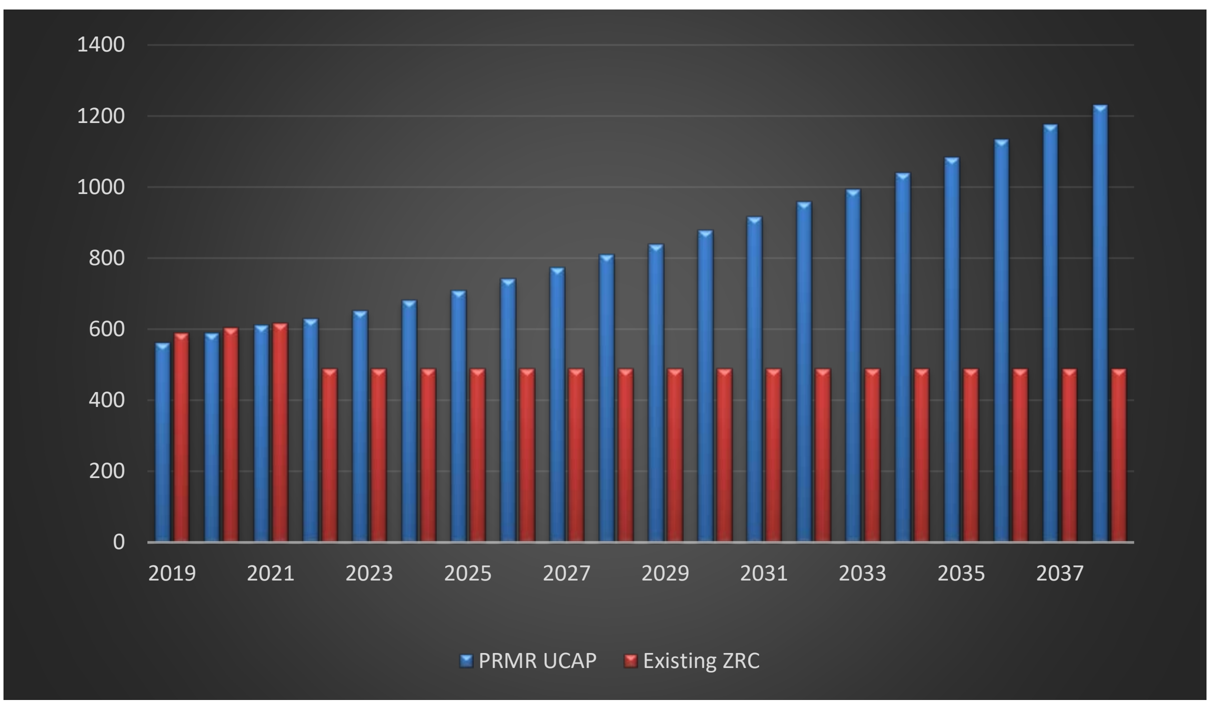

Figure 1-3: Zonal Resource Credit and Planning Reserve Margin Requirement High Growth Forecast

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 2018 with the study period starting in 2019. Costs indicated in this report are in 2018 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2019-2038) 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 2019-2020 planning year, the ELCC study concluded that 15.7 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 20.9 percent of its nameplate capacity to ZRCs, Cedar Hills was allowed up to 23.8 percent of its nameplate capacity to ZRCs, and Thunder Spirit was allowed up to 19.5 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 6.3, 4.6, and 29.3 respectively.

2.1. Current Resources

The existing resource portfolio is broken down into four groups: coal, natural gas/oil, renewable, and Demand Side Management ("DSM"). Figure 2-1 shows Montana-Dakota's 2017 current resource mix by zonal resource credits. Fifty-five percent of Montana-Dakota's ZRCs comes from coal generation, thirty percent from gas-fired generation, eight percent from renewable resources and seven percent from DSM.

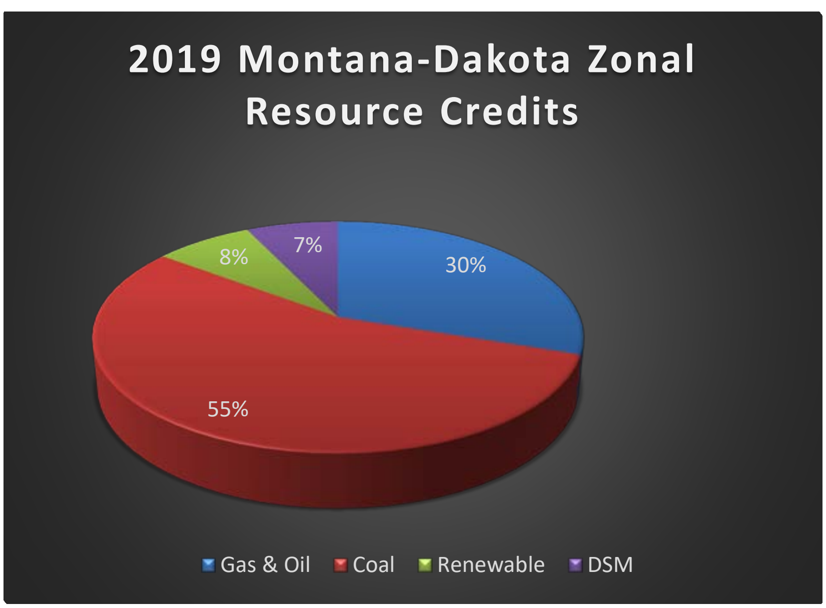

Figure 2-1: Montana-Dakota's Current Generation Mix by Zonal Resource Credits

2.1.1. Coal

Montana-Dakota currently owns five coal-fired units, two of which are jointly owned with other regional utilities. Coal-fired units currently account for 55 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[2,4]	107.1	15.15	90.9	28.15	3.86	1.69
Big Stone[3]	108.5	2.46	105.8	25.81	2.31	1.91
Heskett 1	26.1	20.5	20.5	99.00	15.73	2.81
Heskett 2	73.1	9.24	66.4	58.01	7.29	2.83
Lewis & Clark 1	47	11.88	41.4	90.90	7.22	1.88

1. Based on MISO 2019-20 Planning Year ICAP and XEFORd
2. Montana-Dakota's 25 percent ownership share
3. Montana-Dakota's 22.7 percent ownership share
4. ZRC was increased in model to 98.4 by 2021 to represent a historical XEFORd for this unit. The unit has a high $XEFOR_d$ due to a major outage at the end of 2014 and into 2015.

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 30 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	33.9	4.83	32.3	5.85	2.5	4.02
Glendive	40.5	6.46	37.9	8.23	2.5	4.02
Miles City	21.6	0.35	21.0	42.09	2.5	4.02
Heskett 3[3]	82.9	21.34	65.2	34.19	2.5	3.04
Lewis & Clark 2	18.6	5.41	17.6	29.17	2.5	3.19
Diesel 2	2.1	10.26	1.9	19.89	2.5	18.86
Diesel 3	2.1	10.26	1.9	19.89	2.5	18.86

1. Based on MISO 2019-20 Planning Year ICAP and $XEFOR_d$
2. 2019 natural gas price
3. ZRC was increased in model to 80.2 by 2021 to represent a normal $XEFOR_d$. The unit has a high $XEFOR_d$ due to forced outages when the unit first came online

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[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[2]	6.3	18.05	-11.79	-
Cedar Hills[2]	4.6	19.93	-30.38	-
Glen Ullin Station 6[3]	4.8	55.94	7.33	-
Thunder Spirit	29.3	21.82	-30.38	-

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.
3. Based on MISO 2019-20 Planning Year ICAP and XEFORd

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 2019.

- Montana-Dakota Interruptible loads – 15.4 MW converts to 14.8 ZRC
- Commercial DSM – 25 MW converts to 27.5 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 200 MW block of energy for off-peak and on-peak periods.

2.3. 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,
- Biomass, and
- Responses to 2018 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.

2.3.1. 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.

2.3.2. 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.

2.3.3. 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 131.1 MW (summer net) 2x1 large frame unit, 239.32 MW (summer net) 2x1 large frame unit (Heskett Expansion), and a 329.2 MW (summer net) 1x1 large frame unit.

Montana-Dakota evaluated partnership options related to a CCCT with a local utility regarding the development of the Heskett Expansion project, but no arrangement was reached.

2.3.4. 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 CO2 capture, and a 122 MW net CFBC boiler with CO2 capture.

2.3.5. Wind (Self-Built)

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) North Dakota options. Both projects assume no Federal Production Tax Credits (PTCs) are available for a future wind project.

2.3.6. Solar and 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. 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.

2.3.7. 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.

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

EGEAS Model Input Summary, 2019 $	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	74.23	$1,590.00	$1.40	$1.50	$2.61	$19.41	11770	730	$3.04
GE 7EA Heskett Expansion	78.3	74.23	$878.00	$0.93	$0.90	$2.61	$13.77	11770	730	$3.04
GELMS100PB	90.7	85.96	$1,760.00	$1.20	$1.70	$1.82	$16.22	9050	525	$3.04
GE LM6000PH	45.3	44.79	$2,320.00	$2.50	$1.60	$2.08	$32.08	9510	555	$3.04
GE 7EA (2x1) Heskett Expansion	329.8	312.09	$1,070.00	$1.40	$4.10	$3.23	$20.03	9990	515	$3.04
GE 7FA.05 (1X1)	329.2	311.52	$1,520.00	$1.10	$3.00	$3.22	$16.42	6530	430	$3.04
SIEMENS SGT-800 (2x1)	174	164.61	$2,180.00	$2.90	$4.00	$2.79	$37.59	7180	460	$3.04
WARTSILA 20V34SG	36.5	36.14	$2,710.00	$2.60	$4.40	$1.58	$32.78	8470	495	$3.04
WARTSILA 18V50SG	55.0	54.4	$2,180.00	$1.80	$4.60	$1.56	$23.16	8310	485	$3.04
BIOMASS	25	22.68	$7,980.00	$21.00	$5.60	-	$252.00	12300	1300	$5.11
PV SOLAR + Storage[1]	50+10	35	$1,800.00	$2.90	$0.00	-	$34.80	-	-	$0.00
PVSOLAR + Storage[2]	5+1	3.5	$2,440.00	$3.00	$0.00	-	$36.00	-	-	$0.00
CFBC WITHOUT CO2 Capture	168	152.41	$5,880.00	$14.06	$14.06	-	$168.72	10000	1000	$2.88
CFBC WITH CO2 Capture	122	110.68	$10,400.00	$22.29	$22.29	-	$267.48	13800	150	$2.88
ND Wind	20	4.16	$1,780.00	$4.30	$0.00	-	$51.60	-	-	$0.00
ND Wind	50	10.40	$1,720.00	$4.30	$0.00	-	$51.60	-	-	$0.00

1 - 10 MW battery storage additional $19.1 million
2 - 1 MW battery storage additional $3 million

2.4. Retirements

Montana-Dakota is modeling the retirement of Heskett 1, Heskett 2, and Lewis & Clark 1 at the end of 2021. The units are modeled for retirement at the same time to allow the IRP model to more efficiently replace the units retiring capacity and energy rather than staggered unit retirement dates. The units are scheduled for retirement because of their size, age, and operating characteristics make them uneconomic as compared to other alternatives. Additional information on the retirement analysis for Heskett 1, Heskett 2, and Lewis & Clark 1 can be found in Volume 4 Attachment I.

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.

2.5. 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.

2.6. 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 2019 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

Thirteen planning scenarios, which include the base case, and 12 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 Sensitivity Cases with Base Case												
	Base	**Low Energy**	**High Energy-$5**	**High Energy-$10**	**Low Gas**	**High Gas-$2**	**High Gas-$5**	**Low Growth**	**High Growth**	**High CT**	**90% MISO Coincident Factor**	**Carbon**	**High Gas-$5/High Market$25**
2019											PP(20)		
2020											PP(10)		
2021											PP(10)		
2022	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)	Wind(54), Solar/Storage (75)	Heskett 4, Wind(54), Solar/Storage (75) PP(10)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), Solar/Storage (75) PP(20)	Heskett 4, Wind(54), PP(10)	Heskett 4, Wind(54), PP(10)
2023	Solar(100)	Solar(100)	Solar(100)	Solar(100)	Solar(100)	Solar(100)	Solar(100)	Solar(100)	Solar(100)	Solar(100)	CT(78)	Solar(100)	Solar(100)
2024									PP(10)				
2025	CC(110)	CC(110)	CC(110)	CC(110)	CC(110)	CC(110)	CC(110)		Storage(250)	CC(110)	CC(110)	CC(110)	CC(110)
2026													
2027													
2028								PP(10)					
2029								PP(10)					
2030								PP(10)					
2031								PP(10)	CC(329)				
2032								PP(20)					
2033								PP(20)					
2034								Heskett 4					
2035													
2036													
2037									CC(330)				
2038	Solar(5)	Solar(5)	Solar(5)	PP(10)	PP(10)	Solar(5)	Solar(5)			Solar(5)	Solar(5)	Solar(5)	Solar(5)
NPV ($M)	$2,860.37	$2,749.12	$3,029.88	$3,135.75	$2,719.00	$3,036.76	$3,297.51	$2,219.07	$5,014.51	$2,884.08	$3,081.53	$3,916.57	$4,214.04
Difference	0.00%	-3.89%	5.93%	9.63%	-4.94%	6.17%	15.28%	-22.42%	75.31%	0.83%	7.73%	36.93%	47.33%

Resources:
PP(x) - Purchased Capacity with number representing MW value
CC(329) - Another GE 7EA added with a steam turbine and heat recovery steam generator - 250 MW additional
CC(330) - 330 MW GE 7FA (1x1) combined cycle combustion turbine
CT(78) - 78.4 MW GE7EA simple cycle combustion turbine
Heskett 4 - 78.4 MW GE7EA simple cycle combustion turbine
WIND(54) – 2018 RFP response
Solar(100) – 2018 RFP response
CC(110) – 2018 RFP response
Storage(250) – 2018 RFP response
Solar(5) – Self-built 5 MW solar (1 MW optional storage not selected)

3.1. Base Case Plan Results

The Base Case least-cost plan consists of the following resource additions for 2019-2024:

- Move forward with the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1 by the end of 2021; and
- Install a natural gas-fired Simple Cycle Combustion Turbine unit in 2022.

An additional 54 MW of wind (2022), 100 MW of solar (2023), combined cycle partnership (2025) from the 2018 RFP and 5 MW of self-built solar (2038) were identified as part of the IRP process. At this time, these projects are not being pursued because of uncertainties with their final cost associated with unknown network transmission upgrades as described in Attachment F – 2018 RFP Analysis. The net present value of the Base Case least-cost plan over the 50-year study period equates to $2,860 million in 2018 dollars, as shown in Attachment C Table 3-1. Because of a lack of certainty in final costs of bids and cost competitiveness of additional renewable resources the Company will issue a new request for proposal before the start of the next integrated resource plan.

3.2. Sensitivity Analysis

The 12 sensitivity scenarios consist of various assumptions regarding carbon taxes, low and high natural gas prices, low and high load growth, 90 percent coincident factor for MISO Resource Adequacy, higher capital costs for combustion turbines, high and low market prices, and a high natural gas and high market price.

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 2023. The results of both high natural gas price case were the same as the Base Case. The NPV of the revenue requirement in this scenario increased 6.2 and 15.3 percent respectively over the Base Case. The results of the low natural gas price scenario were like the Base Case but had purchase power in 2038 instead of a 5 MW self-built solar. This case decreased the NPV of the revenue requirement by 4.9 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 the following resource additions: 54 MW of wind, 75 MW solar and storage combination in 2022, 100 MW solar in 2023, and Heskett 4 in 2034. This lowered the NPV by 22.4 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 2019. The results of this scenario indicate the need for the following resources over the Base Case: 75 MW solar and storage combination, 250 MW of storage, and two large combined cycle combustion turbines. This increased the NPV by 75.3 percent over the Base Case.

3.2.4. High Combustion Turbine and Internal Combustion Engines Costs

The costs of materials associated with the construction of generation can fluctuate over time with changes in commodity costs, availability of skilled craft labor, import tariffs, and general inflation both in the United States and the rest of the world. The Base Case reflects the present price forecasted costs for all generation options, but for purposes of risk analysis, Montana-Dakota considered the impact of higher installed costs for new generation (i.e., combustion turbines and internal combustion engines) on the resource plan. This sensitivity scenario included a 20 percent increase in capital and O&M costs for future combustion turbines and internal combustion engines to determine the sensitivity of the Base Case to increases in combustion turbine and internal combustion engine costs. This scenario selects a similar plan to the Base Case. The results of this sensitivity case indicate an increase of 0.8 percent in the NPV of the revenue requirement over the Base Case.

3.2.5. 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 added $5/MWh and $10/MWh to both the on-peak and off-peak market prices of the base year. This resulted in the same results as the Base Case results except for the $10/MWh higher did not select the solar in 2038 instead it selected 10 MW of purchase capacity. These scenarios resulted in an increase of 5.9 and 9.6 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 $3/MWh. This resulted in the same results as the Base Case but lowered the NPV by 3.9 percent.

3.2.7. 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 81.5 percent coincident factor. The selected least-cost plan for this scenario was different from the base case with additional capacity purchases, a 75 MW solar and storage combination, and an additional simple cycle being selected. The results of this scenario indicate an increase of 7.7 percent in the NPV of the revenue requirement over the Base Case.

3.2.8. 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 2025. While no carbon tax was modeled in the Base Case, Montana-Dakota modeled a carbon tax of $30 per ton for a sensitivity analysis. The results were not different from the Base Case. The NPV increased by 36.9 percent over the Base Case.

3.2.9. High Gas and High Market Price

This sensitivity was looking at a worse case if both natural gas prices and the energy market were to increase. A combination of a high gas price increased by $5/MMBtu and a high market price increased by $25/MWh was used over the Base Case. The results from this scenario were the same as the Base Case results but increased the NPV by 47.3 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:

- Retire Lewis & Clark 1 by the end of 2020; and Heskett 1 and Heskett 2 by the end of 2021;
- Continue with the design and development work on a natural gas-fired simple cycle combustion turbine resource to be online in 2022 or early 2023; and
- Issue a new request for proposal prior to the next IRP.

Figure 4-1 and 4-2 show a comparison of the resource mix that Montana-Dakota has available to serve its customers' needs in 2019, as compared to the least cost plan in 2024 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.

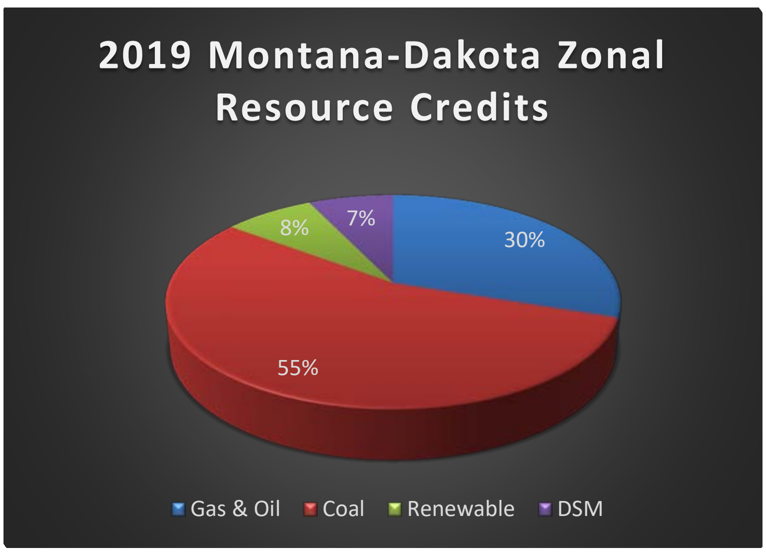

Figure 4-1: 2019 Montana-Dakota Zonal Resource Credits

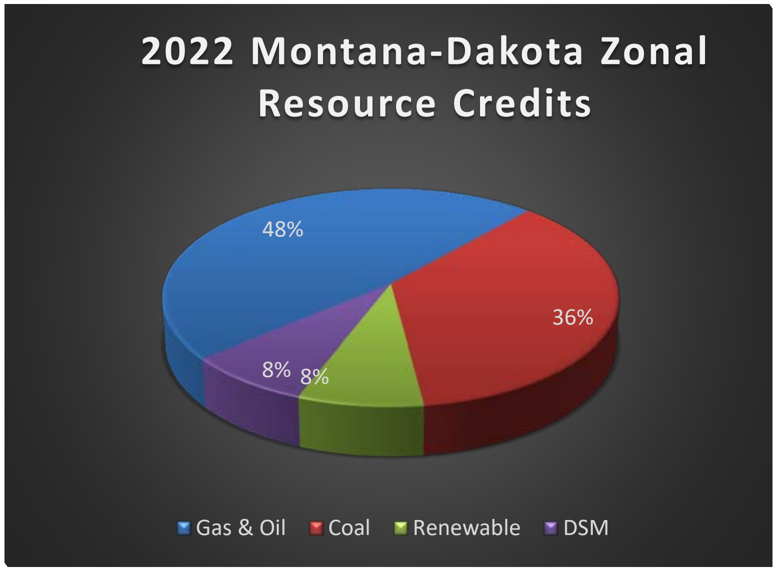

Figure 4-2: 2022 Montana-Dakota Zonal Resource Credits

As shown in Figures 4-1 and 4-2; in 2019 approximately 30 percent of Montana-Dakota's resource capacity comes from natural gas and oil-fired combustion turbines and reciprocating internal combustion engines while in 2022, based on the Base Case plan, approximately 48 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 2019 and after the retirements of Heskett 1, Heskett 2, and Lewis & Clark 1 in 2022. In 2019, 49 percent of Montana-Dakota's energy will come from coal, 27 percent MISO energy market, and 23 percent from renewable. In 2022, 47 percent of energy will come from MISO energy market, 31 percent will come from coal and 22 percent will come from renewable based upon forecasted fuel and MISO energy prices. In 2022, Coyote and Big Stone have an annual capacity factor around 60 percent. 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 for customers.

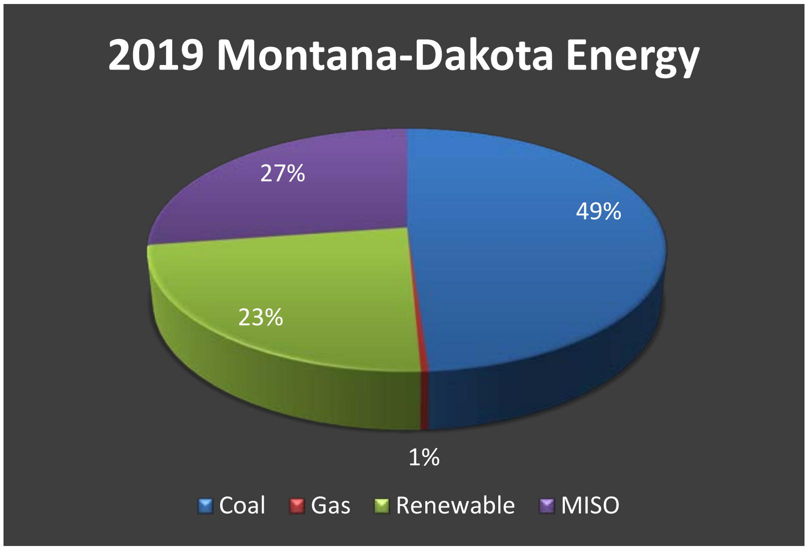

Figure 6-6: 2019 Montana-Dakota Energy by Resource Type

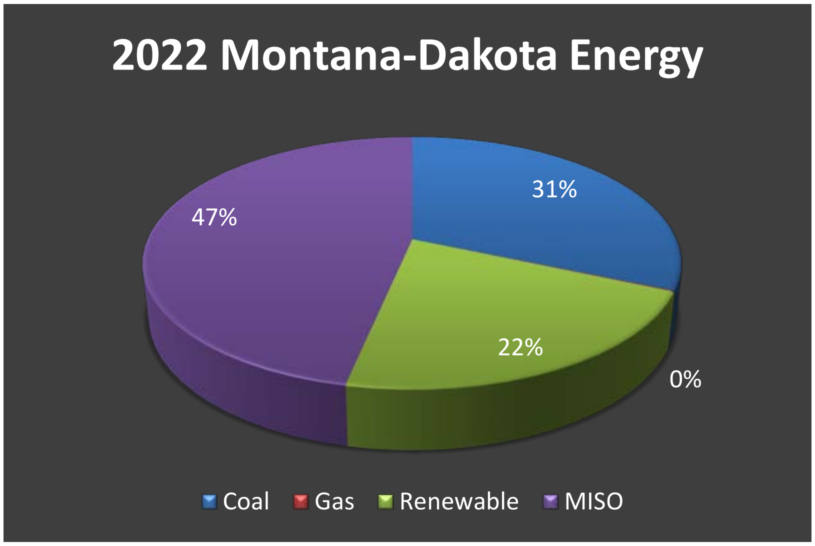

Figure 6-7: 2022 Montana-Dakota Energy by Resource Type

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 2019-2024 period:

- Retire Lewis & Clark 1 by the end of 2020; and Heskett 1 and Heskett 2 by the end of 2021;
- Continue with the design and development work on a natural gas-fired simple cycle combustion turbine resource to be online in 2022 or early 2023; and
- 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 to meet customer peak demands and to hedge against high MISO market prices.

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 – 2018 RFP analysis, are better known to help meet future customer demand and energy requirements.

6. References

MISO Business Practice Manual-11-r21 Resource Adequacy. (February 20, 2019)
EGEAS User's Guide Version 13. EPRI, Palo Alto, CA, November 2018.
MISO Planning Year 2019-2020 Loss of load Expectation Study Report. (October 17, 2018)
MISO Planning Year 2019-2020 Wind Capacity Credit. (January 18, 2019)

Appendix A

EGEAS INPUT DATA FOR THE BASE CASE

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ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

Montana-Dakota Utilities Co.
2019 Model
Base Case Run
-- Data updated for the 2019 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

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

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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				

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                     *           Base Case Run                                                                          4
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                     *                                                                                                  6
                     *           Control record.                                                                        7
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                     *            O     O   C M E    F C                                                               10
                     *            D     S   T I R    I N                                                               11
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                    *                                                                                                68
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                    *                                                                                                72
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                    *              COST 1    COST 2  CARRY.  O+M   O+M   PCT. AFUDC U STR                            74
                    *BP C        ----------++++++++++------++++++-----++++++------+---                               75
                    *                                                                                                76
                    *             INST  FIX  VAR  FOR           OPER                                                 77
                    *             COST  O+M  O+M  OUT  MNT FUEL  CAP ENRG  CAP ENRG WEEK LOAD                        78
                    *               TJ   TJ   TJ   TJ  CYC TYPE   TJ   TJ   SM   SM ENRG  BLK                        79
                    *BP D      1 -----+++++-----+++++-----+++++-----+++++-----+++++-----+++++                        80
                    *                                                                                                81
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                    *              NDT PLNT SITE   TJ   TJ DEPR   TJ                                                 84
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                    *                                                                                                86
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 BASIC PLANT TYPE       BPA    12    RFP6             NDT  B G WIND MDU  NDAK 100.0    1      20 20                               182
                        BPB    12     250.01.00000.3810      0.0000                        0.2080                                 183
                        BPC    12         0.000          9.83300.000014.250             1  1                                      184
                        BPD    12  1             52    0   29        0    0    0    0    0    0                                   185

                                1         2         3         4         5         6         7         8         9
        COLUMNS         123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                                     MIRROR IMAGE REPORT                              PAGE      6
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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

 BASIC PLANT TYPE   BPD    12  2    4    0    0    0    0   21    0                                                      186
                    BPF    12       2400.000              30   380.0000                                                  187
                    BPG    12    0.000000000.000000000.00000000                                                          188
                    *                                                                                                    189
 BASIC PLANT TYPE   BPA    13    RFP7a           NDT  B G PURC MDU  NDAK 100.0    1      20 20                           190
                    BPB    13     200.01.00001.0000     0.0500                         0.5000                            191
                    BPC    13         0.000         9.83300.000035.750             1  1                                  192
                    BPD    13  1              51    0   30         0    0    0    0    0    0                            193
                    BPD    13  2    6    0    0    0    0    0    0                                                      194
                    BPF    13      2558.000              30   380.0000                                                   195
                    BPG    13    0.000000000.000000000.00000000                                                          196
                    *                                                                                                    197
 BASIC PLANT TYPE   BPA    14    RFP7b           STOR P G STRG MDU  NDAK 100.0    1      20 20                           198
                    BPB    14     100.01.00001.00001.00000.0010       80.00 95.00      0.9000                            199
                    BPC    14         0.000               86.4000.0000             2  0                                  200
                    BPD    14  1         53         0    0         0    0    0    0    0    0                            201
                    BPD    14  2    0    0    0    0    0    0    0                                                      202
                    *                                                                                                    203
 BASIC PLANT TYPE   BPA    15    RFP7c           NDT  B G PURC MDU  NDAK 100.0    1      20 20                           204
                    BPB    15     250.01.00001.0000     0.0500                         0.5000                            205
                    BPC    15         0.000         9.83300.000030.750             1  1                                  206
                    BPD    15  1              51    0   31         0    0    0    0    0    0                            207
                    BPD    15  2    6    0    0    0    0    0    0                                                      208
                    BPF    15      2558.000              30   380.0000                                                   209
                    BPG    15    0.000000000.000000000.00000000                                                          210
                    *                                                                                                    211
 BASIC PLANT TYPE   BPA    16    RFP7d           STOR P G STRG MDU  NDAK 100.0    1      20 20                           212
                    BPB    16     125.01.00001.00001.00000.0010      100.00 95.00      0.9000                            213
                    BPC    16         0.000               85.2000.0000             2  0                                  214
                    BPD    16  1         53         0    0         0    0    0    0    0    0                            215
                    BPD    16  2    0    0    0    0    0    0    0                                                      216
                    *                                                                                                    217
 BASIC PLANT TYPE   BPA    17    RFP8a           NDT  B G PURC MDU  NDAK 100.0    1      20 20                           218
                    BPB    17    50.0001.00001.0000     0.0500                         0.5000                            219
                    BPC    17         0.000         9.83300.000029.000             1  1                                  220
                    BPD    17  1              55    0   32         0    0    0    0    0    0                            221
                    BPD    17  2    6    0    0    0    0    0    0                                                      222
                    BPF    17      2558.000              30   380.0000                                                   223
                    BPG    17    0.000000000.000000000.00000000                                                          224
                    *                                                                                                    225
 BASIC PLANT TYPE   BPA    18    RFP8b           STOR P G STRG MDU  NDAK 100.0    1      20 20                           226
                    BPB    18    25.0001.00001.00001.00000.0010       20.00 95.00      0.9000                            227
                    BPC    18         0.000               0.00000.0000             2  0                                  228
                    BPD    18  1                    0    0         0    0    0    0    0    0                            229
                    BPD    18  2    0    0    0    0    0    0    0                                                      230
                    *                                                                                                    231
 BASIC PLANT TYPE   BPA    19    RFP9a           NDT  B G WIND MDU  NDAK 100.0    1      20 20                           232

                                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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         COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

BASIC PLANT TYPE   BPB    19     300.01.00000.3810      0.0000                        0.2080                        233
                   BPC    19         0.000          9.83300.000018.500             1  1                             234
                   BPD    19 1               52     0   34         0    0    0    0    0    0                        235
                   BPD    19 2      4    0    0    0    0   21    0                                                 236
                   BPF    19      2400.000             30   380.0000                                                237
                   BPG    19    0.000000000.000000000.00000000                                                      238
                   *                                                                                                239
BASIC PLANT TYPE   BPA    20    RFP9b            NDT  B G PURC MDU  NDAK 100.0    1      20 20                      240
                   BPB    20     150.01.00001.0000      0.0500                        0.5000                        241
                   BPC    20         0.000          9.83300.000035.950             1  1                             242
                   BPD    20 1               57     0   35         0    0    0    0    0    0                        243
                   BPD    20 2      6    0    0    0    0    0    0                                                 244
                   BPF    20      2558.000             30   380.0000                                                245
                   BPG    20    0.000000000.000000000.00000000                                                      246
                   *                                                                                                247
BASIC PLANT TYPE   BPA    21    RFP9c            STOR P G STRG MDU  NDAK 100.0    1      20 20                      248
                   BPB    21    35.0001.00001.00001.00000.0010       28.00 95.00      0.9000                        249
                   BPC    21         0.000                100.680.0000             2  0                             250
                   BPD    21 1          53          0    0         0    0    0    0    0    0                        251
                   BPD    21 2      0    0    0    0    0    0    0                                                 252
                   *                                                                                                253
BASIC PLANT TYPE   BPA    22    RFP10            NDT  B G WIND MDU  NDAK 100.0    1      20 20                      254
                   BPB    22     200.01.00000.3810      0.0000                        0.2080                        255
                   BPC    22         0.000          9.83300.000012.500             1  1                             256
                   BPD    22 1               52     0   36         0    0    0    0    0    0                        257
                   BPD    22 2      4    0    0    0    0   21    0                                                 258
                   BPF    22      2400.000             30   380.0000                                                259
                   BPG    22    0.000000000.000000000.00000000                                                      260
                   *                                                                                                261
BASIC PLANT TYPE   BPA    23    GE 7EAHESKETT    THRM P G GAS  MDU  NDAK 100.0    1      40 35                      262
                   BPB    23    78.3000.83711.0000      0.5000 11770                  0.9480                        263
                   BPC    23       878.000          8.729013.7700.9000             1  1                             264
                   BPD    23 1     30   22   60    0   37   13    0    0    0    0    0    8                        265
                   BPD    23 2      0    0    0    0    0   20    0                                                 266
                   BPF    23       857.000             30   370.0000                                                267
                   BPG    23    0.000000000.000000000.00000000                                                      268
                   *                                                                                                269
BASIC PLANT TYPE   BPA    24    STORAGE10        STOR P G STRG MDU  NDAK 100.0    1      30 25                      270
                   BPB    24    10.0001.00001.00001.00000.0010        8.00 95.00      0.9500                        271
                   BPC    24       1760.000         10.16535.0000.0000             2  1                             272
                   BPD    24 1     30   22          0    0         0    0    0    0    0    0                        273
                   BPD    24 2      0    0    0    0    0    0    0                                                 274
                   *                                                                                                275
BASIC PLANT TYPE   BPA    25    COMM ADD         DTHR1P G PURC MDU  MISO 100.0    1      30 30                      276
                   BPB    25     5.0001.00001.0000      0.0000     1                  1.1000                        277
                   BPC    25         0.000                50.040300.00             2  0                             278
                   BPD    25 1          48   49    0   38    8    0    0    0    0    0    0                        279

                              1         2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
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 RECORD DESCRIPTION TYP  REF  SQ                         DATA FIELDS                                                  NUM
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          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 BASIC PLANT TYPE   BPD    25  2    0    0    0    0    0    0   41                                                   280
                    BPF    25          0.000                 00.0000                                                 281
                    BPG    25    0.000000000.000000000.00000000                                                      282
                    *                                                                                                283
 BASIC PLANT TYPE   BPA    26    AC CYCLE         DTHR1P G PURC MDU  MISO 100.0    1      30 30                      284
                    BPB    26     2.0001.00001.0000      0.0000     1                 1.1000                         285
                    BPC    26         0.000                363.71100.00            2  0                              286
                    BPD    26  1         48   49    0   39    8    0    0    0    0    0    0                        287
                    BPD    26  2    0    0    0    0    0    0   26                                                   288
                    BPF    26         0.000                 00.0000                                                  289
                    BPG    26    0.000000000.000000000.00000000                                                      290
                    *                                                                                                291
 BASIC PLANT TYPE   BPA    27    STORAGE PP       STOR P G STRG MDU  NDAK 100.0    1      30 25                      292
                    BPB    27    10.0001.00001.00001.00000.0010       8.00 95.00      0.9500                         293
                    BPC    27         0.000                108.000.0000            2  1                              294
                    BPD    27  1         22         0    0         0    0    0    0    0    0                        295
                    BPD    27  2    0    0    0    0    0    0    0                                                   296
                    *                                                                                                297
 BASIC PLANT TYPE   BPA    80    MISO - On peak   HYDR P E PURC MDU  MISO 100.0    1 2014 50 50                      298
                    BPB    80     200.01.00001.0000      0.0000 10500800.00           0.0000                         299
                    BPC    80                              0.000024.920            2  0                              300
                    BPD    80  1              29    0    0    8    0    0    0    0    0    7                        301
                    BPD    80  2    0    0    0    0    0    0    0                                                   302
                    *                                                                                                303
 BASIC PLANT TYPE   BPA    90    MISO - Off peak  HYDR P E PURC MDU  MISO 100.0    1 2014 50 50                      304
                    BPB    90     200.01.00001.0000      0.0000 10500800.00           0.0000                         305
                    BPC    90                              0.000020.430            2  0                              306
                    BPD    90  1              46    0    0    8    0    0    0    0    0    7                        307
                    BPD    90  2    0    0    0    0    0    0    0                                                   308
                    *                                                                                                309
 BASIC PLANT TYPE   BPA   100    INTERRUPTIBLES   DTHR1P E PURC MDU  MISO 100.0    1 2012 30 30                      310
                    BPB   100    15.2001.00001.0000      0.0000     1                 0.9737                         311
                    BPC   100         0.000                50.040300.00            1  1                              312
                    BPD   100  1         48   49    0   14    8    0    0    0    0    0    0                        313
                    BPD   100  2    0    0    0    0    0    0   16                                                   314
                    BPF   100         0.000                 00.0000                                                  315
                    BPG   100    0.000000000.000000000.00000000                                                      316
                    *                                                                                                317
 BASIC PLANT TYPE   BPA   110    COMMERCIAL DSM   DTHR1P E PURC MDU  MISO 100.0    1 2013 30 30                      318
                    BPB   110    25.0001.00001.0000      0.0000     1                 1.1000                         319
                    BPC   110         0.000                50.040300.00            2  0                              320
                    BPD   110  1         48   49    0   14    8    0    0    0    0    0    0                        321
                    BPD   110  2    0    0    0    0    0    0    4                                                   322
                    BPF   110         0.000                 00.0000                                                  323
                    BPG   110    0.000000000.000000000.00000000                                                      324
                    *                                                                                                325
 BASIC PLANT TYPE   BPA   120    MILES CITY C.T.  THRM P E GAS  MDU  MONT 100.0    1 1972 99 30                      326

                                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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          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 BASIC PLANT TYPE   BPB   120    25.2000.82991.0000      0.5000 14459                   0.8333                          327
                    BPC   120                              42.0902.5000             2  0                                328
                    BPD   120  1          3    5    0    2    1    0    0    0    0    0   12                           329
                    BPD   120  2     0    0    0    0    0    0    0                                                   330
                    *                                                                                                   331
 BASIC PLANT TYPE   BPA   130    GLENDIVE CT #1   THRM P E GAS  MDU  MONT 100.0    1 1979 99 30                        332
                    BPB   130    35.5000.80611.0000      0.5000 12465                   0.9127                          333
                    BPC   130                              5.85002.5000             2  0                                334
                    BPD   130  1          3    6    0    3    1    0    0    0    0    0    5                           335
                    BPD   130  2     0    0    0    0    0    0    0                                                   336
                    *                                                                                                   337
 BASIC PLANT TYPE   BPA   132    GLENDIVE CT #2   THRM P E GAS  MDU  MONT 100.0    1 2003 99 30                        338
                    BPB   132    43.3000.80611.0000      0.5000  9322                   0.8868                          339
                    BPC   132                              8.23002.5000             2  0                                340
                    BPD   132  1          3    7    0    4    1    0    0    0    0    0   13                           341
                    BPD   132  2     0    0    0    0    0    0    0                                                   342
                    *                                                                                                   343
 BASIC PLANT TYPE   BPA   136    DIESEL 2         THRM P E GAS  MDU  NDAK 100.0    1 2012 99 30                        344
                    BPB   136     2.1001.00001.0000      0.5000  8687                   0.9048                          345
                    BPC   136                              19.8902.5000             2  0                                346
                    BPD   136  1          3    8    0   23    2    0    0    0    0    0    0                           347
                    BPD   136  2     0    0    0    0    0    0    0                                                   348
                    *                                                                                                   349
 BASIC PLANT TYPE   BPA   138    DIESEL 3         THRM P E GAS  MDU  NDAK 100.0    1 2012 99 30                        350
                    BPB   138     2.1001.00001.0000      0.5000  8687                   0.9048                          351
                    BPC   138                              19.8902.5000             2  0                                352
                    BPD   138  1          3    8    0   23    2    0    0    0    0    0    0                           353
                    BPD   138  2     0    0    0    0    0    0    0                                                   354
                    *                                                                                                   355
 BASIC PLANT TYPE   BPA   140    HESKETT #1       THRM B E COAL MDU  NDAK 100.0    1 1954 68 30                        356
                    BPB   140    29.2000.80591.0000      0.0790 18731                   0.7021                          357
                    BPC   140                              99.00015.730             2  0                                358
                    BPD   140  1          3    9    0    5    3    0    0    0    0    0   14                           359
                    BPD   140  2     0    0    0    0    0    0    0                                                   360
                    BPE   140     M        0.0000    0    0       1980 2080               0                             361
                    *                                                                                                   362
 BASIC PLANT TYPE   BPA   150    HESKETT #2       THRM B E COAL MDU  NDAK 100.0    1 1963 59 30                        363
                    BPB   150    74.6000.93831.0000      0.0858 12447                   0.8901                          364
                    BPC   150                              58.0107.2900             2  0                                365
                    BPD   150  1          3   10    0    6    4    0    0    0    0    0   15                           366
                    BPD   150  2     0    0    0    0    0    0    0                                                   367
                    BPE   150     M        0.0000    0    0       1980 2080               0                             368
                    *                                                                                                   369
 BASIC PLANT TYPE   BPA   152    HESKETT #3       THRM P E GAS  MDU  NDAK 100.0    1 2014 40 25                        370
                    BPB   152    84.5000.83711.0000      0.5000 11482                   0.7716                          371
                    BPC   152                              34.1902.5000             1  1                                372
                    BPD   152  1          3   15    0   17    9    0    0    0    0    0    2                           373

                                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

 BASIC PLANT TYPE   BPD   152  2     0    0    0   27    0    0    0                                                    374
                    *                                                                                                   375
 BASIC PLANT TYPE   BPA   160    LEWIS & CLARK1   THRM B E COAL MDU  NDAK 100.0    1 1958 64 30                         376
                    BPB   160    52.3000.86041.0000      0.0261 12909                 0.7916                            377
                    BPC   160                              90.9007.2200             2  0                                378
                    BPD   160  1          3   11    0   18    5    0    0    0    0    0   16                           379
                    BPD   160  2     0    0    0   64    0    0    0                                                    380
                    BPE   160     M        0.0000    0    0       1980 2080               0                             381
                    *                                                                                                   382
 BASIC PLANT TYPE   BPA   162    LEWIS & CLARK2   THRM P E GAS  MDU  NDAK 100.0    1 2015 40 25                         383
                    BPB   162    18.6000.83711.0000      0.5000  8643                 0.9462                            384
                    BPC   162                              29.1702.5000             1  1                                385
                    BPD   162  1          3   20    0   19   11    0    0    0    0    0   11                           386
                    BPD   162  2     0    0    0    0    0    0    0                                                    387
                    *                                                                                                   388
 BASIC PLANT TYPE   BPA   170    BIG STONE        THRM B E COAL MDU  SDAK 100.0    1 1975 99 30                         389
                    BPB   170     107.80.92511.0000      0.0639 10414                 0.9814                            390
                    BPC   170                              25.8102.3100             2  0                                391
                    BPD   170  1          3   12    0    8    6    0    0    0    0    0   17                           392
                    BPD   170  2     0    0    0    0    0    0    0                                                    393
                    BPE   170     M        0.0000    0    0       1980 2080               0                             394
                    *                                                                                                   395
 BASIC PLANT TYPE   BPA   180    COYOTE           THRM B E COAL MDU  NDAK 100.0    1 1981 99 30                         396
                    BPB   180     106.80.93681.0000      0.0875 11291                 0.8511                            397
                    BPC   180                              28.1503.8600             2  0                                398
                    BPD   180  1          3   13    0   22    7    0    0    0    0    0   18                           399
                    BPD   180  2     0    0    0   28    0    0    0                                                    400
                    BPE   180     M        0.0000    0    0       1980 2080               0                             401
                    *                                                                                                   402
 BASIC PLANT TYPE   BPA   190    DIAMOND WILLOW   NDT  B E WIND MDU  MONT 100.0    1 2008 27 25                         403
                    BPB   190    30.0001.00000.3810      0.0000                       0.2100                            404
                    BPC   190                              18.050-12.38             2  1                                405
                    BPD   190  1          3   17    0   10         0    0    0    0    0    0                           406
                    BPD   190  2     1    0    0    0    0    0   40                                                    407
                    *                                                                                                   408
 BASIC PLANT TYPE   BPA   200    GLEN ULLIN ORMAT THRM B E PURC MDU  NDAK 100.0    1 2009 30 20                         409
                    BPB   200     7.5000.66670.6667      0.1058     1                 0.6400                            410
                    BPC   200                              55.9407.5500             2  1                                411
                    BPD   200  1         44   18    0   15    8    0    0    0    0    0    0                           412
                    BPD   200  2     0    0    0    0    0    0    0                                                    413
                    BPE   200     M        0.0000    0    0       1980 2080               0                             414
                    *                                                                                                   415
 BASIC PLANT TYPE   BPA   210    CEDAR HILLS      NDT  B E WIND MDU  MONT 100.0    1 2010 25 25                         416
                    BPB   210    19.5001.00000.3810      0.0000                       0.2359                            417
                    BPC   210                              19.930-35.38             2  1                                418
                    BPD   210  1          3   19    0   10         0    0    0    0    0    0                           419
                    BPD   210  2     2    0    0    0    0    0    0                                                    420

                                 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 1234567890123456789012345678901234567890123456789012345678901234567890

                  *                                                                                          421
BASIC PLANT TYPE  BPA   220    THUNDER SPIRIT   NDT  B E WIND MDU  NDAK 100.0    1 2015 23 25                422
                  BPB   220     150.01.00000.4186      0.0000                      0.1953                    423
                  BPC   220                              21.820-35.38              2  1                      424
                  BPD   220  1          3   32    0   13        0    0    0    0    0    0                   425
                  BPD   220  2     3    0    0    0    0    0    0                                          426
                  *                                                                                          427
BASIC PLANT TYPE  BPA   230    WAPA PUR-FT PECK HYDR B E HYDR MDU  NDAK 100.0    1 2001 50 30                428
                  BPB   230     2.8000.89291.0000      0.0000      14.35           0.0000                    429
                  BPC   230         0.000                0.000024.000              2  0                      430
                  BPD   230  1              14    0    0        0    0    0    0    0    0                   431
                  BPD   230  2     0    0    0    0    0    0    0                                          432
                  BPE   230     M        0.0000    0    0       1980 2080              0                     433
                  *                                                                                          434
BASIC PLANT TYPE  BPA   310    PURCHASE POWER   THRM P G PURC MDU  MISO 100.0    1       1  1                435
                  BPB   310    10.0001.00001.0000      0.0000     1                1.0000                    436
                  BPC   310         0.000                36.0001000.0              2  0                      437
                  BPD   310  1         21   21    0    0    8    0    0    0    0    0    0                   438
                  BPD   310  2     0    0    0    0    0    0    0                                          439
                  BPF   310         0.000                   00.0000                                          440
                  BPG   310    0.000000000.000000000.00000000                                                441
                  *                                                                                          442
BASIC PLANT TYPE  BPA   320    GE 7EA           THRM P G GAS  MDU  NDAK 100.0    1      40 35                443
                  BPB   320    78.3000.83711.0000      0.5000 11770                0.9480                    444
                  BPC   320      1590.000          9.221019.4101.5000              1  1                      445
                  BPD   320  1    30   22   60    0   28   13    0    0    0    0    0    2                   446
                  BPD   320  2     0    0    0    0    0   20    0                                          447
                  BPF   320       857.000              30   370.0000                                         448
                  BPG   320    0.000000000.000000000.00000000                                                449
                  *                                                                                          450
BASIC PLANT TYPE  BPA   330    GE LMS100PB      THRM P G GAS  MDU  NDAK 100.0    1      40 35                451
                  BPB   330    90.7000.83711.0000      0.5000  9050                0.9477                    452
                  BPC   330      1760.000          9.221016.2201.7000              1  1                      453
                  BPD   330  1    30   22   24    0   28   13    0    0    0    0    0   13                   454
                  BPD   330  2     0    0    0    0    0   20    0                                          455
                  BPF   330       857.000              30   370.0000                                         456
                  BPG   330    0.000000000.000000000.00000000                                                457
                  *                                                                                          458
BASIC PLANT TYPE  BPA   340    GE LM6000PH      THRM P G GAS  MDU  NDAK 100.0    1      40 35                459
                  BPB   340    45.3000.83711.0000      0.5000  9510                0.9887                    460
                  BPC   340      2320.000          9.221032.0801.6000              1  1                      461
                  BPD   340  1    30   22   62    0   28   13    0    0    0    0    0   13                   462
                  BPD   340  2     0    0    0    0    0   20    0                                          463
                  BPF   340       850.000              30   370.0000                                         464
                  BPG   340    0.000000000.000000000.00000000                                                465
                  *                                                                                          466
BASIC PLANT TYPE  BPA   370    GE 7EA 2x1 ADD   THRM I G GAS  MDU  NDAK 100.0    1      50 50                467

                               1         2         3         4         5         6         7         8         9
        COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890
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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

BASIC PLANT TYPE   BPB   370     329.80.85711.0000      0.0537  9990                  0.9463                        468
                   BPC   370      1070.000          8.699020.0304.1000             1  1                             469
                   BPD   370  1    59   59   59    0   21   13    0    0    0    0    0    4                        470
                   BPD   370  2     0    0    0    0    0   20    0                                                 471
                   BPF   370       750.000             30   370.0000                                                472
                   BPG   370    0.000000000.000000000.00000000                                                      473
                   *                                                                                                474
BASIC PLANT TYPE   BPA   380    GE 7FA.05 1x1    THRM I G GAS  MDU  NDAK 100.0    1      50 50                      475
                   BPB   380     329.20.85711.0000      0.0537  6530                  0.9463                        476
                   BPC   380      1520.000          8.699016.4203.0000             1  1                             477
                   BPD   380  1    30   22   54    0   24   13    0    0    0    0    0    2                        478
                   BPD   380  2     0    0    0    0    0   20    0                                                 479
                   BPF   380       750.000             30   370.0000                                                480
                   BPG   380    0.000000000.000000000.00000000                                                      481
                   *                                                                                                482
BASIC PLANT TYPE   BPA   400    SMN SGT-800 2x1  THRM I G GAS  MDU  NDAK 100.0    1      50 50                      483
                   BPB   400     173.90.85711.0000      0.0537  7180                  0.9466                        484
                   BPC   400      2180.000          8.699037.5904.0000             1  1                             485
                   BPD   400  1    30   22   69    0   25   13    0    0    0    0    0    3                        486
                   BPD   400  2     0    0    0    0    0   20    0                                                 487
                   BPF   400       750.000             30   370.0000                                                488
                   BPG   400    0.000000000.000000000.00000000                                                      489
                   *                                                                                                490
BASIC PLANT TYPE   BPA   410    WRTSLA 18V50SG   THRM P G GAS  MDU  NDAK 100.0    1      40 25                      491
                   BPB   410    55.0000.83711.0000      0.5000  8310                  0.9891                        492
                   BPC   410      2180.000          9.221023.1604.6000             1  1                             493
                   BPD   410  1    30   22   56    0    1   13    0    0    0    0    0    1                        494
                   BPD   410  2     0    0    0    0    0   20    0                                                 495
                   BPF   410       857.000             30   370.0000                                                496
                   BPG   410    0.000000000.000000000.00000000                                                      497
                   *                                                                                                498
BASIC PLANT TYPE   BPA   420    WRTSLA 20V34SG   THRM P G GAS  MDU  NDAK 100.0    1      40 25                      499
                   BPB   420    36.5000.83711.0000      0.5000  8470                  0.9901                        500
                   BPC   420      2710.000          9.221032.7804.4000             1  1                             501
                   BPD   420  1    30   22   56    0   28   13    0    0    0    0    0   10                        502
                   BPD   420  2     0    0    0    0    0   20    0                                                 503
                   BPF   420       857.000             30   370.0000                                                504
                   BPG   420    0.000000000.000000000.00000000                                                      505
                   *                                                                                                506
BASIC PLANT TYPE   BPA   430    BIOMASS          THRM B G BMP  MDU  NDAK 100.0    1      40 25                      507
                   BPB   430    25.0000.83711.0000      0.0928 12300                  0.9072                        508
                   BPC   430      7980.000          9.2210252.005.6000             1  1                             509
                   BPD   430  1    30   22   58    0   28   10    0    0    0    0    0   19                        510
                   BPD   430  2     0    0    0    0    0   20    0                                                 511
                   BPF   430       857.000             30   370.0000                                                512
                   BPG   430    0.000000000.000000000.00000000                                                      513
                   *                                                                                                514

                              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 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 BASIC PLANT TYPE   BPA   450    PV SOLAR         NDT  B G PURC MDU  NDAK 100.0    1      30 25                          515
                    BPB   450    50.0000.50000.5000      0.0000                         0.5000                              516
                    BPC   450      1800.000          10.16534.8000.0000               1  1                                  517
                    BPD   450  1    30   22         0   10         0    0    0    0    0    0                              518
                    BPD   450  2     6    0    0    0    0    0    0                                                      519
                    BPF   450      2558.000            30   380.0000                                                        520
                    BPG   450    0.000000000.000000000.00000000                                                          521
                    *                                                                                                       522
 BASIC PLANT TYPE   BPA   460    PV SOLAR + STRG  NDT  B G PURC MDU  NDAK 100.0    1      30 25                          523
                    BPB   460     5.0000.50000.5000      0.0000                         0.5000                              524
                    BPC   460      2440.000          10.16536.0000.0000               1  1                                  525
                    BPD   460  1    30   22         0   10         0    0    0    0    0    0                              526
                    BPD   460  2     6    0    0    0    0    0    0                                                      527
                    BPF   460      2558.000            30   380.0000                                                        528
                    BPG   460    0.000000000.000000000.00000000                                                          529
                    *                                                                                                       530
 BASIC PLANT TYPE   BPA   490    CFBC             THRM B G LIGN MDU  NDAK 100.0    1      50 50                          531
                    BPB   490    30.0000.95001.0000      0.0928 10000                   0.9072                              532
                    BPC   490      5880.000          8.6990168.7214.060               1  1                                  533
                    BPD   490  1    30   22   61    0   33   12    0    0    0    0    0    0                              534
                    BPD   490  2     0    0    0    0    0   20    0                                                      535
                    BPE   490     M        0.0000    0    0       1980 2080              0                                  536
                    BPF   490      3900.000            30   310.0000                                                        537
                    BPG   490    0.000000000.000000000.00000000                                                          538
                    *                                                                                                       539
 BASIC PLANT TYPE   BPA   500    CFBC CO2         THRM B G COAL MDU  NDAK 100.0    1      50 50                          540
                    BPB   500    30.0000.95001.0000      0.0928 13800                   0.9072                              541
                    BPC   500     10400.000          8.6990267.4822.290               1  1                                  542
                    BPD   500  1    30   22   25    0   33   12    0    0    0    0    0    0                              543
                    BPD   500  2     0    0    0    0    0   20    0                                                      544
                    BPE   500     M        0.0000    0    0       1980 2080              0                                  545
                    BPF   500      3900.000            30   310.0000                                                        546
                    BPG   500    0.000000000.000000000.00000000                                                          547
                    *                                                                                                       548
 BASIC PLANT TYPE   BPA   510    WIND20           NDT  B G WIND MDU  NDAK 100.0    1      25 25                          549
                    BPB   510    20.0001.00000.3810      0.0000                         0.2080                              550
                    BPC   510      1780.000          10.16551.6000.0000               1  1                                  551
                    BPD   510  1    30   22         0   10         0    0    0    0    0    0                              552
                    BPD   510  2     4    0    0    0    0   21    0                                                      553
                    BPF   510      2400.000            30   380.0000                                                        554
                    BPG   510    0.000000000.000000000.00000000                                                          555
                    *                                                                                                       556
 BASIC PLANT TYPE   BPA   520    WIND50           NDT  B G WIND MDU  NDAK 100.0    1      25 25                          557
                    BPB   520    50.0001.00000.3810      0.0000                         0.2080                              558
                    BPC   520      1720.000          10.16551.6000.0000               1  1                                  559
                    BPD   520  1    30   22         0   10         0    0    0    0    0    0                              560
                    BPD   520  2     4    0    0    0    0   21    0                                                      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
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                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 BASIC PLANT TYPE   BPF   520      2400.000             30  380.0000                                                    562
                    BPG   520    0.000000000.000000000.00000000                                                         563
                    *                                                                                                   564
                    *            == MAINTENANCE CYCLES ==                                                               565
                    *             Y YBO ----NUMBER OF WEEKS (W) AND STARTING WEEK (S)----                               566
                    *             I RAP   1    2    3    4    5    6    7    8    9   10                                567
                    *             N PST  W S  W S  W S  W S  W S  W S  W S  W S  W S  W S                               568
                    *            ++--+- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++-- ++--                               569
                    *                                                                                                   570
 MAINTENANCE CYCLE  MC      1  1  1 110  2                                                                              571
                    *                                                                                                   572
 MAINTENANCE CYCLE  MC      2  1 101021  420  113  119  116  116  216  119  117  118  116                               573
                    *                                                                                                   574
 MAINTENANCE CYCLE  MC      3  1 101021  522  118  118  216  116  119  117  116  117  118                               575
                    *                                                                                                   576
 MAINTENANCE CYCLE  MC      4  1 101021  120 1132  120  120  216  120  120  120  120  120                               577
                    *                                                                                                   578
 MAINTENANCE CYCLE  MC      5  1 101022  115  122  118  116  116  116  113  113  116  115                               579
                    MC      5  2         143  141  143  141  537  140  140  137  137  140                               580
                    *                                                                                                   581
 MAINTENANCE CYCLE  MC      6  1 101022  214  515  214  217  117  217  220  214  217  216                               582
                    MC      6  2         241  242  240  242  242  243  242  539  337  243                               583
                    *                                                                                                   584
 MAINTENANCE CYCLE  MC      7  1  1 110  1                                                                              585
                    *                                                                                                   586
 MAINTENANCE CYCLE  MC      8  1 101022  216  217  217  217  316  119  615  639  115  139                               587
                    MC      8  2         838  240  241 1238  341  142  142  150  142  142                               588
                    *                                                                                                   589
 MAINTENANCE CYCLE  MC      9  1  1 110  2                                                                              590
                    *                                                                                                   591
 MAINTENANCE CYCLE  MC     10  1  1 110  1                                                                              592
                    *                                                                                                   593
 MAINTENANCE CYCLE  MC     11  1  1 110  1                                                                              594
                    *                                                                                                   595
 MAINTENANCE CYCLE  MC     12  1  1 110  1                                                                              596
                    *                                                                                                   597
 MAINTENANCE CYCLE  MC     13  1  1 110  1                                                                              598
                    *                                                                                                   599
 MAINTENANCE CYCLE  MC     14  1  1 100  1                                                                              600
                    *                                                                                                   601
 MAINTENANCE CYCLE  MC     15  1  1 120  1                                                                              602
                    *                                                                                                   603
 MAINTENANCE CYCLE  MC     16  1  1 110  1                                                                              604
                    *                                                                                                   605
 MAINTENANCE CYCLE  MC     17  1  1 110  1                                                                              606
                    *                                                                                                   607
 MAINTENANCE CYCLE  MC     18  1 101022  614  220  220  220  219  220  614  218  219  219                               608

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                                 MIRROR IMAGE REPORT                                   PAGE     15
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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 12345678901234567890123456789012345678901234567890123456789012345678901234567890

 MAINTENANCE CYCLE  MC     18  2         240  240  239  239  240  240  240  239  240  240                               609
                    *                                                                                                  610
 MAINTENANCE CYCLE  MC     19  1  1 110  1                                                                             611
                    *                                                                                                  612
 MAINTENANCE CYCLE  MC     20  1  1 110  1                                                                             613
                    *                                                                                                  614
 MAINTENANCE CYCLE  MC     21  1  1 110  2                                                                             615
                    *                                                                                                  616
 MAINTENANCE CYCLE  MC     22  1 101022  122  814  123  124  715  122  122  714  123  124                               617
                    MC     22  2         139  138  138  137  137  137  137  138  138  138                               618
                    *                                                                                                  619
 MAINTENANCE CYCLE  MC     23  1  1 110  2                                                                             620
                    *                                                                                                  621
 MAINTENANCE CYCLE  MC     24  1  1 110  2                                                                             622
                    *                                                                                                  623
 MAINTENANCE CYCLE  MC     25  1  1 110  2                                                                             624
                    *                                                                                                  625
 MAINTENANCE CYCLE  MC     26  1  1 110  1                                                                             626
                    *                                                                                                  627
 MAINTENANCE CYCLE  MC     27  1  1 110  1                                                                             628
                    *                                                                                                  629
 MAINTENANCE CYCLE  MC     28  1  1 110  2                                                                             630
                    *                                                                                                  631
 MAINTENANCE CYCLE  MC     29  1  1 110  1                                                                             632
                    *                                                                                                  633
 MAINTENANCE CYCLE  MC     30  1  1 110  1                                                                             634
                    *                                                                                                  635
 MAINTENANCE CYCLE  MC     31  1  1 110  1                                                                             636
                    *                                                                                                  637
 MAINTENANCE CYCLE  MC     32  1  1 110  1                                                                             638
                    *                                                                                                  639
 MAINTENANCE CYCLE  MC     33  1  1 110  3                                                                             640
                    *                                                                                                  641
 MAINTENANCE CYCLE  MC     34  1  1 110  1                                                                             642
                    *                                                                                                  643
 MAINTENANCE CYCLE  MC     35  1  1 110  1                                                                             644
                    *                                                                                                  645
 MAINTENANCE CYCLE  MC     36  1  1 110  1                                                                             646
                    *                                                                                                  647
 MAINTENANCE CYCLE  MC     37  1  1 110  2                                                                             648
                    *                                                                                                  649
 MAINTENANCE CYCLE  MC     38  1  1 100  1                                                                             650
                    *                                                                                                  651
 MAINTENANCE CYCLE  MC     39  1  1 100  1                                                                             652
                    *                                                                                                  653
                    *-- ----- -- ------------------------------------------------------------------                   654
                    *            == FUEL TYPES ==                                                                      655

                                1         2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                                MIRROR IMAGE REPORT                                  PAGE     16
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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

                    *                 MASS    HEAT   AVAILABLE   FUEL      AV   CS   AV   CS  LONG                      656
                    *            NAME UNIT  CONTENT    FUEL      COST      TJ   TJ   SM   SM  NAME                      657
                    *FL A        ---- ++++ ----------++++++++++----------+++++-----+++++----++++++++                   658
                    *            MIN. FUEL    TJ   SM                                                                  659
                    *FL B        ----------+++++-----                                                                  660
                    *-- ----- -- --------------------------------------------------------------------                 661
                    *                                                                                                  662
 FUEL TYPE          FLA     1    GAS  DKT      1.1400 -1.000000  2.630000    0   33    0    0GAS                        663
                    *                                                                                                  664
 FUEL TYPE          FLA     2    OIL2 GAL     39.1700 -1.000000 23.320000    0   34    0    0OIL2                       665
                    *                                                                                                  666
 FUEL TYPE          FLA     3    COAL TON     14.2700 -1.000000  2.810000    0   35    0    0COAL                       667
                    *                                                                                                  668
 FUEL TYPE          FLA     4    COAL TON     14.2700 -1.000000  2.830000    0   36    0    0COAL                       669
                    *                                                                                                  670
 FUEL TYPE          FLA     5    COAL TON     13.2200 -1.000000  1.880000    0   37    0    0COAL                       671
                    *                                                                                                  672
 FUEL TYPE          FLA     6    COAL TON     16.4800 -1.000000  1.910000    0   38    0    0COAL                       673
                    *                                                                                                  674
 FUEL TYPE          FLA     7    COAL TON     13.6800 -1.000000  1.690000    0   39    0    0COAL                       675
                    *                                                                                                  676
 FUEL TYPE          FLA     8    PURC NONE     0.0100 -1.000000  0.000000    0         0    0PURC                       677
                    *                                                                                                  678
 FUEL TYPE          FLA     9    GAS  DKT      1.1400 -1.000000  2.630000    0   23    0    0GAS                        679
                    *                                                                                                  680
 FUEL TYPE          FLA    10    BMP  TON     14.9000 -1.000000  6.750000    0   63    0    0BMP                        681
                    *                                                                                                  682
 FUEL TYPE          FLA    11    GAS  DKT      1.1400 -1.000000  2.630000    0   47    0    0GAS                        683
                    *                                                                                                  684
 FUEL TYPE          FLA    12    COAL TON     14.0700 -1.000000  2.880000    0   43    0    0COAL                       685
                    *                                                                                                  686
 FUEL TYPE          FLA    13    GAS  DKT      1.1400 -1.000000  2.630000    0   50    0    0GAS                        687
                    *                                                                                                  688
 FUEL TYPE          FLA    14    GAS  DKT      1.1400 -1.000000  2.630000    0   42    0    0GAS                        689
                    *                                                                                                  690
                    *            == PLANNING ALTERNATIVES ==                                                           691
                    *                                      1ST LAST T EXIST ---PREREQ ALT---                           692
                    *            NAME             BP   YEAR YEAR Y   RET   PA   NfR L L R                              693
                    *            ----------------+++++ ---- ++++ - +++++-----  ++-+ -++ +                              694
                    *                                                                                                  695
 PLANNING ALTERN    PA      1  1 GE 7EA           320 2021 2038 0     0    0    00 0-1 0                              696
                    *                                                                                                  697
 PLANNING ALTERN    PA      2  1 WRTSLA 18V50SG   410 2021 2038 0     0    0    00 0-1 0                              698
                    *                                                                                                  699
 PLANNING ALTERN    PA      3  1 STORAGE1           1 2021 2038 0     0   12   100 0-1 0                              700
                    *                                                                                                  701
 PLANNING ALTERN    PA      4  1 RFP1               2 2023 2023 0     0    0    00 0-1 0                              702

                                1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
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 EGEAS   EDIT                                              MIRROR IMAGE REPORT                                  PAGE     17
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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

                    *                                                                                                703
 PLANNING ALTERN    PA      5  1 CFBC              490 2025 2038 0     0    0    00 0-1 0                            704
                    *                                                                                                705
 PLANNING ALTERN    PA      6  1 GE LM6000PH       340 2021 2038 0     0    0    00 0-1 0                            706
                    *                                                                                                707
 PLANNING ALTERN    PA      7  1 PURCHASE POWER    310 2019 2038 1     0    0    00 0-1 0                            708
                    *                                                                                                709
 PLANNING ALTERN    PA      8  1 GE 7EA 2x1 ADD    370 2025 2038 0   152    0    00 0-1 0                            710
                    *                                                                                                711
 PLANNING ALTERN    PA      9  1 GE 7FA.05 1x1     380 2024 2038 0     0    0    00 0-1 0                            712
                    *                                                                                                713
 PLANNING ALTERN    PA     10  1 BIOMASS           430 2022 2038 0     0    0    00 0-1 0                            714
                    *                                                                                                715
 PLANNING ALTERN    PA     11  1 CFBC CO2          500 2025 2038 0     0    0    00 0-1 0                            716
                    *                                                                                                717
 PLANNING ALTERN    PA     12  1 PV SOLAR + STRG   460 2021 2038 0     0    0    00 0-1 0                            718
                    *                                                                                                719
 PLANNING ALTERN    PA     13  1 RFP2                3 2025 2025 0     0    0    00 0-1 0                            720
                    *                                                                                                721
 PLANNING ALTERN    PA     14  1 GE LMS100PB       330 2021 2038 0     0    0    00 0-1 0                            722
                    *                                                                                                723
 PLANNING ALTERN    PA     15  1 RFP3                4 2022 2022 0     0    0    00 0-1 0                            724
                    *                                                                                                725
 PLANNING ALTERN    PA     16  1 PV SOLAR          450 2021 2038 0     0    0    00 0-1 0                            726
                    *                                                                                                727
 PLANNING ALTERN    PA     17  1 RFP4a               5 2021 2021 0     0    0    00 0-1 0                            728
                    *                                                                                                729
 PLANNING ALTERN    PA     18  1 RFP4b               6 2023 2023 0     0    0    00 0-1 0                            730
                    *                                                                                                731
 PLANNING ALTERN    PA     19  1 SMN SGT-800 2x1   400 2024 2038 0     0    0    00 0-1 0                            732
                    *                                                                                                733
 PLANNING ALTERN    PA     20  1 WIND20            510 2021 2038 0     0    0    00 0-1 0                            734
                    *                                                                                                735
 PLANNING ALTERN    PA     21  1 RFP4c               7 2023 2023 0     0    0    00 0-1 0                            736
                    *                                                                                                737
 PLANNING ALTERN    PA     22  1 WIND50            520 2021 2038 0     0    0    00 0-1 0                            738
                    *                                                                                                739
 PLANNING ALTERN    PA     23  1 WRTSLA 20V34SG    420 2021 2038 0     0    0    00 0-1 0                            740
                    *                                                                                                741
 PLANNING ALTERN    PA     24  1 RFP4e               8 2025 2025 0     0    0    00 0-1 0                            742
                    *                                                                                                743
 PLANNING ALTERN    PA     25  1 RFP5a               9 2022 2022 0     0    0    00 0-1 0                            744
                    *                                                                                                745
 PLANNING ALTERN    PA     26  1 RFP5b              10 2022 2022 0     0   25   100 0 0 1                            746
                    *                                                                                                747
 PLANNING ALTERN    PA     27  1 RFP5c              11 2022 2022 0     0   25   100 0-1 0                            748
                    PA     27  2                                       0   26   100 0 0 1                            749

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

                   *                                                                                                   750
 PLANNING ALTERN   PA     28  1 RFP6              12 2023 2023 0     0    0    00 0-1 0                                751
                   *                                                                                                   752
 PLANNING ALTERN   PA     29  1 RFP7a             13 2024 2024 0     0    0    00 0-1 0                                753
                   *                                                                                                   754
 PLANNING ALTERN   PA     30  1 RFP7b             14 2024 2024 0     0   29   100 0 0 1                                755
                   *                                                                                                   756
 PLANNING ALTERN   PA     31  1 RFP7c             15 2024 2024 0     0    0    00 0-1 0                                757
                   *                                                                                                   758
 PLANNING ALTERN   PA     32  1 RFP7d             16 2024 2024 0     0   31   100 0 0 1                                759
                   *                                                                                                   760
 PLANNING ALTERN   PA     33  1 RFP8a             17 2022 2025 0     0    0    00 0-1 0                                761
                   *                                                                                                   762
 PLANNING ALTERN   PA     34  1 RFP8b             18 2022 2025 0     0   33   100 0 0 1                                763
                   *                                                                                                   764
 PLANNING ALTERN   PA     35  1 RFP9a             19 2021 2021 0     0    0    00 0-1 0                                765
                   *                                                                                                   766
 PLANNING ALTERN   PA     36  1 RFP9b             20 2024 2024 0     0    0    00 0-1 0                                767
                   *                                                                                                   768
 PLANNING ALTERN   PA     37  1 RFP9c             21 2024 2024 0     0   36   100 0 0 1                                769
                   *                                                                                                   770
 PLANNING ALTERN   PA     38  1 RFP10             22 2021 2021 0     0    0    00 0-1 0                                771
                   *                                                                                                   772
 PLANNING ALTERN   PA     39  1 GE 7EAHESKETT     23 2021 2038 0     0    0    00 0-1 0                                773
                   *                                                                                                   774
 PLANNING ALTERN   PA     40  1 STORAGE10         24 2021 2038 0     0   16   100 0-1 0                                775
                   *                                                                                                   776
 PLANNING ALTERN   PA     41  1 COMM ADD          25 2020 2038 0     0    0    00 0-1 0                                777
                   *                                                                                                   778
 PLANNING ALTERN   PA     42  1 AC CYCLE          26 2020 2038 0     0    0    00 0-1 0                                779
                   *                                                                                                   780
 PLANNING ALTERN   PA     43  1 STORAGE PP        27 2020 2038 0     0    0    00 0-1 0                                781
                   *                                                                                                   782
                   *            == TRAJECTORIES ==                                                                     783
                   *             T B                                                                                   784
                   *             Y A  N YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE  YEAR RATE                          785
                   *             - + -- ++++------ ++++------ ++++------ ++++------ ++++------                         786
                   *                                                                                                   787
 TRAJECTORY        TJ      1  1  1 1 21 20181.1949 20191.1808 20202.5092 20212.3150 20221.3724                         788
                   TJ      1  2         20231.0976 20241.0676 20251.0743 20261.0983 20271.0688                         789
                   TJ      1  3         20281.0749 20291.0806 20301.0860 20311.0743 20321.0629                         790
                   TJ      1  4         20331.0846 20341.0567 20351.0778 20361.0663 20371.0708                         791
                   TJ      1  5         20381.3700                                                                     792
                   *                                                                                                   793
 TRAJECTORY        TJ      2  1  1 1 21 2018.87614 20191.0790 20203.3842 20214.3797 20222.2746                         794
                   TJ      2  2         20231.1107 20241.0722 20251.1206 20261.1262 20271.1264                         795
                   TJ      2  3         20281.1314 20291.1337 20301.1382 20311.1424 20321.1439                         796

                                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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          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890

 TRAJECTORY         TJ      2  4        20331.1476 20341.1534 20351.1611 20361.1638 20371.1799                  797
                    TJ      2  5        20381.5600                                                              798
                    *                                                                                           799
 TRAJECTORY         TJ      3  1  1 1  1 20183.0000                                                             800
                    *                                                                                           801
 TRAJECTORY         TJ      4  1  1 1  4 2018.00000 2019.00000 2020.00000 2021.00000                            802
                    *                                                                                           803
 TRAJECTORY         TJ      5  1  1 1  1 20183.0000                                                             804
                    *                                                                                           805
 TRAJECTORY         TJ      6  1  1 1  1 20183.0000                                                             806
                    *                                                                                           807
 TRAJECTORY         TJ      7  1  1 1  1 20183.0000                                                             808
                    *                                                                                           809
 TRAJECTORY         TJ      8  1  1 1  1 20183.0000                                                             810
                    *                                                                                           811
 TRAJECTORY         TJ      9  1  1 1  1 20183.0000                                                             812
                    *                                                                                           813
 TRAJECTORY         TJ     10  1  1 1  1 20183.0000                                                             814
                    *                                                                                           815
 TRAJECTORY         TJ     11  1  1 1  1 20183.0000                                                             816
                    *                                                                                           817
 TRAJECTORY         TJ     12  1  1 1  1 20183.0000                                                             818
                    *                                                                                           819
 TRAJECTORY         TJ     13  1  1 1  1 20183.0000                                                             820
                    *                                                                                           821
 TRAJECTORY         TJ     14  1  1 1  1 2018.00000                                                             822
                    *                                                                                           823
 TRAJECTORY         TJ     15  1  1 1  1 20183.0000                                                             824
                    *                                                                                           825
 TRAJECTORY         TJ     16  1  1 1  4 2018.00000 20196.4935 20206.0975 2021.00000                            826
                    *                                                                                           827
 TRAJECTORY         TJ     17  1  1 1  3 2018.00000 2019-100.0 2020-100.0                                       828
                    *                                                                                           829
 TRAJECTORY         TJ     18  1  1 1  6 20181.4569 20191.4360 20201.5444 20211.5209 20221.4981                 830
                    TJ     18  2        20231.5000                                                              831
                    *                                                                                           832
 TRAJECTORY         TJ     19  1  1 1  3 2018.00000 2019-100.0 2020-100.0                                       833
                    *                                                                                           834
 TRAJECTORY         TJ     20  1  1 1  1 20183.0000                                                             835
                    *                                                                                           836
 TRAJECTORY         TJ     21  1  1 1  1 20183.0000                                                             837
                    *                                                                                           838
 TRAJECTORY         TJ     22  1  1 1  1 20193.0000                                                             839
                    *                                                                                           840
 TRAJECTORY         TJ     23  1  1 1  8 201815.589 2019-5.921 2020-12.23 20212.3904 20223.8910                 841
                    TJ     23  2        20236.7415 20244.5614 20253.0000                                        842
                    *                                                                                           843

                             1          2         3         4         5         6         7         8         9
          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890
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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     24  1  1 1  1 20193.0000                                                                   844
                       *                                                                                                 845
TRAJECTORY             TJ     25  1  1 1  1 20193.0000                                                                   846
                       *                                                                                                 847
TRAJECTORY             TJ     26  1  1 1  8 2018.00000 2019.00000 2020100.00 202150.000 202233.333                       848
                       TJ     26  2         202325.000 2024.00000 2025.00000                                             849
                       *                                                                                                 850
TRAJECTORY             TJ     27  1  1 1  5 2018.00000 201918.404 20203.8860 2021.00000 2022.00000                       851
                       *                                                                                                 852
TRAJECTORY             TJ     28  1  1 1  5 2018.00000 20193.3003 20205.8573 2021.00000 2022.00000                       853
                       *                                                                                                 854
TRAJECTORY             TJ     29  1  1 1  4 2018-4.654 20193.0000 20203.0241 20213.0000                                  855
                       *                                                                                                 856
TRAJECTORY             TJ     30  1  1 1  1 20193.0000                                                                   857
                       *                                                                                                 858
TRAJECTORY             TJ     31  1  1 1  1 20183.0000                                                                   859
                       *                                                                                                 860
TRAJECTORY             TJ     32  1  1 1  9 2018.00000 2019.00000 2020.00000 2021.00000 2022.00000                       861
                       TJ     32  2         2023.00000 2024.00000 2025-100.0 2026.00000                                  862
                       *                                                                                                 863
TRAJECTORY             TJ     33  1  1 1  6 201852.851 2019-7.213 202011.528 2021.96154 20223.3333                       864
                       TJ     33  2         20233.0000                                                                   865
                       *                                                                                                 866
TRAJECTORY             TJ     34  1  1 1  6 2018-19.12 2019.00000 20203.0222 20212.9850 20222.8985                       867
                       TJ     34  2         20233.0000                                                                   868
                       *                                                                                                 869
TRAJECTORY             TJ     35  1  1 1  6 2018-2.846 20192.5641 20202.5000 20218.0139 20223.2258                       870
                       TJ     35  2         20233.0000                                                                   871
                       *                                                                                                 872
TRAJECTORY             TJ     36  1  1 1  6 2018-2.826 20192.9090 20202.1201 20217.9584 20223.2051                       873
                       TJ     36  2         20233.0000                                                                   874
                       *                                                                                                 875
TRAJECTORY             TJ     37  1  1 1  6 20181.5957 2019.00000 20201.5706 2021.51546 20222.5641                       876
                       TJ     37  2         20233.0000                                                                   877
                       *                                                                                                 878
TRAJECTORY             TJ     38  1  1 1  6 2018-8.900 20194.0229 20207.1823 20212.5773 20223.0150                       879
                       TJ     38  2         20233.0000                                                                   880
                       *                                                                                                 881
TRAJECTORY             TJ     39  1  1 1  6 201832.544 2019-12.50 20206.6326 2021-9.569 2022-12.69                       882
                       TJ     39  2         20233.0000                                                                   883
                       *                                                                                                 884
TRAJECTORY             TJ     40  1  1 1 21 2018.00000 2019.00000 2020.00000 2021.00000 2022.00000                       885
                       TJ     40  2         2023.00000 2024.00000 2025.00000 2026.00000 2027.00000                       886
                       TJ     40  3         2028.00000 2029.00000 2030.00000 2031.00000 2032.00000                       887
                       TJ     40  4         2033-65.00 2034.00000 2035.00001 2036.00000 2037.00000                       888
                       TJ     40  5         2038.00000                                                                   889
                       *                                                                                                 890

                                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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          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

 TRAJECTORY         TJ     41  1  1 1  7 2018.00000 2019.00000 2020100.00 202150.000 202233.333                         891
                    TJ     41  2         2023.00000 2024.00000                                                          892
                    *                                                                                                   893
 TRAJECTORY         TJ     42  1  1 1  8 201853.612 2019-4.455 2020-9.067 20211.7094 20222.8011                         894
                    TJ     42  2         20234.9046 20243.3766 20253.0000                                               895
                    *                                                                                                   896
 TRAJECTORY         TJ     43  1  1 1  1 20193.0000                                                                     897
                    *                                                                                                   898
 TRAJECTORY         TJ     44  1  1 1  1 20183.0000                                                                     899
                    *                                                                                                   900
 TRAJECTORY         TJ     45  1  1 1  1 2018.00000                                                                     901
                    *                                                                                                   902
 TRAJECTORY         TJ     46  1  1 1  3 20181.3210 20193.0000 20203.0000                                               903
                    *                                                                                                   904
 TRAJECTORY         TJ     47  1  1 1  8 20184.5627 2019-6.181 2020-13.95 20213.1531 20224.3668                         905
                    TJ     47  2         20237.5313 20245.0583 20253.0000                                               906
                    *                                                                                                   907
 TRAJECTORY         TJ     48  1  1 1  1 20183.0000                                                                     908
                    *                                                                                                   909
 TRAJECTORY         TJ     49  1  1 1  1 2018.00000                                                                     910
                    *                                                                                                   911
 TRAJECTORY         TJ     50  1  1 1  8 201815.589 2019-5.921 2020-12.23 20212.3904 20223.8910                         912
                    TJ     50  2         20236.7415 20244.5614 20253.0000                                               913
                    *                                                                                                   914
 TRAJECTORY         TJ     51  1  1 1  1 2018.00000                                                                     915
                    *                                                                                                   916
 TRAJECTORY         TJ     52  1  1 1  1 2018.00000                                                                     917
                    *                                                                                                   918
 TRAJECTORY         TJ     53  1  1 1  1 2018.00000                                                                     919
                    *                                                                                                   920
 TRAJECTORY         TJ     54  1  1 1  1 20193.0000                                                                     921
                    *                                                                                                   922
 TRAJECTORY         TJ     55  1  1 1  1 20182.5000                                                                     923
                    *                                                                                                   924
 TRAJECTORY         TJ     56  1  1 1  1 20193.0000                                                                     925
                    *                                                                                                   926
 TRAJECTORY         TJ     57  1  1 1  1 2018.00000                                                                     927
                    *                                                                                                   928
 TRAJECTORY         TJ     58  1  1 1  1 20193.0000                                                                     929
                    *                                                                                                   930
 TRAJECTORY         TJ     59  1  1 1  1 20193.0000                                                                     931
                    *                                                                                                   932
 TRAJECTORY         TJ     60  1  1 1  1 20193.0000                                                                     933
                    *                                                                                                   934
 TRAJECTORY         TJ     61  1  1 1  1 20193.0000                                                                     935
                    *                                                                                                   936
 TRAJECTORY         TJ     62  1  1 1  1 20193.0000                                                                     937

                                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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          COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890

                    *                                                                                                    938
 TRAJECTORY         TJ     63  1  1 1  1 20193.0000                                                                      939
                    *                                                                                                    940
 TRAJECTORY         TJ     64  1  1 1  6 2018.00000 2019.00000 2020.00000 202121.497 2022.00000                          941
                    TJ     64  2         2023.00000                                                                      942
                    *                                                                                                    943
 TRAJECTORY         TJ     68  1  1 1  1 20193.0000                                                                      944
                    *                                                                                                    945
 TRAJECTORY         TJ     69  1  1 1  1 20193.0000                                                                      946
                    *                                                                                                    947
                    *            == LOADING BLOCKS ==                                                                    948
                    *              -A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-                                            949
                    *            N     1       2       3       4       5                                                 950
                    *            - ++++++++--------++++++++--------++++++++                                              951
                    *                                                                                                    952
 LOADING BLOCK      LBA     1    5 0.2325580.2093020.1860470.1860470.186047                                              953
                    LBB     1      1.8436370.7766110.6303580.7719000.794509                                              954
                    LBC     1      1.0000000.0000000.0000000.0000000.000000                                              955
                    *                                                                                                    956
 LOADING BLOCK      LBA     2    5 0.0946750.2130180.2011830.3076920.183432                                              957
                    LBB     2      3.2613650.8753020.6785150.6585090.903074                                              958
                    LBC     2      1.0000000.0000000.0000000.0000000.000000                                              959
                    *                                                                                                    960
 LOADING BLOCK      LBA     3    5 0.0873940.1966630.1857260.2841110.246106                                              961
                    LBB     3      3.0457110.8174080.6336880.6219161.132123                                              962
                    LBC     3      1.0000000.0000000.0000000.0000000.000000                                              963
                    *                                                                                                    964
 LOADING BLOCK      LBA     4    5 0.0946330.2129470.2011220.2171920.274106                                              965
                    LBB     4      2.9498470.7916370.6136950.6402401.057082                                              966
                    LBC     4      1.0000000.0000000.0000000.0000000.000000                                              967
                    *                                                                                                    968
 LOADING BLOCK      LBA     5    5 0.2535210.1690140.1690140.2253520.183099                                              969
                    LBB     5      1.6222220.7421580.7319290.7941840.877250                                              970
                    LBC     5      1.0000000.0000000.0000000.0000000.000000                                              971
                    *                                                                                                    972
 LOADING BLOCK      LBA     6    5 0.0946330.2129470.2011220.2171920.274106                                              973
                    LBB     6      2.9498470.7916370.6136950.6402401.057082                                              974
                    LBC     6      1.0000000.0000000.0000000.0000000.000000                                              975
                    *                                                                                                    976
 LOADING BLOCK      LBA     7    5 0.2000000.2000000.2000000.2000000.200000                                              977
                    LBB     7      1.0000001.0000001.0000001.0000001.000000                                              978
                    LBC     7      1.0000000.0000000.0000000.0000000.000000                                              979
                    *                                                                                                    980
 LOADING BLOCK      LBA     8    5 0.0946750.2130180.2011830.3076920.183432                                              981
                    LBB     8      3.2613650.8753020.6785150.6585090.903074                                              982
                    LBC     8      1.0000000.0000000.0000000.0000000.000000                                              983
                    *                                                                                                    984

                                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

 LOADING BLOCK      LBA    10    5 0.2325580.2093020.1860470.1860470.186047                                           985
                    LBB    10      1.8436370.7766110.6303580.7719000.794509                                           986
                    LBC    10      1.0000000.0000000.0000000.0000000.000000                                           987
                    *                                                                                                 988
 LOADING BLOCK      LBA    11    5 0.1891890.2432430.2162160.2162160.135135                                           989
                    LBB    11      1.2000461.1529430.8809440.8645150.851903                                           990
                    LBC    11      1.0000000.0000000.0000000.0000000.000000                                           991
                    *                                                                                                 992
 LOADING BLOCK      LBA    12    5 0.2777780.1587300.2380950.1190480.206349                                           993
                    LBB    12      1.6629090.1229151.1262310.7842410.761127                                           994
                    LBC    12      0.7885320.0841890.1095830.1287550.227864                                           995
                    *                                                                                                 996
 LOADING BLOCK      LBA    13    5 0.2309470.2078520.1847570.1847570.191686                                           997
                    LBB    13      1.8148470.7642730.6209910.7594000.871078                                           998
                    LBC    13      1.0000000.0000000.0000000.0000000.000000                                           999
                    *                                                                                                1000
 LOADING BLOCK      LBA    14    5 0.2226030.1883560.2054790.2054790.178082                                          1001
                    LBB    14      1.1014360.6004480.5689500.9914581.803029                                          1002
                    LBC    14      0.5990180.0967090.3117780.2505240.258642                                          1003
                    *                                                                                                1004
 LOADING BLOCK      LBA    15    5 0.3927610.1970510.1340480.1340480.142091                                          1005
                    LBB    15      1.0653170.9015531.1667870.9644570.832163                                          1006
                    LBC    15      0.6892410.1361860.3041380.2250420.289710                                          1007
                    *                                                                                                1008
 LOADING BLOCK      LBA    16    5 0.3632890.1147230.1147230.1720840.235182                                          1009
                    LBB    16      1.1031060.9346200.9345930.9345930.952387                                          1010
                    LBC    16      0.6857320.1000710.0984190.2329840.443454                                          1011
                    *                                                                                                1012
 LOADING BLOCK      LBA    17    5 0.3157750.1571920.1483820.2225730.156079                                          1013
                    LBB    17      1.1763010.9333160.8687580.8851910.998962                                          1014
                    LBC    17      1.0000000.0000000.0000000.0000000.000000                                          1015
                    *                                                                                                1016
 LOADING BLOCK      LBA    18    5 0.4213480.1310860.1217230.1966290.129214                                          1017
                    LBB    18      1.1859890.8754510.8248570.8384050.930764                                          1018
                    LBC    18      1.0000000.0000000.0000000.0000000.000000                                          1019
                    *                                                                                                1020
 LOADING BLOCK      LBA    19    5 0.2325580.2093020.1860470.1860470.186047                                          1021
                    LBB    19      1.8436370.7766110.6303580.7719000.794509                                          1022
                    LBC    19      1.0000000.0000000.0000000.0000000.000000                                          1023
                    *                                                                                                1024
                    *            == ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ==                                  1025
                    *            YEAR OPT   RATE                                                                     1026
                    *            ---- +    ------                                                                    1027
 A. F. U. D. C.     ZA      1    2019 1    10.500                                                                    1028
                    *                                                                                                1029
                    *-- ----- -- -------------------------------------------------------------------                1030
                    *            == EXPENDITURE PATTERNS - CONSTRUCTION COST AND CAPITAL EXPENSES ==                 1031

                                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 1234567890123456789012345678901234567890123456789012345678901234567890123456789012

                   *                        COST PERCENTAGES FOR YEARS BEFORE ON-LINE                                1032
                   *            YR          1    2    3    4    5    6    7    8    9   10                         1033
                   *ZC A        --        +++++-----+++++-----+++++-----+++++-----+++++-----                         1034
                   *                      ANNUAL EXPENDITURES FOR YEARS OF OPERATING LIFE                            1035
                   *            YR F   TJ      1         2         3         4         5                             1036
                   *ZC B        -- +----- ++++++++++----------++++++++++----------++++++++++                         1037
                   *-- ----- -- -------------------------------------------------------------------                  1038
                   *                                                                                                 1039
CONSTRUCTION EXPEN ZCA    31  1  4        13.7035.1034.8016.50                                                       1040
                   *                                                                                                 1041
CONSTRUCTION EXPEN ZCA    37  1  3        69.0027.004.000                                                            1042
                   *                                                                                                 1043
CONSTRUCTION EXPEN ZCA    38  1  1        100.0                                                                      1044
                   *                                                                                                 1045
                   *            == RETURN ON RATE BASE ==                                                            1046
                   *                --CAPITAL STRUC-- -RATES OF RETURN- INCOME  PROP                                 1047
                   *            YEAR COMM  PREF  DEBT  COMM  PREF  DEBT  TAX    TAX                                  1048
                   *            ----+++++-----+++++-----+++++-----+++++------                                        1049
RETURN ON RATEBASE ZR      1  1 201950.0000.000050.00010.000       2.7325.0001.1840                                  1050
                   *                                                                                                 1051
                   *            == TAX DEPRECIATION TABLES ==                                                        1052
                   *                              DEPRECIATION PERCENTAGES FOR YEARS                                 1053
                   *            YR          1    2    3    4    5    6    7    8    9   10                         1054
                   *            --        +++++-----+++++-----+++++-----+++++-----+++++-----                         1055
                   *                                                                                                 1056
TAX DEPRECIATION   ZT     20  1 21        3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464                         1057
                   ZT     20  2           4.4624.4624.4624.4624.4624.4624.4624.4624.4624.462                         1058
                   ZT     20  3           2.224                                                                      1059
                   *                                                                                                 1060
TAX DEPRECIATION   ZT     21  1 20        3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464                         1061
                   ZT     21  2           4.4624.4624.4624.4624.4624.4624.4624.4624.4626.686                         1062
                   *                                                                                                 1063

                              1         2         3         4         5         6         7         8         9
         COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012
```

```
****************************************************
****************************************************
**                                                **
**                                                **
**              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.
	2019	1	0	6/18/19	15:47:28	2019 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	2018	
LAST CALENDAR YEAR	2038	
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	2019	1	0	6/18/19	15:47:24	2019 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	FILE YEARS 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 2018
ALL DATA BASE COSTS
ARE IN 2018 DOLLARS

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

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

SYSTEM DISCOUNT RATE (PERCENT) 5.85
CUSTOMER DISCOUNT RATE (PERCENT) 5.85
INFLATION RATE (PERCENT) 3.00

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

BENCHMARK YEAR 2018
BENCHMARK PEAK . . . . . 499. 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 2018 -
PEAK LOAD . . . . 502.1 MW
ENERGY . . . . 3344.2 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	2018	INITIAL LOAD	502.1	316.6	3344.2	0.76241137	0.63062392	SUNDAY
		LOAD AFTER CONTRACTS	502.1	316.6	3344.2	0.76241137	0.63062392	

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	0.996831340003898	0.981727108017088	0.903138541482896	0.831585867043956
0.754232490885079	0.623260601997116	0.485974394690735	0.356756763423894	0.259100963637025
0.173803386236855	0.110809644147070	0.064933766755597	0.035833396768468	0.021112033127920
0.012553100778765	0.006276550389384	0.002168262861789	0.000570595489947	0.000000000000000

CUMULANTS

0.762411371343728D+00	0.374725434187995D-02	0.994965786489193D-04	0.234400879222613D-08
-0.263769298733597D-06	-0.552040723758789D-07	-0.102853818030657D-07	-0.203575393166728D-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	2019	INITIAL LOAD	508.1	318.5	3373.5	0.76000925	0.62688937	SUNDAY
		LOAD AFTER CONTRACTS	508.1	318.5	3373.5	0.76000925	0.62688937	

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	0.995184606371349	0.970398131278419	0.892213768468429	0.821687305579492
0.733809402179287	0.610083737910499	0.465824116656355	0.346177511350785	0.250118379662599
0.166707603392431	0.108593537958297	0.063811522829641	0.034070795225113	0.020852694067546
0.012306507974291	0.006039304839237	0.002165033810295	0.000569745739554	0.000000000000000

CUMULANTS

0.760009247463225D+00	0.382341052462575D-02	0.102545056366157D-03	0.244016843811168D-08
-0.277375523564167D-06	-0.586386714705096D-07	-0.110357659148192D-07	-0.220652100371448D-09

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	2020	INITIAL LOAD	514.1	321.7	3409.9	0.75924410	0.62569978	SUNDAY
		LOAD AFTER CONTRACTS	514.1	321.7	3409.9	0.75924410	0.62569978	

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	0.995654476175081	0.967299045477838	0.888210886480571	0.818787888472444
0.728899982799113	0.603325237452932	0.466119605636452	0.341380161270925	0.244918031533049
0.162366516249099	0.106724058433398	0.062597765042667	0.034092407555115	0.020865921680891
0.012314314434626	0.006043135787364	0.002166407169057	0.000570107149754	0.000000000000000

CUMULANTS

0.759244099919069D+00	0.384783026808543D-02	0.103529036655473D-03	0.247050298148580D-08
-0.281825669874662D-06	-0.597693932301649D-07	-0.112844321918587D-07	-0.226344699399944D-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
4	2021	INITIAL LOAD	527.0	335.1	3525.3	0.76572504	0.63577566	SUNDAY
		LOAD AFTER CONTRACTS	527.0	335.1	3525.3	0.76572504	0.63577566	

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	0.997253394716677	0.990996018233965	0.922699660176832	0.846907133331081
0.776013702117171	0.648542868824174	0.505249989994732	0.378896986732519	0.273413161562033
0.179117014818719	0.117813103437170	0.068952630306252	0.036645354848192	0.022147036886448
0.012671758218536	0.006278799117294	0.002169039695067	0.000570799919757	0.000000000000000

CUMULANTS

0.765725036273645D+00	0.364345804670966D-02	0.953913631540287D-04	0.221622427127813D-08
-0.245881357278135D-06	-0.507426238777554D-07	-0.932227839455618D-08	-0.181964033703227D-09

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	2022	INITIAL LOAD	539.2	355.8	3679.7	0.78117780	0.65979987	SUNDAY
		LOAD AFTER CONTRACTS	539.2	355.8	3679.7	0.78117780	0.65979987	

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	0.995832995204652	0.992382030475489	0.928394634061545
0.845532171163477	0.766686211411682	0.629122583680067	0.478994944124596	0.346308100963952
0.233797865397324	0.148873726089180	0.090509753839824	0.049358593718697	0.026902143458691
0.015730914395337	0.007751465064371	0.002165850532694	0.000683952799800	0.000000000000000

CUMULANTS

0.781177803876460D+00	0.317866557845497D-02	0.777330214725147D-04	0.168551274148588D-08
-0.174804628912672D-06	-0.336950171887417D-07	-0.578204618030082D-08	-0.105399797827272D-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
6	2023	INITIAL LOAD	546.6	366.6	3763.4	0.78813050	0.67060913	SUNDAY
		LOAD AFTER CONTRACTS	546.6	366.6	3763.4	0.78813050	0.67060913	

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	0.993976229023470	0.970401192790032
0.880304021752954	0.802400602039639	0.683062214704721	0.540049164333432	0.383256592064522
0.266959609555633	0.169779939239986	0.103324520663478	0.054734685505655	0.030382871164263
0.017069028743970	0.008079340272147	0.002275870499199	0.000682761149762	0.000000000000000

CUMULANTS

0.788130501716418D+00	0.297988087167725D-02	0.705564403933986D-04	0.148188538052939D-08
-0.148743503993584D-06	-0.277605566350378D-07	-0.461232560770113D-08	-0.814165638902236D-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	2024	INITIAL LOAD	552.6	370.7	3805.2	0.78823188	0.67076673	SUNDAY
		LOAD AFTER CONTRACTS	552.6	370.7	3805.2	0.78823188	0.67076673	

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	0.994614102760539	0.971574345903800
0.881965395407747	0.803901667850699	0.684956901209674	0.536084987475097	0.383501175522929
0.267129975586934	0.169888287969185	0.103390459434331	0.056249875507226	0.030402260648644
0.017079921712723	0.008084496277357	0.002277322895033	0.000683196868512	0.000000000000000

CUMULANTS

0.788231878383055D+00	0.297702999568430D-02	0.704552149357910D-04	0.147899021745009D-08
-0.148388060945616D-06	-0.276809420858155D-07	-0.459690145567031D-08	-0.811039688990243D-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	2025	INITIAL LOAD	558.5	374.7	3846.0	0.78826723	0.67082172	SUNDAY
		LOAD AFTER CONTRACTS	558.5	374.7	3846.0	0.78826723	0.67082172	

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	0.994577537809460	0.971730690340073
0.882315418062569	0.804215929045744	0.685432491085043	0.536633531867097	0.383486599962175
0.267119822895269	0.169881831099635	0.103386529918546	0.056247737642911	0.030401105163275
0.017079272563639	0.008084189013458	0.002277236341822	0.000683170902549	0.000000000000000

CUMULANTS

0.788267226427478D+00	0.297603594957607D-02	0.704200215756585D-04	0.147187016246641D-08
-0.148266532301478D-06	-0.276532914838494D-07	-0.459147673106071D-08	-0.809838086354557D-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	2026	INITIAL LOAD	564.5	379.0	3889.1	0.78862866	0.67138358	SUNDAY
		LOAD AFTER CONTRACTS	564.5	379.0	3889.1	0.78862866	0.67138358	

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	0.994829786632540	0.973847594129563
0.882318435730539	0.804285866045200	0.687324213932305	0.542585851635379	0.384385900386348
0.267184174701509	0.173453323985678	0.106600335686538	0.056261288279008	0.030408429090072
0.017083387129256	0.008086136574516	0.002277784950570	0.000683335485173	0.000000000000000

CUMULANTS

0.788628664299747D+00	0.296588484119892D-02	0.700599403589533D-04	0.146787645066657D-08
-0.147003222262855D-06	-0.273712368849005D-07	-0.453694196349086D-08	-0.799169331668513D-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	2027	INITIAL LOAD	570.7	383.4	3932.9	0.78884627	0.67172193	SUNDAY
		LOAD AFTER CONTRACTS	570.7	383.4	3932.9	0.78884627	0.67172193	

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	0.992546490438038	0.972665257954273
0.882660315320338	0.804437879702347	0.689044330081052	0.544833947299137	0.390308688304985
0.272136625470289	0.173053895862736	0.106354856551230	0.056131729846484	0.030338404593142
0.017044047524238	0.008067515828141	0.002272539669901	0.000681761900973	0.000000000000000

CUMULANTS

0.788846268737509D+00	0.295978035333516D-02	0.698437450103245D-04	0.146198027502134D-08
-0.146247745210011D-06	-0.272025553088764D-07	-0.450435818637268D-08	-0.792426217162734D-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	2028	INITIAL LOAD	576.8	387.9	3977.2	0.78929536	0.67242014	SUNDAY
		LOAD AFTER CONTRACTS	576.8	387.9	3977.2	0.78929536	0.67242014	

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	0.994955971270176	0.977007730555686
0.886679441390291	0.807788466182808	0.692320026862530	0.547253267143707	0.391251181801742
0.272793764313006	0.173471775803220	0.106611675739866	0.056267273307153	0.030411663912977
0.017085204445494	0.008086996770869	0.002278027259402	0.000683408177823	0.000000000000000

CUMULANTS

0.789295358375766D+00	0.294720350501715D-02	0.693990446587048D-04	0.144953875548429D-08
-0.144699217251423D-06	-0.268572649631255D-07	-0.443770799822572D-08	-0.779158930475969D-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	2029	INITIAL LOAD	583.0	392.4	4022.2	0.78973697	0.67310670	SUNDAY
		LOAD AFTER CONTRACTS	583.0	392.4	4022.2	0.78973697	0.67310670	

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	0.994069871358977	0.978092050379074
0.888542817670604	0.810704281901305	0.691215234002489	0.550284768889527	0.395451625436138
0.276873037319749	0.175705700625440	0.108450474544071	0.058151303769173	0.030611938774772
0.017411251422084	0.008193530080982	0.002617377664761	0.000682794173418	0.000000000000000

CUMULANTS

0.789736973518741D+00	0.293486280891133D-02	0.689636219938702D-04	0.143745680943470D-08
-0.143189167429403D-06	-0.265212747833929D-07	-0.437301517692868D-08	-0.766100069704406D-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	2030	INITIAL LOAD	589.3	397.0	4067.8	0.79015180	0.67375160	SUNDAY
		LOAD AFTER CONTRACTS	589.3	397.0	4067.8	0.79015180	0.67375160	

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	0.993741274795329	0.979469484162206
0.892238217405688	0.810430314903704	0.701516054870413	0.556629311610381	0.395317987688150
0.276779471667705	0.175646323162737	0.108413825112753	0.058131652290260	0.030601593867086
0.017405367515482	0.008190761183758	0.002616493155925	0.000682563431983	0.000000000000000

CUMULANTS

0.790151798978488D+00	0.292329386200238D-02	0.685562483954500D-04	0.142571376641922D-08
-0.141782396443178D-06	-0.262088939970049D-07	-0.431298555640075D-08	-0.753916740834876D-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	2031	INITIAL LOAD	595.7	401.7	4114.1	0.79055961	0.67438564	SUNDAY
		LOAD AFTER CONTRACTS	595.7	401.7	4114.1	0.79055961	0.67438564	

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	0.996509919598815	0.983741573551676
0.895425571083191	0.816332795658566	0.701730237757531	0.557592603548395	0.396416498730231
0.277548587456304	0.176134409795535	0.108715085838826	0.058293188734146	0.030686629685883
0.017453733613162	0.008213521700313	0.002623763876491	0.000684460141696	0.000000000000000

CUMULANTS

0.790559614191468D+00	0.291194322668741D-02	0.681573470644601D-04	0.141403168826752D-08
-0.140410199835748D-06	-0.259047905564877D-07	-0.425465243542871D-08	-0.742358967825604D-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	2032	INITIAL LOAD	602.1	406.5	4161.1	0.79109187	0.67521318	SUNDAY
		LOAD AFTER CONTRACTS	602.1	406.5	4161.1	0.79109187	0.67521318	

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	0.994819089965818	0.983880553108586
0.897276685016680	0.814939961667644	0.708361118479922	0.564963462967271	0.401206467992611
0.282313606061222	0.178680939052062	0.110579472160327	0.058193728397455	0.030634271896118
0.017423953903741	0.008199507719410	0.002619287188147	0.000683292309954	0.000000000000000

CUMULANTS

0.791091874582871D+00	0.289716115614368D-02	0.676390162388645D-04	0.140070424631337D-08
-0.138634962422068D-06	-0.255123071703439D-07	-0.417954055615208D-08	-0.727451027544882D-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	2033	INITIAL LOAD	608.5	411.5	4208.7	0.79172577	0.67619867	SUNDAY
		LOAD AFTER CONTRACTS	608.5	411.5	4208.7	0.79172577	0.67619867	

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	0.995161395597050	0.986067503890707
0.901562499856770	0.818059175065891	0.714437225474331	0.569336225189864	0.406694228517650
0.286394759241842	0.178740404634230	0.110616273358725	0.059694054830045	0.030758387030750
0.017429752650760	0.008202236541536	0.002620158895215	0.000683519711798	0.000000000000000

CUMULANTS

0.791725772504018D+00	0.287960616899643D-02	0.670251745172803D-04	0.138282338185429D-08
-0.136544453241662D-06	-0.250513248422566D-07	-0.409157901753976D-08	-0.709775600433006D-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	2034	INITIAL LOAD	615.1	416.4	4257.0	0.79221912	0.67696564	SUNDAY
		LOAD AFTER CONTRACTS	615.1	416.4	4257.0	0.79221912	0.67696564	

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	0.996294157956362	0.988470455837851
0.904221930465294	0.822404615381036	0.721618206246435	0.571119826383110	0.407153581598989
0.286718236453743	0.182135649807729	0.110741212250036	0.059761478083440	0.030793128020095
0.018133730945168	0.008211500805361	0.002623118312826	0.000684291733783	0.000000000000000

CUMULANTS

0.792219121011793D+00	0.286598023994309D-02	0.665500125369532D-04	0.137179061652222D-08
-0.134934628765019D-06	-0.246973885092551D-07	-0.402419866450578D-08	-0.696788044432188D-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	2035	INITIAL LOAD	621.6	421.5	4306.1	0.79297684	0.67814372	SUNDAY
		LOAD AFTER CONTRACTS	621.6	421.5	4306.1	0.79297684	0.67814372	

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	0.995856172758598	0.989699953254026
0.909030904439051	0.824425924688345	0.728580657864359	0.578180701613480	0.414948889085397
0.290122231517126	0.182053125238842	0.112628984180325	0.062584324205465	0.030779175838755
0.018125514660602	0.008663768013874	0.002621929793675	0.000683981685309	0.000000000000000

CUMULANTS

0.792976841326420D+00	0.284511489654458D-02	0.658245762150570D-04	0.135148276225774D-08
-0.132492172900285D-06	-0.241618881294308D-07	-0.392258962762126D-08	-0.676657617409250D-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	2036	INITIAL LOAD	628.3	426.7	4356.1	0.79363018	0.67915941	SUNDAY
		LOAD AFTER CONTRACTS	628.3	426.7	4356.1	0.79363018	0.67915941	

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	0.995448503932668	0.990452535661418
0.913225466226216	0.827257531425701	0.735487521899858	0.582243312071338	0.421611138351603
0.290000093812117	0.186420492525197	0.115316343786981	0.062557977014876	0.031563860898218
0.018117884053491	0.008660120679658	0.002620825995162	0.000683693737871	0.000000000000000

CUMULANTS

0.793630183810819D+00	0.282718643041954D-02	0.652033633603683D-04	0.133428592301458D-08
-0.130414779632654D-06	-0.237079830583842D-07	-0.383677290396938D-08	-0.659510370463721D-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	2037	INITIAL LOAD	635.0	432.0	4406.8	0.79439586	0.68034980	SUNDAY
		LOAD AFTER CONTRACTS	635.0	432.0	4406.8	0.79439586	0.68034980	

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	0.990244654484295
0.918787558648782	0.830378975220143	0.740679016263984	0.587897623459847	0.427448149786663
0.293273131522959	0.190280433025375	0.115169735778518	0.063730288573094	0.031523732026336
0.018663870224980	0.008649110592066	0.002617493994970	0.000682824520429	0.000000000000000

CUMULANTS

0.794395863400247D+00	0.280624576292911D-02	0.644802774247041D-04	0.131469015508061D-08
-0.128013299722027D-06	-0.231850717406465D-07	-0.373821834382907D-08	-0.640224480939515D-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	2038	INITIAL LOAD	641.8	437.5	4458.8	0.79525364	0.68168336	SUNDAY
		LOAD AFTER CONTRACTS	641.8	437.5	4458.8	0.79525364	0.68168336	

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	0.991896782960726
0.924874393688742	0.836931043784999	0.745043520993636	0.595718689832887	0.435441202091280
0.298568732187066	0.190391655307695	0.117514466673172	0.063767540055211	0.032111511242090
0.018674779587600	0.008654166150353	0.002619023966557	0.000683223643452	0.000000000000000

CUMULANTS

0.795253642010039D+00	0.278288090614160D-02	0.636766533008282D-04	0.129226751182911D-08
-0.125365303111996D-06	-0.226107627258956D-07	-0.363041545085033D-08	-0.619233595219756D-10

BASIC PLANT TYPES - 1

DATA SET REF. NO.	1	2	3	4	5
NAME	STORAGE1	RFP1	RFP2	RFP3	RFP4a
TYPE / LOADING / STATUS /AVD	STOR P G	NDT B G	THRM I G	NDT B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	PURC MDU NDAK	GAS MDU NDAK	WIND 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	20 20	50 50	20 20	25 25
RATED CAPACITY, MW	1.000	100.000	110.000	54.000	200.000
- RESERVE	0.9500	0.5000	0.9612	0.2080	0.2080
CAPACITY - OPERATING	1.0000	1.0000	0.8571	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	0.3810	0.3810
- CHARGING	1.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0500	0.0392	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	6800.	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	2600.00	0.00	1190.00	0.00	0.00
INSTALLATION COST 2, $/KW	2600.00	0.00	1190.00	0.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	10.16	9.83	8.07	9.83	9.83
FIXED O+M COST, $/KW-YR	60.00	0.00	23.73	0.00	0.00
VARIABLE O+M COST, $/MWH	0.00	35.50	4.10	24.64	15.23
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	1	1	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	30 22 0	0 0 51	30 22 68	0 0 52	0 0 52
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.	1	2	3	4	5
MAINTENANCE REQUIREMENTS	0	7	9	11	12
FUEL 1 / FUEL 2	0 0	0 0	14 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 0	0 6	6 0	0 4	0 4
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 20	0 0 21	0 0 21
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	2558.00	750.00	2400.00	2400.00
CONSTRUCTION COST 2, $/KW	0.00	2558.00	750.00	2400.00	2400.00
TRAJECTORY / EXPEND. PATTERN	0 0	30 38	30 37	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.	6	7	8	9	10
NAME	RFP4b	RFP4c	RFP4e	RFP5a	RFP5b
TYPE / LOADING / STATUS /AVD	NDT B G	NDT B G	STOR P G	NDT B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MDU NDAK	PURC MDU NDAK	STRG MDU NDAK	WIND MDU NDAK	PURC 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	25 25	25 25	20 20	20 20	20 20
RATED CAPACITY, MW	150.000	200.000	250.000	200.000	100.000
- RESERVE	0.5000	0.5000	0.9000	0.2080	0.5000
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	0.3810	1.0000
- CHARGING	0.0000	0.0000	1.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0500	0.0500	0.0010	0.0000	0.0500
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	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	200.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	95.00	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	1	2	1	1
LEVEL. CARRYING CHARGE, PCT	9.83	9.83	0.00	9.83	9.83
FIXED O+M COST, $/KW-YR	0.00	0.00	50.52	0.00	0.00
VARIABLE O+M COST, $/MWH	30.95	31.82	0.00	24.67	24.67
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	0	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 0 51	0 0 51	0 45 0	0 0 52	0 0 51
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.	6	7	8	9	10
MAINTENANCE REQUIREMENTS	16	20	0	26	27
FUEL 1 / FUEL 2	0 0	0 0	0 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 6	0 6	0 0	0 4	0 6
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 21	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	2558.00	2558.00	0.00	2400.00	2558.00
CONSTRUCTION COST 2, $/KW	2558.00	2558.00	0.00	2400.00	2558.00
TRAJECTORY / EXPEND. PATTERN	30 38	30 38	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.	11	12	13	14	15
NAME	RFP5c	RFP6	RFP7a	RFP7b	RFP7c
TYPE / LOADING / STATUS /AVD	STOR P G	NDT B G	NDT B G	STOR P G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	WIND MDU NDAK	PURC MDU NDAK	STRG MDU NDAK	PURC 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	20 20	20 20	20 20	20 20	20 20
RATED CAPACITY, MW	50.000	250.000	200.000	100.000	250.000
- RESERVE	0.9000	0.2080	0.5000	0.9000	0.5000
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	0.3810	1.0000	1.0000	1.0000
- CHARGING	1.0000	0.0000	0.0000	1.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0000	0.0500	0.0010	0.0500
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	0.	0.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	40.000000	0.000000	0.000000	80.000000	0.000000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	0.00	95.00	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	1	1	2	1
LEVEL. CARRYING CHARGE, PCT	0.00	9.83	9.83	0.00	9.83
FIXED O+M COST, $/KW-YR	111.12	0.00	0.00	86.40	0.00
VARIABLE O+M COST, $/MWH	0.00	14.25	35.75	0.00	30.75
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	0	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 53 0	0 0 52	0 0 51	0 53 0	0 0 51
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.	11	12	13	14	15
MAINTENANCE REQUIREMENTS	0	29	30	0	31
FUEL 1 / FUEL 2	0 0	0 0	0 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 0	0 4	0 6	0 0	0 6
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 21	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	2400.00	2558.00	0.00	2558.00
CONSTRUCTION COST 2, $/KW	0.00	2400.00	2558.00	0.00	2558.00
TRAJECTORY / EXPEND. PATTERN	0 0	30 38	30 38	0 0	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.	16	17	18	19	20
NAME	RFP7d	RFP8a	RFP8b	RFP9a	RFP9b
TYPE / LOADING / STATUS /AVD	STOR P G	NDT B G	STOR P G	NDT B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	PURC MDU NDAK	STRG MDU NDAK	WIND MDU NDAK	PURC 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	20 20	20 20	20 20	20 20	20 20
RATED CAPACITY, MW	125.000	50.000	25.000	300.000	150.000
- RESERVE	0.9000	0.5000	0.9000	0.2080	0.5000
CAPACITY - OPERATING	1.0000	1.0000	1.0000	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	0.3810	1.0000
- CHARGING	1.0000	0.0000	1.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0500	0.0010	0.0000	0.0500
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	0.	0.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	100.000000	0.000000	20.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	95.00	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	1	2	1	1
LEVEL. CARRYING CHARGE, PCT	0.00	9.83	0.00	9.83	9.83
FIXED O+M COST, $/KW-YR	85.20	0.00	0.00	0.00	0.00
VARIABLE O+M COST, $/MWH	0.00	29.00	0.00	18.50	35.95
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	0	1	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 53 0	0 0 55	0 0 0	0 0 52	0 0 57
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.	16	17	18	19	20
MAINTENANCE REQUIREMENTS	0	32	0	34	35
FUEL 1 / FUEL 2	0 0	0 0	0 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 0	0 6	0 0	0 4	0 6
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 21	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	2558.00	0.00	2400.00	2558.00
CONSTRUCTION COST 2, $/KW	0.00	2558.00	0.00	2400.00	2558.00
TRAJECTORY / EXPEND. PATTERN	0 0	30 38	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.	21	22	23	24	25
NAME	RFP9c	RFP10	GE 7EAHESKETT	STORAGE10	COMM ADD
TYPE / LOADING / STATUS /AVD	STOR P G	NDT B G	THRM P G	STOR P G	DTHR P G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	STRG MDU NDAK	WIND MDU NDAK	GAS MDU NDAK	STRG MDU NDAK	PURC MDU MISO
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	20 20	20 20	40 35	30 25	30 30
RATED CAPACITY, MW	35.000	200.000	78.300	10.000	5.000
- RESERVE	0.9000	0.2080	0.9480	0.9500	1.1000
CAPACITY - OPERATING	1.0000	1.0000	0.8371	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	0.3810	1.0000	1.0000	1.0000
- CHARGING	1.0000	0.0000	0.0000	1.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0010	0.0000	0.5000	0.0010	0.0000
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	11770.	0.	1.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	28.000000	0.000000	0.000000	8.000000	0.000000
STORAGE EFFICIENCY, PERCENT	95.00	0.00	0.00	95.00	0.00
INSTALLATION COST 1, $/KW	0.00	0.00	878.00	1760.00	0.00
INSTALLATION COST 2, $/KW	0.00	0.00	878.00	1760.00	0.00
MULTI-UNIT CAPITAL COST OPT.	2	1	1	2	2
LEVEL. CARRYING CHARGE, PCT	0.00	9.83	8.73	10.16	0.00
FIXED O+M COST, $/KW-YR	100.68	0.00	13.77	35.00	50.04
VARIABLE O+M COST, $/MWH	0.00	12.50	0.90	0.00	300.00
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	0	1	1	1	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 53 0	0 0 52	30 22 60	30 22 0	0 48 49
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	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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	21	22	23	24	25
MAINTENANCE REQUIREMENTS	0	36	37	0	38
FUEL 1 / FUEL 2	0 0	0 0	13 0	0 0	8 0
LOADING BLOCKS / NDT NO.	0 0	0 4	8 0	0 0	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 21	0 0 20	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	2400.00	857.00	0.00	0.00
CONSTRUCTION COST 2, $/KW	0.00	2400.00	857.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	0 0	30 38	30 37	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.	26	27	80	90	100
NAME	AC CYCLE	STORAGE PP	MISO - On peak	MISO - Off peak	INTERRUPTIBLES
TYPE / LOADING / STATUS /AVD	DTHR P G	STOR P G	HYDR P E	HYDR P E	DTHR P E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	PURC MDU MISO	STRG MDU NDAK	PURC MDU MISO	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	1/ 1/2012
OPERATING/BOOK LIVES, YEARS	30 30	30 25	50 50	50 50	30 30
RATED CAPACITY, MW	2.000	10.000	200.000	200.000	15.200
- RESERVE	1.1000	0.9500	0.0000	0.0000	0.9737
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	0.0000	1.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0000	0.0010	0.0000	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	1.	0.	10500.	10500.	1.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	8.000000	800.000000	800.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	95.00	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	363.71	108.00	0.00	0.00	50.04
VARIABLE O+M COST, $/MWH	100.00	0.00	24.92	20.43	300.00
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	0	1	0	0	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 48 49	0 22 0	0 0 29	0 0 46	0 48 49
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	26	0	0	0	16
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0

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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.	26	27	80	90	100
MAINTENANCE REQUIREMENTS	39	0	0	0	14
FUEL 1 / FUEL 2	8 0	0 0	8 0	8 0	8 0
LOADING BLOCKS / NDT NO.	0 0	0 0	7 0	7 0	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					
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

BASIC PLANT TYPES - 1

DATA SET REF. NO.	110	120	130	132	136
NAME	COMMERCIAL DSM	MILES CITY C.T.	GLENDIVE CT #1	GLENDIVE CT #2	DIESEL 2
TYPE / LOADING / STATUS /AVD LOAD COMPONENT FOR DSM	DTHR P E	THRM P E	THRM P E	THRM P E	THRM P E
CLASS / AREA / GENERATING CO.	PURC MDU MISO	GAS MDU MONT	GAS MDU MONT	GAS MDU MONT	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/ 1/2013	1/ 1/1972	1/ 1/1979	1/ 1/2003	1/ 1/2012
OPERATING/BOOK LIVES, YEARS	30 30	99 30	99 30	99 30	99 30
RATED CAPACITY, MW	25.000	25.200	35.500	43.300	2.100
- RESERVE	1.1000	0.8333	0.9127	0.8868	0.9048
CAPACITY - OPERATING	1.0000	0.8299	0.8061	0.8061	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	0.0000	0.5000	0.5000	0.5000	0.5000
FULL LOAD HEAT RATE, BTU/KWH	1.	14459.	12465.	9322.	8687.
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	2
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	50.04	42.09	5.85	8.23	19.89
VARIABLE O+M COST, $/MWH	300.00	2.50	2.50	2.50	2.50
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	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 48 49	0 3 5	0 3 6	0 3 7	0 3 8
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	4	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.	110	120	130	132	136
MAINTENANCE REQUIREMENTS	14	2	3	4	23
FUEL 1 / FUEL 2	8 0	1 0	1 0	1 0	2 0
LOADING BLOCKS / NDT NO.	0 0	12 0	5 0	13 0	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					
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

BASIC PLANT TYPES - 1

DATA SET REF. NO.	138	140	150	152	160
NAME	DIESEL 3	HESKETT #1	HESKETT #2	HESKETT #3	LEWIS & CLARK1
TYPE / LOADING / STATUS /AVD	THRM P E	THRM B E	THRM B E	THRM P E	THRM B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	COAL MDU NDAK	COAL MDU NDAK	GAS MDU NDAK	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/ 1/2012	1/ 1/1954	1/ 1/1963	1/ 1/2014	1/ 1/1958
OPERATING/BOOK LIVES, YEARS	99 30	68 30	59 30	40 25	64 30
RATED CAPACITY, MW	2.100	29.200	74.600	84.500	52.300
- RESERVE	0.9048	0.7021	0.8901	0.7716	0.7916
CAPACITY - OPERATING	1.0000	0.8059	0.9383	0.8371	0.8604
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	0.0790	0.0858	0.5000	0.0261
FULL LOAD HEAT RATE, BTU/KWH	8687.	18731.	12447.	11482.	12909.
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	1	2
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	0.00
FIXED O+M COST, $/KW-YR	19.89	99.00	58.01	34.19	90.90
VARIABLE O+M COST, $/MWH	2.50	15.73	7.29	2.50	7.22
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	1	0
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 8	0 3 9	0 3 10	0 3 15	0 3 11
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 27 0	0 64 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.	138	140	150	152	160
MAINTENANCE REQUIREMENTS	23	5	6	17	18
FUEL 1 / FUEL 2	2 0	3 0	4 0	9 0	5 0
LOADING BLOCKS / NDT NO.	0 0	14 0	15 0	2 0	16 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		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

BASIC PLANT TYPES - 1

DATA SET REF. NO.	162	170	180	190	200
NAME	LEWIS & CLARK2	BIG STONE	COYOTE	DIAMOND WILLOW	GLEN ULLIN ORMAT
TYPE / LOADING / STATUS /AVD	THRM P E	THRM B E	THRM B E	NDT B E	THRM B E
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	COAL MDU SDAK	COAL MDU NDAK	WIND MDU MONT	PURC MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE	1/ 1/2015	1/ 1/1975	1/ 1/1981	1/ 1/2008	1/ 1/2009
OPERATING/BOOK LIVES, YEARS	40 25	99 30	99 30	27 25	30 20
RATED CAPACITY, MW	18.600	107.800	106.800	30.000	7.500
- RESERVE	0.9462	0.9814	0.8511	0.2100	0.6400
CAPACITY - OPERATING	0.8371	0.9251	0.9368	1.0000	0.6667
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	0.3810	0.6667
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.5000	0.0639	0.0875	0.0000	0.1058
FULL LOAD HEAT RATE, BTU/KWH	8643.	10414.	11291.	0.	1.
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	29.17	25.81	28.15	18.05	55.94
VARIABLE O+M COST, $/MWH	2.50	2.31	3.86	-12.38	7.55
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	0 3 20	0 3 12	0 3 13	0 3 17	0 44 18
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 28 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	40	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.	162	170	180	190	200
MAINTENANCE REQUIREMENTS	19	8	22	10	15
FUEL 1 / FUEL 2	11 0	6 0	7 0	0 0	8 0
LOADING BLOCKS / NDT NO.	11 0	17 0	18 0	0 1	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		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

BASIC PLANT TYPES - 1

DATA SET REF. NO.	210	220	230	310	320
NAME	CEDAR HILLS	THUNDER SPIRIT	WAPA PUR-FT PECK	PURCHASE POWER	GE 7EA
TYPE / LOADING / STATUS /AVD	NDT B E	NDT B E	HYDR B E	THRM P G	THRM P G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	WIND MDU MONT	WIND MDU NDAK	HYDR MDU NDAK	PURC MDU MISO	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/ 1/2010	1/ 1/2015	1/ 1/2001		
OPERATING/BOOK LIVES, YEARS	25 25	23 25	50 30	1 1	40 35
RATED CAPACITY, MW	19.500	150.000	2.800	10.000	78.300
- RESERVE	0.2359	0.1953	0.0000	1.0000	0.9480
CAPACITY - OPERATING	1.0000	1.0000	0.8929	1.0000	0.8371
MULTIPLIERS - EMERGENCY	0.3810	0.4186	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	0.0000	0.0000	0.5000
FULL LOAD HEAT RATE, BTU/KWH	0.	0.	0.	1.	11770.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	14.350000	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	1590.00
INSTALLATION COST 2, $/KW	0.00	0.00	0.00	0.00	1590.00
MULTI-UNIT CAPITAL COST OPT.	2	2	2	2	1
LEVEL. CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00	9.22
FIXED O+M COST, $/KW-YR	19.93	21.82	0.00	36.00	19.41
VARIABLE O+M COST, $/MWH	-35.38	-35.38	24.00	1000.00	1.50
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	0	0	1
YEARLY TRAJECTORIES					
COSTS-CAPITAL/FIX OM/VAR OM	0 3 19	0 3 32	0 0 14	0 21 21	30 22 60
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.	210	220	230	310	320
MAINTENANCE REQUIREMENTS	10	13	0	0	28
FUEL 1 / FUEL 2	0 0	0 0	0 0	8 0	13 0
LOADING BLOCKS / NDT NO.	0 2	0 3	0 0	0 0	2 0
EMISSIONS / SITE / TAX DEPR.	0 0 0	0 0 0	0 0 0	0 0 0	0 0 20
MUST RUN / 1ST YR / LAST YR			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	857.00
CONSTRUCTION COST 2, $/KW	0.00	0.00	0.00	0.00	857.00
TRAJECTORY / EXPEND. PATTERN	0 0	0 0	0 0	0 0	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.	330	340	370	380	400
NAME	GE LMS100PB	GE LM6000PH	GE 7EA 2x1 ADD	GE 7FA.05 1x1	SMN SGT-800 2x1
TYPE / LOADING / STATUS /AVD	THRM P G	THRM P G	THRM I G	THRM I G	THRM I G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	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	40 35	40 35	50 50	50 50	50 50
RATED CAPACITY, MW	90.700	45.300	329.800	329.200	173.900
- RESERVE	0.9477	0.9887	0.9463	0.9463	0.9466
CAPACITY - OPERATING	0.8371	0.8371	0.8571	0.8571	0.8571
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	0.0537	0.0537	0.0537
FULL LOAD HEAT RATE, BTU/KWH	9050.	9510.	9990.	6530.	7180.
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	1760.00	2320.00	1070.00	1520.00	2180.00
INSTALLATION COST 2, $/KW	1760.00	2320.00	1070.00	1520.00	2180.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	9.22	9.22	8.70	8.70	8.70
FIXED O+M COST, $/KW-YR	16.22	32.08	20.03	16.42	37.59
VARIABLE O+M COST, $/MWH	1.70	1.60	4.10	3.00	4.00
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 24	30 22 62	59 59 59	30 22 54	30 22 69
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.	330	340	370	380	400
MAINTENANCE REQUIREMENTS	28	28	21	24	25
FUEL 1 / FUEL 2	13 0	13 0	13 0	13 0	13 0
LOADING BLOCKS / NDT NO.	13 0	13 0	4 0	2 0	3 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	857.00	850.00	750.00	750.00	750.00
CONSTRUCTION COST 2, $/KW	857.00	850.00	750.00	750.00	750.00
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.	410	420	430	450	460
NAME	WRTSLA 18V50SG	WRTSLA 20V34SG	BIOMASS	PV SOLAR	PV SOLAR + STRG
TYPE / LOADING / STATUS /AVD	THRM P G	THRM P G	THRM B G	NDT B G	NDT B G
LOAD COMPONENT FOR DSM					
CLASS / AREA / GENERATING CO.	GAS MDU NDAK	GAS MDU NDAK	BMP MDU NDAK	PURC MDU NDAK	PURC 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	40 25	40 25	40 25	30 25	30 25
RATED CAPACITY, MW	55.000	36.500	25.000	50.000	5.000
- RESERVE	0.9891	0.9901	0.9072	0.5000	0.5000
CAPACITY - OPERATING	0.8371	0.8371	0.8371	0.5000	0.5000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	1.0000	0.5000	0.5000
- CHARGING	0.0000	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.5000	0.5000	0.0928	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	8310.	8470.	12300.	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	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	2180.00	2710.00	7980.00	1800.00	2440.00
INSTALLATION COST 2, $/KW	2180.00	2710.00	7980.00	1800.00	2440.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	9.22	9.22	9.22	10.16	10.16
FIXED O+M COST, $/KW-YR	23.16	32.78	252.00	34.80	36.00
VARIABLE O+M COST, $/MWH	4.60	4.40	5.60	0.00	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 56	30 22 56	30 22 58	30 22 0	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.	410	420	430	450	460
MAINTENANCE REQUIREMENTS	1	28	28	10	10
FUEL 1 / FUEL 2	13 0	13 0	10 0	0 0	0 0
LOADING BLOCKS / NDT NO.	1 0	10 0	19 0	0 6	0 6
EMISSIONS / SITE / TAX DEPR.	0 0 20	0 0 20	0 0 20	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	857.00	857.00	857.00	2558.00	2558.00
CONSTRUCTION COST 2, $/KW	857.00	857.00	857.00	2558.00	2558.00
TRAJECTORY / EXPEND. PATTERN	30 37	30 37	30 37	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.	490	500	510	520
NAME	CFBC	CFBC CO2	WIND20	WIND50
TYPE / LOADING / STATUS /AVD	THRM B G	THRM B G	NDT B G	NDT B G
LOAD COMPONENT FOR DSM				
CLASS / AREA / GENERATING CO.	LIGN MDU NDAK	COAL MDU NDAK	WIND MDU NDAK	WIND MDU NDAK
OWNERSHIP PCT. / NO. UNITS	100.0 1	100.0 1	100.0 1	100.0 1
INSTALLATION DATE				
OPERATING/BOOK LIVES, YEARS	50 50	50 50	25 25	25 25
RATED CAPACITY, MW	30.000	30.000	20.000	50.000
- RESERVE	0.9072	0.9072	0.2080	0.2080
CAPACITY - OPERATING	0.9500	0.9500	1.0000	1.0000
MULTIPLIERS - EMERGENCY	1.0000	1.0000	0.3810	0.3810
- CHARGING	0.0000	0.0000	0.0000	0.0000
EQUIVALENT FORCED OUTAGE RATE	0.0928	0.0928	0.0000	0.0000
FULL LOAD HEAT RATE, BTU/KWH	10000.	13800.	0.	0.
HEAT RATE MULT. - 2ND FUEL	0.0000	0.0000	0.0000	0.0000
ANNUAL ENERGY LIMIT, GWH	0.000000	0.000000	0.000000	0.000000
STORAGE EFFICIENCY, PERCENT	0.00	0.00	0.00	0.00
INSTALLATION COST 1, $/KW	5880.00	10400.00	1780.00	1720.00
INSTALLATION COST 2, $/KW	5880.00	10400.00	1780.00	1720.00
MULTI-UNIT CAPITAL COST OPT.	1	1	1	1
LEVEL. CARRYING CHARGE, PCT	8.70	8.70	10.16	10.16
FIXED O+M COST, $/KW-YR	168.72	267.48	51.60	51.60
VARIABLE O+M COST, $/MWH	14.06	22.29	0.00	0.00
DEFAULT AFUDC, PCT. OF GBV	0.00	0.00	0.00	0.00
DEFAULT DEBT, PCT. OF AFUDC	0.00	0.00	0.00	0.00
CAPITAL STRUCTURE	1	1	1	1
YEARLY TRAJECTORIES				
COSTS-CAPITAL/FIX OM/VAR OM	30 22 61	30 22 25	30 22 0	30 22 0
F.O.R./RESERVE CAP/OPER CAP	0 0 0	0 0 0	0 0 0	0 0 0
ENERGY / HEAT RATE	0 0	0 0	0 0	0 0
RATED CAPACITY	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0 0	0 0	0 0	0 0
SUBWEEK ENERGY ALLOCATION	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.	490	500	510	520
MAINTENANCE REQUIREMENTS	33	33	10	10
FUEL 1 / FUEL 2	12 0	12 0	0 0	0 0
LOADING BLOCKS / NDT NO.	0 0	0 0	0 4	0 4
EMISSIONS / SITE / TAX DEPR.	0 0 20	0 0 20	0 0 21	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
TJ-DISP MODIF / SM-MUST-RUN	0 0	0 0	0 0	0 0
CONSTRUCTION COST 1, $/KW	3900.00	3900.00	2400.00	2400.00
CONSTRUCTION COST 2, $/KW	3900.00	3900.00	2400.00	2400.00
TRAJECTORY / EXPEND. PATTERN	30 31	30 31	30 38	30 38
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00	0.00
STARTING VALUE OF CWIP, $/KW	0.00	0.00	0.00	0.00
EQUITY AFUDC, $/KW	0.00	0.00	0.00	0.00
DEBT AFUDC, $/KW	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
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0
REBOUND BENEFITS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0
CUSTOMER BENEFITS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	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
BK LIFE/CAP STRUCT/TAX DEPR	0 0 0	0 0 0	0 0 0	0 0 0
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0	0
OTHER COSTS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00	0.00
EXPENDITURE PATTERN	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
MAXIMUM / TRAJ / SEG MULT	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
BID MULTIPLIERS	1.00	1.00	1.00	1.00
TRAJECTORY / SEG MULT	0 0	0 0	0 0	0 0
NDT REVENUES	0.00	0.00	0.00	0.00
TRAJECTORY	0	0	0	0

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	..FIRST PERIOD.. START WEEK	..SECOND PERIOD.. NO. OF WEEKS	..SECOND PERIOD.. 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	4	20		
					2	1	13		
					3	1	19		
					4	1	16		
					5	1	16		
					6	2	16		
					7	1	19		
					8	1	17		
					9	1	18		
					10	1	16		
3	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	5	22		
					2	1	18		
					3	1	18		
					4	2	16		
					5	1	16		
					6	1	19		
					7	1	17		
					8	1	16		
					9	1	17		
					10	1	18		
4	10	10	2 - BASE YEAR=1	1 - START WEEKS	1	1	20		
					2	11	32		
					3	1	20		
					4	1	20		
					5	2	16		
					6	1	20		
					7	1	20		
					8	1	20		
					9	1	20		
					10	1	20		
5	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	1	15	1	43
					2	1	22	1	41
					3	1	18	1	43
					4	1	16	1	41
					5	1	16	5	37
					6	1	16	1	40
					7	1	13	1	40
					8	1	13	1	37
					9	1	16	1	37
					10	1	15	1	40

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD.. NO. OF WEEKS	..FIRST PERIOD.. START WEEK	..SECOND PERIOD.. NO. OF WEEKS	..SECOND PERIOD.. START WEEK
6	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	2	14	2	41
					2	5	15	2	42
					3	2	14	2	40
					4	2	17	2	42
					5	1	17	2	42
					6	2	17	2	43
					7	2	20	2	42
					8	2	14	5	39
					9	2	17	3	37
					10	2	16	2	43
7	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
8	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	2	16	8	38
					2	2	17	2	40
					3	2	17	2	41
					4	2	17	12	38
					5	3	16	3	41
					6	1	19	1	42
					7	6	15	1	42
					8	6	39	1	50
					9	1	15	1	42
					10	1	39	1	42
9	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
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			
12	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			
16	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
17	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			

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
18	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	6	14	2	40
					2	2	20	2	40
					3	2	20	2	39
					4	2	20	2	39
					5	2	19	2	40
					6	2	20	2	40
					7	6	14	2	40
					8	2	18	2	39
					9	2	19	2	40
					10	2	19	2	40
19	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
20	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
21	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
22	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	1	22	1	39
					2	8	14	1	38
					3	1	23	1	38
					4	1	24	1	37
					5	7	15	1	37
					6	1	22	1	37
					7	1	22	1	37
					8	7	14	1	38
					9	1	23	1	38
					10	1	24	1	38
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			
26	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
27	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
28	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
29	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
30	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
31	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
32	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
33	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	3			

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
34	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
35	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
36	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
37	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
38	1	1	0 - INSTALLATION	0 - NO. WEEKS ONLY	1	1			
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	2.630000	0	0	33	0	0	0
2	OIL2	GAL	39.17	-1.00	0.00	23.320000	0	0	34	0	0	0
3	COAL	TON	14.27	-1.00	0.00	2.810000	0	0	35	0	0	0
4	COAL	TON	14.27	-1.00	0.00	2.830000	0	0	36	0	0	0
5	COAL	TON	13.22	-1.00	0.00	1.880000	0	0	37	0	0	0
6	COAL	TON	16.48	-1.00	0.00	1.910000	0	0	38	0	0	0
7	COAL	TON	13.68	-1.00	0.00	1.690000	0	0	39	0	0	0
8	PURC	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
9	GAS	DKT	1.14	-1.00	0.00	2.630000	0	0	23	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	2.630000	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	2.630000	0	0	50	0	0	0
14	GAS	DKT	1.14	-1.00	0.00	2.630000	0	0	42	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	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
2	WRTSLA 18V50SG	410	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
3	STORAGE1	1	0	2021	2038	0	0	12	1	0	0 - NO	0	-1	0
4	RFP1	2	0	2023	2023	0	0	0	0	0	0 - NO	0	-1	0
5	CFBC	490	0	2025	2038	0	0	0	0	0	0 - NO	0	-1	0
6	GE LM6000PH	340	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
7	PURCHASE POWER	310	0	2019	2038	1	0	0	0	0	0 - NO	0	-1	0
8	GE 7EA 2x1 ADD	370	0	2025	2038	0	152	0	0	0	0 - NO	0	-1	0
9	GE 7FA.05 1x1	380	0	2024	2038	0	0	0	0	0	0 - NO	0	-1	0
10	BIOMASS	430	0	2022	2038	0	0	0	0	0	0 - NO	0	-1	0
11	CFBC CO2	500	0	2025	2038	0	0	0	0	0	0 - NO	0	-1	0
12	PV SOLAR + STRG	460	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
13	RFP2	3	0	2025	2025	0	0	0	0	0	0 - NO	0	-1	0
14	GE LMS100PB	330	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
15	RFP3	4	0	2022	2022	0	0	0	0	0	0 - NO	0	-1	0
16	PV SOLAR	450	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
17	RFP4a	5	0	2021	2021	0	0	0	0	0	0 - NO	0	-1	0
18	RFP4b	6	0	2023	2023	0	0	0	0	0	0 - NO	0	-1	0
19	SMN SGT-800 2x1	400	0	2024	2038	0	0	0	0	0	0 - NO	0	-1	0
20	WIND20	510	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
21	RFP4c	7	0	2023	2023	0	0	0	0	0	0 - NO	0	-1	0
22	WIND50	520	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
23	WRTSLA 20V34SG	420	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0

CAPACITY PLANNING ALTERNATIVES

								------PREREQUISITE PLANNING ALTERNATIVE------						
DATA SET REF. NO.	NAME	BASIC PLANT INSTALLED	GENERIC SITE	-AVAILABLE- FIRST YEAR	LAST YEAR	TYPE	BASIC PLANT RETIRED	PLAN. ALT.	DEPENDENCY MULTIPLIER NO.	FLAG	RETIRE. OPTION	LAG YEAR MIN	MAX	REQUIRED OPTION
24	RFP4e	8	0	2025	2025	0	0	0	0	0	0 - NO	0	-1	0
25	RFP5a	9	0	2022	2022	0	0	0	0	0	0 - NO	0	-1	0
26	RFP5b	10	0	2022	2022	0	0	25	1	0	0 - NO	0	0	1
27	RFP5c	11	0	2022	2022	0	0	25	1	0	0 - NO	0	-1	0
							0	26	1	0	0 - NO	0	0	1
28	RFP6	12	0	2023	2023	0	0	0	0	0	0 - NO	0	-1	0
29	RFP7a	13	0	2024	2024	0	0	0	0	0	0 - NO	0	-1	0
30	RFP7b	14	0	2024	2024	0	0	29	1	0	0 - NO	0	0	1
31	RFP7c	15	0	2024	2024	0	0	0	0	0	0 - NO	0	-1	0
32	RFP7d	16	0	2024	2024	0	0	31	1	0	0 - NO	0	0	1
33	RFP8a	17	0	2022	2025	0	0	0	0	0	0 - NO	0	-1	0
34	RFP8b	18	0	2022	2025	0	0	33	1	0	0 - NO	0	0	1
35	RFP9a	19	0	2021	2021	0	0	0	0	0	0 - NO	0	-1	0
36	RFP9b	20	0	2024	2024	0	0	0	0	0	0 - NO	0	-1	0
37	RFP9c	21	0	2024	2024	0	0	36	1	0	0 - NO	0	0	1
38	RFP10	22	0	2021	2021	0	0	0	0	0	0 - NO	0	-1	0
39	GE 7EAHESKETT	23	0	2021	2038	0	0	0	0	0	0 - NO	0	-1	0
40	STORAGE10	24	0	2021	2038	0	0	16	1	0	0 - NO	0	-1	0
41	COMM ADD	25	0	2020	2038	0	0	0	0	0	0 - NO	0	-1	0
42	AC CYCLE	26	0	2020	2038	0	0	0	0	0	0 - NO	0	-1	0
43	STORAGE PP	27	0	2020	2038	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	2018	1.19	2019	1.18	2020	2.51	2021	2.32	2022	1.37
		2023	1.10	2024	1.07	2025	1.07	2026	1.10	2027	1.07
		2028	1.07	2029	1.08	2030	1.09	2031	1.07	2032	1.06
		2033	1.08	2034	1.06	2035	1.08	2036	1.07	2037	1.07
		2038	1.37								
2	1 - RATE	2018	0.88	2019	1.08	2020	3.38	2021	4.38	2022	2.27
		2023	1.11	2024	1.07	2025	1.12	2026	1.13	2027	1.13
		2028	1.13	2029	1.13	2030	1.14	2031	1.14	2032	1.14
		2033	1.15	2034	1.15	2035	1.16	2036	1.16	2037	1.18
		2038	1.56								
3	1 - RATE	2018	3.00								
4	1 - RATE	2018	0.00	2019	0.00	2020	0.00	2021	0.00		
5	1 - RATE	2018	3.00								
6	1 - RATE	2018	3.00								
7	1 - RATE	2018	3.00								
8	1 - RATE	2018	3.00								
9	1 - RATE	2018	3.00								
10	1 - RATE	2018	3.00								
11	1 - RATE	2018	3.00								
12	1 - RATE	2018	3.00								
13	1 - RATE	2018	3.00								
14	1 - RATE	2018	0.00								
15	1 - RATE	2018	3.00								
16	1 - RATE	2018	0.00	2019	6.49	2020	6.10	2021	0.00		
17	1 - RATE	2018	0.00	2019	-100.00	2020	-100.00				
18	1 - RATE	2018	1.46	2019	1.44	2020	1.54	2021	1.52	2022	1.50
		2023	1.50								
19	1 - RATE	2018	0.00	2019	-100.00	2020	-100.00				
20	1 - RATE	2018	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
21	1 - RATE	2018	3.00								
22	1 - RATE	2019	3.00								
23	1 - RATE	2018	15.59	2019	-5.92	2020	-12.23	2021	2.39	2022	3.89
		2023	6.74	2024	4.56	2025	3.00				
24	1 - RATE	2019	3.00								
25	1 - RATE	2019	3.00								
26	1 - RATE	2018	0.00	2019	0.00	2020	100.00	2021	50.00	2022	33.33
		2023	25.00	2024	0.00	2025	0.00				
27	1 - RATE	2018	0.00	2019	18.40	2020	3.89	2021	0.00	2022	0.00
28	1 - RATE	2018	0.00	2019	3.30	2020	5.86	2021	0.00	2022	0.00
29	1 - RATE	2018	-4.65	2019	3.00	2020	3.02	2021	3.00		
30	1 - RATE	2019	3.00								
31	1 - RATE	2018	3.00								
32	1 - RATE	2018	0.00	2019	0.00	2020	0.00	2021	0.00	2022	0.00
		2023	0.00	2024	0.00	2025	-100.00	2026	0.00		
33	1 - RATE	2018	52.85	2019	-7.21	2020	11.53	2021	0.96	2022	3.33
		2023	3.00								
34	1 - RATE	2018	-19.12	2019	0.00	2020	3.02	2021	2.98	2022	2.90
		2023	3.00								
35	1 - RATE	2018	-2.85	2019	2.56	2020	2.50	2021	8.01	2022	3.23
		2023	3.00								
36	1 - RATE	2018	-2.83	2019	2.91	2020	2.12	2021	7.96	2022	3.21
		2023	3.00								
37	1 - RATE	2018	1.60	2019	0.00	2020	1.57	2021	0.52	2022	2.56
		2023	3.00								
38	1 - RATE	2018	-8.90	2019	4.02	2020	7.18	2021	2.58	2022	3.02
		2023	3.00								
39	1 - RATE	2018	32.54	2019	-12.50	2020	6.63	2021	-9.57	2022	-12.69
		2023	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
40	1 - RATE	2018	0.00	2019	0.00	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	2037	0.00
		2038	0.00								
41	1 - RATE	2018	0.00	2019	0.00	2020	100.00	2021	50.00	2022	33.33
		2023	0.00	2024	0.00						
42	1 - RATE	2018	53.61	2019	-4.45	2020	-9.07	2021	1.71	2022	2.80
		2023	4.90	2024	3.38	2025	3.00				
43	1 - RATE	2019	3.00								
44	1 - RATE	2018	3.00								
45	1 - RATE	2018	0.00								
46	1 - RATE	2018	1.32	2019	3.00	2020	3.00				
47	1 - RATE	2018	4.56	2019	-6.18	2020	-13.95	2021	3.15	2022	4.37
		2023	7.53	2024	5.06	2025	3.00				
48	1 - RATE	2018	3.00								
49	1 - RATE	2018	0.00								
50	1 - RATE	2018	15.59	2019	-5.92	2020	-12.23	2021	2.39	2022	3.89
		2023	6.74	2024	4.56	2025	3.00				
51	1 - RATE	2018	0.00								
52	1 - RATE	2018	0.00								
53	1 - RATE	2018	0.00								
54	1 - RATE	2019	3.00								
55	1 - RATE	2018	2.50								
56	1 - RATE	2019	3.00								
57	1 - RATE	2018	0.00								
58	1 - RATE	2019	3.00								
59	1 - RATE	2019	3.00								
60	1 - RATE	2019	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
61	1 - RATE	2019	3.00								
62	1 - RATE	2019	3.00								
63	1 - RATE	2019	3.00								
64	1 - RATE	2018	0.00	2019	0.00	2020	0.00	2021	21.50	2022	0.00
		2023	0.00								
68	1 - RATE	2019	3.00								
69	1 - RATE	2019	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	0.094633	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
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	0.094675	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

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	0.315775	1.176301	1.000000
		2	0.157192	0.933316	0.000000
		3	0.148382	0.868758	0.000000
		4	0.222573	0.885191	0.000000
		5	0.156079	0.998962	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	0.421348	1.185989	1.000000
		2	0.131086	0.875451	0.000000
		3	0.121723	0.824857	0.000000
		4	0.196629	0.838405	0.000000
		5	0.129214	0.930764	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	2019	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
2019	50.00	0.00	50.00	10.00	0.00	2.73	25.00	1.18	8.03

TAX DEPRECIATION TABLE

DATA SET REF. NO.	TAX LIFE YEARS	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT	YEAR	DEPRECIATION PERCENT	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 INPUT DATA 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.
2019 Model
Base Case Run
-- Data updated for the 2019 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	2019	1	0		2/13/19	11:18: 5	2019 IRP	1300
EXPANSION PLAN	2019	1	0	1	2/13/19	11:18: 9	2019 IRP	1300
SUBPERIOD REPORT	2019	1	0	1	2/13/19	11:18: 9	2019 IRP	1300
UNIT REPORT	2019	1	0	1	2/13/19	11:18: 9	2019 IRP	1300
UNIT CAPITAL COST REPORT	2019	1	0	1	2/13/19	11:18: 9	2019 IRP	1300

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

 HEADER RECORD        PROGRAM   VERSION   DATE & TIME MODIFIED                                                           NUM
                      REPORT    13        02/13/19  11:17:58                                                               1


 RECORD DESCRIPTION   TYP  REF  SQ                         DATA FIELDS                                                   NUM
 -------------------- --- ----- -- ------------------------------------------------------------------------------------ ----
                                 1          2         3         4         5         6         7         8         9
            COLUMNS   123 45678 90 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
                      *            Montana-Dakota Utilities Co.                                                              2
                      *            2019 Model                                                                                3
                      *            Base Case Run                                                                             4
                      *              -- Data updated for the 2019 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       2019 IRP                                                     14
                      *                                                                                                     15
                      *            --INPUT FILES---                                                                         16
                      *            NAME     V U RUN                                                                         17
                      *            --------+-+--++++                                                                        18
 FILE IDENTIFICATION  FF           2019     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           2019 2038  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 1234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
```

```
 -----------------------------------------------------------------------------------------------------------------------
 EGEAS   REPORT                                             MIRROR IMAGE REPORT                                  PAGE      3
 ***********************************************************************************************************************

 RECORD DESCRIPTION   TYP  REF  SQ                          DATA FIELDS                                                  NUM
 -------------------- --- ----- -- -------------------------------------------------------------------------------- ----
                                 1          2         3         4         5         6         7         8         9
            COLUMNS   123 45678 90 12345678901234567890123456789012345678901234567890123456789012345678901234567890

                      *              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 12345678901234567890123456789012345678901234567890123456789012345678901234567890
```

```
****************************************************
****************************************************
**                                                **
**                                                **
**               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 = 2019         FIRST SEGMENT =  1        FIRST SUBWEEK =  1
        LAST  YEAR = 2038         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

YEAR	NEW UNITS ADDED 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2019	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2020	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2021	0	0.	0.	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0
2022	1	0.	0.	0.	1+	0	0.	0.	0.	0.	0	0	0.	0.	1+
2023	0	0.	1+	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+	1+	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	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2031	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2032	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2033	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2034	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2035	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2036	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2037	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+
2038	0	0	0+	0+	0+	0	0	0	0	0	0	0	0	0	0+

PLAN 1

YEAR	NEW UNITS ADDED 16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
2019	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2020	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	1+	0	0	0	0	0	0	0	0	0

TOTAL COST, M$
--W/O EXT 1422.023
--WITH EXT 2860.366

UNIT TYPES

1 PA	7 PURCHASE POWER	10.000 MW	2 PA	8 GE 7EA 2x1 ADD	329.800 MW	3 PA	4 RFP1	100.000 MW
4 PA	13 RFP2	110.000 MW	5 PA	15 RFP3	54.000 MW	6 PA	17 RFP4a	200.000 MW
7 PA	18 RFP4b	150.000 MW	8 PA	21 RFP4c	200.000 MW	9 PA	24 RFP4e	250.000 MW
10 PA	28 RFP6	250.000 MW	11 PA	33 RFP8a	50.000 MW	12 PA	34 RFP8b	25.000 MW
13 PA	36 RFP9b	150.000 MW	14 PA	37 RFP9c	35.000 MW	15 PA	39 GE 7EAHESKETT	78.300 MW
16 PA	1 GE 7EA	78.300 MW	17 PA	6 GE LM6000PH	45.300 MW	18 PA	14 GE LMS100PB	90.700 MW
19 PA	9 GE 7FA.05 1x1	329.200 MW	20 PA	16 PV SOLAR	50.000 MW	21 PA	12 PV SOLAR + STRG	5.000 MW
22 PA	10 BIOMASS	25.000 MW	23 PA	5 CFBC	30.000 MW	24 PA	11 CFBC CO2	30.000 MW
25 PA	3 STORAGE1	1.000 MW	26 PA	40 STORAGE10	10.000 MW	27 PA	20 WIND20	20.000 MW
28 PA	22 WIND50	50.000 MW	29 PA	2 WRTSLA 18V50SG	55.000 MW	30 PA	23 WRTSLA 20V34SG	36.500 MW

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2018.
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
2019	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2020	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2021	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00	0.00 .	0.00 .	0.00 .	0.00 .
2022	1.00	0.00 .	0.00 .	0.00 .	1.00 +	0.00	0.00 .	0.00 .	0.00 .	0.00 .
2023	0.00	0.00 .	1.00 +	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 +	1.00 +	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	0.00	0.00	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	0.00	0.00
2032	0.00	0.00	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	0.00	0.00
2034	0.00	0.00	0.00 +	0.00 +	0.00 +	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	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	0.00	0.00
2037	0.00	0.00	0.00 +	0.00 +	0.00 +	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00 +	0.00 +	0.00 +	0.00	0.00	0.00	0.00	0.00
TOTAL	1.00	0.00	1.00	1.00	1.00	0.00	0.00	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	4 RFP1	100.000 MW
4 PA	13 RFP2	110.000 MW	5 PA	15 RFP3	54.000 MW	6 PA	17 RFP4a	200.000 MW
7 PA	18 RFP4b	150.000 MW	8 PA	21 RFP4c	200.000 MW	9 PA	24 RFP4e	250.000 MW
10 PA	28 RFP6	250.000 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14	15	16	17	18	19	20
2019	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2020	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
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 .	1.00 +	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	0.00	0.00	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	0.00	0.00
2032	0.00	0.00	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	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	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	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00 +	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	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	1.00	0.00	0.00	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

11 PA	33 RFP8a	50.000 MW	12 PA	34 RFP8b	25.000 MW	13 PA	36 RFP9b	150.000 MW
14 PA	37 RFP9c	35.000 MW	15 PA	39 GE 7EAHESKETT	78.300 MW	16 PA	1 GE 7EA	78.300 MW
17 PA	6 GE LM6000PH	45.300 MW	18 PA	14 GE LMS100PB	90.700 MW	19 PA	9 GE 7FA.05 1x1	329.200 MW
20 PA	16 PV SOLAR	50.000 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	21	22	23	24	25	26	27	28	29	30
2019	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2020	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
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	0.00	0.00	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	0.00	0.00
2032	0.00	0.00	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	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	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	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	1.00 +	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	1.00	0.00	0.00	0.00	0.00	0.00	0.00	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

21 PA	12 PV SOLAR + STRG	5.000 MW	22 PA	10 BIOMASS	25.000 MW	23 PA	5 CFBC	30.000 MW
24 PA	11 CFBC CO2	30.000 MW	25 PA	3 STORAGE1	1.000 MW	26 PA	40 STORAGE10	10.000 MW
27 PA	20 WIND20	20.000 MW	28 PA	22 WIND50	50.000 MW	29 PA	2 WRTSLA 18V50SG	55.000 MW
30 PA	23 WRTSLA 20V34SG	36.500 MW						

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2022	10.000	0.000	0.000	0.000	54.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	100.000	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	110.000	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	0.000	0.000	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	0.000	0.000
2032	0.000	0.000	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	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	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	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	10.000	0.000	100.000	110.000	54.000	0.000	0.000	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	4 RFP1	100.000 MW	
4 PA	13 RFP2	110.000 MW	
5 PA	15 RFP3	54.000 MW	
6 PA	17 RFP4a	200.000 MW	
7 PA	18 RFP4b	150.000 MW	
8 PA	21 RFP4c	200.000 MW	
9 PA	24 RFP4e	250.000 MW	
10 PA	28 RFP6	250.000 MW	

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14	15	16	17	18	19	20
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
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	78.300	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	0.000	0.000	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	0.000	0.000
2032	0.000	0.000	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	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	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	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	0.000	0.000	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	78.300	0.000	0.000	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

11 PA	33 RFP8a	50.000 MW	12 PA	34 RFP8b	25.000 MW	13 PA	36 RFP9b	150.000 MW
14 PA	37 RFP9c	35.000 MW	15 PA	39 GE 7EAHESKETT	78.300 MW	16 PA	1 GE 7EA	78.300 MW
17 PA	6 GE LM6000PH	45.300 MW	18 PA	14 GE LMS100PB	90.700 MW	19 PA	9 GE 7FA.05 1x1	329.200 MW
20 PA	16 PV SOLAR	50.000 MW						

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	21	22	23	24	25	26	27	28	29	30
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
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	0.000	0.000	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	0.000	0.000
2032	0.000	0.000	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	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2035	0.000	0.000	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	0.000	0.000
2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2038	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

UNIT TYPES

21 PA	12 PV SOLAR + STRG	5.000 MW	22 PA	10 BIOMASS	25.000 MW	23 PA	5 CFBC	30.000 MW
24 PA	11 CFBC CO2	30.000 MW	25 PA	3 STORAGE1	1.000 MW	26 PA	40 STORAGE10	10.000 MW
27 PA	20 WIND20	20.000 MW	28 PA	22 WIND50	50.000 MW	29 PA	2 WRTSLA 18V50SG	55.000 MW
30 PA	23 WRTSLA 20V34SG	36.500 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	498.7	3321.55				1232.0	590.7	20.16	1.0000		
2019	508.1	3373.50	0.0	0.0	0.0	1232.0	590.7	17.73	99.9999	0.000	0.000
2020	514.1	3409.90	0.0	0.0	1.0	1233.0	606.6	19.66	99.9999	0.000	0.000
2021	527.0	3525.29	0.0	0.0	1.0	1234.0	616.1	18.46	99.9999	0.000	0.000
2022	539.2	3679.69	142.3	156.1	0.0	1220.2	583.3	8.90	99.9999	75.122	0.000
2023	546.6	3763.39	100.0	10.0	0.0	1310.2	623.3	15.26	99.9999	0.000	0.000
2024	552.6	3805.19	0.0	0.0	0.0	1310.2	623.3	13.90	99.9999	0.000	0.000
2025	558.5	3845.99	110.0	0.0	0.0	1420.2	729.0	33.15	99.9999	156.301	0.000
2026	564.5	3889.09	0.0	0.0	0.0	1420.2	729.0	31.62	99.9999	0.000	0.000
2027	570.7	3932.88	0.0	0.0	0.0	1420.2	729.0	30.07	99.9999	0.000	0.000
2028	576.8	3977.18	0.0	0.0	0.0	1420.2	729.0	28.58	99.9999	0.000	0.000
2029	583.0	4022.18	0.0	0.0	0.0	1420.2	729.0	27.10	99.9999	0.000	0.000
2030	589.3	4067.78	0.0	0.0	0.0	1420.2	729.0	25.63	99.9999	0.000	0.000
2031	595.7	4114.08	0.0	0.0	0.0	1420.2	729.0	24.17	1.7952	0.000	0.000
2032	602.1	4161.08	0.0	0.0	0.0	1420.2	729.0	22.75	5.7625	0.000	0.000
2033	608.5	4208.67	0.0	0.0	0.0	1420.2	729.0	21.36	1.5572	0.000	0.000
2034	615.1	4256.97	0.0	0.0	-19.5	1400.7	724.9	19.24	3.4183	0.000	0.000
2035	621.6	4306.07	0.0	30.0	0.0	1370.7	718.1	16.71	1.5672	0.000	0.000
2036	628.3	4356.07	0.0	0.0	0.0	1370.7	718.1	15.38	2.1163	0.000	0.000
2037	635.0	4406.76	0.0	0.0	0.0	1370.7	718.1	14.07	1.5942	0.000	0.000
2038	641.8	4458.76	5.0	150.0	0.0	1225.7	691.3	8.29	0.1664	21.393	0.000

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	COST SUMMARY: ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2019	73.861	0.000	73.861	73.861	69.779	69.779
2020	79.875	0.000	79.875	153.736	71.290	141.069
2021	86.888	0.000	86.888	240.624	73.263	214.333
2022	71.426	6.557	77.983	318.607	62.121	276.454
2023	74.508	6.557	81.065	399.673	61.007	337.461
2024	78.405	6.557	84.962	484.635	60.406	397.866
2025	85.578	19.171	104.749	589.384	70.358	468.225
2026	109.870	19.171	129.041	718.425	81.884	550.109
2027	114.136	19.171	133.307	851.732	79.916	630.025
2028	118.964	19.171	138.135	989.867	78.234	708.259
2029	124.228	19.171	143.399	1133.266	76.727	784.986
2030	128.171	19.171	147.342	1280.608	74.479	859.465
2031	134.880	19.171	154.051	1434.659	73.567	933.032
2032	140.059	19.171	159.230	1593.889	71.838	1004.870
2033	143.960	19.171	163.131	1757.021	69.530	1074.400
2034	153.141	19.171	172.312	1929.333	69.384	1143.785
2035	164.446	19.171	183.617	2112.950	69.850	1213.635
2036	168.820	19.171	187.991	2300.941	67.562	1281.197
2037	175.997	19.171	195.168	2496.108	66.264	1347.461
2038	211.107	21.346	232.453	2728.561	74.562	1422.023
EXT.	1339.114	99.229			1438.343	2860.366

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 2018.
- CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES. SEE RESERVE REPORT FOR DETAILS.

PLAN 1

	......TOTAL SYSTEM.....		..SERVICE AREA - MDU ..	
YEAR	ENERGY, GWH	COST, M$	ENERGY, GWH	COST, M$
2019	3373.50	73.861	3373.50	73.861
2020	3409.90	79.875	3409.90	79.875
2021	3525.29	86.888	3525.29	86.888
2022	3679.64	71.418	3679.64	71.418
2023	3763.42	74.494	3763.42	74.494
2024	3805.19	78.388	3805.19	78.388
2025	3846.00	85.572	3846.00	85.572
2026	3889.11	109.861	3889.11	109.861
2027	3932.91	114.128	3932.91	114.128
2028	3977.18	118.961	3977.18	118.961
2029	4022.18	124.222	4022.18	124.222
2030	4067.78	128.167	4067.78	128.167
2031	4113.82	134.832	4113.82	134.832
2032	4160.96	140.037	4160.96	140.037
2033	4208.66	143.958	4208.66	143.958
2034	4256.83	153.112	4256.83	153.112
2035	4305.41	164.304	4305.41	164.304
2036	4355.77	168.755	4355.77	168.755
2037	4406.16	175.860	4406.16	175.860
2038	4453.92	209.970	4453.92	209.970
EXT.	4453.92	1331.744	4453.92	1331.744

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2018.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1

YEAR	......TOTAL SYSTEM..... ENERGY, GWH	COST, M$	..FUEL CLASS - STRG.. ENERGY, GWH	COST, M$	..FUEL CLASS - PURC.. ENERGY, GWH	COST, M$	..FUEL CLASS - GAS .. ENERGY, GWH	COST, M$
2019	3373.50	73.861	0.00	0.000	1225.55	28.559	0.28	5.305
2020	3409.90	79.875	0.00	0.000	1017.32	24.367	0.24	5.462
2021	3525.29	86.888	0.00	0.000	1170.11	29.003	67.11	7.098
2022	3679.64	71.418	0.00	0.000	1296.24	33.664	69.76	8.620
2023	3763.42	74.494	0.00	0.000	1259.80	34.591	45.87	8.285
2024	3805.19	78.388	0.00	0.000	1354.51	38.085	46.60	8.617
2025	3846.00	85.572	0.00	0.000	1466.73	42.191	55.93	12.262
2026	3889.11	109.861	0.00	0.000	1354.77	40.006	50.60	12.469
2027	3932.91	114.128	0.00	0.000	1394.35	42.223	52.51	12.905
2028	3977.18	118.961	0.00	0.000	1544.02	47.958	60.38	13.558
2029	4022.18	124.222	0.00	0.000	1584.84	50.535	77.21	14.935
2030	4067.78	128.167	0.00	0.000	1541.83	50.448	59.90	14.363
2031	4113.82	134.832	0.00	0.000	1670.12	56.297	127.30	18.001
2032	4160.96	140.037	0.00	0.000	1694.10	58.563	116.54	18.119
2033	4208.66	143.958	0.00	0.000	1641.76	58.178	65.46	15.927
2034	4256.83	153.112	0.00	0.000	1758.11	64.151	127.93	20.106
2035	4305.41	164.304	0.00	0.000	1801.05	67.845	311.28	29.533
2036	4355.77	168.755	0.00	0.000	1800.20	69.437	193.17	24.703
2037	4406.16	175.860	0.00	0.000	1800.82	71.519	242.54	27.639
2038	4453.92	209.970	0.00	0.000	1813.33	76.272	987.46	65.381
EXT.	4453.92	1331.744	0.00	0.000	1813.80	477.305	986.99	422.854

YEAR	..FUEL CLASS - WIND.. ENERGY, GWH	COST, M$	..FUEL CLASS - COAL.. ENERGY, GWH	COST, M$	..FUEL CLASS - HYDR.. ENERGY, GWH	COST, M$	..FUEL CLASS - BMP .. ENERGY, GWH	COST, M$
2019	736.70	-19.624	1396.62	59.277	14.35	0.344	0.00	0.000
2020	736.70	-16.297	1641.29	65.998	14.35	0.344	0.00	0.000
2021	736.70	-16.163	1537.03	66.605	14.35	0.344	0.00	0.000
2022	949.89	-10.772	1349.40	39.561	14.35	0.344	0.00	0.000
2023	949.89	-10.630	1493.50	41.904	14.35	0.344	0.00	0.000
2024	949.89	-10.484	1439.84	41.826	14.35	0.344	0.00	0.000
2025	949.89	-10.333	1359.10	41.108	14.35	0.344	0.00	0.000
2026	949.89	10.577	1519.51	46.464	14.35	0.344	0.00	0.000
2027	949.89	10.737	1521.80	47.919	14.35	0.344	0.00	0.000
2028	949.89	10.902	1408.54	46.198	14.35	0.344	0.00	0.000
2029	949.89	11.071	1395.89	47.337	14.35	0.344	0.00	0.000
2030	949.89	11.246	1501.81	51.766	14.35	0.344	0.00	0.000
2031	949.89	11.425	1352.17	48.764	14.35	0.344	0.00	0.000
2032	949.89	11.611	1386.09	51.400	14.35	0.344	0.00	0.000
2033	949.89	11.801	1537.20	57.708	14.35	0.344	0.00	0.000
2034	890.23	11.433	1466.21	57.077	14.35	0.344	0.00	0.000
2035	799.84	10.663	1378.90	55.919	14.35	0.344	0.00	0.000
2036	799.84	10.825	1548.20	63.446	14.35	0.344	0.00	0.000
2037	799.84	10.992	1548.61	65.364	14.35	0.344	0.00	0.000
2038	213.19	5.253	1425.59	62.720	14.35	0.344	0.00	0.000
EXT.	213.19	23.570	1425.59	406.469	14.35	1.545	0.00	0.000

PLAN 1

YEAR	..FUEL CLASS - LIGN.. ENERGY, GWH	COST, M$
2019	0.00	0.000
2020	0.00	0.000
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
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 2018.
- COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1 YEAR 2019 * 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.	-1136.	558.	-579.	-6.30
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	-2061.	400.	-1661.	-28.51
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3371.	-17385.	-29.63
BIG STONE		MUST	107.800	10415.	1.740	79.73	750.88	13607.	1787.	2866.	18259.	24.32
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.	293.	432.	726.	18.94
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	16560.	0.	16560.	20.70
HESKETT #2		MUST	74.600	13260.	2.750	30.01	195.59	7132.	1469.	4457.	13058.	66.76
COYOTE		MUST	106.800	13384.	2.240	29.84	278.44	8347.	1107.	3097.	12551.	45.08
LEWIS & CLARK1		MUST	52.300	14235.	1.910	28.41	129.78	3529.	965.	4897.	9390.	72.36
MISO - On peak		HYDR	200.000	10500.	0.000	22.16	387.23	0.	9201.	0.	9201.	23.76
HESKETT #1		MUST	29.200	20630.	2.730	16.44	41.93	2361.	679.	2978.	6018.	143.53
LEWIS & CLARK2			18.600	8822.	2.750	0.10	0.16	4.	0.	559.	563.	3583.77
HESKETT #3			84.500	16430.	3.040	0.01	0.09	5.	0.	2976.	2981.	32116.50
GLENDIVE CT #2			43.300	10621.	4.020	0.01	0.02	1.	0.	367.	368.	16716.26
GLENDIVE CT #1			35.500	13822.	4.020	0.00	0.01	0.	0.	214.	214.	38636.57
INTERRUPTIBLES	D		15.200	1.	0.000	0.00	0.00	0.	1.	783.	784.	390584.97
MILES CITY C.T.			25.200	16214.	4.020	0.00	0.00	0.	0.	1092.	1093.	334411.31
DIESEL 2			2.100	8687.	18.861	0.00	0.00	0.	0.	43.	43.	198713.75
DIESEL 3			2.100	8687.	18.861	0.00	0.00	0.	0.	43.	43.	209230.77
COMMERCIAL DSM	D		25.000	1.	0.000	0.00	0.00	0.	0.	1289.	1289.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

PLAN 1 YEAR 2020 * 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.	574.	574.	6.26
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	412.	412.	7.08
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3472.	-17283.	-29.46
BIG STONE		MUST	107.800	10414.	1.810	79.74	750.92	14155.	1840.	2952.	18947.	25.23
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.	298.	445.	743.	19.39
COYOTE		MUST	106.800	11989.	1.960	54.67	510.07	11986.	2089.	3190.	17264.	33.85
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	17057.	0.	17057.	21.32
HESKETT #2		MUST	74.600	13260.	2.830	32.01	208.62	7828.	1613.	4591.	14033.	67.27
LEWIS & CLARK1		MUST	52.300	14235.	1.910	28.40	129.76	3528.	994.	5044.	9566.	73.72
HESKETT #1		MUST	29.200	20630.	2.800	16.44	41.92	2422.	700.	3067.	6188.	147.60
MISO - On peak		HYDR	200.000	10500.	0.000	10.25	179.01	0.	4381.	0.	4381.	24.47
LEWIS & CLARK2			18.600	8825.	2.580	0.08	0.14	3.	0.	576.	579.	4275.64
HESKETT #3			84.500	17259.	2.860	0.01	0.07	4.	0.	3065.	3069.	42675.23
GLENDIVE CT #2			43.300	10436.	3.730	0.01	0.03	1.	0.	378.	379.	13211.35
GLENDIVE CT #1			35.500	14401.	3.730	0.00	0.00	0.	0.	220.	220.	87815.20
INTERRUPTIBLES		D	16.187	1.	0.000	0.00	0.00	0.	0.	859.	860.	*********
MILES CITY C.T.			25.200	16181.	3.730	0.00	0.00	0.	0.	1125.	1125.	877866.12
DIESEL 2			2.100	8687.	18.861	0.00	0.00	0.	0.	44.	44.	508269.78
DIESEL 3			2.100	8687.	18.861	0.00	0.00	0.	0.	44.	44.	535925.00
COMMERCIAL DSM		D	25.000	1.	0.000	0.00	0.00	0.	0.	1327.	1327.	*********

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	592.	592.	6.45
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	425.	425.	7.29
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3576.	-17179.	-29.28
COYOTE		MUST	106.800	11706.	2.090	61.82	576.75	14110.	2433.	3285.	19828.	34.38
BIG STONE		MUST	107.800	10414.	1.940	61.53	579.45	11707.	1463.	3040.	16210.	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.	302.	458.	761.	19.86
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	17568.	0.	17568.	21.96
LEWIS & CLARK2			18.600	8644.	2.220	41.00	66.63	1279.	182.	593.	2054.	30.82
HESKETT #2		MUST	74.600	13259.	2.890	32.03	208.74	7999.	1663.	4729.	14390.	68.94
LEWIS & CLARK1		MUST	52.300	14229.	1.940	28.49	130.16	3593.	1027.	5195.	9815.	75.41
MISO - On peak		HYDR	200.000	10500.	0.000	18.99	331.79	0.	8365.	0.	8365.	25.21
HESKETT #1		MUST	29.200	20627.	2.870	16.44	41.94	2483.	721.	3159.	6363.	151.70
HESKETT #3			84.500	15231.	2.510	0.05	0.38	14.	1.	3157.	3172.	8410.23
GLENDIVE CT #2			43.300	10495.	4.160	0.02	0.08	3.	0.	389.	393.	5220.75
GLENDIVE CT #1			35.500	13617.	4.160	0.01	0.02	1.	0.	227.	228.	14684.52
INTERRUPTIBLES		D	17.174	1.	0.000	0.00	0.01	0.	2.	939.	941.	145844.92
MILES CITY C.T.			25.200	16042.	4.160	0.00	0.01	1.	0.	1159.	1160.	133031.83
DIESEL 2			2.100	8687.	19.431	0.00	0.00	0.	0.	46.	46.	75278.87
DIESEL 3			2.100	8687.	19.431	0.00	0.00	0.	0.	46.	46.	79029.93
COMMERCIAL DSM		D	25.000	1.	0.000	0.00	0.00	0.	1.	1367.	1368.	588851.00

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	609.	609.	6.64
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	437.	437.	7.51
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3684.	-17072.	-29.10
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10414.	1.990	74.22	698.96	14486.	1817.	3132.	19434.	27.80
COYOTE		MUST	106.800	11321.	1.890	69.71	650.44	13917.	2826.	3384.	20127.	30.94
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.	472.	779.	20.34
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	18095.	0.	18095.	22.62
LEWIS & CLARK2			18.600	8646.	2.290	40.61	65.98	1306.	186.	611.	2103.	31.87
MISO - On peak		HYDR	200.000	10500.	0.000	26.19	457.59	0.	11883.	0.	11883.	25.97
GE 7EAHESKETT	2022		78.300	14611.	2.570	0.27	1.85	69.	2.	1178.	1249.	677.02
HESKETT #3			84.500	14739.	2.570	0.15	1.08	41.	3.	3252.	3296.	3057.80
INTERRUPTIBLES		D	17.174	1.	0.000	0.12	0.18	0.	55.	967.	1022.	5596.68
GLENDIVE CT #2			43.300	10243.	4.200	0.11	0.42	18.	1.	401.	420.	1008.10
GLENDIVE CT #1			35.500	13307.	4.200	0.08	0.26	14.	1.	234.	249.	964.74
DIESEL 2			2.100	8687.	20.011	0.08	0.01	3.	0.	47.	50.	3346.61
DIESEL 3			2.100	8687.	20.011	0.08	0.01	2.	0.	47.	50.	3456.85
MILES CITY C.T.			25.200	15767.	4.200	0.07	0.15	10.	0.	1194.	1204.	7884.30
COMMERCIAL DSM		D	25.000	1.	0.000	0.06	0.13	0.	40.	1408.	1448.	10908.11
PURCHASE POWER	2022		10.000	1.	0.000	0.03	0.03	0.	31.	405.	437.	15649.16

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	628.	628.	6.84
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	451.	451.	7.73
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3794.	-16961.	-28.91
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11294.	1.650	81.88	763.98	14238.	3419.	3485.	21142.	27.67
COYOTE		DUMP					-0.01				3.	
BIG STONE		MUST	107.800	10419.	2.050	77.46	729.52	15582.	1954.	3225.	20761.	28.46
BIG STONE		DUMP					-0.03				8.	
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.	486.	798.	20.83
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	18638.	0.	18638.	23.30
LEWIS & CLARK2			18.600	8676.	2.390	27.44	44.59	925.	129.	629.	1683.	37.74
MISO - On peak		HYDR	200.000	10500.	0.000	14.90	260.30	0.	6963.	0.	6963.	26.75
GE 7EAHESKETT	2022		78.300	14963.	2.670	0.10	0.65	26.	1.	1214.	1240.	1906.92
HESKETT #3			84.500	15142.	2.670	0.05	0.35	14.	1.	3349.	3365.	9490.98
GLENDIVE CT #2			43.300	10353.	4.340	0.04	0.14	6.	0.	413.	420.	2974.16
INTERRUPTIBLES		D	17.174	1.	0.000	0.04	0.05	0.	16.	996.	1012.	18934.74
GLENDIVE CT #1			35.500	13403.	4.340	0.03	0.08	5.	0.	241.	246.	3009.29
DIESEL 2			2.100	8687.	20.591	0.02	0.00	1.	0.	48.	49.	11138.78
DIESEL 3			2.100	8687.	20.591	0.02	0.00	1.	0.	48.	49.	11629.51
MILES CITY C.T.			25.200	15844.	4.340	0.02	0.05	3.	0.	1230.	1233.	26330.00
COMMERCIAL DSM		D	25.000	1.	0.000	0.02	0.04	0.	11.	1450.	1461.	40400.70

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	647.	647.	7.04
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	464.	464.	7.97
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	3908.	-16848.	-28.72
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11293.	1.700	82.01	765.12	14686.	3526.	3590.	21802.	28.49
BIG STONE		MUST	107.800	10417.	2.112	71.65	674.72	14840.	1861.	3322.	20024.	29.68
BIG STONE		DUMP					-0.03				8.	
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.	501.	817.	21.33
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	19197.	0.	19197.	24.00
LEWIS & CLARK2			18.600	8677.	2.570	27.27	44.32	988.	132.	648.	1768.	39.90
MISO - On peak		HYDR	200.000	10500.	0.000	20.31	354.92	0.	9778.	0.	9778.	27.55
GE 7EAHESKETT	2022		78.300	14737.	2.850	0.16	1.12	47.	1.	1250.	1298.	1156.81
HESKETT #3			84.500	14908.	2.850	0.09	0.64	27.	2.	3450.	3479.	5421.65
INTERRUPTIBLES		D	17.174	1.	0.000	0.07	0.10	0.	31.	1026.	1057.	10240.38
GLENDIVE CT #2			43.300	10303.	4.470	0.07	0.26	12.	1.	426.	438.	1695.30
GLENDIVE CT #1			35.500	13352.	4.470	0.05	0.15	9.	0.	248.	257.	1695.91
DIESEL 2			2.100	8687.	21.209	0.05	0.01	2.	0.	50.	51.	6119.75
DIESEL 3			2.100	8687.	21.209	0.04	0.01	2.	0.	50.	51.	6238.09
MILES CITY C.T.			25.200	15808.	4.470	0.04	0.09	6.	0.	1266.	1273.	14302.02
COMMERCIAL DSM		D	25.000	1.	0.000	0.03	0.07	0.	22.	1494.	1515.	20964.25

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	666.	666.	7.26
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	478.	478.	8.20
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	-20756.	4025.	-16730.	-28.52
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10415.	2.175	72.73	684.97	15516.	1946.	3422.	20884.	30.49
BIG STONE		DUMP					-0.02				6.	
COYOTE		MUST	106.800	11292.	1.751	72.25	674.14	13326.	3200.	3698.	20224.	30.00
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.	321.	516.	837.	21.84
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	19773.	0.	19773.	24.72
LEWIS & CLARK2			18.600	8669.	2.700	32.03	52.04	1218.	160.	667.	2045.	39.31
MISO - On peak		HYDR	200.000	10500.	0.000	26.75	467.30	0.	13261.	0.	13261.	28.38
RFP2	2025		110.000	8779.	3.980	0.38	3.61	126.	18.	3117.	3261.	903.15
GE 7EAHESKETT	2022		78.300	15561.	2.980	0.02	0.14	7.	0.	1287.	1294.	9029.12
HESKETT #3			84.500	15780.	2.980	0.01	0.08	4.	0.	3553.	3557.	46501.81
GLENDIVE CT #2			43.300	10491.	4.604	0.01	0.03	2.	0.	438.	440.	13914.99
INTERRUPTIBLES		D	17.174	1.	0.000	0.01	0.01	0.	3.	1057.	1060.	97648.94
GLENDIVE CT #1			35.500	13527.	4.604	0.01	0.02	1.	0.	255.	257.	14420.36
DIESEL 2			2.100	8687.	21.845	0.00	0.00	0.	0.	51.	52.	56635.91
DIESEL 3			2.100	8687.	21.845	0.00	0.00	0.	0.	51.	52.	58268.58
MILES CITY C.T.			25.200	15951.	4.604	0.00	0.01	1.	0.	1304.	1305.	128646.27
COMMERCIAL DSM		D	25.000	1.	0.000	0.00	0.01	0.	2.	1539.	1541.	230586.30

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	686.	686.	7.47
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	492.	492.	8.45
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4146.	4146.	7.07
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11293.	1.803	82.03	765.35	15584.	3742.	3808.	23135.	30.23
BIG STONE		MUST	107.800	10416.	2.240	80.08	754.16	17597.	2207.	3525.	23329.	30.93
BIG STONE		DUMP					-0.03				9.	
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.	326.	531.	857.	22.37
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	20367.	0.	20367.	25.46
LEWIS & CLARK2			18.600	8675.	2.781	29.40	47.77	1152.	151.	687.	1991.	41.68
MISO - On peak		HYDR	200.000	10500.	0.000	20.34	355.34	0.	10386.	0.	10386.	29.23
RFP2	2025		110.000	8699.	4.099	0.27	2.61	93.	13.	3210.	3317.	1268.54
GE 7EAHESKETT	2022		78.300	15660.	3.070	0.02	0.11	5.	0.	1326.	1331.	12426.46
HESKETT #3			84.500	15880.	3.070	0.01	0.06	3.	0.	3660.	3663.	64208.86
GLENDIVE CT #2			43.300	10510.	4.742	0.01	0.02	1.	0.	451.	453.	18970.98
INTERRUPTIBLES		D	17.174	1.	0.000	0.01	0.01	0.	2.	1089.	1091.	134838.98
GLENDIVE CT #1			35.500	13544.	4.742	0.00	0.01	1.	0.	263.	264.	19720.28
DIESEL 2			2.100	8687.	22.501	0.00	0.00	0.	0.	53.	53.	77413.91
DIESEL 3			2.100	8687.	22.501	0.00	0.00	0.	0.	53.	53.	80293.99
MILES CITY C.T.			25.200	15957.	4.742	0.00	0.01	1.	0.	1344.	1344.	176752.33
COMMERCIAL DSM		D	25.000	1.	0.000	0.00	0.00	0.	1.	1585.	1586.	321524.09

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	707.	707.	7.70
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	507.	507.	8.70
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4271.	4271.	7.28
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11292.	1.857	82.06	765.60	16057.	3856.	3923.	23836.	31.13
BIG STONE		MUST	107.800	10416.	2.307	80.30	756.20	18174.	2279.	3630.	24083.	31.85
BIG STONE		DUMP					-0.02				7.	
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.	331.	547.	878.	22.92
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	20978.	0.	20978.	26.22
LEWIS & CLARK2			18.600	8673.	2.865	30.19	49.05	1219.	160.	708.	2087.	42.54
MISO - On peak		HYDR	200.000	10500.	0.000	22.60	394.92	0.	11889.	0.	11889.	30.11
RFP2	2025		110.000	8650.	4.222	0.33	3.19	117.	17.	3307.	3440.	1077.45
GE 7EAHESKETT	2022		78.300	15492.	3.162	0.02	0.14	7.	0.	1366.	1373.	10010.54
HESKETT #3			84.500	15693.	3.162	0.01	0.07	4.	0.	3770.	3773.	51201.70
GLENDIVE CT #2			43.300	10472.	4.885	0.01	0.03	2.	0.	465.	467.	15237.77
INTERRUPTIBLES		D	17.174	1.	0.000	0.01	0.01	0.	3.	1121.	1124.	106021.27
GLENDIVE CT #1			35.500	13505.	4.885	0.01	0.02	1.	0.	271.	272.	15747.60
DIESEL 2			2.100	8687.	23.176	0.00	0.00	0.	0.	54.	55.	61111.80
DIESEL 3			2.100	8687.	23.176	0.00	0.00	0.	0.	54.	55.	63978.31
MILES CITY C.T.			25.200	15935.	4.885	0.00	0.01	1.	0.	1384.	1385.	140448.02
COMMERCIAL DSM		D	25.000	1.	0.000	0.00	0.01	0.	2.	1632.	1634.	245345.62

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	728.	728.	7.93
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	522.	522.	8.97
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4399.	4399.	7.50
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11292.	1.913	82.13	766.32	16553.	3975.	4040.	24569.	32.06
BIG STONE		MUST	107.800	10415.	2.377	68.19	642.22	15896.	1994.	3739.	21629.	33.68
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.	336.	564.	899.	23.48
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	21607.	0.	21607.	27.01
LEWIS & CLARK2			18.600	8666.	2.951	33.45	54.35	1390.	183.	729.	2301.	42.35
MISO - On peak		HYDR	200.000	10500.	0.000	31.17	544.57	0.	16887.	0.	16887.	31.01
RFP2	2025		110.000	8679.	4.349	0.58	5.54	209.	30.	3406.	3645.	657.32
GE 7EAHESKETT	2022		78.300	15127.	3.257	0.04	0.25	12.	0.	1407.	1419.	5792.03
HESKETT #3			84.500	15331.	3.257	0.02	0.14	7.	0.	3883.	3890.	28783.37
GLENDIVE CT #2			43.300	10400.	5.031	0.01	0.06	3.	0.	479.	482.	8699.08
INTERRUPTIBLES		D	17.174	1.	0.000	0.01	0.02	0.	6.	1155.	1161.	57228.98
GLENDIVE CT #1			35.500	13432.	5.031	0.01	0.03	2.	0.	279.	281.	9038.64
DIESEL 3			2.100	8687.	23.871	0.01	0.00	0.	0.	56.	56.	33833.64
DIESEL 2			2.100	8687.	23.871	0.01	0.00	0.	0.	56.	56.	33953.85
MILES CITY C.T.			25.200	15876.	5.031	0.01	0.02	1.	0.	1425.	1427.	78749.04
COMMERCIAL DSM		D	25.000	1.	0.000	0.01	0.01	0.	4.	1681.	1685.	125683.72

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	750.	750.	8.17
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	538.	538.	9.23
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4531.	4531.	7.72
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10414.	2.448	78.22	736.61	18778.	2355.	3851.	24985.	33.92
COYOTE		MUST	106.800	11291.	1.970	70.66	659.28	14668.	3523.	4162.	22352.	33.90
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.	341.	581.	921.	24.05
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	22255.	0.	22255.	27.82
LEWIS & CLARK2			18.600	8664.	3.039	34.02	55.28	1456.	191.	751.	2398.	43.38
MISO - On peak		HYDR	200.000	10500.	0.000	33.50	585.35	0.	18696.	0.	18696.	31.94
RFP2	2025		110.000	11144.	4.480	2.18	20.95	1046.	115.	3508.	4669.	222.87
GE 7EAHESKETT	2022		78.300	14895.	3.354	0.07	0.50	25.	1.	1449.	1474.	2966.45
HESKETT #3			84.500	15087.	3.354	0.04	0.27	14.	1.	3999.	4014.	14757.72
INTERRUPTIBLES		D	17.174	1.	0.000	0.03	0.04	0.	13.	1190.	1203.	27341.05
GLENDIVE CT #2			43.300	10321.	5.182	0.03	0.10	5.	0.	493.	499.	5037.25
GLENDIVE CT #1			35.500	13384.	5.182	0.02	0.06	4.	0.	287.	292.	4578.85
DIESEL 2			2.100	8687.	24.587	0.02	0.00	1.	0.	58.	59.	16050.48
DIESEL 3			2.100	8687.	24.587	0.02	0.00	1.	0.	58.	59.	16431.22
MILES CITY C.T.			25.200	15845.	5.182	0.02	0.04	3.	0.	1468.	1472.	37999.74
COMMERCIAL DSM		D	25.000	1.	0.000	0.01	0.03	0.	9.	1732.	1741.	58193.93

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	772.	772.	8.41
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	554.	554.	9.51
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4667.	4667.	7.95
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11291.	2.029	82.16	766.55	17566.	4219.	4286.	26071.	34.01
BIG STONE		MUST	107.800	10415.	2.521	78.07	735.26	19306.	2422.	3967.	25695.	34.95
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.	346.	598.	944.	24.64
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	22923.	0.	22923.	28.65
LEWIS & CLARK2			18.600	8666.	3.130	33.32	54.14	1469.	193.	774.	2435.	44.98
MISO - On peak		HYDR	200.000	10500.	0.000	31.04	542.38	0.	17843.	0.	17843.	32.90
RFP2	2025		110.000	8567.	4.614	0.55	5.25	207.	30.	3613.	3851.	733.60
GE 7EAHESKETT	2022		78.300	15100.	3.455	0.04	0.26	13.	0.	1492.	1506.	5896.20
HESKETT #3			84.500	15277.	3.455	0.02	0.14	7.	1.	4119.	4127.	29226.50
GLENDIVE CT #2			43.300	10384.	5.338	0.02	0.06	3.	0.	508.	511.	8869.07
INTERRUPTIBLES		D	17.174	1.	0.000	0.01	0.02	0.	6.	1225.	1232.	57488.70
GLENDIVE CT #1			35.500	13431.	5.338	0.01	0.03	2.	0.	296.	299.	9003.15
DIESEL 2			2.100	8687.	25.325	0.01	0.00	0.	0.	60.	60.	33435.31
DIESEL 3			2.100	8687.	25.325	0.01	0.00	0.	0.	60.	60.	35983.32
MILES CITY C.T.			25.200	15864.	5.338	0.01	0.02	2.	0.	1512.	1514.	79080.45
COMMERCIAL DSM		D	25.000	1.	0.000	0.01	0.01	0.	4.	1784.	1788.	127488.02

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	795.	795.	8.66
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	571.	571.	9.80
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4807.	4807.	8.19
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11291.	2.090	82.17	766.63	18095.	4346.	4415.	26856.	35.03
BIG STONE		MUST	107.800	10414.	2.597	62.18	585.54	15836.	1986.	4086.	21908.	37.42
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.	351.	616.	967.	25.24
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	23610.	0.	23610.	29.51
MISO - On peak		HYDR	200.000	10500.	0.000	38.35	670.04	0.	22704.	0.	22704.	33.88
LEWIS & CLARK2			18.600	8659.	3.224	36.18	58.80	1641.	216.	797.	2654.	45.14
RFP2	2025		110.000	8789.	4.752	6.42	61.66	2576.	360.	3722.	6658.	107.97
GE 7EAHESKETT	2022		78.300	14362.	3.559	0.48	3.26	167.	4.	1537.	1708.	523.48
HESKETT #3			84.500	14295.	3.559	0.26	1.94	99.	7.	4243.	4348.	2241.88
INTERRUPTIBLES		D	17.174	1.	0.000	0.24	0.36	0.	109.	1262.	1371.	3781.23
GLENDIVE CT #2			43.300	10095.	5.498	0.21	0.80	44.	3.	523.	570.	716.82
GLENDIVE CT #1			35.500	13167.	5.498	0.16	0.49	35.	2.	305.	342.	700.36
DIESEL 2			2.100	8687.	26.084	0.16	0.03	6.	0.	61.	68.	2381.79
DIESEL 3			2.100	8687.	26.084	0.15	0.03	6.	0.	61.	68.	2472.21
COMMERCIAL DSM		D	25.000	1.	0.000	0.14	0.30	0.	89.	1837.	1926.	6496.05
MILES CITY C.T.			25.200	15648.	5.498	0.13	0.29	25.	1.	1558.	1584.	5371.85

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	819.	819.	8.92
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	588.	588.	10.09
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	4951.	4951.	8.44
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10414.	2.675	75.53	711.33	19815.	2485.	4209.	26508.	37.27
COYOTE		MUST	106.800	11291.	2.153	72.32	674.76	16404.	3940.	4547.	24891.	36.89
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.	635.	991.	25.86
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	24319.	0.	24319.	30.40
MISO - On peak		HYDR	200.000	10500.	0.000	39.74	694.31	0.	24232.	0.	24232.	34.90
LEWIS & CLARK2			18.600	8659.	3.321	36.28	58.95	1695.	223.	821.	2739.	46.46
RFP2	2025		110.000	9321.	4.895	5.60	53.79	2454.	324.	3833.	6612.	122.91
GE 7EAHESKETT	2022		78.300	14600.	3.665	0.27	1.84	98.	2.	1583.	1684.	916.44
HESKETT #3			84.500	14594.	3.665	0.15	1.09	59.	4.	4370.	4433.	4051.72
INTERRUPTIBLES		D	17.174	1.	0.000	0.14	0.21	0.	62.	1300.	1362.	6575.21
GLENDIVE CT #2			43.300	10157.	5.663	0.11	0.40	23.	2.	539.	564.	1405.68
DIESEL 2			2.100	8687.	26.867	0.09	0.02	4.	0.	63.	67.	4072.43
DIESEL 3			2.100	8687.	26.867	0.09	0.02	4.	0.	63.	67.	4127.85
GLENDIVE CT #1			35.500	13240.	5.663	0.09	0.27	20.	1.	314.	335.	1254.69
MILES CITY C.T.			25.200	15718.	5.663	0.07	0.16	14.	1.	1604.	1619.	10013.69
COMMERCIAL DSM		D	25.000	1.	0.000	0.07	0.16	0.	48.	1892.	1940.	12205.51

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	844.	844.	9.19
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	605.	605.	10.39
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5099.	5099.	8.69
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11291.	2.218	82.18	766.71	19199.	4611.	4684.	28493.	37.16
BIG STONE		MUST	107.800	10414.	2.755	81.82	770.49	22107.	2773.	4335.	29214.	37.92
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.	654.	1015.	26.50
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	25048.	0.	25048.	31.31
MISO - On peak		HYDR	200.000	10500.	0.000	36.76	642.28	0.	23089.	0.	23089.	35.95
LEWIS & CLARK2			18.600	8662.	3.420	35.00	56.87	1685.	221.	845.	2752.	48.39
RFP2	2025		110.000	8496.	5.042	0.81	7.78	333.	48.	3948.	4330.	556.33
GE 7EAHESKETT	2022		78.300	14877.	3.775	0.06	0.40	23.	1.	1631.	1654.	4119.21
HESKETT #3			84.500	15019.	3.775	0.03	0.23	13.	1.	4501.	4515.	19808.78
GLENDIVE CT #2			43.300	10321.	5.833	0.02	0.09	6.	0.	555.	561.	6030.70
INTERRUPTIBLES		D	17.174	1.	0.000	0.02	0.04	0.	11.	1339.	1350.	37878.45
GLENDIVE CT #1			35.500	13373.	5.833	0.02	0.05	4.	0.	324.	328.	6055.17
DIESEL 2			2.100	8687.	27.673	0.02	0.00	1.	0.	65.	66.	22904.21
DIESEL 3			2.100	8687.	27.673	0.02	0.00	1.	0.	65.	66.	23593.46
MILES CITY C.T.			25.200	15817.	5.833	0.01	0.03	3.	0.	1652.	1655.	52819.06
COMMERCIAL DSM		D	25.000	1.	0.000	0.01	0.02	0.	7.	1949.	1957.	78303.70

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	304.	304.	9.47
CEDAR HILLS		NDT	19.500	0.	0.000	34.20	58.26	0.	0.	624.	624.	10.70
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5252.	5252.	8.95
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
COYOTE		MUST	106.800	11291.	2.284	82.19	766.86	19778.	4750.	4824.	29353.	38.28
BIG STONE		MUST	107.800	10414.	2.838	74.26	699.35	20667.	2592.	4465.	27724.	39.64
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.	673.	1040.	27.15
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	25800.	0.	25800.	32.25
MISO - On peak		HYDR	200.000	10500.	0.000	43.40	758.26	0.	28076.	0.	28076.	37.03
LEWIS & CLARK2			18.600	8656.	3.523	37.77	61.38	1872.	246.	871.	2989.	48.69
RFP2	2025		110.000	10263.	5.193	6.44	61.88	3298.	395.	4067.	7760.	125.40
GE 7EAHESKETT	2022		78.300	14481.	3.889	0.33	2.26	128.	3.	1680.	1810.	799.40
HESKETT #3			84.500	14505.	3.889	0.18	1.34	75.	5.	4636.	4717.	3528.31
INTERRUPTIBLES		D	17.174	1.	0.000	0.16	0.24	0.	73.	1379.	1452.	5954.45
GLENDIVE CT #2			43.300	10165.	6.008	0.14	0.52	32.	2.	572.	606.	1161.06
DIESEL 2			2.100	8687.	28.503	0.11	0.02	5.	0.	67.	72.	3692.52
GLENDIVE CT #1			35.500	13222.	6.008	0.10	0.32	25.	1.	333.	360.	1127.46
DIESEL 3			2.100	8687.	28.503	0.10	0.02	5.	0.	67.	72.	3801.86
MILES CITY C.T.			25.200	15693.	6.008	0.09	0.19	18.	1.	1702.	1721.	8940.71
COMMERCIAL DSM		D	25.000	1.	0.000	0.09	0.19	0.	57.	2007.	2064.	10923.15

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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
THUNDER SPIRIT		NDT	150.000	0.	0.000	44.77	586.65	0.	0.	5410.	5410.	9.22
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10414.	2.923	74.76	704.05	21430.	2688.	4599.	28717.	40.79
COYOTE		MUST	106.800	11291.	2.353	72.33	674.85	17927.	4306.	4969.	27202.	40.31
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.	693.	1066.	27.82
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	30510.	0.	30510.	38.14
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	26574.	0.	26574.	33.22
LEWIS & CLARK2			18.600	8648.	3.629	40.06	65.09	2043.	269.	897.	3208.	49.29
RFP2	2025		110.000	8311.	5.349	23.89	229.54	10204.	1510.	4189.	15903.	69.28
GE 7EAHESKETT	2022		78.300	14264.	4.005	1.15	7.88	450.	11.	1730.	2191.	278.25
HESKETT #3			84.500	14227.	4.005	0.65	4.77	272.	20.	4775.	5067.	1061.27
INTERRUPTIBLES		D	17.174	1.	0.000	0.59	0.89	0.	267.	1420.	1687.	1898.52
GLENDIVE CT #2			43.300	10088.	6.188	0.51	1.94	121.	8.	589.	718.	370.87
GLENDIVE CT #1			35.500	13158.	6.188	0.39	1.20	97.	5.	343.	446.	372.46
DIESEL 2			2.100	8687.	29.358	0.39	0.07	18.	0.	69.	87.	1236.50
DIESEL 3			2.100	8687.	29.358	0.35	0.06	17.	0.	69.	86.	1323.21
COMMERCIAL DSM		D	25.000	1.	0.000	0.34	0.74	0.	222.	2068.	2290.	3092.88
MILES CITY C.T.			25.200	15645.	6.188	0.33	0.73	70.	3.	1753.	1826.	2517.48

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	5572.	5572.	9.50
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10414.	3.011	82.97	781.32	24496.	3073.	4737.	32305.	41.35
COYOTE		MUST	106.800	11291.	2.423	82.19	766.88	20983.	5039.	5118.	31141.	40.61
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.	714.	1092.	28.51
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	31425.	0.	31425.	39.28
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	27371.	0.	27371.	34.21
LEWIS & CLARK2			18.600	8651.	3.738	39.41	64.03	2070.	273.	924.	3267.	51.02
RFP2	2025		110.000	9211.	5.509	12.59	120.96	6138.	820.	4314.	11272.	93.19
GE 7EAHESKETT	2022		78.300	14308.	4.125	0.56	3.85	227.	6.	1782.	2015.	523.39
HESKETT #3			84.500	14286.	4.125	0.32	2.35	139.	10.	4918.	5067.	2155.24
INTERRUPTIBLES		D	17.174	1.	0.000	0.29	0.43	0.	130.	1463.	1593.	3670.36
GLENDIVE CT #2			43.300	10114.	6.373	0.26	0.97	62.	4.	607.	673.	695.39
GLENDIVE CT #1			35.500	13180.	6.373	0.19	0.59	50.	3.	354.	406.	684.67
DIESEL 2			2.100	8687.	30.239	0.18	0.03	9.	0.	71.	80.	2386.08
DIESEL 3			2.100	8687.	30.239	0.18	0.03	9.	0.	71.	80.	2449.71
MILES CITY C.T.			25.200	15664.	6.373	0.16	0.36	36.	2.	1806.	1843.	5160.69
COMMERCIAL DSM		D	25.000	1.	0.000	0.16	0.35	0.	106.	2130.	2236.	6320.92

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.	5739.	5739.	9.78
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
BIG STONE		MUST	107.800	10414.	3.101	83.01	781.73	25244.	3166.	4879.	33289.	42.58
COYOTE		MUST	106.800	11291.	2.496	82.19	766.88	21613.	5191.	5272.	32075.	41.83
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.	384.	736.	1119.	29.22
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	32368.	0.	32368.	40.46
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	28192.	0.	28192.	35.24
LEWIS & CLARK2			18.600	8650.	3.850	39.65	64.43	2145.	282.	951.	3379.	52.45
RFP2	2025		110.000	8351.	5.675	16.85	161.94	7674.	1130.	4444.	13249.	81.81
GE 7EAHESKETT	2022		78.300	14167.	4.249	1.11	7.57	456.	12.	1836.	2303.	304.23
HESKETT #3			84.500	14113.	4.249	0.64	4.75	285.	21.	5066.	5371.	1131.86
GLENDIVE CT #2			43.300	10065.	6.565	0.52	1.98	131.	9.	625.	764.	385.81
INTERRUPTIBLES		D	17.174	1.	0.000	0.51	0.76	0.	227.	1507.	1734.	2287.41
GLENDIVE CT #1			35.500	13393.	6.565	0.37	1.14	100.	5.	364.	469.	412.83
DIESEL 2			2.100	8687.	31.146	0.31	0.06	15.	0.	73.	89.	1565.69
DIESEL 3			2.100	8687.	31.146	0.30	0.06	15.	0.	73.	88.	1604.44
COMMERCIAL DSM		D	25.000	1.	0.000	0.29	0.64	0.	193.	2194.	2387.	3711.33
MILES CITY C.T.			25.200	15631.	6.565	0.28	0.62	64.	3.	1860.	1927.	3088.32

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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
RFP1	2023	NDT	100.000	0.	0.000	18.44	161.11	0.	5719.	0.	5719.	35.50
RFP3	2022	NDT	54.000	0.	0.000	45.19	213.19	0.	5253.	0.	5253.	24.64
PV SOLAR + STRG	2038	NDT	5.000	0.	0.000	9.71	4.24	0.	0.	316.	316.	74.45
COYOTE		MUST	106.800	11291.	2.571	82.20	766.89	22261.	5346.	5430.	33037.	43.08
RFP2	2025		110.000	6848.	5.845	72.65	698.12	27944.	5019.	4577.	37540.	53.77
BIG STONE		MUST	107.800	10414.	3.194	69.95	658.70	21909.	2748.	5025.	29682.	45.06
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.	758.	1147.	29.94
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	29038.	0.	29038.	36.30
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	33339.	0.	33339.	41.67
LEWIS & CLARK2			18.600	8643.	3.965	41.05	66.70	2286.	301.	980.	3567.	53.48
GE 7EAHESKETT	2022		78.300	12682.	4.377	19.00	130.00	7215.	205.	1891.	9311.	71.62
HESKETT #3			84.500	13671.	4.377	8.55	63.08	3774.	285.	5218.	9277.	147.07
GLENDIVE CT #2			43.300	10237.	6.762	4.89	18.48	1279.	83.	644.	2006.	108.55
INTERRUPTIBLES		D	17.174	1.	0.000	3.41	5.11	0.	1533.	1552.	3085.	603.83
DIESEL 2			2.100	8687.	32.081	2.09	0.38	107.	2.	75.	184.	479.82
COMMERCIAL DSM		D	25.000	1.	0.000	2.09	4.56	0.	1369.	2259.	3628.	795.12
GLENDIVE CT #1			35.500	13049.	6.762	2.05	6.37	562.	29.	375.	966.	151.65
DIESEL 3			2.100	8687.	32.081	1.98	0.36	101.	2.	75.	178.	491.32
MILES CITY C.T.			25.200	15560.	6.762	1.80	3.97	418.	18.	1916.	2351.	592.10

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2018.

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.
2019	508.1	3373.50	590.7	17.73	1229.5	0.00	0.000000	1160.4	0.00	0.00
2020	514.1	3409.90	606.6	19.66	1230.5	0.00	0.000000	1161.4	0.00	0.00
2021	527.0	3525.29	616.1	18.46	1231.5	0.00	0.000000	1162.4	0.00	0.00
2022	539.2	3679.69	583.3	8.90	1217.7	0.00	0.000000	1153.4	0.05	0.00
2023	546.6	3763.39	623.3	15.26	1307.7	0.00	0.000000	1243.4	0.02	0.00
2024	552.6	3805.19	623.3	13.90	1307.7	0.00	0.000000	1243.4	0.04	0.00
2025	558.5	3845.99	729.0	33.15	1417.7	0.00	0.000000	1337.7	0.00	0.00
2026	564.5	3889.09	729.0	31.62	1417.7	0.00	0.000000	1337.7	0.00	0.00
2027	570.7	3932.88	729.0	30.07	1417.7	0.00	0.000000	1337.7	0.00	0.00
2028	576.8	3977.18	729.0	28.58	1417.7	0.00	0.000000	1337.7	0.01	0.00
2029	583.0	4022.18	729.0	27.10	1417.7	0.00	0.000000	1337.7	0.02	0.00
2030	589.3	4067.78	729.0	25.63	1417.7	0.00	0.000000	1337.7	0.01	0.00
2031	595.7	4114.08	729.0	24.17	1417.7	0.03	0.000004	1337.7	0.25	0.01
2032	602.1	4161.08	729.0	22.75	1417.7	0.01	0.000001	1337.7	0.11	0.00
2033	608.5	4208.67	729.0	21.36	1417.7	0.04	0.000004	1337.7	0.01	0.00
2034	615.1	4256.97	724.9	19.24	1398.2	0.02	0.000002	1318.2	0.14	0.00
2035	621.6	4306.07	718.1	16.71	1368.2	0.04	0.000004	1288.2	0.66	0.02
2036	628.3	4356.07	718.1	15.38	1368.2	0.03	0.000003	1288.2	0.30	0.01
2037	635.0	4406.76	718.1	14.07	1368.2	0.04	0.000004	1288.2	0.60	0.01
2038	641.8	4458.76	691.3	8.29	1220.7	0.35	0.000040	1140.7	4.84	0.11
EXT.	641.8	4458.76	691.3	8.29	1220.7	0.35	0.000040	1140.7	4.84	0.11

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

YEAR	LOADS: PEAK LOAD MW	LOADS: PURCH./SALE CONTRACTS	LOADS: DEMAND-SIDE MANAGEMENT	LOADS: NET LOADS MW	RESOURCES: CAPACITY MW	RESOURCES: RESERVE SHARING	RESOURCES: PURCH./SALE CONTRACTS	RESOURCES: NET RESOURCES MW	RESERVE MARGIN PCT.
2019	508.1	0.0	-42.3	465.8	548.4	0.0	0.0	548.4	17.73
2020	514.1	0.0	-43.3	470.8	563.4	0.0	0.0	563.4	19.66
2021	527.0	0.0	-44.2	482.8	571.9	0.0	0.0	571.9	18.46
2022	539.2	0.0	-44.2	495.0	539.0	0.0	0.0	539.0	8.90
2023	546.6	0.0	-44.2	502.4	579.0	0.0	0.0	579.0	15.26
2024	552.6	0.0	-44.2	508.4	579.0	0.0	0.0	579.0	13.90
2025	558.5	0.0	-44.2	514.3	684.8	0.0	0.0	684.8	33.15
2026	564.5	0.0	-44.2	520.3	684.8	0.0	0.0	684.8	31.62
2027	570.7	0.0	-44.2	526.5	684.8	0.0	0.0	684.8	30.07
2028	576.8	0.0	-44.2	532.6	684.8	0.0	0.0	684.8	28.58
2029	583.0	0.0	-44.2	538.8	684.8	0.0	0.0	684.8	27.10
2030	589.3	0.0	-44.2	545.1	684.8	0.0	0.0	684.8	25.63
2031	595.7	0.0	-44.2	551.5	684.8	0.0	0.0	684.8	24.17
2032	602.1	0.0	-44.2	557.9	684.8	0.0	0.0	684.8	22.75
2033	608.5	0.0	-44.2	564.3	684.8	0.0	0.0	684.8	21.36
2034	615.1	0.0	-44.2	570.9	680.7	0.0	0.0	680.7	19.24
2035	621.6	0.0	-44.2	577.4	673.9	0.0	0.0	673.9	16.71
2036	628.3	0.0	-44.2	584.1	673.9	0.0	0.0	673.9	15.38
2037	635.0	0.0	-44.2	590.8	673.9	0.0	0.0	673.9	14.07
2038	641.8	0.0	-44.2	597.6	647.1	0.0	0.0	647.1	8.29
EXT.	641.8	0.0	-44.2	597.6	647.1	0.0	0.0	647.1	8.29

PLAN 1 YEAR 2019

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	0.03	11789.	DKT	1.14	3.18826E+02				4.02	1.	47.39
OIL2	0.00	8687.	GAL	39.17	9.36937E-02				18.86	0.	163.85
COAL	41.93	20630.	TON	14.27	6.06148E+04				2.73	2361.	56.32
COAL	195.59	13260.	TON	14.27	1.81746E+05				2.75	7132.	36.46
COAL	129.78	14235.	TON	13.22	1.39745E+05				1.91	3529.	27.19
COAL	750.88	10415.	TON	16.48	4.74517E+05				1.74	13607.	18.12
COAL	278.44	13384.	TON	13.68	2.72407E+05				2.24	8347.	29.98
PURC	1225.55	10172.	NONE	0.01	1.24660E+09				0.00	0.	0.00
GAS	0.09	16430.	DKT	1.14	1.33755E+03				3.04	5.	49.95
GAS	0.16	8822.	DKT	1.14	1.21577E+03				2.75	4.	24.26

PLAN 1 YEAR 2020

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	0.03	10969.	DKT	1.14	3.12701E+02				3.73	1.	40.91
OIL2	0.00	8687.	GAL	39.17	3.76848E-02				18.86	0.	163.85
COAL	41.92	20630.	TON	14.27	6.06104E+04				2.80	2422.	57.77
COAL	208.62	13260.	TON	14.27	1.93849E+05				2.83	7828.	37.53
COAL	129.76	14235.	TON	13.22	1.39724E+05				1.91	3528.	27.19
COAL	750.92	10414.	TON	16.48	4.74540E+05				1.81	14155.	18.85
COAL	510.07	11989.	TON	13.68	4.47034E+05				1.96	11986.	23.50
PURC	1017.32	10105.	NONE	0.01	1.02796E+09				0.00	0.	0.00
GAS	0.07	17259.	DKT	1.14	1.08868E+03				2.86	4.	49.36
GAS	0.14	8825.	DKT	1.14	1.04836E+03				2.58	3.	22.77

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
GAS	0.10	11468.	DKT	1.14	1.00083E+03				4.16	5.	47.71
OIL2	0.00	8687.	GAL	39.17	2.63133E-01				19.43	0.	168.80
COAL	41.94	20627.	TON	14.27	6.06284E+04				2.87	2483.	59.20
COAL	208.74	13259.	TON	14.27	1.93949E+05				2.89	7999.	38.32
COAL	130.16	14229.	TON	13.22	1.40088E+05				1.94	3593.	27.60
COAL	579.45	10414.	TON	16.48	3.66175E+05				1.94	11707.	20.20
COAL	576.75	11706.	TON	13.68	4.93504E+05				2.09	14110.	24.46
PURC	1170.11	10156.	NONE	0.01	1.18838E+09				0.00	0.	0.00
GAS	0.38	15231.	DKT	1.14	5.03981E+03				2.51	14.	38.23
GAS	66.63	8644.	DKT	1.14	5.05215E+05				2.22	1279.	19.19

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.83	12218.	DKT	1.14	8.86891E+03				4.20	42.	51.31
OIL2	0.03	8687.	GAL	39.17	6.46749E+00				20.01	5.	173.84
COAL	698.96	10414.	TON	16.48	4.41700E+05				1.99	14486.	20.72
COAL	650.44	11321.	TON	13.68	5.38280E+05				1.89	13917.	21.40
PURC	1296.24	10187.	NONE	0.01	1.32047E+09				0.00	0.	0.00
GAS	1.08	14739.	DKT	1.14	1.39343E+04				2.57	41.	37.88
GAS	65.98	8646.	DKT	1.14	5.00404E+05				2.29	1306.	19.80
GAS	1.85	14611.	DKT	1.14	2.36495E+04				2.57	69.	37.55

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
GAS	0.27	12230.	DKT	1.14	2.89297E+03				4.34	14.	53.08
OIL2	0.01	8687.	GAL	39.17	1.91816E+00				20.59	2.	178.88
COAL	729.52	10419.	TON	16.48	4.61229E+05				2.05	15582.	21.36
COAL	763.98	11294.	TON	13.68	6.30734E+05				1.65	14238.	18.64
PURC	1098.70	10133.	NONE	0.01	1.11332E+09				0.00	0.	0.00
GAS	0.35	15142.	DKT	1.14	4.70876E+03				2.67	14.	40.43
GAS	44.59	8676.	DKT	1.14	3.39358E+05				2.39	925.	20.74
GAS	0.65	14963.	DKT	1.14	8.53591E+03				2.67	26.	39.95

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.50	12212.	DKT	1.14	5.34864E+03				4.47	27.	54.59
OIL2	0.02	8687.	GAL	39.17	3.69246E+00				21.21	3.	184.24
COAL	674.72	10417.	TON	16.48	4.26479E+05				2.11	14840.	21.99
COAL	765.12	11293.	TON	13.68	6.31605E+05				1.70	14686.	19.19
PURC	1193.40	10161.	NONE	0.01	1.21267E+09				0.00	0.	0.00
GAS	0.64	14908.	DKT	1.14	8.39105E+03				2.85	27.	42.49
GAS	44.32	8677.	DKT	1.14	3.37327E+05				2.57	988.	22.30
GAS	1.12	14737.	DKT	1.14	1.45078E+04				2.85	47.	42.00

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
GAS	0.06	12328.	DKT	1.14	6.44025E+02				4.60	3.	56.76
OIL2	0.00	8687.	GAL	39.17	3.98018E-01				21.85	0.	189.77
COAL	684.97	10415.	TON	16.48	4.32898E+05				2.17	15516.	22.65
COAL	674.14	11292.	TON	13.68	5.56449E+05				1.75	13326.	19.77
PURC	1305.62	10192.	NONE	0.01	1.33066E+09				0.00	0.	0.00
GAS	0.08	15780.	DKT	1.14	1.05879E+03				2.98	4.	47.03
GAS	52.04	8669.	DKT	1.14	3.95731E+05				2.70	1218.	23.41
GAS	0.14	15561.	DKT	1.14	1.95659E+03				2.98	7.	46.38
GAS	3.61	8779.	DKT	1.14	2.78034E+04				3.98	126.	34.94

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.04	12339.	DKT	1.14	4.85487E+02				4.74	3.	58.52
OIL2	0.00	8687.	GAL	39.17	2.98480E-01				22.50	0.	195.46
COAL	754.16	10416.	TON	16.48	4.76670E+05				2.24	17597.	23.33
COAL	765.35	11293.	TON	13.68	6.31782E+05				1.80	15584.	20.36
PURC	1193.66	10163.	NONE	0.01	1.21311E+09				0.00	0.	0.00
GAS	0.06	15880.	DKT	1.14	7.94603E+02				3.07	3.	48.75
GAS	47.77	8675.	DKT	1.14	3.63505E+05				2.78	1152.	24.13
GAS	0.11	15660.	DKT	1.14	1.47168E+03				3.07	5.	48.07
GAS	2.61	8699.	DKT	1.14	1.99507E+04				4.10	93.	35.66

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
GAS	0.06	12312.	DKT	1.14	6.23866E+02				4.88	3.	60.14
OIL2	0.00	8687.	GAL	39.17	3.87967E-01				23.18	0.	201.33
COAL	756.20	10416.	TON	16.48	4.77946E+05				2.31	18174.	24.03
COAL	765.60	11292.	TON	13.68	6.31978E+05				1.86	16057.	20.97
PURC	1233.24	10174.	NONE	0.01	1.25467E+09				0.00	0.	0.00
GAS	0.07	15693.	DKT	1.14	1.01452E+03				3.16	4.	49.62
GAS	49.05	8673.	DKT	1.14	3.73156E+05				2.86	1219.	24.84
GAS	0.14	15492.	DKT	1.14	1.86347E+03				3.16	7.	48.98
GAS	3.19	8650.	DKT	1.14	2.42240E+04				4.22	117.	36.52

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.10	12250.	DKT	1.14	1.12454E+03				5.03	6.	61.63
OIL2	0.00	8687.	GAL	39.17	7.39201E-01				23.87	1.	207.37
COAL	642.22	10415.	TON	16.48	4.05868E+05				2.38	15896.	24.75
COAL	766.32	11292.	TON	13.68	6.32532E+05				1.91	16553.	21.60
PURC	1382.91	10209.	NONE	0.01	1.41180E+09				0.00	0.	0.00
GAS	0.14	15331.	DKT	1.14	1.81737E+03				3.26	7.	49.93
GAS	54.35	8666.	DKT	1.14	4.13139E+05				2.95	1390.	25.57
GAS	0.25	15127.	DKT	1.14	3.25113E+03				3.26	12.	49.26
GAS	5.54	8679.	DKT	1.14	4.22157E+04				4.35	209.	37.75

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
GAS	0.20	12351.	DKT	1.14	2.18392E+03				5.18	13.	64.01
OIL2	0.01	8687.	GAL	39.17	1.60068E+00				24.59	2.	213.59
COAL	736.61	10414.	TON	16.48	4.65493E+05				2.45	18778.	25.49
COAL	659.28	11291.	TON	13.68	5.44163E+05				1.97	14668.	22.25
PURC	1423.73	10217.	NONE	0.01	1.45462E+09				0.00	0.	0.00
GAS	0.27	15087.	DKT	1.14	3.59936E+03				3.35	14.	50.60
GAS	55.28	8664.	DKT	1.14	4.20133E+05				3.04	1456.	26.33
GAS	0.50	14895.	DKT	1.14	6.49430E+03				3.35	25.	49.96
GAS	20.95	11144.	DKT	1.14	2.04802E+05				4.48	1046.	49.92

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
GAS	0.11	12257.	DKT	1.14	1.18247E+03				5.34	7.	65.42
OIL2	0.00	8687.	GAL	39.17	7.67009E-01				25.32	1.	220.00
COAL	735.26	10415.	TON	16.48	4.64646E+05				2.52	19306.	26.26
COAL	766.55	11291.	TON	13.68	6.32705E+05				2.03	17566.	22.92
PURC	1380.73	10208.	NONE	0.01	1.40950E+09				0.00	0.	0.00
GAS	0.14	15277.	DKT	1.14	1.89231E+03				3.45	7.	52.78
GAS	54.14	8666.	DKT	1.14	4.11610E+05				3.13	1469.	27.13
GAS	0.26	15100.	DKT	1.14	3.38347E+03				3.45	13.	52.17
GAS	5.25	8567.	DKT	1.14	3.94451E+04				4.61	207.	39.53

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
GAS	1.58	12082.	DKT	1.14	1.67366E+04				5.50	105.	66.43
OIL2	0.06	8687.	GAL	39.17	1.23906E+01				26.08	13.	226.60
COAL	585.54	10414.	TON	16.48	3.70028E+05				2.60	15836.	27.05
COAL	766.63	11291.	TON	13.68	6.32769E+05				2.09	18095.	23.60
PURC	1509.01	10229.	NONE	0.01	1.54355E+09				0.00	0.	0.00
GAS	1.94	14295.	DKT	1.14	2.43227E+04				3.56	99.	50.87
GAS	58.80	8659.	DKT	1.14	4.46570E+05				3.22	1641.	27.92
GAS	3.26	14362.	DKT	1.14	4.11099E+04				3.56	167.	51.11
GAS	61.66	8789.	DKT	1.14	4.75423E+05				4.75	2576.	41.77

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
GAS	0.83	12233.	DKT	1.14	8.90454E+03				5.66	57.	69.27
OIL2	0.03	8687.	GAL	39.17	7.25476E+00				26.87	8.	233.39
COAL	711.33	10414.	TON	16.48	4.49506E+05				2.67	19815.	27.86
COAL	674.76	11291.	TON	13.68	5.56933E+05				2.15	16404.	24.31
PURC	1532.99	10235.	NONE	0.01	1.56903E+09				0.00	0.	0.00
GAS	1.09	14594.	DKT	1.14	1.40049E+04				3.67	59.	53.49
GAS	58.95	8659.	DKT	1.14	4.47791E+05				3.32	1695.	28.76
GAS	1.84	14600.	DKT	1.14	2.35349E+04				3.67	98.	53.51
GAS	53.79	9321.	DKT	1.14	4.39840E+05				4.89	2454.	45.63

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	0.18	12212.	DKT	1.14	1.91272E+03				5.83	13.	71.23
OIL2	0.01	8687.	GAL	39.17	1.25500E+00				27.67	1.	240.40
COAL	770.49	10414.	TON	16.48	4.86899E+05				2.76	22107.	28.69
COAL	766.71	11291.	TON	13.68	6.32829E+05				2.22	19199.	25.04
PURC	1480.65	10228.	NONE	0.01	1.51440E+09				0.00	0.	0.00
GAS	0.23	15019.	DKT	1.14	3.00274E+03				3.78	13.	56.70
GAS	56.87	8662.	DKT	1.14	4.32110E+05				3.42	1685.	29.63
GAS	0.40	14877.	DKT	1.14	5.23971E+03				3.78	23.	56.16
GAS	7.78	8496.	DKT	1.14	5.80041E+04				5.04	333.	42.83

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	1.03	12139.	DKT	1.14	1.10045E+04				6.01	75.	72.93
OIL2	0.04	8687.	GAL	39.17	8.50715E+00				28.50	9.	247.61
COAL	699.35	10414.	TON	16.48	4.41936E+05				2.84	20667.	29.55
COAL	766.86	11291.	TON	13.68	6.32946E+05				2.28	19778.	25.79
PURC	1597.01	10245.	NONE	0.01	1.63618E+09				0.00	0.	0.00
GAS	1.34	14505.	DKT	1.14	1.70102E+04				3.89	75.	56.40
GAS	61.38	8656.	DKT	1.14	4.66019E+05				3.52	1872.	30.50
GAS	2.26	14481.	DKT	1.14	2.87697E+04				3.89	128.	56.31
GAS	61.88	10263.	DKT	1.14	5.57084E+05				5.19	3298.	53.29

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	3.86	12085.	DKT	1.14	4.08928E+04				6.19	288.	74.78
OIL2	0.14	8687.	GAL	39.17	3.00555E+01				29.36	35.	255.04
COAL	704.05	10414.	TON	16.48	4.44902E+05				2.92	21430.	30.44
COAL	674.85	11291.	TON	13.68	5.56998E+05				2.35	17927.	26.56
PURC	1639.94	10244.	NONE	0.01	1.68000E+09				0.00	0.	0.00
GAS	4.77	14227.	DKT	1.14	5.95829E+04				4.01	272.	56.98
GAS	65.09	8648.	DKT	1.14	4.93787E+05				3.63	2043.	31.38
GAS	7.88	14264.	DKT	1.14	9.85437E+04				4.01	450.	57.13
GAS	229.54	8311.	DKT	1.14	1.67342E+06				5.35	10204.	44.45

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	1.92	12095.	DKT	1.14	2.03486E+04				6.37	148.	77.08
OIL2	0.07	8687.	GAL	39.17	1.46668E+01				30.24	17.	262.69
COAL	781.32	10414.	TON	16.48	4.93733E+05				3.01	24496.	31.35
COAL	766.88	11291.	TON	13.68	6.32958E+05				2.42	20983.	27.36
PURC	1639.10	10250.	NONE	0.01	1.68000E+09				0.00	0.	0.00
GAS	2.35	14286.	DKT	1.14	2.94614E+04				4.13	139.	58.93
GAS	64.03	8651.	DKT	1.14	4.85898E+05				3.74	2070.	32.33
GAS	3.85	14308.	DKT	1.14	4.83196E+04				4.13	227.	59.02
GAS	120.96	9211.	DKT	1.14	9.77337E+05				5.51	6138.	50.75

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	3.74	12004.	DKT	1.14	3.93962E+04				6.56	295.	78.80
OIL2	0.11	8687.	GAL	39.17	2.48023E+01				31.15	30.	270.57
COAL	781.73	10414.	TON	16.48	4.93994E+05				3.10	25244.	32.29
COAL	766.88	11291.	TON	13.68	6.32956E+05				2.50	21613.	28.18
PURC	1639.71	10246.	NONE	0.01	1.68000E+09				0.00	0.	0.00
GAS	4.75	14113.	DKT	1.14	5.87487E+04				4.25	285.	59.97
GAS	64.43	8650.	DKT	1.14	4.88864E+05				3.85	2145.	33.30
GAS	7.57	14167.	DKT	1.14	9.40602E+04				4.25	456.	60.20
GAS	161.94	8351.	DKT	1.14	1.18633E+06				5.67	7674.	47.39

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	28.82	11591.	DKT	1.14	2.93072E+05				6.76	2259.	78.38
OIL2	0.75	8687.	GAL	39.17	1.65479E+02				32.08	208.	278.68
COAL	658.70	10414.	TON	16.48	4.16245E+05				3.19	21909.	33.26
COAL	766.89	11291.	TON	13.68	6.32961E+05				2.57	22261.	29.03
PURC	1647.98	10194.	NONE	0.01	1.68000E+09				0.00	0.	0.00
GAS	63.08	13671.	DKT	1.14	7.56458E+05				4.38	3774.	59.83
GAS	66.70	8643.	DKT	1.14	5.05707E+05				3.97	2286.	34.27
GAS	130.00	12682.	DKT	1.14	1.44612E+06				4.38	7215.	55.50
GAS	698.12	6848.	DKT	1.14	4.19385E+06				5.84	27944.	40.03

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 $/MBTU	TOTAL FUEL COST K$	TOTAL FUEL COST $/MWH
GAS	28.82	11591.	DKT	1.14	2.93072E+05				43.82	14640.	507.94
OIL2	0.28	8687.	GAL	39.17	6.13262E+01				207.91	499.	1806.07
COAL	658.70	10414.	TON	16.48	4.16245E+05				20.70	141985.	215.55
COAL	766.89	11291.	TON	13.68	6.32961E+05				16.66	144268.	188.12
PURC	1648.45	10191.	NONE	0.01	1.68000E+09				0.00	0.	0.00
GAS	63.08	13671.	DKT	1.14	7.56458E+05				28.36	24460.	387.76
GAS	66.70	8643.	DKT	1.14	5.05707E+05				25.70	14815.	222.10
GAS	130.00	12682.	DKT	1.14	1.44612E+06				28.36	46759.	359.70
GAS	698.12	6848.	DKT	1.14	4.19385E+06				37.88	181097.	259.41

INDEX OF REPORTS

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
2018-2019 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
Shawn Nieuwsma	Manager of Gas Supply
Cory Fong	Director of Communications & Public Affairs
Justin Dever	Public Affairs Specialist
Matt Lund	Engineer – Power Production
Jacob Hein	Engineer – Power Production
Brent Logan	Engineer - Communications

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

October 30, 2018 Meeting Agenda

IRP Planning Process and Public Advisory Group	Darcy Neigum
2017 IRP Action Plan Updates	Brian Giggee Kathy Baerlocher
Gas Supply Update	Shawn Nieuwsma
Load Forecast	Joanne Mahrer
Request for Proposals	Brian Giggee
Environmental Update	Abbie Krebsbach
Supply-side analysis and modeling	Brian Giggee
Overview of MISO and SPP	Darcy Neigum
Wrap-up Meeting Logistics Discussion Topics for Future Meetings	Group Discussion

March 6, 2019 Meeting Agenda

Plant Closure Announcement	Darcy Neigum
Demand Response Event – January 30	Larry Oswald
MISO Overview	Darcy Neigum
Legislative Update	Cory Fong Justin Dever
Supply Side Resources	Matt Lund Jacob Hein
Modeling Results	Brian Giggee
Draft Action Items	Darcy Neigum

Wrap-up

Meeting Logistics

Discussion Topics for Future Meetings

May 22, 2019 Meeting Agenda

Plant Retirements	Darcy Neigum
Cyber Security	Brent Logan
MISO Overview	Darcy Neigum
Legislative Session Recap	Cory Fong Justin Dever
Environmental Update	Abbie Krebsbach
IRP Modeling Results	Brian Giggee
IRP Action Items	Darcy Neigum

Wrap-up

IRP Filing Timeline

Feedback from the PAG members

Future PAG membership for 2021 IRP

Attachment E

SUPPLY-SIDE RESOURCES STUDY

2019 IRP Technology Assessment

Montana-Dakota Utilities Co.

2019 IRP Technology Assessment
Project No. 109770

Revision 3
March 2019

2019 IRP Technology Assessment

prepared for

Montana-Dakota Utilities Co.

2019 IRP Technology Assessment
Bismarck, North Dakota

Project No. 109770

Revision 3
March 2019

prepared by

Burns & McDonnell Engineering Company, Inc.

Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BMcD	Burns & McDonnell Engineering Company, Inc.
BACT	Best Available Control Technology
BFB	Bubbling Fluidized Bed
CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
COD	Commercial Operating Date
DLN	Dry Low NOx
DOE	Department of Energy
EPA	Environmental Protection Agency
EpCM	Engineer, Procurement-Assistance, Construction Management
FAA	Federal Aviation Administration
FGD	Flue Gas Desulfurization
FTE	Full-Time Equivalent
GCF	Gross Capacity Factor
GSU	Generator Step-Up Transformer
GTG	Gas Turbine Generator
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
ITC	Investment Tax Credit

Abbreviation	**Term/Phrase/Name**
LAES	Liquid Air Energy Storage
LEC	Lignite Energy Council
LHV	Lower Heating Value
LLI	Late Lean Injection
MCFC	Molten-Carbonate Fuel Cell
MDU	Montana-Dakota Utilities Co.
MECL	Minimum Emissions Compliant Load
NCF	Net Capacity Factor
NOx	Nitrous Oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
OEM	Original Equipment Manufacturer
PM	Particulate Matter
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SOFC	Solid Oxide Fuel Cell
STG	Steam Turbine Generator
VOC	Volatile Organic Compounds

1.0 INTRODUCTION

Montana-Dakota Utilities Co. (Montana-Dakota or Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various power generation technologies in support of its power supply planning efforts. The 2019 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

- Simple cycle gas turbine (SCGT) technologies
  - LM6000 PF+ Aeroderivative
    - SCR option
  - LMS 100 PB+ Aeroderivative
    - SCR and CO Oxidation Catalyst Included
  - 7E.03 LLI SCGT
    - SCR option
    - R.M. Heskett expansion option
  - All options include evaporative coolers
  - Natural gas only
- Reciprocating engine technology:
  - 4x 9MW engine plant
  - 3x18MW engine plant
  - Natural gas only
  - SCR and CO Catalyst included
- Combined cycle gas turbine (CCGT) technologies
  - 2x1 SGT-800

    - SCR and CO Catalyst included
  - 1x1 F class
    - SCR and CO Catalyst included
  - 2x1 7E.03 LLI R.M. Heskett Expansion
    - SCR option
  - Incremental duct firing option included for all CCGT technologies
  - Evaporative coolers included for all CCGT technologies
  - Natural gas only
- Wind Generation
  - 20 MW – 9 x GE 2.72-116
  - 50 MW – 23 x GE 2.72-116
- Solar PV
  - 5 MWac
    - Single axis tracking
    - Add-On Cost for 1 MW / 4 MWh co-located Li-Ion battery energy storage
  - 50 MWac
    - Single axis tracking
    - Add-On Cost for 10 MW / 40 MWh co-located Li-Ion battery energy storage
- Biomass
  - 25 MW
    - Bubbling Fluidized Bed
  - Grasses Fuel Design
- Coal
  - Circulating Fluidized Bed without Carbon Capture
  - Circulating Fluidized Bed with Carbon Capture
  - Coal technology information provided by Montana-Dakota, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council (2012).

1.2 Assessment Approach

This report accompanies the 2019 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 Montana-Dakota 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 2019 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.
- Ambient conditions are based on Montana-Dakota requests:
  - North Dakota
    - Elevation: 1690 ft.
    - Winter Conditions: 6.8°F and 70% RH
    - Summer Conditions: 84.5°F and 40% RH
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- The primary fuel for the SCGT, CCGT, and reciprocating engine options is pipeline quality natural gas. SCGT, CCGT and reciprocating engine performance is based on natural gas operation.
- Interconnection allowances for water, natural gas, and transmission are listed in the Summary Table and general assumptions are discussed in the Owner Cost section of this report.

  - o Supplemental metering and regulation equipment is included for natural gas technology options. This equipment is not intended for billing purposes, but rather for Owner confirmation and regulation of fuel provided by the gas company.
  - o Based on the provided natural gas, it is assumed that fuel gas compression is unnecessary. Pressure regulation and dew point heaters are included for applicable technologies.
- Incremental impacts of duct firing are included in the Summary Table for capital costs and performance estimates for combined cycle plant options.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- Effluent discharge to ponds onsite as applicable.
- EpCM electrical scope is assumed to end at the high side of the generator step up transformer (GSU). Unless otherwise stated, GSU costs assume 115 kV transmission voltage. 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.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- Emissions are estimated at base load operation at ISO conditions.
- Water and ammonia consumption are estimated at ISO conditions.

2.3 EPC Project Indirect Costs

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

- Performance testing and CEMS/stack emissions 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
- Land allowance, as applicable:
  - Allowance is $5,000/acre for all applicable technology options
  - Exceptions:
    - Wind and PV projects assumed leased land. Land costs are excluded from Owner costs and covered instead in the O&M category.
    - Wind options assume typical industry spacing expected to meet any minimum site control requirement.
    - Solar options assume 8 acres/MW for tracking.
    - All options located at R.M. Heskett Station.
- Permitting and licensing fees
- Construction power, temporary utilities
- Startup consumables
- Site security
- Operating spare parts
- Switchyard (assumes 115 kV for transmission voltage)
  - Exceptions: Storage and PV options assume interconnection at distribution voltage.
- Transmission interconnection
  - Allowances for 15 miles of transmission at 115 kV. Simple cycle options assume a single circuit while combined cycle plant options assume double circuit transmission, unless otherwise noted on the Summary Table. Costs are based on public planning documents. Assumes no major geographic obstructions to the line.
- Gas Interconnection
  - Allowances for a five mile pipeline, utility interconnection and metering station, unless otherwise noted on the Summary Table. Assumes no major geographic obstructions to the line. The pipeline diameters assumed for each of the technologies in the assessment are listed below:
    - 4": LM6000 PF+, Reciprocating Engines, Coal and Biomass options
    - 6": LMS100 PB+, 7E.03 LLI (SCGT)
    - 8": 2x1 SGT-800, 1x1 F class
- Water Interconnection
  - Allowances for site wells and piping for raw water supply.

- 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 Montana-Dakota.
- 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 2019 USD.
- O&M estimates exclude emissions credit costs.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.
- 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, makeup water, water treatment, water disposal, ammonia, selective catalytic reduction (SCR) replacements, and other consumables not including fuel.
- Fuel costs are excluded from O&M estimates.
- Where applicable, major maintenance costs are shown separately from variable O&M costs.
- Gas turbine and reciprocating engine major maintenance assumes third party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer (OEM).
- Base O&M costs are based on performance estimates at ISO conditions.

3.0 SIMPLE CYCLE GAS TURBINE TECHNOLOGY

3.1 Simple Cycle Gas Turbine Technology Description

An SCGT plant utilizes natural gas to produce power in a gas turbine generator. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Simple cycle gas turbines are typically used for peaking power due to their fast load ramp rates and relatively low capital costs. However, the units have high heat rates compared to combined cycle technologies. Simple cycle gas turbine generation is a widely used, mature technology.

Evaporative coolers or inlet foggers are often used to cool the air entering the gas turbine by evaporating additional water vapor into the air, which increases the mass flow through the turbine and therefore increases the output. Evaporative coolers or inlet foggers, depending on the turbine OEM, are included as options on all SCGT technologies in this assessment.

While this is a mature technology category, it is also a highly competitive marketplace. Manufacturers are continuously seeking incremental gains in output and efficiency while reducing emissions and onsite construction time. Frame unit manufacturers are striving to implement faster starts and improved efficiency. Combustor design updates allow improved ramp rates, turndown, fuel variation, efficiency, and emissions characteristics. Aeroderivative turbines also benefit from the research and development (R&D) efforts of the aviation industry, including advances in metallurgy and other materials.

Low load or part load capability may be an important characteristic depending on the expected operational profile of the plant. Low load operation allows the SCGT's to remain online and generate a small amount of power while having the ability to quickly ramp to full load without going through the full start sequence. Most turbines can sustain stable operation at synchronous idle, when the SCGT generator is synched with the grid but there is virtually no load on the turbine. At synchronous idle, a turbine runs on minimal fuel input and generates minimal power.

3.1.1 Aeroderivative Gas Turbines

Aeroderivative gas turbine technology is based on aircraft jet engine design, built with high quality materials that allow for increased turbine cycling. The output of commercially available aeroderivative turbines ranges from less than 20 MW to approximately 100 MW in generation capacity. In simple cycle configurations, these machines typically operate more efficiently than larger frame units and exhibit shorter ramp up and turndown times, making them ideal for peaking and load following applications. Aeroderivative units typically require fuel gas to be supplied at higher pressures (i.e. 675 psig to 960 psig for many models) than more traditional frame units.

A desirable attribute of aeroderivative turbines is the ability to start and ramp up load quickly. Most manufacturers will guarantee ten-minute starts, measured from the time the start sequence is initiated to when the unit is at 100 percent load. Simple cycle gas turbine starts are generally not affected by cold, warm, or hot conditions. However, all gas turbine start times in this Assessment assume that all start permissives are met, which can include purge credits, lube oil temperature, fuel pressure, etc. Available aeroderivative gas turbines models include both Dry Low NOx (DLN) and water injection methods to control emissions during natural gas operation. Additionally, some aeroderivative models include intercooler or fogging systems that would also require greater water usage. Both factors can greatly influence variable O&M to acquire water of the quality necessary to meet these needs.

Aeroderivative turbines are considered mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including General Electric (GE), Siemens (including Rolls Royce turbines), and Mitsubishi-owned Pratt & Whitney Power Systems (PWPS). This assessment includes GE LM6000 and GE LMS100 options.

3.1.2 Frame Gas Turbines

Frame style turbines are industrial engines, more conventional in design, that are typically used in intermediate to baseload applications. In simple cycle configurations, these engines typically have higher heat rates when compared to aeroderivative engines. The smaller frame units have simple cycle heat rates around 11,000 Btu/kWh (HHV) or higher while the largest units exhibit heat rates approaching 9,000 Btu/kWh (HHV). However, frame units have higher exhaust temperatures (≈1,100°F) compared to aeroderivative units (≈850°F), making them more efficient in combined cycle operation because exhaust energy is further utilized. Frame units typically require fuel gas at lower pressures than aeroderivative units (i.e. ~500 psig).

Traditionally, frame turbines exhibit slower startup times and ramp rates than aeroderivative models, but manufacturers are consistently improving these characteristics. Conventional start times are commonly 30 minutes for frame turbines, but fast start options allow 10 to 15 minute starts. Most available frame gas turbine models utilize DLN to control emissions during natural gas operation. This can result in decreased water usage in comparison to aeroderivative gas turbines which can influence variable O&M.

Frame engines are offered in a large range of sizes by multiple suppliers, including GE, Siemens, Mitsubishi, and Alstom. Commercially available frame units range in size from approximately 5 MW to 425 MW for 60 Hz applications. Continued development by gas turbine manufacturers has resulted in the separation of gas turbines into several classes, grouped by output and firing temperature: E class turbines (nominal 85 to 100 MW); F class turbines (nominal 200 to 240 MW); G/H class turbines (nominal 270 to 300 MW); and J class turbines (nominal 325 to 400 MW). This Assessment includes a GE 7E.03 LLI option.

3.2 Simple Cycle Gas Turbine Emissions Controls

All emissions discussion below is preliminary and should not be used for permitting purposes. It assumes that completed sites would be considered a major emissions source located at a greenfield non-listed source. For all options located at the R.M. Heskett Station, further analysis would be required to provide the same level of information.

Emissions levels and required NO_x and CO controls vary by technology and site constraints. Historically, natural gas SCGT peaking plants have not required post-combustion emissions control systems because they normally operate at low capacity factors. However, permitting trends suggest post-combustion controls may be required depending on annual number of gas turbine operating hours, proximity of the site to a non-attainment area, and current state regulations.

In addition, there is a New Source Performance Standard (NSPS) limit for NO_x emissions measured in parts per million (ppm), independent of operating hours. Per NSPS, units with heat inputs below 850 MMBtu/hr have a NO_x limit of 25 ppm, but units with heat inputs greater than 850 MMBtu/hr have a NOx limit of 15 ppm. Furthermore, in the event the overall facility has the potential to emit greater than 250 tons per year of NO_x emissions, a new source review as a major emissions source at a non-listed facility could be triggered. In that case, selective catalytic reduction may be required or the number of operating hours available for the facility may be limited. Additionally, under Subpart TTTT, newly constructed stationary combustion turbines must emit less than 1000 lb CO_2/MWh (gross) or be limited to a net capacity factor of its design efficiency (or 50 percent; whichever is lower).

Most turbine manufacturers will guarantee emissions down to a specified minimum load, commonly 40 to 50 percent load. Below this load, turbine emissions may spike. As such, emissions on a ppm basis may be significantly higher at low loads.

The greenfield 7E.03 LLI gas turbine in this evaluation uses dry-low-NO_x (DLN) combustors to achieve minimum NO_x emissions of 5 ppm at 15 percent O_2 at full load and ISO conditions while operating on natural gas fuel. Since these units emit less than 15 ppm NO_x, and because emissions will be less than 250 tpy using a capacity factor of 15 percent, it is assumed that an SCR is not required. For a single unit installation as investigated in this Study, no capacity factor is expected to trigger operating limits by exceeding the 250 tpy NO_x limit. However, using the summer design efficiency and output without evaporative coolers of 29 percent (HHV) and 73,800 kW respectively, the 7E.03 LLI has a maximum net generation limit of 192,780 MWh on a 12-operating month basis. This corresponds to a maximum net capacity factor of approximately 29.8 percent. The 7E.03 LLI gas turbine located at R.M. Heskett station utilizes the same emissions control technology but may face different emissions controls requirements.

Capital and owner's costs for an SCR system are included as optional costs in the Summary Table for the 7E.03 LLI simple cycle gas turbine option in this Assessment.

Aeroderivative units commonly have options for DLN combustors or water injection to control NOx emissions to approximately 15-25 ppm. The GE LM6000 PF+ option in this Assessment utilizes DLN combustors to achieve NO_x emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel. Because the LM6000 PF+ has a heat input below 850 MMBtu/hr, it is expected to meet the appropriate 25ppm NO_x limit per the NSPS limits discussed previously. Furthermore, because NO_x emissions will be less than 250 tpy using an assumed capacity factor of 15 percent, it is assumed that an SCR is not required. For a single unit installation as investigated in this Study, the LM6000 PF+ no capacity factor is expected to trigger operating limits by exceeding the 250 tpy NOx limit. However, using the summer design efficiency and output without evaporative coolers of 35 percent (HHV) and 47,900 kW respectively, the LM6000 PF+ has a maximum net generation limit of 127,540 MWh on a 12-operating month basis. This corresponds to a maximum net capacity factor of approximately 35.8 percent.

Capital and owner's costs for an SCR system are included as optional costs for the LM6000 PF+ option in this Assessment.

Similarly, the GE LMS100 PB+ option ins this Assessment utilizes DLN combustor to achieve NO_x emissions of 25 ppm at 15 percent O_2 while operating on natural gas fuel. However, this unit has an expected heat input greater than 850 MMBtu/hr and a design NO_x emissions rating of 25 ppm at 15 percent O_2 while operating on natural gas fuel. This means that an SCR system would be required. Additionally, using the summer design efficiency and output without evaporative coolers of 38 percent (HHV) and 90,300 kW respectively, the LMS100 PB+ has a maximum net generation limit of 301,630 MWh on a 12-operating month basis. This corresponds to a maximum net capacity factor of 38.9 percent. Capital and owner's costs for an SCR system are included in the base option.

Oxidation catalysts can be used to control CO emissions while operating on natural gas fuel. It is assumed that CO controls are not required on the base LM6000 PF+ and 7E.03 LLI options, but the costs of the CO catalyst are included in the SCR costs. CO catalysts are included in the SCR costs for the LMS100 PB+ to control CO emissions to 4 ppm at 15 percent O_2.

Volatile Organic Compounds (VOC) are primarily the result of incomplete combustion. VOCs include a wide spectrum of volatile organic compounds, some of which some are hazardous air pollutants. Some VOC destruction is expected to occur in the oxidation catalyst when installed to control CO emissions. Otherwise, VOCs are not controlled beyond good combustion practice.

Outside of good combustion practices, it is assumed that emissions control equipment is not required for CO_2 and particulate matter (PM). Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines.

Emissions estimates are shown in the Summary Tables for full load operation at ISO conditions. Emissions are also shown for units equipped with SCR and CO catalyst systems.

3.3 Simple Cycle Gas Turbine Performance

Performance results are shown in the Summary Table. Estimated performance results are based on data outputs from proprietary GE software. Full load and minimum load performance estimates are shown for winter and summer conditions.

Minimum load is defined as the minimum emissions compliant load (MECL), as reflected in the OEM ratings.

The general assumptions in Section 2.0 apply to the evaluation of all SCGT options, and additional assumptions are listed in the scope matrix in Appendix A.

- All performance ratings are based on natural gas fuel.
- Summer ratings include evaporative coolers.

The frame 7E.03 LLI SCGT option does not include fast start capability. Fast start packages allow simple cycle frame units to compare more favorably with aeroderivative units, which commonly start in 10 minutes as standard. However, depending on the OEM, fast-start packages may impact turbine maintenance costs and/or performance. SCGT start times assume that purge credits are available.

Outage and availability statistics are also shown in the Summary Tables. They were collected using the NERC Generating Availability Data System (GADS). Simple cycle gas turbine GADS data are based on the 2012 to 2016 operating statistics for applicable North American units that are no more than 10 years old.

3.4 Simple Cycle Gas Turbine Cost Estimates

The simple cycle gas turbine cost estimate results are included in the Summary Tables. The project cost includes all equipment procurement, construction, and indirect costs for a greenfield simple cycle gas turbine project.

Additional cost clarifications and assumptions are shown below:

- Balance of Plant (BOP) Equipment Assumptions:
    - Mechanical equipment, electrical equipment, instrumentation and controls, chemical storage, fire protection equipment, and other miscellaneous items as required.
    - Includes supplemental fuel gas metering equipment for verification of billing/consumption information provided by gas supplier.
    - Fuel gas metering and conditioning equipment owned by the gas supplier is excluded from the EpCM estimate and included as an Owner's cost allowance.
    - Onsite water treatment systems are not included. SCGT plants assume that trailers are used to treat raw water for service use.
- Construction
    - Accounts for labor adjustments for each service area.
    - Includes major equipment erection, civil/structural construction, mechanical construction, and electrical construction.
- Costs are for units firing natural gas only.
- The estimate assumes the turbines are installed outdoors with OEM standard enclosures.
- Greenfield cost estimates include a building with administrative/control spaces and a warehouse.
- Brownfield cost estimate at R.M. Heskett assumes that the administrative/control spaces and warehouses will be re-utilized as well as some plant controls.
- Interconnection allowances are presented as Owner's Costs as described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

3.5 Simple Cycle Gas Turbine O&M

The results of the simple cycle gas turbine O&M evaluations are shown in the Summary Tables. Additional assumptions are listed in the scope matrix in Appendix A.

Fixed O&M costs include four (4) FTE personnel for greenfield options and two (2) FTEs for the option at R.M. Heskett. Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.

Major maintenance costs for aeroderivative engines are estimated on a dollar per gas turbine hourly operation ($/GTG-hr) basis and are not affected by number of starts. Major maintenance in $/MWh is calculated assuming 75% of net capacity for operating hours. Variable O&M and major maintenance costs are based on natural gas operation. Fixed costs include an allowance for four full time employees as requested by Montana-Dakota.

Major Maintenance costs for the frame engines are estimated on a dollar per gas turbine start ($/GT-start) basis. In general, if there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27 hours per start, maintenance will be start-based. Note that the $/GT-hr and $/start costs are not meant to be additive or combined in any way. The operational profile determines which value to use to determine annual major maintenance costs. Major maintenance in $/MWh is calculated assuming 75% of net capacity for operating hours.

4.0 RECIPROCATING ENGINE TECHNOLOGY

This Assessment includes two (2) simple cycle reciprocating engine plants for comparison among the SCGT options.

4.1 Reciprocating Engine Technology Description

The internal combustion reciprocating engine operates on a four-stroke cycle for the conversion of pressure into rotational energy. Utility scale engines are commonly compression-ignition models, but some are spark-ignition engines. By design, cooling systems are typically closed-loop radiators, minimizing water consumption.

Reciprocating engines are generally less impacted by altitude and ambient temperature than gas turbines. With site conditions below 3,000 feet and 95°F, altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines, though the efficiency may be slightly affected.

Reciprocating engines can start up and ramp load more quickly than most gas turbines, but it should be noted that the engine jacket temperature must be kept warm to accommodate start times under 10 minutes. However, it is common to keep water jacket heaters energized during all hours that the engines may be expected to run (associated costs have been included within the fixed O&M costs).

Many different vendors, such as Wärtsilä, Fairbanks Morse (MAN Engines), Caterpillar, Hyundai, Rolls Royce, etc. offer reciprocating engines and they are becoming popular as a means to follow wind turbine generation with their quick start times and operational flexibility. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and quick start up when compared to gas turbines.

Utility scale applications most commonly rely on medium speed engines in the 9-10 MW and 18-20 MW classes. All the OEMs indicated above offer a spark ignition engine in the 9-10 MW class, but only Wärtsilä and MAN have commercially available 18-20 MW class engines in the US. Wärtsilä and MAN are also the only major OEMs who offer compression ignition engines in either class that can operate on natural gas or liquid fuels.

The 4x 9 MW and 3 x 18 MW plants evaluated in this Assessment are based on Wärtsilä natural gas only engines, models 20V34SG and 18V50SG respectively. These heavy duty, medium speed engines are easily adaptable to grid-load variations.

4.2 Reciprocating Engine Emissions Controls

Emissions estimates are shown in the Summary Tables for full load at ISO conditions on natural gas fuel. In addition to good combustion practices, it is expected that reciprocating engines will require SCR and CO catalysts to control NO_x and CO emissions. Operation on natural gas fuel with an SCR yields reduction of NO_x emissions to 5 ppm at 15 percent excess O2, while a CO catalyst results in anticipated CO emissions of 15 ppm. Some VOC destruction is expected to occur in the oxidation catalyst, otherwise, VOCs are not controlled beyond good combustion practice. It is assumed that emissions control equipment is not required for CO_2 and particulate matter (PM). Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel. It is assumed that CEMS monitoring systems are also not required.

4.3 Reciprocating Engine Performance

Performance results are shown in the Summary Table. Estimated performance results are based on data from OEM ratings. Full load and minimum load performance estimates are shown for winter and summer conditions. Minimum load assumes a single engine at 50% load. The general assumptions in Section 2.0 apply to the evaluation of reciprocating engine options, and additional assumptions are listed in the scope matrix in Appendix A.

The Summary Tables includes startup times for engine options. Start times of 5-10 minutes require that the engine jacket temperatures are kept warm for standby operation (this is addressed in the O&M costs). Outage and availability statistics are also shown in the Summary Tables. They were collected using the NERC Generating Availability Data System (GADS). It should be noted that EFOR data from GADS may not accurately represent the benefits of a reciprocating engine plant, depending on how outage events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so only a portion of the plant would be unavailable.

Reciprocating engines consume minimal water (approximately 5 gallons per engine, per week for cooling loop makeup, plus a gallon per day for turbo rinses). Depending on site conditions and access to water, the low water consumption rate can be advantageous for comparison to other simple cycle plants.

4.4 Reciprocating Engine Cost Estimates

The cost estimate results are included in the Summary Table. The project cost includes all equipment procurement, construction, and indirect costs for a greenfield reciprocating engine project.

Additional cost clarifications and assumptions are shown below:

- SCR and CO catalysts are included for reciprocating engines. It is assumed that CEMS equipment is not required.
- Pressure regulation and dew point heating are included.
- The reciprocating engine plant includes an indoor engine hall with associated administrative/ control/ warehouse facilities.
- All engines are tied to a single, three-winding GSU.
- Interconnection allowances are presented as Owner's Costs as described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

4.5 Reciprocating Engine O&M

The results of the O&M evaluations are shown in the Summary Tables. Additional assumptions are listed in the scope matrix in Appendix A.

Fixed O&M costs include four (4) FTE personnel for both the 4 x 20V34SG and 3 x 18V50SG engine blocks. Fixed O&M also includes an estimate for standby electricity costs to keep the engines warm and accommodate start times of less than ten minutes. Additional fixed O&M costs include allowances for administrative, communications, and other routine maintenance items. Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.

Major maintenance costs are shown per engine, regardless of configuration. It is assumed that an LTSA with the OEM or other third party would include parts and labor for major overhauls and catalyst replacements.

Variable costs account for lube oil, SCR reagent, routine BOP maintenance, and scheduled minor engine maintenance. It is expected that the maintenance agreement would include supervision and parts for these minor intervals (i.e. ~2,000 hour intervals), but that these may not be considered capital maintenance intervals, so they are included in the variable O&M.

5.0 COMBINED CYCLE GAS TURBINE TECHNOLOGIES

5.1 Combined Cycle Technology Description

The basic principle of the combined cycle gas turbine (CCGT) plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and to also use the hot exhaust gases from the gas turbine to produce steam in a heat recovery steam generator (HRSG). This steam is then used to drive a steam turbine and generator to produce electric power. The use of both gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing. The heat rate will increase during duct fired operation, though this incremental duct fired heat rate is generally less than the resultant heat rate from a similarly sized SCGT peaking plant.

As discussed in prior sections, continued development by gas turbine manufacturers has resulted in the separation of gas turbine technology into various classes. For this assessment, BMcD is evaluating greenfield 2x1 SGT-800 and 1x1 F Class options. For comparisons purpose, the 2x1 7E.03 R.M. Heskett expansion was included in the Summary Table.

5.2 Combined Cycle Emissions Controls

Emissions estimates are shown in the Summary Tables for base load and peak (duct-fired) load, assuming natural gas operation at ISO conditions.

Greenfield combined cycle plants are designed for capacity factors consistent with intermediate or base load operation, and therefore it is expected that NO_x and CO emissions will need to be controlled. An SCR will be required to reduce NO_x to approximately 2 ppm at 15 percent O_2 which correlates to approximately 0.01 lb/MMBtu. It is expected that a CO catalyst will also be required to reduce CO emissions. This assessment assumes CO emissions will be controlled to 2 ppm CO at 15 percent O2, which correlates to approximately 0.006 lb/MMBtu. Some VOC destruction is expected to occur in the oxidation catalyst, otherwise, VOCs are not controlled beyond good combustion practice. Emissions rates for the CCGT options in this Assessment are included in the Summary Table.

For the R.M. Heskett expansion, no SCR or CO controls are included in the base cost estimate. Add-on costs are provided for an SCR on both gas turbines.

The use of an SCR and CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with NO_x molecules. This requires on-site ammonia storage and provisions for ammonia unloading and transfer. The costs associated with these requirements have been included in this Assessment.

For all CCGT options, untreated CO_2 emissions are estimated to be 120 lb/MMBtu. Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. Sulfur dioxide emissions of a CCGT plant are very low compared to coal technologies, and the emission rate of sulfur dioxide for a combined cycle unit is estimated to be less than 0.001 lb/MMBtu.

5.3 Combined Cycle Performance

Estimated performance results are shown in the Summary Table, based on data outputs from Ebsilon heat balance models. The general assumptions in Section 2.0 apply to the evaluation of CCGT options, and additional assumptions are listed in the scope matrix in Appendix A.

Additional cost clarifications and assumptions are shown below:

- Evaporative cooling is included in the performance and capital cost of the base plants.
- Performance estimates are based on heat rejection through wet cooling towers.
- Duct fired options include capability for duct firing to 1,600°F for greenfield options. Incremental duct fired output and heat rate are provided. The incremental heat rate is only applicable to the fired output. It does not represent the total plant heat rate when duct firing is operational.
- All greenfield CCGT plants assume SCR and CO catalyst technologies are installed.

The Summary Table includes combined cycle start times to stack emissions compliance and base load according to cold start conditions. Stack emissions compliance is commonly driven by the time required for the CO catalyst to reach its optimum temperature, which typically occurs after the turbine reaches MECL. Start times reflect unrestricted, conventional starts for all gas turbines. Capital costs assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. GTG fast start options are not reflected in combined cycle startup information.

Outage and availability statistics are also shown in the Summary Table. They were collected using the NERC Generating Availability Data System (GADS). Combined cycle plant GADS data are based on the 2012-2016 operating statistics for applicable North American units that are no more than 10 years old.

Full load, part load, and minimum load performance estimates are shown for winter and summer conditions. All performance assumes new and clean equipment. Emissions estimates assume that SCR and CO catalyst systems are installed.

5.4 Combined Cycle Cost Estimates

The combined cycle plant cost results are included in the Summary Tables. The project cost includes all equipment procurement, construction, and indirect costs for combined cycle projects. The general cost assumptions in Section 2.0 apply to the combined cycle options.

Cost estimates were developed using in-house information based on BMcD project experience. Cost estimates assume an EpCM project plus typical Owner's costs. In line with the assumptions matrix in Appendix A, the following items are highlighted:

- Steam Turbine Basis:
  - 2x1 SGT-800: Two pressure condensing steam turbine.
  - 1x1 7F.05: Three pressure condensing steam turbine.
  - 2x1 7E.03 R.M. Heskett Expansion: New two pressure condensing steam turbine.
- HRSG Basis:
  - 2x1 SGT-800: Two pressure HRSG (no reheat), duct firing add-on costs included in the Summary Table.
  - 1x1 7F.05: Three pressure HRSG (including reheat), duct firing add-on costs included in the Summary Table.
  - 2x1 7E.03 R.M. Heskett Expansion: Two pressure HRSG (no reheat), duct firing add-on costs included in the Summary Table.
- BOP Equipment Assumptions:
  - Mechanical equipment, electrical equipment, instrumentation and controls, chemical storage, fire protection equipment, and other miscellaneous items as required.
  - Includes supplemental fuel gas metering equipment for verification of billing/consumption information provided by gas supplier.
  - Pressure regulation and dew point heating are included.
  - Fuel gas metering and conditioning equipment owned by the gas supplier is excluded.
  - Onsite water treatment systems.
- Construction
  - Accounts for labor adjustments

  - Includes major equipment erection, civil/structural construction, mechanical construction, and electrical construction
- Indirect Costs and Fees
- Capital costs assume the inclusion of terminal point desuperheaters, full bypass, and associated controls to accommodate the startup times shown in the Summary Table.
- Base unit estimates assume natural gas operation.
- Evaporative cooling is included in the base project costs.
- The estimate assumes that gas turbines are installed outdoors in OEM standard enclosures.
- The estimate assumes that HRSGs and steam turbines are installed indoors.
- An administrative/control building and a warehouse are included for greenfield options.
- Interconnection allowances are presented as Owner's Costs and described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.
- The owner's cost for a switchyard assumes a breaker and ½ configuration for 115kV interconnection.

5.5 Combined Cycle O&M

The results of the combined cycle O&M evaluations are shown in the Summary Table. In line with the assumptions matrix in Appendix A, the following items are highlighted:

- O&M estimates are based on plant performance at ISO conditions.
- Incremental O&M costs for optional items are meant to be added directly the base fixed or variable O&M costs, as applicable.
- Greenfield combined cycle plants assume the following FTE personnel quantities.
  - 1x1: 22 FTE
  - 2x1: 25 FTE
- The R.M. Heskett expansion combined cycle plant assumes 20 FTE.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.
- SCR systems are included in the O&M evaluations for all greenfield combined cycle plants. SCR systems assume 19 percent aqueous ammonia and 25,000 hours as applicable.
- Major maintenance costs are based on $/GT-hr, but are also shown in $/MWh. These numbers reflect the same total annual cost and are not meant to be combined.
- Note that major maintenance costs vary by term coverage and scope, OEM, and operational profile.

- Chemical costs were updated based on recent BMcD experience.

6.0 RENEWABLE TECHNOLOGY – ONSHORE WIND

6.1 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.

6.2 Wind Energy Emission Controls

No emission controls are necessary for a wind energy installation.

6.3 Wind Performance

This Assessment includes 20 MW and 50 MW wind generating facilities in the Montana-Dakota service area. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. A generic project location in southwestern North Dakota was selected as directed by Montana-Dakota for its proximity to relatively high wind speeds in accordance with NREL wind maps but is otherwise arbitrary. The location was not selected with respect to actual, expected, or preferred locations for current or future wind development.

As instructed by Montana-Dakota, the GE 2.72-116 wind turbine model was assumed for this analysis, with a nameplate capacity of 2.72 MW, a rotor diameter of 116 meters, and a hub height of 80 meters. The maximum tip height of this package is under 500 feet, which means there are less likely to be conflicts with the Federal Aviation Administration (FAA) altitudes available for general aircraft. BMcD utilized the GE product information provided by Montana-Dakota to develop performance estimates at standard atmospheric conditions (sea level air density and normal turbulence intensity). Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition.

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated for the appropriate hub height 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. The NCF estimates are shown in the Summary Table.

6.4 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 for 20 and 50 MW plants are based on 2.72 MW turbines (9 and 23 total turbines respectively) and 80 meter hub heights.

- The project scope includes a GSU transformer for interconnection at 115 kV.
- Land costs are excluded from the project and Owner's cost. For the study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate.
- Interconnection allowances are presented as Owner's Costs and described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

6.5 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.)
- Land lease payments
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.

No allowances for capital replacement costs are 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.

6.6 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, currently worth approximately $24/MWh.

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 2019, but with a phaseout schedule that began in 2017. Projects that started construction in 2015 and 2016 will receive the full value of the PTC, but those that start or have started construction in later years will receive reduced credits:

- 2017: 80% of the full PTC value
- 2018: 60% of the full PTC value
- 2019: 40% of the full PTC value
- 2020: PTC Expires

To avoid receiving a reduction in the PTC, a "Safe Harbor" clause allowed for developers to avoid the reduction through an upfront investment in wind turbines by the end of 2016. The Safe Harbor clause allowed 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, 2017.

Many wind farms were planned for construction and operation when it was assumed 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.

7.0 RENEWABLE TECHNOLOGY – SOLAR PHOTOVOLTAIC

This Assessment includes a 5 MW and a 50 MW single axis tracking photovoltaic (PV) option with add-on costs for co-located battery energy storage of 1 MW / 4 MWh and 10 MW/ 40 MWh respectively.

7.1 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.

7.2 PV Emission Controls

No emission controls are necessary for a PV system.

7.3 PV Performance

BMcD ran simulations of the PV options using PVsyst software. The resultant capacity factors for the single axis tracking systems are shown in the Summary Table. The inverter loading ratio for the systems are 1.32 at the inverter and 1.35 at the point of injection. Model outputs are intended to be representative of plant of performance in North Dakota.

Capacity factors are better for tracking systems, but costs are generally higher for similar ILR ratios. 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. Additional assumptions are listed in the scope matrix in Appendix A.

7.4 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 single axis tracking system are included in the Summary Tables. Costs are based on the DC/AC ratios mentioned in the PV Performance section of this report. The project scope assumes a medium voltage interconnection and the Owner's costs include an allowance for interconnection downstream of the 34.5 kV circuit breaker. Add-on costs for co-located Lithium Ion battery energy storage are included for a 1 MW / 4 MWh and 10 MW / 40 MWh.

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. All PV costs have been updated to account for the impacts of 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 2018 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.

7.5 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 Assessment includes allowances for a land lease.

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

- O&M costs assume that the system is remotely operated, and all O&M costs are modeled as fixed costs, shown in terms of $MM per year.
- O&M costs include a land lease allowance.
- Property tax and insurance are presented in the Summary Table as part of Fixed O&M costs with rates provided by Montana-Dakota.
- Equipment O&M costs account for inverter maintenance, other routine equipment inspections and an allowance for potential inverter replacements.
- BOP costs account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs.

8.0 BIOMASS

This Assessment includes a 25 MW biomass facility based on the information provided by Montana-Dakota on the feasibility of supplying biomass to the Spiritwood Industrial Park submitted by Great River Energy, the Great Plains Institute and others.

8.1 Biomass General Description

The term "biomass" refers to any regenerative organic material used as a fuel for energy production, which can be grown, harvested and re-grown. Biomass fuel typically consists of forestry materials, wood residues, agricultural residues, and energy crops. Biomass power generation facilities are typically located near the source of the fuel to reduce transportation costs in fuel delivery.

In a bubbling fluidized bed (BFB) boiler, combustion occurs on a sand bed at the base of the boiler. The bed becomes suspended or fluidized bed upon the introduction of air flow from the bottom of the boiler. Solid fuels are introduced on the bed for combustion, and ash particles fall to the bottom for periodic removal. This study evaluates a BFB boiler burning 100% grass biomass assumed to be in a concentrated form and of moderate moisture content. The nominal size of the biomass facility was sized to require less annual fuel than estimated to be available for the highest ranked biomass resource recommended for co-firing at the Spiritwood Facility, CRP grasses and switchgrass.

8.2 Biomass Emissions Controls

The BFB option is assumed to require SNCR to control NO_x emissions. SO_2 emissions are controlled by furnace limestone injection followed by a polishing scrubber using hydrated furnace ash as sorbent. This evaluation also includes a baghouse to remove particulate from the flue gas, dry sorbent injection to control acid gases, and a carbon injection system to control mercury. It is assumed that CO emissions are controlled through sound combustion practices. Due to the expected makeup of the particulates in the flue gas, an oxidation catalyst is not likely feasible.

8.3 Biomass Performance

Performance and cost estimates are shown in the Summary Table.

8.4 Biomass Cost Estimates

Biomass BFB cost information from prior BMcD research was evaluated in comparison to industry research documents. Cost estimates assume an EPC project plus typical Owner's costs. The general cost assumptions in Section 2.0 apply to the evaluation of the BFB option.

Additional cost clarifications and assumptions are shown below:

- Assumes one BFB boiler and one STG with wet cooling for heat rejection.
- Estimate includes selective non-catalytic reduction (SNCR), dry sorbent injection, baghouse, and activated carbon injection.
- The switchyard cost estimate assumes a 3-position ring bus.
- Interconnection allowances are presented as Owner's Costs and described in Section 2.4.
- Interest during construction is presented as a loaded cost as provided by Montana-Dakota.

8.5 Biomass O&M Cost Estimate

General assumptions for fixed and variable O&M costs are listed in Section 2.7. Additional assumptions are listed in the Scope Matrix.

- O&M Costs are derived from in-house information based on BMcD experience and industry research.
- Variable O&M accounts for costs due to routine maintenance, major maintenance and emissions controls consumables.

9.0 COAL

9.1 General Description

The Coal performance and cost information represented in this assessment is provided by Montana-Dakota and based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council (LEC Study, 2012).

9.2 Circulating Fluidized Bed (CFB)

The combustion process within a CFB boiler occurs in a suspended or fluidized bed of solid particles. The solid particles are a mixture of fuel, ash products from prior combustion, and some form of inert material such as sand, slag, etc. The boiler operates by blowing air into the boiler through air nozzles in the bottom as fuel is injected into the furnace, thereby creating a fluidized bed of material. As combustion takes place, smaller particles are carried out of the boiler and collected by solid separators. This material is circulated back into the bottom of the furnace to combine with the large particles that did not get carried out and provides the ignition source for the new fuel being fed into the unit. CFB combustion is a mature technology with inherently low emission rates compared to pulverized coal combustion.

Due to the combustion process, CFB technology is well suited to burn fuels with large variability in constituents. Deviations in fuel type, size, and heat content have minimal effect on the furnace performance characteristics. Unlike pulverized coal units, CFB units do not require tuning of the burners for each fuel to obtain the appropriate air fuel mixture and optimal settings. Sites with access to abundant sources of fuels that vary significantly in constituents or that present combustion challenges to other boiler types are typically good prospects for CFB plants.

9.3 Coal CFB Emissions Controls

The CFB combustion process yields inherently low NO_x emissions, while some SO_2 emissions are typically removed by limestone in the furnace. CO emissions are assumed to be uncontrolled. The study used for this assessment assumes installation of a Selective Non-Catalytic Reduction (SNCR) system to further reduce NO_x emissions. The most economical and efficient form of additional SO_2 removal on a CFB is a polishing dry FGD. Dry scrubbing involves spraying an atomized solution of an alkaline reagent, typically lime-based, into hot flue gas for the absorption of SO_2. Moisture in the spray then evaporates so that the absorbed SO_2 is carried in suspension out of the boiler and collected in the baghouse filtration system.

This assessment also includes an option with carbon capture utilizing an amine process. In advanced amine processes, a continuous scrubbing system is used to separate CO_2 from the flue gas stream. These systems consist of two main elements: an absorber where CO_2 is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where CO_2 is released (in concentrated form) from the solvent and the original solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the CO_2 in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat recovery exchanger and is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated CO_2 gas stream. The hot CO_2-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added as make up for losses incurred in the process.

Emissions control for the coal options in this assessment are based on the information provided by Montana-Dakota in the LEC Study which were designed to meet EPA regulation at the time of its writing (2012). No update to emissions control requirements or operating limits for new energy generating units firing coal is included.

9.4 Coal Performance

Coal performance information is shown in the Summary Table. Performance information is provided by Montana-Dakota and based on the LEC Study.

9.5 Coal Cost Estimates

Coal capital cost estimates are shown in the Summary Table. Project cost information is provided by Montana-Dakota and based on the LEC Study.

The general assumptions in Section 2.4 for Owner's Costs govern as applicable for the Coal options with additional assumptions listed in the Summary Table.

9.6 Coal O&M Cost Estimates

Coal O&M estimates are shown in the Summary Table. O&M information is provided by Montana-Dakota and based on the LEC Study.

10.0 EMERGING TECHNOLOGIES

10.1 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

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

10.1.1 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 or over-sizing 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.

10.1.2 Liquid Air Energy Storage

Liquid Air Energy Storage (LAES) systems convert ambient air to liquefied air stored in above-ground cryogenic storage tanks which is expanded to meet power demand. LAES systems are typically advantageous when co-located with industrial processes that result in waste heat and might produce electricity. In these applications, LAES systems can serve to manage energy demand and reduce peak hour energy use.

During periods of low demand, lower cost electrical energy can be used to draw air from the environment, filter for contaminants, and then compress the air through multiple stages to supply the storage tanks at medium-pressure and low temperature. The liquid air is stored in these tanks resulting in scalable amounts of potential energy storage. The tanks used in LAES systems are similar to those used in other industries for bulk storage of nitrogen, oxygen and liquefied natural gas. When power is to be discharged from the LAES system, the liquid air is pumped to a higher pressure, evaporated and superheated. This high-pressure fluid is expanded across a turbine to recuperate the energy stored. With additional sources of waste heat, from industrial processes or co-located energy generation assets, the air can be superheated to a greater extent. This additional energy input results in a higher-pressure fluid to expand through the turbine leading to greater energy generated in the discharge phase.

Due to the modular nature of the storage components, LAES systems can be scaled to meet the applications' needs with commercially available options existing in the 5-100 MW range. LAES systems differ from other energy storage options as they do not involve an electrochemical reaction and are based mechanical compression and expansion. However, their construction does not require limited geologic conditions as compressed air energy storage systems (CAES) which are limited to suitable caverns.

LAES systems exhibit round trip efficiencies in the 60% - 70% range. Like flow batteries, an advantage of LAES is long project life and minimal performance degradation over that life. There is a 5MW / 15MWh system installed in the United Kingdom, so the technology is commercially available, but there is little market penetration currently in the USA. It is recommended that Montana-Dakota monitor the market and technology development for LAES systems in the coming years.

10.1.3 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.

11.0 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 simple cycle 7E.03 LLI option exhibits the lowest capital cost per kW generated. If an SCR is required for the simple cycle application, or other emissions regulations where to pass, then the 7E.03 LLI cost could increase, or would face other operational limits.

Aeroderivative turbines generally exhibit excellent heat rates, fast start and ramp rates, and reliable operation, but they also tend to be more expensive than frame units on a $/kW scale.

Reciprocating engine plants offer the lowest heat rates and fastest start times when compared to simple cycle gas turbine options. Reciprocating engine plants are also likely to exhibit the greatest capacity range among simple cycle options, with a minimum load of a single engine at 25% - 50% load. Variable O&M for engine plants is higher than frame GTs and should be considered in an analysis. It is expected that reciprocating engine plants will require SCR systems and CO catalysts to control emissions.

Combined cycle plants offer better heat rates than all other combustion plants evaluated. Of the evaluated greenfield plants, the 1x1 F class option shows the lowest capital cost per kW.

Renewable options include PV and wind systems. 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 have impacted market trends. Wind energy generation is a proven technology and turbine costs have dropped considerably over the past few years.

Biomass and coal information are also presented in this Assessment based on information provided by Montana-Dakota Utilities and prepared by others.

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

APPENDIX A – SCOPE MATRIX

2019 MDU TECHNOLOGY ASSESSMENT ASSUMPTIONS

	Simple Cycle	Reciprocating Engines	Combined Cycle	Wind	PV	PV + Storage	Biomass	Coal (Note 1)
Project Description								
Plant Size(s):	Aero LM6000 PF+	4x 9MW Engines	2 x 1 SGT-800 with Duct Firing	20 MW	50 MW - Single Axis Tracking	Co-Located w/50 MW PV 10 MW / 40 MWh Storage	25 MW Bubbling Fluidized Bed	Circulating Fluidized Bed w/o CC
	Aero LMS100 PB+	3x 18MW Engines	1 x 1 7F.05 with Duct Firing	50 MW	5 MW Single Axis Tracking PV	Co-Located w/5 MW PV 1 MW / 4 MWh Storage		Circulating Fluidized Bed w/ CC
	GE 7E.03 LLI (Greenfield & at RM Heskett)		2 x 1 7EA with Duct Firing Heskett Expansion					
Fuel:	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	N/A	Grasses (CRP and Switchgrass)	100% Raw ND Lignite
Project Location:	North Dakota							
Contract Philosophy:	Multiple Contract Approach (EpCM)							
Project COD:	Shown in 2019 USD (i.e. no escalation)							
Labor Type:	Union							
Labor Incentives:	50 hrs / week & $80 per day per diem							
Site Description:	Greenfield (with exception to RM Heskett Expansion)							
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. 2 x 100% boiler feed pumps and ID/FD/ PA fans							
Site Condition:	Flat, minimal rock, soils stable for spread footings for all foundations except turbines and coal plant stacks.							
Site Elevation:	1690 ft AMSL							
Site Summer Ambient Conditions:	84.5°F / 40% RH							
Site Winter Ambient Conditions:	6.8°F / 70% RH							
Water Supply:	Fresh Water supply from wells or surface water; pipeline/intake excluded from cost.							
Waste Water Disposal:	Effluent discharge to evaporation pond onsite.	Discharge offsite, piping beyond site boundary excluded.	Effluent discharge to evaporation pond onsite.	N/A	N/A	N/A	Effluent discharge to pond onsite.	Not specified in report provided by MDU
Performance Basis								
Steam Design Pressure:	N/A	N/A	2400 psia (7F.05) 1400 psia (SGT-800) 1500 psia (Heskett)	N/A	N/A	N/A	1500 psia	2400 psia
Steam Design Temperature:	N/A	N/A	1050 F/ 1050F 1000 F (SGT-800) 1000 F (Heskett)	N/A	N/A	N/A	950 F	1050 F
Inlet cooling	Evaporative Cooling Included for Summer Performance	N/A	Evaporative Cooling Included for Summer Performance	N/A	N/A	N/A	N/A	N/A
Heat Rejection Design:	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Wet Cooling Tower	N/A	N/A	N/A	Wet Cooling Tower	50% Wet Colled / 50% Air Cooled
Availability Metrics	GADS data, as applicable.							
Fuel, Sorbent, and Ash Landfill								
Design Fuel:	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	N/A	Grasses (CRP and Switchgrass)	100% Raw ND Lignite
Back-up Fuel:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Start-up Fuel:	Natural Gas	Natural Gas	Natural Gas	N/A	N/A	N/A	Natural Gas Assumed	Natural Gas Assumed
Fuel for Duct Burners:	N/A	N/A	Natural Gas	N/A	N/A	N/A	N/A	N/A
Unloading System:	N/A	N/A	N/A	N/A	N/A	N/A	Truck Dumper	Not specified in report provided by MDU
Live Storage:	N/A	N/A	N/A	N/A	N/A	N/A	Covered Storage	Day Silos
Long-term storage:	N/A	N/A	N/A	N/A	N/A	N/A	Open Pile	Not specified in report provided by MDU
SO_2 Control Reagent:	N/A	N/A	N/A	N/A	N/A	N/A	Limestone / Lime in Polishing Scrubber	FDA + LKP
SO_2 Control Reagent Delivery:	N/A	N/A	N/A	N/A	N/A	N/A	Truck	Not specified in report provided by MDU
SO_2 Control Reagent Storage:	N/A	N/A	N/A	N/A	N/A	N/A	Outdoor, uncovered pile	Not specified in report provided by MDU
Ammonia:	Aqueous Ammonia delivered by truck for LMS100	Urea delivered by truck	Aqueous Ammonia delivered by truck for units with SCR	N/A	N/A	N/A	Aqueous Ammonia delivered by truck	Not specified in report provided by MDU
Mercury Sorbent Storage:	N/A	N/A	N/A	N/A	N/A	N/A	Silo	Not specified in report provided by MDU
Fly Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	Onsite Landfill	Onsite Silo
Scrubber Sludge / Byproduct Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	Included in Fly Ash	Included in Fly Ash
Bottom Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	Onsite Landfill	Onsite Silo
Landfill Size:	N/A	N/A	N/A	N/A	N/A	N/A	5 Year Cell	Not specified in report provided by MDU
Landfill delivery:	N/A	N/A	N/A	N/A	N/A	N/A	Truck	Not specified in report provided by MDU
Enclosures:								
Gas Turbine or Engine:	Outdoor	Indoor	Outdoor	N/A	N/A	N/A	N/A	N/A
Steam Turbine:	N/A	N/A	Indoor	N/A	N/A	N/A	Indoor	Not specified in report provided by MDU
Boiler or HRSG:	N/A	N/A	Indoor	N/A	N/A	N/A	Indoor	Not specified in report provided by MDU
Scrubber:	N/A	N/A	N/A	N/A	N/A	N/A	Indoor	Not specified in report provided by MDU
Buildings:								
Administration Building	Included	Included in Engine Hall	Included	Included	Included	Co-Located with PV	Included	Included
Warehouse	Included	Included in Engine Hall	Included	Included	Included	Co-Located with PV	Included	Included
Maintenance	Included	Included in Engine Hall	Included	Included	Included	Co-Located with PV	Included	Included
Misc. Equipment Enclosures	Minimal Included. Limited to Electrical Equipment, CEMS enclosure, etc							

2019 MDU TECHNOLOGY ASSESSMENT ASSUMPTIONS

	Simple Cycle	Reciprocating Engines	Combined Cycle	Wind	PV	PV + Storage	Biomass	Coal (Note 1)
Emissions and Emissions Controls*								
NOx Control:	DLN, SCR included for LMS100 PB+, option for all others	SCR	DLN / SCR	N/A	N/A	N/A	SNCR	SNCR
CO Control:	Good Combustion Practice, Catalyst included for LSM100PB+	CO Catalyst	CO Catalyst	N/A	N/A	N/A	Good Combustion Practice	Good Combustion Practice
SO_2 Control:	Low Sulfur Fuel	Low Sulfur Fuel	Low Sulfur Fuel	N/A	N/A	N/A	Dry Sorbent Injection	FDA + LKP
SO_3 Control:	N/A	N/A	N/A	N/A	N/A	N/A	Polishing Scrubber	Not specified in report provided by MDU
PM10 Control (filterable & condensable particulate):	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	N/A	N/A	N/A	Baghouse	Baghouse
Mercury Control:	N/A	N/A	N/A	N/A	N/A	N/A	Activated Carbon Injection into Exhaust Gas	Activated Carbon Injection into Exhaust Gas
VOC Control:	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	N/A	N/A	N/A	Good Combustion Practice	Good Combustion Practice
CO2 Capture/Compression	N/A	N/A	N/A	N/A	N/A	N/A	N/A	CO2 Capture as described in option description
Interconnection:								
Switchyard:	Included with position for generators & 2 outgoing lines. PV + Storage assume interconnection at distribution voltage.							
Transmission Interconnect:	Cost for 15 mile of transmission line at interconnection voltage, excludes land costs.							
Interconnection Voltage:	115 kV for all except PV + Storage which is at 34.5 kV							
Gas Interconnection:	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4": LM6000 PF+ 6": LMS100 PB+, 7E.03 LLI	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4"	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 8": 2x1 SGT-800, 1x1 7F.05	N/A	N/A	N/A	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4"	Included, 5 mi. of interconnection, easement allowance and metering. Line diam.: 4"
Water Interconnection:	Interconnection includes onsite wells and associated piping.	Interconnection includes onsite wells and associated piping.	Interconnection includes onsite wells and associated piping.	N/A	N/A	N/A	Interconnection includes onsite wells and associated piping.	Interconnection includes onsite wells and associated piping.
MISO Queue Fees:	Included							
Network Upgrades:	Included as provided by MDU							
Miscellaneous Equipment:								
Fire protection:	New Fire Pump and Emergency Diesel Backup for dedicated onsite storage			N/A	N/A	N/A	Included	Not specified in report provided by MDU
Emergency Generator:	New Diesel Generator			N/A	N/A	N/A	Included	Not specified in report provided by MDU
Auxiliary Boiler:	N/A	N/A	Included	N/A	N/A	N/A	Included	Not specified in report provided by MDU
Black Start:	Excluded							
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:	Allowance is 1% of Project Cost							
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	Allowance Included							
Labor Camp	Assumed to not be required. Plant has local towns/ housing							
Construction Power	Allowance Included							
Fuel Consumed during Commissioning	Allowance Included							
Power Generated & Sold during Commissioning	Allowance Included							
Initial Fuel Inventory	Allowance Included							
Builder's Risk Insurance	Allowance Included							
Operating Spare Parts	Allowance Included for critical equipment only & minor parts. No spare GSU included							
Workshop Tools & Test Equipment	Allowance Included							
Warehouse Shelves	Allowance Included							
Mobile Equipment, Vehicles	Allowance Included							
Laboratory Equipment & Furniture	Allowance Included							
Kitchen Furniture	Allowance Included							
Locker Room Furniture	Allowance Included							
Building Furniture	Allowance Included							
Owner's Contingency:	Included @ 10% to reflect anticipated spent contingency for screening purposes.							
Financing Fees	Excluded							
Interest During Construction	Provided by MDU							
Sales Tax:	Excluded							
Notes								
Note 1	Coal technology option information provided by MDU, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council. Their assumptions govern the information presented and may not be completely represented in the table above.							

2019 MDU TECH ASSESSMENT OPERATING ASSUMPTIONS

	Simple Cycle - Aero	Simple Cycle - Frame	Reciprocating Engines	Combined Cycle	Wind	PV / PV + Storage	Biomass	Coal (Note 1)
General								
Staffing:								
Number of Personnel:	4	4	4	1x1: 22, 2x1: 25 RM Heskett Expansion: 20	2	2	44	Not specified in report provided by MDU
Labor Cost:	$120,000 per person per year (all in including burdens, benefits, bonuses, and overtime							
Operating Hours Considered:	1,314 Hours	1,314 Hours	1,314 Hours	6,132 Hours	N/A	N/A	7,446 Hours (85% CF)	7,884 Hours w/o CC, 7446 Hours w/CC
Standby Power:	Included for Non-Operating 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. (0.416% of Total Loaded Project Cost)							
Maintenance Considerations								
Major Maintenance Basis	Major Maintenance assumes third party contract	Major Maintenance assumes third party contract	Major Maintenance assumes third party contract	Major Maintenance assumes third party contract	Wind Turbine maintenance assumes third party contract	Storage assumes third party contract for augmentation.	Major Maintenance assumes third party contract	Not specified in report provided by MDU
Service Director Included:	No	Yes	No	Yes	N/A		N/A	N/A
Engine Lease Agreement Included (Engine Swap)	No	No	No	No	N/A			
SCR and CO Catalyst Replacements:	25,000 hours as applicable							
Fuel / Ash Handling Mobile Equipment:	N/A							
Scope Basis / Assumptions								
Water Supply Cost:	Raw water assumes $0.10/kgal.							
Water Quality Assumptions:	Suitable for use in evaporative coolers / cooling towers with 4 cycles of concentration and without any pretreatment. Standard chemical treatment for corrosion / biological growth only							
Demineralizer System	N/A	N/A	N/A	Permanent On-Site RO w/Mixed Bed Polisher	N/A		Permanent On-Site RO w/Mixed Bed Polisher	Not specified in report provided by MDU
Water Discharge Treatment:	Neutralize Only for discharge to onsite evaporation pond, as applicable							Not specified in report provided by MDU
Water Discharge Cost:	Water Discharge Treatment Cost included in Variable O&M. No Water Discharge Demand Cost included.							Not specified in report provided by MDU
Fuel, Sorbent, and Ash Landfill								
SO2 Control:	N/A	N/A	N/A	N/A	N/A	N/A	Furnace Limestone Injection Followed by a Polishing Scrubber Utilizing Hydrated Furnace Ash for Sorbent	Sulfur Capture in Circulating Fluid Bed with Subsequent Polishing in Flash Dryer Absorber and Baghouse
Lime Costs:	N/A	N/A	N/A	N/A	N/A	N/A	None (assumes that excess lime from boiler is hydrated and utilized in the polishing scrubber)	Not specified in report provided by MDU
NOx Control:	DLN combustors with SCR option for LM6000. DLN combustors with SCR standard for LMS100.	DLN with SCR option.	SCR	DLN and SCR for greenfield options DLN only for RM Heskett Expansion	N/A	N/A	SNCR	SNCR
CO Control:	Good Combustion Practice Oxidation Catalyst for LMS100PB+	Good Combustion Practice	Oxidation Catalyst	Oxidation Catalyst Good Combustion Practice for Heskett Expansion	N/A	N/A	Good Combustion Practice	Good Combustion Practice
Ammonia Type:	Aqueous	N/A	Urea	Aqueous	N/A	N/A	Aqueous	Anhydrous or Aqueous not specified in report provided by MDU
Mercury Sorbent Type:	N/A	N/A	N/A	N/A	N/A	N/A	Activated Carbon Injection	Activated Carbon Injection
CO2 Control	N/A	N/A	N/A	N/A	N/A	N/A	N/A	CO2 Capture as Applicable
Fly Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Bottom Ash / Slag Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Scrubber Sludge / Sulfur Byproduct Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Fly Ash Disposal:	N/A	N/A	N/A	N/A	N/A	N/A	On-Site Landfill	On-Site Landfill
Emissions and Emissions Controls								
NOx Emissions Allowance Costs:	Excluded							
SOx Emissions Allowance Costs:	Excluded							
Mercury Emissions Allowance Costs:	Excluded							
Carbon Dioxide Emissions Allowance Costs / Tax:	Excluded							
Emissions and Emissions Controls								
Note 1	Coal technology option information provided by MDU, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council. Their assumptions govern the information presented and may not be completely represented in the table above.							

APPENDIX B – 2019 IRP TECHNOLOGY ASSESSMENT SUMMARY TABLE

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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PROJECT TYPE	1x Aeroderivative SCGT - Natural Gas	1x Aeroderivative SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion	Reciprocating Engine (9MW Engines)	Reciprocating Engine (18 MW Engines)
BASE PLANT DESCRIPTION						
Number of Gas Turbines/Engines/Units	1	1	1	1	4	3
Representative Class Gas Turbine	GE LM6000 PF+	GE LMS100 PB+	GE 7E.03 LLI	GE 7E.03 LLI	Wartsila 20V34SG	Wartsila 18V50SG
Capacity Factor (%)	15%	15%	15%	15%	15%	15%
Startup Time to Maximum Load, minutes (Notes 1, 2)	5	5	30	30	5	5
Startup Time to MECL, minutes (Note 3)	4	4	20	20	4	4
Startup Time to Stack Emissions Compliance, minutes (Note 20)	9	30	25	25	30	30
Maximum Ramp Rate, MW/min (Online)	14	25	24	24	18	28
Forced Outage Factor (%) (Notes 4, 5)	3.8%	3.8%	0.7%	0.7%	1.8%	1.8%
Equivalent Forced Outage Rate (%) (Notes 4, 5)	25.9%	25.9%	5.8%	5.8%	4.5%	4.5%
Availability Factor (%) (Notes 4, 5)	90.6%	90.6%	93.8%	93.8%	95.3%	95.3%
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger & Intercooler	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NO_x Control	DLN	DLN & SCR	DLN	DLN	SCR	SCR
CO Control	Good Combustion Practice	Oxidation Catalyst	Good Combustion Practice	Good Combustion Practice	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
ESTIMATED PERFORMANCE (Note 6)						
WINTER AMBIENT						
Base Load Performance @ 6.8°F / 70% RH (MDU Winter)						
Gross Plant Output, kW	55,570	101,470	99,470	99,470	37,480	56,450
Net Plant Output, kW	54,730	99,340	97,680	97,680	36,540	55,040
Net Plant Heat Rate, Btu/kWh (HHV)	9,210	8,860	11,180	11,180	8,450	8,310
Heat Input, MMBtu/h (HHV)	504	880	1,093	1,093	309	458
Minimum Load Operational Status @ 6.8°F / 70% RH (MDU Winter)					(Single Engine)	(Single Engine)
Gross Plant Output, kW	27,780	50,730	49,740	49,740	3,710	7,480
Net Plant Output, kW	27,370	49,670	48,840	48,840	3,620	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,850	10,820	14,490	14,490	10,220	9,630
Heat Input, MMBtu/h (HHV)	324	537	708	708	37	70
SUMMER AMBIENT						
Base Load Performance @ 84.5°F / 40% RH (MDU Summer, Incl. Evap Cooler)						
Gross Plant Output, kW	46,020	92,510	80,290	80,290	37,480	56,450
Net Plant Output, kW	45,280	90,660	78,280	78,280	36,540	55,040
Net Plant Heat Rate, Btu/kWh (HHV)	9,510	9,050	11,770	11,770	8,470	8,310
Heat Input, MMBtu/h (HHV)	431	821	922	922	309	458
Minimum Load Operational Status @ 84.5°F / 40% RH (MDU Summer)					(Single Engine)	(Single Engine)
Gross Plant Output, kW	20,640	45,160	37,590	37,590	3,710	7,480
Net Plant Output, kW	20,330	44,210	36,910	36,910	3,620	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	13,210	11,330	15,790	15,790	10,240	9,630
Heat Input, MMBtu/h (HHV)	269	501	583	583	37	70

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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PROJECT TYPE	1x Aeroderivative SCGT - Natural Gas	1x Aeroderivative SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion	Reciprocating Engine (9MW Engines)	Reciprocating Engine (18 MW Engines)
ESTIMATED CAPITAL AND O&M COSTS						
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$58**	**$102**	**$70**	**$66**	**$54**	**$70**
Project Cost Per Summer kW, 2019 $/kW	**$1,280**	**$1,120**	**$890**	**$840**	**$1,470**	**$1,280**
Owner's Costs, 2019 MM$	**$47**	**$58**	**$55**	**$15**	**$46**	**$49**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Operational Personnel Prior to COD	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Engineer	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Management	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Owner's Legal Costs	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Owner's Start-up Engineering	$1.2	$1.2	$1.2	$1.2	$0.9	$0.9
Temporary Utilities	$0.5	$0.5	$0.5	$0.1	$0.5	$0.5
Permitting and Licensing Fees	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Switchyard (Note 18)	$4.0	$4.0	$4.0	$1.0	$4.0	$4.0
Land (Note 17)	$0.1	$0.1	$0.1	N/A	$0.1	$0.1
Transmission Interconnection (Notes 7, 19)	$15.0	$15.0	$15.0	$0.5	$15.0	$15.0
Gas Interconnection (Note 8)	$7.4	$8.7	$8.7	$1.3	$7.4	$7.4
Water Interconnection (Note 9)	$0.1	$0.1	$0.1	Existing	$0.1	$0.1
MISO Queue Fees (Note 10)	$0.3	$0.3	$0.3	$0.1	$0.2	$0.3
Network Upgrades	$6.2	$11.2	$11.0	$0.0	$4.1	$6.2
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.0	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.5	$0.5	$0.5	$0.5	$1.4	$1.4
Site Security	$0.4	$0.4	$0.4	$0.0	$0.4	$0.4
Operating Spare Parts	$1.8	$1.8	$1.8	$0.0	$2.0	$2.0
Permanent Plant Equipment and Furnishings	$0.3	$0.3	$0.3	$0.0	$0.3	$0.3
Builders Risk Insurance (0.45% of Construction Costs)	$0.3	$0.5	$0.3	$0.3	$0.2	$0.3
Owner's Contingency (10% for Screening Purposes)	$5.8	$10.2	$7.0	$6.6	$5.4	$7.0
Total Project Costs, 2019 MM$	**$105**	**$160**	**$124**	**$80**	**$99**	**$120**
Total Cost Per Summer kW, 2019 $/kW	**$2,320**	**$1,760**	**$1,590**	**$1,030**	**$2,710**	**$2,180**
Loaded Costs						
Interest During Construction, MM$	$5	$8	$8	$5	$5	$6
Total Project Costs, 2019 MM$ (Loaded)	**$110**	**$168**	**$132**	**$85**	**$104**	**$126**
Total Cost Per Summer kW, 2019 $/kW (Loaded)	**$2,440**	**$1,850**	**$1,680**	**$1,090**	**$2,850**	**$2,290**
SCR ADD-ON COSTS						
Capital Costs, 2019 MM$	$5.3	Included	$19	$19	Included	Included
Owner's Costs, 2019 MM$	$0.3	Included	$1.1	$1.1	Included	Included
Loaded Costs, Interest During Construction, 2019 MM$	$0.3	Included	$1.2	$1.2	Included	Included

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
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PROJECT TYPE	1x Aeroderivative SCGT - Natural Gas	1x Aeroderivative SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas	1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion	Reciprocating Engine (9MW Engines)	Reciprocating Engine (18 MW Engines)
FIXED O&M COST						
Fixed O&M Cost, 2019$/kW-mo (Note 11)	$2.50	$1.20	$1.40	$0.80	$2.60	$1.80
Property Tax, 2019 $/kW-mo (Note 21)	$0.80	$0.60	$0.60	$0.40	$1.00	$0.80
Property Insurance, 2019 $/kW-mo (Note 22)	$0.30	$0.20	$0.20	$0.10	$0.30	$0.30
NON-FUEL VARIABLE & MAINTENANCE COSTS						
Major Maintenance Cost, 2019$/Unit-hr (Notes 2, 12, 16)	$170.0	$300	$330.0	$330.0	$25	$22
Major Maintenance Cost, 2019$/Unit-Start	N/A	N/A	$9,000.0	$9,000.0	N/A	N/A
Major Maintenance Cost, 2019$/MWh (Note 23)	$5.00	$4.40	$5.60	$5.60	$2.60	$1.20
Variable O&M Cost, 2019$/MWh (Note 13)	$0.9	$1.7	$0.9	$0.9	$4.4	$4.6
SCR O&M Costs						
Incremental Fixed O&M Costs, 2019$/kWh	$0.00	Included	$0.00	$0.00	Included	Included
Incremental Variable O&M Cost, 2019$/MWh	$0.70	Included	$0.60	$0.60	Included	Included
ESTIMATED BASE LOAD OPERATING EMISSIONS (ISO) (Note 14)						
Turbine/Engine Only						
Gross Carbon Intensity (lb/MWh)	1,110	1,050	1,460	1,460	N/A	N/A
NO_X [lb/MMBtu, HHV]	0.090	0.100	0.020	0.020	N/A	N/A
NO_X [ppmvd @ 15% O_2]	25	25	5.0	5.0	N/A	N/A
NO_X [lb/hr]	40.0	86	19.0	19.0	N/A	N/A
CO [lb/MMBtu, HHV]	0.050	0.500	0.050	0.050	N/A	N/A
CO [ppmvd @ 15% O_2]	25	187	25	25	N/A	N/A
CO [lb/hr]	24.0	390	55.0	55.0	N/A	N/A
CO_2 [lb/MMBtu, HHV]	120	120	120	120	N/A	N/A
CO_2 [ppmvd @ 15% O_2]	49,500	34,400	34,700	34,700	N/A	N/A
CO_2 [lb/hr]	53,200	103,900	121,000	121,000	N/A	N/A
PM/PM_{10} [lb/MMBtu, HHV]	0.007	0.005	0.004	0.004	N/A	N/A
PM/PM_{10} [lb/hr]	3.00	4	4.20	4.20	N/A	N/A
Turbine /Engine with SCR and CO Catalyst						
Gross Carbon Intensity (lb/MWh)	1,120	1,050	1,460	1,460	990	970
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.010	0.010	0.020	0.020
NO_X [ppmvd @ 15% O_2]	2.5	2.5	2.0	2.0	5.0	5.0
NO_X [lb/hr]	4.40	8.60	8.30	8.30	1.20	2.50
CO [lb/MMBtu, HHV]	0.000	0.010	0.010	0.010	0.030	0.030
CO [ppmvd @ 15% O_2]	2.0	4.00	2.00	2.00	15.0	15.0
CO [lb/hr]	2.20	8.40	5.00	5.00	2.50	5.00
CO_2 [lb/MMBtu, HHV]	120	120	120	120	120	120
CO_2 [ppmvd @ 15% O_2]	34,300	34,300	34,300	34,300	N/A	N/A
CO_2 [lb/hr]	53,200	104,000	121,000	121,000	9,300	18,300
PM/PM_{10} [lb/MMBtu, HHV]	0.010	0.008	0.008	0.008	0.020	0.020
PM/PM_{10} [lb/hr]	4.40	6.70	7.40	7.40	1.70	3.30

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3						
PROJECT TYPE	**1x Aeroderivative SCGT - Natural Gas**	**1x Aeroderivative SCGT - Natural Gas**	**1x GE 7E.03 LLI SCGT - Natural Gas**	**1x GE 7E.03 LLI SCGT - Natural Gas Heskett Expansion**	**Reciprocating Engine (9MW Engines)**	**Reciprocating Engine (18 MW Engines)**

Notes:

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available. Recip engine start times assume the engines are kept warm when not operational.
Note 2: OEM specific frame turbine option (7E.03 LLI) does not include a fast start package.
Note 3: MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate.
Note 4: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2007 or later. Reporting period is 2011-2016. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.
Note 5: EFOR data from GADS may not accurately represent the benefits of a reciprocating plant, depending on how events are recorded. Typically, a maintenance event will not impact all engines simultaneously, so the plant would not be completely offline as it may be during an event at 1x gas turbine plant.
Note 6: Performance estimates were developed with natural gas only at the conditions provided by Montana-Dakota Utilities.
Note 7: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage, land costs excluded.
Note 8: Natural gas interconnection includes an allowance for 5 mile pipeline, utility interconnect and metering station. R.M. Heskett interconnection cost excludes existing pipeline to site, and includes additional pressure regulation equipment.
Note 9: Water interconnection allowance includes on site wells and pipe for raw water supply.
Note 10: 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 down payment on Network Upgrades which are shown separately as provided by MDU.
Note 11: All Gas Turbine FOM costs assume 4 full time personnel for greenfield options. Brownfield options assume 2 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
Note 12: Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27.
Note 13: VOM assumes the use of temporarily trailers for demineralized water treatment, where applicable.
Note 14: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable. Estimates are not for use for permitting purposes.
Note 15: Performance ratings are based on elevation of 1690 ft above msl.
Note 16: Reciprocating Engine major maintenance cost assumes no major overhaul falls within 20 year service period.
Note 17: Land allowance includes 15 acres at $5000/acre.
Note 18: Switchyard allowance for the Heskett Expansion as provided by MDU.
Note 19: Transmission allowance for Heskett Expansion provided by MDU.
Note 20: Startup time to stack emissions compliance is not the same as the start time to MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst (which impacts VOC emissions) and the time required for the emissions monitoring equipment to measure values matching the unit emissions rates included in this table. Estimates are not for use for permitting purposes.
Note 21: Property tax rate provided by MDU.
Note 22: Property Insurance rate provided by MDU.
Note 23: Major maintenance per MWh assumes 75% of summer net capacity for operating hours.

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**
BASE PLANT DESCRIPTION			**OPTION 1**
Number of Gas Turbines	2	1	1 Exist / 1 New
Number of Steam Turbines	1	1	1
Representative Class Gas Turbine	Siemens SGT-800	GE 7F.05	GE 7E.03
Steam Conditions (Main Steam / Reheat)	1000 °F	1050 °F / 1050 °F	1000 °F
Main Steam Pressure, psia	1400	2400	1500
Steam Cycle Type	Subcritical	Subcritical	Subcritical
Capacity Factor (%)	70%	70%	70%
Startup Time, minutes (Cold Start to Unfired Base Load) (Note 1)	170	180	180
Startup Time, minutes (Cold Start to Stack Emissions Compliance) (Notes 1, 2)	50	60	25
Maximum Ramp Rate (Online, MW/min)	14	34	26
Forced Outage Factor (%) (Note 3)	2.2%	2.2%	2.2%
Equivalent Forced Outage Rate (%) (Note 3)	3.6%	3.6%	3.6%
Availability Factor (%) (Note 3)	87.8%	87.8%	87.8%
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only
Heat Rejection	Wet Cooling	Wet Cooling	Wet Cooling
NO_x Control	DLN & SCR	DLN & SCR	DLN
CO Control	Oxidation Catalyst	Oxidation Catalyst	Good Combustion Practice
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel	Low Sulfur Fuel
CO_2 Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**
ESTIMATED PERFORMANCE (Note 4)			
WINTER AMBIENT			**OPTION 1**
Base Load Performance @ 6.8°F / 70% RH (MDU Winter)			
Gross Plant Output, kW	154,700	347,150	289,110
Net Plant Output, kW	150,160	338,510	279,070
Net Plant Heat Rate, Btu/kWh (HHV)	7,060	6,570	7,710
Heat Input, MMBtu/h (HHV)	1,060	2,224	2,153
			7,713
Incremental Duct Fired Performance @ 6.8°F / 70% RH (MDU Winter)			
Gross Incremental Duct Fired Output, kW	36,290	95,870	88,400
Incremental Duct Fired Output, kW	35,290	95,380	86,300
Incremental Heat Rate, Btu/kWh (HHV)	9,120	8,270	10,210
Incremental Heat Input, MMBtu/h (HHV)	322	789	881
Minimum Load Performance @ 6.8°F / 70% RH (MDU Winter)			
Gross Plant Output, kW	40,620	198,150	115,730
Net Plant Output, kW	37,250	191,160	108,750
Net Plant Heat Rate, Btu/kWh (HHV)	8,920	7,150	8,300
Heat Input, MMBtu/h (HHV)	332	1,368	903
SUMMER AMBIENT (Note 5)			
Base Load Performance @ 84.5°F / 40% RH (MDU Summer)			
Gross Plant Output, kW	136,140	337,830	250,200
Net Plant Output, kW	131,100	329,180	239,320
Net Plant Heat Rate, Btu/kWh (HHV)	7,180	6,530	7,700
Heat Input, MMBtu/h (HHV)	942	2,150	1,843
Incremental Duct Fired Performance @ 84.5°F / 40% RH (MDU Summer)			
Gross Incremental Duct Fired Output, kW	43,630	91,960	91,350
Incremental Duct Fired Output, kW	42,850	91,210	90,450
Incremental Heat Rate, Btu/kWh (HHV)	9,040	8,020	9,990
Incremental Heat Input, MMBtu/h (HHV)	387	731	903
Minimum Load Performance @ 84.5°F / 40% RH (MDU Summer)			
Gross Plant Output, kW	34,540	183,090	94,190
Net Plant Output, kW	30,680	175,220	86,460
Net Plant Heat Rate, Btu/kWh (HHV)	9,360	7,210	8,460
Heat Input, MMBtu/h (HHV)	287	1,263	731

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
December 2018 - Revision 3

PROJECT TYPE	2x1 SGT-800 CCGT - Fired	1x1 F Class CCGT - Fired	2x1 E Class CCGT - Fired Heskett Expansion
ESTIMATED CAPITAL AND O&M COSTS			
Project Capital Cost, 2019 MM$ (w/o Owner's Costs) (NOTE 9)	**$246**	**$343**	**$274**
Project Cost Per UNFIRED Summer kW, 2019 $/kW	**$1,870**	**$1,040**	**$1,150**
Owner's Costs, 2019 MM$	**$119**	**$159**	**$68**
Owner's Project Development	$3.5	$3.5	$0.7
Owner's Operational Personnel Prior to COD	$1.8	$1.8	$1.8
Owner's Engineer	$0.0	$0.0	$0.0
Owner's Project Management	$4.5	$5.9	$2.0
Owner's Legal Costs	$1.0	$1.0	$0.8
Owner's Start-up Engineering and Training	$0.6	$0.5	$0.4
Temporary Utilities	$1.4	$1.6	$0.1
Permitting and Licensing Fees	$1.0	$1.0	$1.0
Switchyard	$7.4	$6.5	$3.0
Land (Note 11)	$0.4	$0.4	N/A
Transmission Interconnection (Note 12)	$30.0	$30.0	$1.7
Gas Interconnection (Note 13)	$10.0	$10.0	$1.3
Water Interconnection (Note 14)	$1.3	$1.3	Existing
MISO Queue Fees (Note 10)	$0.3	$0.4	$0.3
Network Upgrades	$20.9	$48.9	$21.1
Political Concessions & Area Development Fees	$0.5	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$2.0	$2.0	$2.0
Site Security	$0.5	$0.8	$0.4
Operating Spare Parts	$5.0	$6.0	$1.0
Permanent Plant Equipment and Furnishings	$1.3	$1.3	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.1	$1.5	$1.2
Owner's Contingency (10% for Screening Purposes)	$24.6	$34.3	$27.4
Total Project Cost, 2019 MM$ (Unloaded)	**$365**	**$502**	**$342**
Total Cost Per UNFIRED Summer kW, 2019 $/kW (Unloaded)	**$2,780**	**$1,520**	**$1,430**
Loaded Costs			
Interest During Construction, MM$	$29	$40	$27
Total Project Cost, UNFIRED, 2019 MM$ (Loaded)	**$394**	**$542**	**$369**
Total Cost Per UNFIRED Summer kW, 2019 $/kW (Loaded)	**$3,000**	**$1,650**	**$1,540**

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**
DUCT FIRING ADD-ON COST			
Capital Costs, 2019 $MM	$12.8	$8.7	$9.9
Owner's Costs, 2019 $MM	$1.3	$0.9	$1.0
Loaded Costs, Interest During Construction, 2019 MM$	$1.1	$0.8	$0.9
Total Project Cost, FIRED, 2019 $MM (Unloaded)	**$379**	**$512**	**$353**
Total Cost Per FIRED Summer kW, 2019 $/kW (Unloaded)	**$2,180**	**$1,220**	**$1,070**
Total Project Cost, FIRED, 2019 $MM (Loaded)	$409	$552	$381
Total Cost Per FIRED Summer kW, 2019 $/kW (Loaded)	$2,350	$1,310	$1,160
SCR ADD-ON COSTS			
Capital Costs, 2019 $MM	Included	Included	$5.1
Owner's Costs, 2019 $MM	Included	Included	$0.5
Loaded Costs, Interest During Construction, 2019 MM$	Included	Included	$0.4
FIXED O&M COSTS			
Fixed O&M Cost, 2019$/kW-mo (unfired kW) (Note 6)	$2.90	$1.10	$1.40
Property Tax, 2019 $/kW-mo (Note 15)	$1.00	$0.50	$0.50
Property Insurance, 2019 $/kW-mo (Note 16)	$0.40	$0.20	$0.20
MAJOR MAINTENANCE COSTS			
Major Maintenance Cost, 2019$/MWh	$2.35	$1.20	$2.24
Major Maintenance Cost, 2019$/GT-hr	$190	$400	$330
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)			
Total Variable O&M Cost, 2019$/MWh (Note 7)	$2.30	$1.80	$2.00
Incremental Duct Fired Variable O&M, 2019$/MWh	$1.70	$1.20	$2.10

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**
ESTIMATED BASE LOAD OPERATING EMISSIONS, (ISO) (Note 8)			
Unfired			
Gross Carbon Intensity (lb/MWh)	870	810	940
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.020
NO_X [ppmvd @ 15% O_2]	2.0	2.0	5.0
NO_X [lb/hr]	29.0	78.0	19.0
CO [lb/MMBtu, HHV]	0.004	0.004	0.050
CO [ppmvd @ 15% O_2]	5.0	10.0	10.0
CO [lb/hr]	2.30	11.0	55.0
CO_2 [lb/MMBtu, HHV]	120	120	120
CO_2 [ppmvd @ 15% O_2]	34,300	34,300	34,700
CO_2 [lb/hr]	61,600	280,200	121,000
PM/PM_{10} [lb/MMBtu, HHV]	0.006	0.006	0.004
PM/PM_{10} [lb/hr]	3.00	13.5	4.2
Fired			
Gross Carbon Intensity (lb/MWh)	920	860	1,030
NO_X [lb/MMBtu, HHV]	0.010	0.010	0.060
NO_X [ppmvd @ 15% O_2]	2.0	2.0	10.0
NO_X [lb/hr]	41.0	78.0	58.0
CO [lb/MMBtu, HHV]	0.006	0.006	0.090
CO [ppmvd @ 15% O_2]	2.0	2.0	28.0
CO [lb/hr]	3.00	10.6	94.1
CO_2 [lb/MMBtu, HHV]	120	120	120
CO_2 [ppmvd @ 15% O_2]	34,300	34,300	34,700
CO_2 [lb/hr]	79,900	374,600	178,700
PM/PM_{10} [lb/MMBtu, HHV]	0.006	0.006	0.004
PM/PM_{10} [lb/hr]	3.00	13.5	11.1

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**2x1 SGT-800 CCGT - Fired**	**1x1 F Class CCGT - Fired**	**2x1 E Class CCGT - Fired Heskett Expansion**

Notes:

Note 1: Cold start is >72 hours after shutdown. Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls.
Note 2: Startup time to stack emissions compliance with SCR/CO Catalyst is not the same as the start time for gas turbine MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.
Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined Cycle data is based on North American units that came online in 2007 or later. Reporting period is 2011-2016.
Note 4: Performance estimates assumed new and clean condition were developed with natural gas only at the conditions provided by Montana-Dakota Utilities.
Note 5: Summer ambient performances include incremental performance for evaporative cooling.
Note 6: Fixed O&M assumes 22 FTE for 1x1 and 25 FTE for 2x1 configurations (except for Heskett Expansion Option which assumes 20 FTEs).
Note 7: Variable O&M costs assume onsite demin treatment system.
Note 8: Emissions estimates are shown for steady state operation at ISO. Estimates account for the impacts of SCR and CO catalysts. Estimates are not for use for permitting purposes.
Note 9: Combined cycle base costs are for unfired plants. Add-on costs for duct firing provided.
Note 10: 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 11: Land allowance includes 85 acres at $5000/acre.
Note 12: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage, land costs excluded.
Note 13: Natural gas interconnection includes an allowance for 5 mile pipeline, utility interconnect and metering station.
Note 14: Water interconnection allowance includes on site wells and pipe for raw water supply.
Note 15: Property tax rate provided by MDU.
Note 16: Property insurance rate provided by MDU.

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COAL AND BIOMASS TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**Coal w/o CC (Note 1)**	**Coal w/90% CC (Note 1)**	**Biomass**
BASE PLANT DESCRIPTION			
Representative Technology	Circulating Fluidized Bed	Circulating Fluidized Bed	Bubbling Fluidized Bed (BFB)
Number of Steam Turbines	1	1	1
Capacity Factor (%)	90%	85%	85%
Startup Time (Cold Start)	4-18 hours	4-18 hours	12 hours
Equivalent Availability Factor (%)	90%	85%	85%
Fuel Design	100% Raw ND Lignite	100% Raw ND Lignite	Grasses
Heat Rejection	50% Wet-Cooled / 50% Air-Cooled	50% Wet-Cooled / 50% Air-Cooled	Wet Cooling
NO_x Control	SNCR	SNCR	SNCR
CO Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
SO_2 Control	Limestone Injection in Bed	Limestone Injection in Bed	Dry Sorbent Injection
Particulate Control	Baghouse	Baghouse	Baghouse
ESTIMATED PERFORMANCE			
Base Load Performance			
Gross Plant Output, kW	185,000	145,000	30,100
Net Plant Output, kW	168,000	122,000	25,000
Net Plant Heat Rate, Btu/kWh (HHV)	10,000	13,800	12,300
Heat Input, MMBtu/h (HHV)	1,680	1,680	310

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE COAL AND BIOMASS TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION December 2018 - Revision 3			
PROJECT TYPE	**Coal w/o CC (Note 1)**	**Coal w/90% CC (Note 1)**	**Biomass**
ESTIMATED CAPITAL AND O&M COSTS			
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$764**	**$1,023**	**$119**
Project Cost Per kW, 2019 $/kW	**$4,550**	**$8,390**	**$4,760**
Owner's Costs, 2019 MM$	**$224**	**$246**	**$80**
Owner's Project Development	$5.0	$5.0	$3.0
Owner's Operational Personnel Prior to COD	$12	$12	$1.3
Owner's Engineer	$0	$0	$0.0
Owner's Project Management	$9.3	$9.3	$2.0
Owner's Legal Costs	$5.0	$5.0	$1.0
Owner's Start-up Engineering	$0.9	$0.9	$0.2
Land (Note 2)	$2.3	$2.3	$1.5
Temporary Utilities	$2.1	$2.1	$1.3
Permitting and Licensing Fees	$3.0	$3.0	$1.0
Switchyard	$5.5	$5.5	$5.5
Transmission Interconnection (Note 8)	$30.0	$30.0	$30.0
Gas Interconnection (Note 9)	$7.4	$7.4	$7.4
Water Interconnection (Note 10)	$1.3	$1.3	$1.3
MISO Queue Fees (Note 4)	$0.3	$0.3	$0.2
Network Upgrades	$20.9	$16.3	$2.8
Political Concessions & Area Development Fees	$7.0	$7.0	$0.5
Startup/Testing (Fuel & Consumables)	$7.0	$7.0	$1.4
Site Security	$1.6	$1.6	$0.6
Operating Spare Parts	$5.3	$5.3	$0.8
Permanent Plant Equipment and Furnishings	$4.8	$4.8	$0.3
Builder's Risk Insurance (0.45% Project Cost)	$3.4	$4.6	$0.3
Owner's Contingency (10% for Screening Purposes)	$89.8	$115.4	$18.1
Total Project Costs, 2019 MM$ (Unloaded)	**$988**	**$1,269**	**$200**
Total Cost Per kW, 2019 $/kW (Unloaded)	**$5,880**	**$10,400**	**$7,980**
Loaded Costs			
Interest During Construction, MM$	$138	$177	$14
Total Project Costs, 2019 MM$ (Loaded)	**$1,125**	**$1,446**	**$213**
Total Cost Per kW, 2019 $/kW (Loaded)	**$6,700**	**$11,850**	**$8,530**

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
COAL AND BIOMASS TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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PROJECT TYPE	Coal w/o CC (Note 1)	Coal w/90% CC (Note 1)	Biomass
FIXED O&M COSTS			
Fixed O&M Cost, 2019$/kW-mo	$21.00	$29.00	$21.00
Property Tax, 2019 $/kW-mo (Note 5)	$2.30	$4.10	$3.00
Property Insurance, 2019 $/kW-mo (Note 6)	$0.80	$1.50	$1.10
NON-FUEL VARIABLE & MAINTENANCE COSTS			
Major Maintenance Cost, 2019$/MWh	Included in VOM	Included in VOM	$3.10
Variable O&M Cost, 2019$/MWh	$14.06	$22.29	$5.60
ESTIMATED BASE LOAD OPERATING EMISSIONS (Note 3)			
Gross Carbon Intensity (lb/MWh)	2000	300	2,600
NO_X [lb/MMBtu, HHV]	0.06	0.06	0.120
NO_X [ppmvd @ 15% O_2]	14.40	14.40	N/A
NO_X [lb/hr]	101	101	37
CO [lb/MMBtu, HHV]	0.10	0.10	0.10
CO [ppmvd @ 15% O_2]	39.40	39.40	N/A
CO [lb/hr]	168	168	33
CO_2 [lb/MMBtu, HHV]	215	22	210
CO_2 [ppmvd @ 15% O_2]	Not specified in report	N/A	N/A
CO_2 [lb/hr]	361,200	37,000	65,700
PM/PM_{10} [lb/MMBtu, HHV]	< 0.0008	< 0.0008	0.020
PM/PM_{10} [lb/hr]	1.3	1.3	4.9

Notes:
Note 1: Coal technology option information provided by MDU, based on Study of Lignite-Based Advanced Generation Technology Systems prepared by Others for the Lignite Energy Council. Their assumptions govern the information presented.
Note 2: Land allowance is 450 acres for the coal options and 300 acres for the biomass option at $5,000/acre.
Note 3: Emissions estimates are not for use for permitting purposes.
Note 4: 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 down payment on Network Upgrades which are shown separately as provided by MDU.
Note 5: Property tax rate provided by MDU.
Note 6: Property Insurance rate provided by MDU.
Note 7: Transmission interconnect allowance assumes 15 miles of transmission line at 115 kV interconnection voltage, land costs excluded.
Note 8: Natural gas interconnection includes an allowance for 5 mile pipeline, utility interconnect and metering station.
Note 9: Water interconnection allowance includes on site wells and pipe for raw water supply.

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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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 2.72-116	GE 2.72-116	PV: Single Axis Tracking Storage: Li-Ion Batteries	PV: Single Axis Tracking Storage: Li-Ion Batteries
Number of Turbines	9 x 2.7 MW	23 x 2.7 MW	N/A	N/A
Capacity Factor (%) (Notes 1, 2)	43%	43%	26%	26%
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	1.32	1.32
PV Degradation (%/yr) (Note 3)	N/A	N/A	First year: 2% After 1st Year: 0.5% per year	First year: 2% After 1st Year: 0.5% per year
Startup Time (Cold Start)	N/A	N/A	N/A	N/A
Equivalent Availability Factor (%) (Note 4)	95%	95%	99%	97%
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

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
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PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
ESTIMATED CAPITAL AND O&M COSTS (Note 6)				
Project Capital Costs, 2019 MM$ (w/o Owner's Costs)	**$26**	**$62**	**$71**	**$7**
Project Cost Per kW, 2019 $/kW	**$1,280**	**$1,240**	**$1,430**	**$1,370**
Owner's Costs, 2019 MM$	**$7**	**$18**	**$19**	**$5**
Owner's Project Development	Included	Included	$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	$0.3	$0.3
Owner's Start-up Engineering	$0	$0	$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	$2.0
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)	Included	Included	$0.3	$0.0
Owner's Contingency (10% for Screening Purposes)	$2.8	$6.8	$8.2	$1.1
Total Project Costs, 2019 MM$ (Unloaded)	**$33**	**$80**	**$90**	**$12**
Total Cost Per kW, 2019 $/kW (Unloaded)	**$1,640**	**$1,600**	**$1,800**	**$2,440**
Loaded Costs				
Interest During Construction, 2019 MM$	$2.8	$6.3	$4.0	$0.9
Total Project Costs, 2019 MM$ (Loaded)	**$36**	**$86**	**$94**	**$13**
Total Cost Per kW, 2019 $/kW (Loaded)	**$1,780**	**$1,720**	**$1,880**	**$2,610**

MONTANA-DAKOTA UTILITIES CO. 2019 GENERATION TECHNOLOGY ASSESSMENT SUMMARY TABLE
RENEWABLE, AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY AND CONFIDENTIAL - NOT FOR CONSTRUCTION
December 2018 - Revision 3

PROJECT TYPE	Wind Energy	Wind Energy	Solar Photovoltaic	Solar Photovoltaic
FIXED O&M COST				
Fixed O&M Cost, 2019$/kW-mo (Note 10)	$4.30	$4.30	$2.90	$3.00
Property Tax, 2019 $/kW-mo (Note 11)	$0.60	$0.60	$0.70	$0.90
Property Insurance, 2019 $/kW-mo (Note 12)	$0.20	$0.20	$0.20	$0.30
NON-FUEL VARIABLE & MAINTENANCE COST				
Major Maintenance Cost, 2019$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Variable O&M Cost, 2019$/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM
Co-Located Energy Storage			**10 MW | 40 MWh**	**1 MW | 4 MWh**
Add-On Costs				
Capital Costs, 2019 MM$	N/A	N/A	$17.6	$2.6
Owner's Costs, 2019 MM$	N/A	N/A	$1.50	$0.40
Incremental O&M Cost, 2019 MM$/Yr	N/A	N/A	$0.35	$0.06
Loaded Costs, Interest During Construction, 2019 MM$	N/A	N/A	$1.19	$0.49

Notes:

Note 1: Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on GE 2.72-116 turbines with 80 meter hub height and 8.5 m/s average wind speed.
Note 2: Solar capacity factor accounts for typical losses. Fixed tilt systems assumes 42 degree tilt.
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: NERC GADS performance statistics are not available for PV, battery storage, and wind technologies. 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 Fixed O&M. Onshore wind assumes one acre per turbine. PV assumes seven acres per MW for fixed tilt and eight acres per MW for tracking options.
Note 6: Estimated Costs exclude decommissioning costs and salvage values.
Note 7: EPC costs for wind include 34.5 kV collection system and GSU to 115 kV. Owner's costs include 3 position ring bus switchyard for interconnection at 115 kV.
Note 8: PV scope for EPC includes 34.5 kV collector bus and circuit breaker. Owner costs include allowance for interconnection at 115 kV.
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.

CREATE AMAZING.

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Appendix A

HESKETT 4 ANALYSIS

INTRODUCTION

As part of the 2019 Integrated Resource Plan (IRP) development, Montana-Dakota retained Burns & McDonnell Engineering Company (BMcD) to prepare a 2019 IRP Technology Assessment (Assessment) to evaluate various power generation technologies as self-build supply-side resource options for Montana-Dakota's Electric Generation Expansion Analysis System (EGEAS) modeling. As further detailed in the Assessment, BMcD stated that the information provided was screening-level in nature and for comparative purposes only (not to be used for construction purposes). BMcD recommended that any self-build supply-side resource options of interest to Montana-Dakota should be followed by additional detailed studies.

In the preliminary EGEAS modeling results of feasible supply-side and demand-side resource options, the natural gas fired large frame General Electric (GE) 7E.03 simple cycle combustion turbine (SCCT) Heskett Expansion (Heskett 4) was selected in the base case model to economically and reliably meet future customer generation requirements beginning in the 2022-2023 timeframe, and therefore became a self-build supply-side resource option of interest to Montana-Dakota. As an interim step prior to hiring a consultant to perform additional detailed studies of Heskett 4, Montana-Dakota used its extensive knowledge obtained from the construction of the R.M. Heskett Station Unit 3 (Heskett 3) GE 7EA combustion turbine to perform a more detailed internal cost investigation of Heskett 4. This investigation would provide a more refined cost estimate for inclusion in the final EGEAS modeling.

Presented below are details on Heskett 3 & Heskett 4 plant synergies, assumptions, methodology, and results of Montana-Dakota's cost investigation.

HESKETT 3

Commissioned in 2014, Heskett 3 is a Montana-Dakota self-built GE 7EA large frame SCCT with a nameplate rating of 88MW. Heskett 3 is equipped with evaporative cooling for power augmentation, a Dry Low NOx (DLN) combustion system for emissions control, a closed cooling water system for cooling the generator and other systems, and a service building with an electrical room, control room, offices, and shop area. Heskett 3 shares portions of the water treatment and fire protection systems with R.M. Heskett Unit 1 (Heskett 1) & Unit 2 (Heskett 2) and is operated by the main plant control room located at the Heskett 1 & Heskett 2 building. Heskett 3 can also be operated remotely from other locations. During the design and construction of Heskett 3, the possibility of future expansion of the site by adding an additional SCCT combustion turbine or the conversion to a 2x1 combined cycle combustion turbine was taken into consideration. Included in these considerations were the sizing and location of the natural gas supply pipeline, underground fire protection loop, storm water drainage, electrical equipment room, and underground electrical conduit, among others. It is expected that Heskett 4 will take advantage of this existing infrastructure, reducing the overall capital cost of the project as compared to a greenfield site.

HESKETT 4

Heskett 4 will be located adjacent to Heskett 3. It is expected that the unit will be a near mirror image of Heskett 3, with the major equipment being nearly identical. Heskett 4 will consist of a new GE 7E.03 SCCT connected to a GE supplied generator, nominally rated at approximately 88MW, but capable of producing over 100MW under certain ambient conditions. It is planned to be equipped with an evaporative cooler at the air intake for power augmentation, DLN combustion system, and a closed cooling water system for cooling the generator and other systems.

The existing Heskett 3 service building will be used to house equipment associated with Heskett 4 and five to seven full-time employees. To accommodate these needs, the building will likely need to be expanded. Expansion of the existing service building is expected to cost significantly less than a new service building for a greenfield project. The 24-mile natural gas supply pipeline connecting the facility to Northern Border Pipeline is sized to provide enough fuel capacity to operate both Heskett 3 & Heskett 4 at full load continuously. Existing Heskett 3 on-hand spare parts will reduce the need to purchase additional spare parts for Heskett 4. The underground fire loop, oily drains tank, storm water drainage, underground electrical conduit and other systems are expected to be used with only minor modifications required.

Heskett 3 water supply is currently sourced from the existing Heskett 1 & Heskett 2 Missouri River water intake. Montana-Dakota’s analysis assumed the intake would be shuttered during the decommissioning of Heskett 1 & Heskett 2, with future water being sourced from the local rural water supply. However, Montana-Dakota will further evaluate whether reuse of the water intake for Heskett 3 and Heskett 4 would better suit the plant from a cost and operability standpoint. Possible future expansion of the site to a 2x1 combined cycle power plant will be taken into consideration during the detailed design phase of the project.

Montana-Dakota expects to use the existing construction parking, equipment laydown area, and overall site layout for Heskett 4 with minimal modifications. This will reduce the amount of pre-construction work to be completed and support an overall shorter construction schedule and reduced project cost as compared to a greenfield site.

Montana-Dakota is expecting that decommissioning of Heskett 1 & 2 will allow for emissions netting of Heskett 4. Emissions netting will help maximize the number of permitted operating hours of the unit and eliminate the need for emissions control equipment such as Selective Catalytic Reduction for NOx emissions control and Catalytic Oxidation for CO & VOC emissions control. Decommissioning of Heskett 1 & 2 will allow Montana-Dakota to eliminate the Midcontinent Independent System Operator (MISO) transmission interconnect network upgrade costs, which can cost in excess of $400 to $1,000 per kW for new generator interconnections.

Heskett 4 is currently expected to be in service in the 2022-2023 timeframe to meet the capacity requirements of Montana-Dakota's electric service customers served by its integrated electric system. Under the assumption that Heskett 4 would be nearly identical to the existing Heskett 3, the actual costs incurred during permitting, design, and construction of Heskett 3 were used as the basis of Montana-Dakota’s capital cost estimate of Heskett 4. The next step is to obtain an Engineering Consultant to verify Montana-Dakota’s assumptions and provide a detailed Class 3 cost estimate. The engineering cost estimate is expected to be completed fall of 2019.

Montana-Dakota has hired BMcD to perform additional detailed studies to create the final cost estimate for Heskett 4. This work was still on-going at time of printing for the 2019 IRP.

CAPITAL COST ASSUMPTIONS

At the end of 2018, Montana-Dakota received an indictive quotation from GE for the supply of the prime mover and associated equipment. The scope of supply was requested to be the same as provided for Heskett 3. Equipment in this scope of supply included the gas turbine package, air inlet system, exhaust diffuser, generator, electronic electrical control cabinet, turbine package fire protection, cooling system, generator circuit breaker, as well as transportation of equipment, technical advisory services, O&M manuals and training. The estimates for the remaining equipment not provided in the prime mover contract, consisting of the generator step-up transformer and substation, auxiliary transformer, distributed control system, 480V transformer, continuous emissions monitoring equipment, exhaust stack, medium voltage equipment, fuel gas conditioning skid and regulation, and spare parts were based on the costs incurred in the Heskett 3 project and escalated to 2019 dollars.

Engineering, construction, construction management support, permitting support, internal Montana-Dakota labor, legal support, commissioning, first fills and commissioning fuel, and various testing requirements were estimated based on Heskett 3 actual costs and escalated to 2019 dollars. In addition, estimates for expansion of the existing service building office, fire protection upgrades, water storage tanks and an emergency generator were included based on Montana-Dakota experience and publicly available equipment costs.

To account for potential cost increases related to project risks, Montana-Dakota reviewed the scope of work and included a contingency to the capital cost estimate. The contingency is intended to cover pricing accuracy and productivity assumptions but does not cover any major scope of work changes. Possible risks considered in the contingency estimate included, but were not limited to: equipment delivery delay, craft labor availability, labor productivity, labor market volatility, safety, force majeure, procurement delay, delay in startup/commissioning, environmental permitting delay, and generator interconnect agreement delay.

Montana-Dakota assumed the existing 30 MW Heskett 1 and 73.1 MW Heskett 2 of MISO Network Resource Interconnection Service (NRIS) would no longer be in service at the time of commercial operation of the new combustion turbine. However, the in-service date of Heskett 4 would be timed so that the existing 103.1 MW of MISO NRIS rights for Heskett 1 and Heskett 2 would be retained for use by Heskett 4. By maintaining the NRIS of Heskett 1 and Heskett 2, Montana-Dakota assumed that the new combustion turbine would not incur additional transmission system network upgrade requirements and their associated costs.

Assuming emissions netting from the retirement of Heskett 1 and Heskett 2, no Selective Catalytic Reduction or Catalytic Oxidizer are assumed to be required for emissions control and are excluded from the estimate. The capital cost estimate for Heskett 4 is provided in the Summary Table.

OPERATIONS AND MAINTENANCE COST ASSUMPTIONS

Operations and maintenance (O&M) costs were estimated based on previous consultant support and Montana-Dakota’s experience. O&M cost estimates are provided in the Summary Table.

Fixed O&M costs assume five Montana-Dakota personnel supporting the operation and maintenance of both Heskett 3 and Heskett 4, as well as costs associated with maintenance, administration, property taxes, and insurance. Major maintenance and variable O&M costs were sourced from the BMcD Assessment.

Summary Table:

Base Load Performance @ 84.5°F / 40% RH (MDU Summer, Incl. Evap Cooler)	1x GE 7E.03 SCGT - Natural Gas Heskett 4
Gross Plant Output, kW	80,290
Net Plant Output, kW	78,280
Net Plant Heat Rate, Btu/kWh (HHV)	11,770
Heat Input, MMBtu/h (HHV)	922
Total Project Costs, 2019 MM$	$68.7
Total Cost Per Summer kW, 2019 $/kW	$878
Total Project Costs, 2019 MM$ (Loaded)	$73.0
Total Cost Per Summer kW, 2019 $/kW (Loaded)	$933
Fixed O&M Cost, 2019$/kW-mo	$1.52
Major Maintenance Cost, 2019$/MWh	$5.60
Non-Fuel Variable O&M Cost, 2019$/MWh	$0.90
Gross Carbon Intensity (lb/MWh)	1,460
NO_X [lb/MMBtu, HHV]	0.020
CO [lb/MMBtu, HHV]	0.50
PM/PM_{10} [lb/hr]	4.20

Attachment F

August 1, 2016 Request for Proposal for Capacity and Energy Supply

2018 RFP for Capacity and Energy

Overview

Montana-Dakota issued a Request for Proposal (RFP) on August 1, 2018 for capacity and energy totaling at least 10 MW and no more than 250 MW for the period beginning June 1, 2025. The RFP indicated that proposals received would be evaluated against a combined cycle natural-gas fired generation project that the Company was studying to construct and be on-line as early as June 1, 2025.

Process

Once the RFP was issued, companies had until August 15, 2018 to submit a Notice of Intent to Bid (NOIB). Twenty-two companies submitted a NOIB. The companies then had until September 15, 2018, to submit their final proposals. This resulted in ten companies submitting final bids with several companies submitting multiple proposals.

The original date for a shortlist was to be October 16, 2018, but with the number of bids that were received the shortlist date was delayed until November 7, 2018. Ultimately no projects were shortlisted over concerns with proposals not meeting RFP requirements, size of the proposals, and uncertainty of potential network upgrades costs.

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 – 6
- Solar – 3
- Distributed Solar – 1
- Wind/Solar - 1
- Combined Cycle Combustion Turbine – 1
- Battery Storage – 1
- Solar/ Battery Storage – 4
- Wind/Solar/Battery - 2

Analysis Results

All but one 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. Once the magnitude of network upgrade costs was known, these additional costs would be passed along as an additional charge to Montana-Dakota and its customers. Based on MISO's recent generator interconnection studies, the costs of network upgrades could be as high $1,000 per installed kW of generation. Adding $1,000 per installed kW to wind projects and $500 per installed kW to solar projects adds an additional 25 year levelized cost to wind of $25.63 per MWh and $26.46 per MWh to solar. The inclusion of these network transmission upgrade costs would double the cost of the projects to Montana-Dakota's customers. One proposal had an interconnection with SPP which would have resulted in additional SPP transmission costs to deliver to Montana-Dakota's MISO customer load. Six of the proposals were greater than the maximum request of 250 MW, ranging from 300 MW to 375 MW in size. Montana-Dakota's peak customer load is only 600 MW. Because of a lack of certainty in final costs of bids and many of the project's sizes being almost half the size of Montana-Dakota's peak customer load, no proposals were short-listed, and the Company will issue a new request for proposal before the start of the next integrated resource plan.

Appendix A

2018 RFP Matrix

2018 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]												
Solar	Yes	[redacted]	20 Years (2023)	Network Upgrades	100-140 MW	Solar	Yes	North Dakota	Not studied	No	Medium	Project site to be determined. Network Upgrade costs unknown and assigned to off-taker.
2 [redacted]												
Combined Cycle	Yes	[redacted]	Own (Q4 2024)	Network Upgrades	110 MW	Combined Cycle	No	Other State	Queue	Yes	None	Requires Wisconsin business entity to own.
3 [redacted]												
Wind	Yes	[redacted]	20 Years (Q4 2021)	Network Upgrades	54 MW	Wind	Yes	South Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
4 [redacted]												
Wind	Yes	[redacted]	25 Years (Q4 2020)	Network Upgrades	200 MW	Wind	Yes	South Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Solar	Yes	[redacted]	25 Years (Q1 2023)	Network Upgrades	150 MW	Solar	Yes	South Dakota	Not studied	No	Medium	GIA not filed. Network Upgrade costs unknown and assigned to off-taker.
Solar	Yes	[redacted]	25 Years (Q2 2023)	Network Upgrades	200 MW	Solar	No	North Dakota	Not studied	No	Medium	GIA not filed. Network Upgrade costs unknown and assigned to off-taker.
Wind	Yes	[redacted]	25 Years (Q2 2021)	Network Upgrades	200 MW	Wind	No	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Battery	Yes	[redacted]	20 years (2025)	Network Upgrades	250 MW	Battery	Yes	South Dakota	Other	No	Low	GIA not filed. Network Upgrade costs unknown and assigned to off-taker.
5 [redacted]												
Wind, Solar, Battery	Yes	[redacted]	20 Years (Q4 2021)	Network Upgrades	350 MW	Wind, Solar, Battery	No	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Wind, Solar	Yes	[redacted]	20 Years (Q4 2021)	Network Upgrades	300 MW	Wind, Solar	No	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Wind, Solar, Battery	Yes	[redacted]	Own (Q4 2022)	Network Upgrades	350 MW	Wind, Solar, Battery	No	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
Distributed Solar	Yes	[redacted]	2020-2022	None	50-100 MW	Solar	Yes	North Dakota	N/A	Unknown	Medium	Assumes no network upgrades to interconnect to distribution system
6 [redacted]												
Wind	Yes	[redacted]	20 Years (Q4 2022)	Network Upgrades	250 MW	Wind	Yes	North Dakota	Queue	No	Medium	Network Upgrade costs unknown and assigned to off-taker.
7 [redacted]												
Solar, Battery	Yes	[redacted]	N/A Years (Q4 2023)	Network Upgrades	300 MW	Solar, Battery	No	Other State	Queue	No	Low	Network Upgrade costs unknown and assigned to off-taker.
Solar, Battery	No	[redacted]	N/A Years (Q4 2023)	Network Upgrades	375 MW	Solar, Battery	No	Other State	Queue	No	Low	Network Upgrade costs unknown and assigned to off-taker.
8 [redacted]												
Solar, Battery	Yes	[redacted]	20 Years (2022-2025)	Network Upgrades	75 MW	Solar, Battery	Yes	North Dakota	Not studied	No	Low	GIA not filed. Network Upgrade costs unknown and assigned to off-taker.
9 [redacted]												
Wind	Yes	[redacted]	20 Years (Q4 2020 or Q4 2025)	None	300 MW	Wind	No	South Dakota	Queue	No	Medium	
Solar, Battery	Yes	[redacted]	20 Years (Q4 2023)	Network Upgrades	185 MW	Solar, Battery	No	Other State	Queue	No	Low	Network Upgrade costs unknown and assigned to off-taker.
10 [redacted]												
Wind	No - SPP	[redacted]	20 Years (Q4 2020)	Network Upgrades, Transmission Service	200 MW	Wind	No	North Dakota	Queue	No	Medium	Project interconnects with SPP . Network Upgrade costs unknown and assigned to off-taker.

* 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)

Area of Non-Conformance to RFP Requirements

Appendix B

2018 Request for Proposal for Capacity and Energy

Montana-Dakota Utilities Co.

Request for Proposal for

Capacity and Energy Supply

August 1, 2018

Table of Contents

1. INTRODUCTION

1.1. Purpose

Montana-Dakota Utilities Co., a Division 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 250 MW beginning June 1, 2025. Persons or entities responding to this RFP are referred to as "Respondents." Proposals received will be evaluated against a combined cycle natural-gas fired generation project that the Company is studying to construct, which is scheduled to have an on-line date of June 1, 2025, or later.

1.2. Product Description and Requirements

Montana-Dakota is seeking Proposals involving the purchase of capacity and energy resources beginning June 1, 2025 totaling at least 10 megawatts (MW) and no more than 250 MW. Proposals received will be evaluated against a combined cycle natural-gas fired generation project that the Company is studying to construct, which is scheduled to have an on-line date of June 1, 2025, or later.

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 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	August 1, 2018
Bidder's Conference	None
Notice of Intent to Bid Due	August 15, 2018
RFP Responses Due	September 14, 2018
Shortlist Notification	October 26, 2018
Selection Process Complete	December 12, 2018

* 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 August 15, 2018. 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 September 14, 2018 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, DVD, or flash drive. **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 2018 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 December 12, 2018. 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 October 26, 2018 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 cost 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 December 12, 2018.

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 Clean Power Plan 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, on an hour by hour basis. 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, landfill gas, and anaerobic digestion 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 intends to compare system impacts of short-listed Proposals against a combined cycle natural-gas fired project that the Company is studying to construct to meet Montana-Dakota's future capacity and energy needs. The proposed in-service date for this combined cycle resource is June 1, 2025, or later.

3.1.4. 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.

3.1.5. All Proposals related to renewable resources, 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).

3.1.6. 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.

3.1.7. 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.

3.1.8. 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.

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

3.1.10 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, 2025 and fully deliverable to Montana-Dakota's system.

g. The capacity is at least 10 MW and no more than 250 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.

i. Preference will be given to Proposals with dispatchable resources.

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. Montana-Dakota prefers the identified generating unit be fully dispatchable and has an Automatic Generator Control that is tied into Montana-Dakota's Electric Dispatch Center. The costs associated with this installation are the responsibility of the Respondent.

e. 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 October 26, 2018, 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 division 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 August 1, 2018. 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 ___________________, 2018.

_____________________________	MONTANA-DAKOTA UTILITIES CO. a Division 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; and (5) the allocation of MISO Multi-Value Projects (MVP).

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 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 81.5% of their full capacity requirements which provides 124 MWs of capacity savings. If Montana-Dakota were to join SPP, Montana-Dakota would have to add 105 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 $242.36 per MW-day for 2019/2020, the resource adequacy diversity value that Montana-Dakota receives in MISO is equal to $11.0 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 $9.3 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 2019 load forecast, the estimated cost of taking MISO transmission service is $7.8 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 $13.4 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 ($11.0 million benefit as calculated above), tariff management, coordinated transmission planning studies, and generator interconnection queue management.

In 2019, the total net cost of taking both MISO and SPP transmission services is estimated at $13.9 million or $6.1 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

[1] 2019/2020 Planning Resource Auction (PRA) Results. Page 8. https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf

Transmission Service taken from MISO and the Basin Electric Facility Sharing Agreement. Montana-Dakota also received an additional $3.1 million in market revenues from SPP in 2018 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 $9.3 million using the current MISO CONE value for capacity resources calculated above. If Montana-Dakota would exit MISO and join SPP as a transmission owning member, it would continue to make annual transmission investment payments of $6.5 million (2019 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 $1.2 million dollars in 2019, which includes the cost of the Mandan 230 kV Junction Substation.[2] 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. 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.

[2] MISO Indicative Annual charges for approved Baseline Reliability Projects (Schedule 26). https://www.misoenergy.org/planning/planning-test/schedule-26-and-26a-indicative-reports/

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

LRZ	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE,MGE,MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMI, SME

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]

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.

[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

The 2019 forecasted MISO Schedule 26-A (MVP Cost Adder) charge is $1.76 per MWh.[5] Assuming a 2019 Total Energy Requirements of 3,371,540 MWh, this would result in a total charge of $5,933,910 to Montana-Dakota's customers.

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

[5] MISO Indicative Annual charges for approved Multi-Value Projects (Schedule 26-A). https://www.misoenergy.org/planning/planning-test/schedule-26-and-26a-indicative-reports/

Attachment H

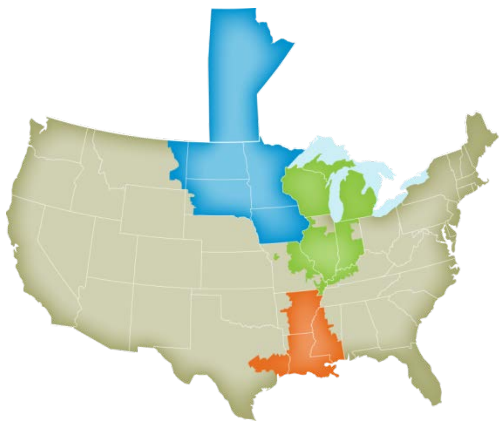
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO)

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
   - 174,678 MW (market)
   - 188,818 MW (reliability)
2. Generation Fuel Mix
   - 42% Gas
   - 32% Coal
   - 15% Renewable (17,270 MW of in-service wind generation)
   - 8% Nuclear
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 February 2019**
https://cdn.misoenergy.org/Q1%202019%20Corporate%20Fact%20Sheet%20Update_2_8_19317878.pdf

- 65,800 miles

6. Balancing Authorities
   - 36 Local Balancing Authorities in MISO
7. Network Model
   - 294,042 SCADA data points
   - 6,623 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

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[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.

An overview of the MISO Energy and Operating Reserves Market can be found at https://cdn.misoenergy.org/Level%20100%20-%20Energy%20and%20Operating%20Reserves%20Markets330118.pdf

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 644 projects totaling 101 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.

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[3] MISO Website. Generation Interconnection Queue Summary updated 6/1/2019.
https://cdn.misoenergy.org/MTEP18%20Futures%20One-Pager111484.pdf

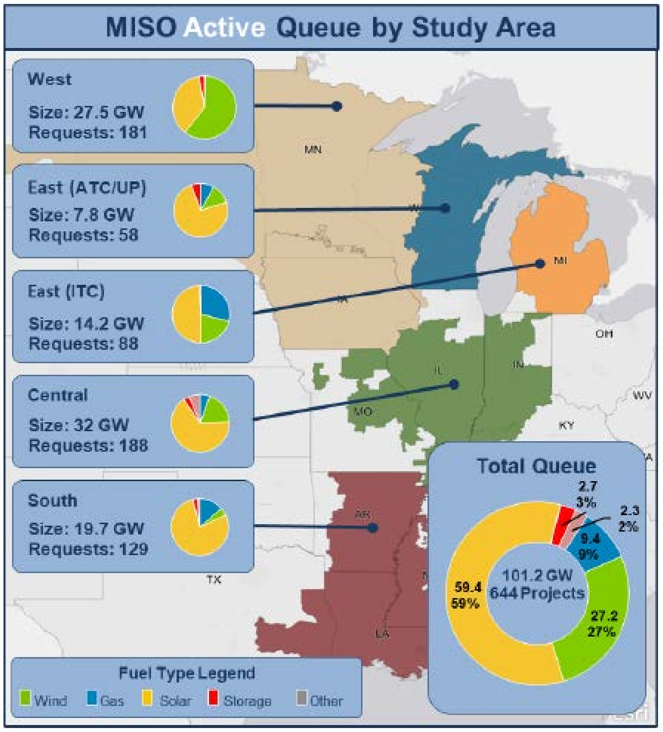

Figure 1 – MISO Generation Queue Summary

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

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 opertation 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 studies analyze the following scenarios: Limited Fleet Change, Continued Fleet Change, Accelerated Fleet Change, and Distributed & Emerging Technologies. A breakdown of the MTEP 2018 Futures[4] is illustrated in Figure 2.

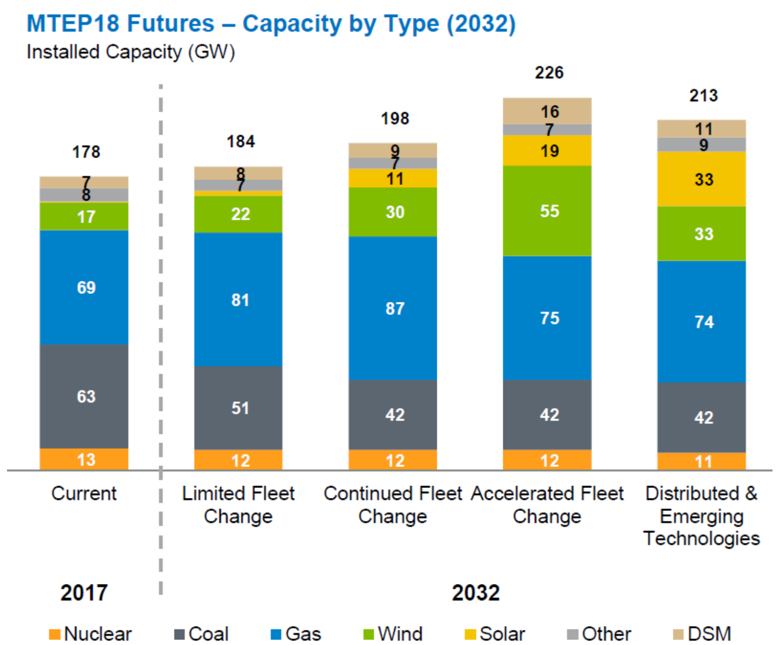

Figure 2 – MTEP 2018 Futures

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.

Value Proposition

As a means of providing a measurement of value related services to its members, MISO annually updates its Value Proposition. The 2018 MISO Value Proposition consists of the following benefits:

[4] MISO Website. MTEP 2018 Future Summary. https://cdn.misoenergy.org/MTEP18%20Futures%20One-Pager111484.pdf.

A. IMPROVED RELIABILITY

MISO's broad regional view and state-of-the-art reliability tool set enables 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 from 21.92% to 17.1%. This decrease delays the need to construct new capacity.

H. GENERATOR AVAILABILITY IMPROVEMENT

MISO's wholesale power market improved power plant availability by 0.61%, delaying the need to construct new capacity.

I. DEMAND RESPONSE

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

J. MISO COST STRUCTURE

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

The 2018 Value Proposition study indicates that MISO provides between $3.2 and $3.9 billion in annual economic benefits to its members and the surrounding region.

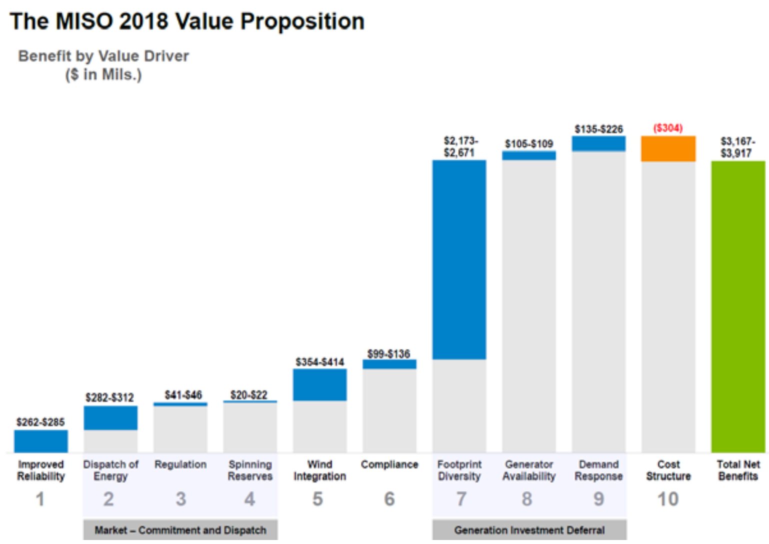

Figure 3 – MISO 2018 Value Proposition

Attachment I

RETIREMENT ANALYSIS

ATTACHMENT I

RETIREMENT ANALYSIS

The purpose of this Attachment I is to discuss the information and analysis underlying Montana-Dakota's decision to retire the Lewis & Clark 1, Heskett 1 and Heskett 2 coal-fired generators at the end of 2020 and 2021, respectively.

As discussed below, the decision to retire the coal-fired generators at the Lewis & Clark and Heskett sites was the age of the plants, low-cost and availability of natural gas, and low-cost power on the MISO market, as well as rising fuel costs and operating & maintenance expenses at Lewis & Clark 1, Heskett 1, and Heskett 2. The IRP EGEAS model was also used to further substantiate the economic savings to customers associated with the Resource Plan with and without the retired units.

2018 Request for Proposal (2018 RFP)

Montana-Dakota's 2015 and 2017 Integrated Resources Plans indicated that at the retirement of Heskett 1, Heskett 2, and Lewis & Clark 1; a natural gas-fired combined cycle generation unit was the best future resource for the Company.

Montana-Dakota issued the 2018 RFP in August of 2018 to support the replacement analysis for Heskett 1, Heskett 2 and Lewis & Clark 1 at their future retirement date. Bids from the 2018 RFP, coupled with (1) a lower natural gas forecast price, (2) lower MISO energy market forecast prices, (3) higher capital costs for the combined cycle generator, and (4) lower prices for wind, solar, and storage; indicated that the combined cycle generator was no longer the best future resource to meet its customers' requirements.

With the Company's decision to move away from a future combined cycle generation unit, significant analysis was done that led the Company to review the age and condition, economic competitiveness, and future environmental compliance costs for Heskett 1, Heskett 2, and Lewis & Clark 1.

Unit Age and Condition

Heskett 1 has a 25 MW net generation capacity. The unit is located near Mandan, ND, commenced commercial operation in 1954 and has been in service for 65 years.

Heskett 2 has a 73 MW net generation capacity. The unit is located near Mandan, ND, commenced commercial operation in 1963 and has been in service for 56 years.

Lewis & Clark 1 has a 52 MW net generation capacity. The unit is located near Sidney, MT, commenced commercial operation in 1958 and has been in service for 61 years.

All the units have been well maintained, have high availability factors, and are in compliance with all environmental requirements and operating permits. The units, however, have low net capacity factors because of a lack of economic competitiveness with other alternatives available to the Company, including the MISO energy market.

Figure 1 shows the unit availability factor and the percent of actual generation compared to potential generation referred to as net capacity factors for the last seven years.

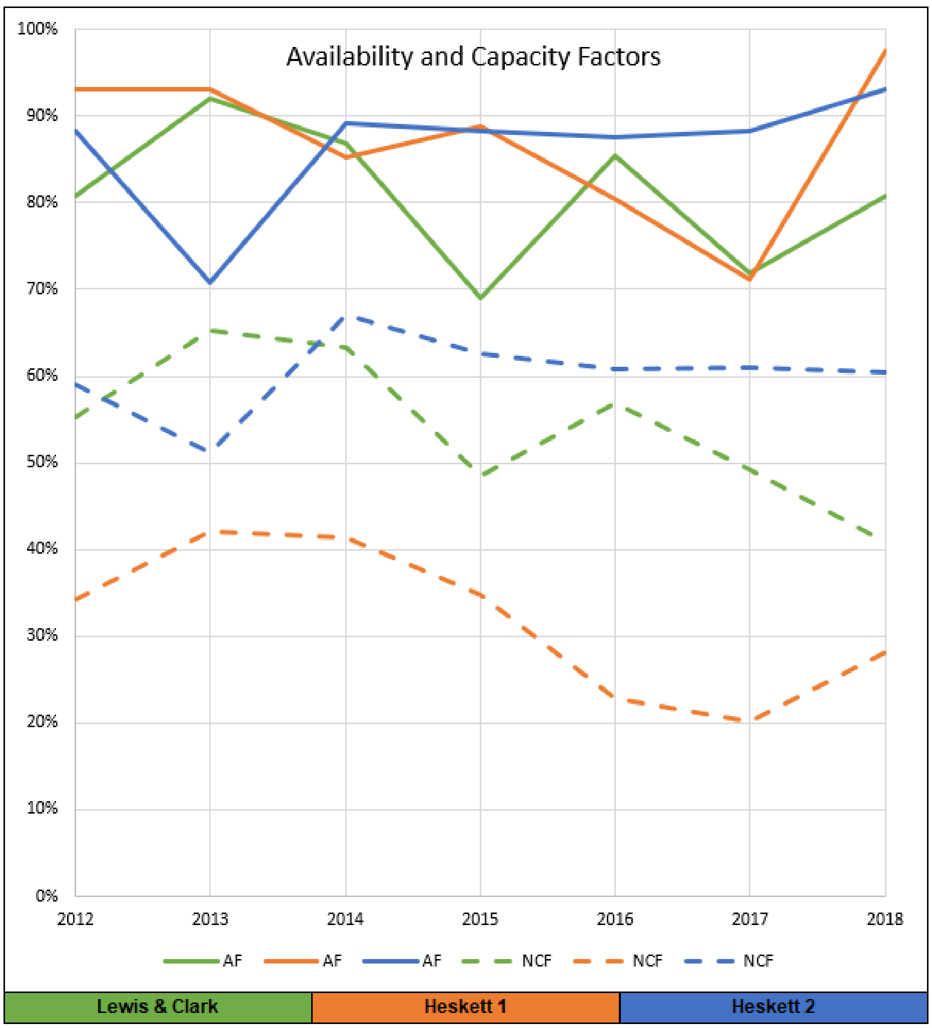

Figure 1 – Availability (AF) and Net Capacity Factor (NCF)

The difference in the relative magnitude of the net capacity factors between the three units is related to the level at which each unit has the physical capability or operating environment permit capability of reducing its output generation levels (otherwise called the "minimum output level" for each unit). If a unit is available to run, Montana-Dakota starts the unit and the generator will generate at its minimum output level in the market and any generation above the minimum output is economically dispatched against other generation available in the market.

Economic Competitiveness

As seen in Figure 1, the net capacity factors for the past seven years have been declining due to the lack of economic competitiveness with other generating resources within the MISO energy market. Heskett 2 has seen an increase due to a change in the plant operation and an increase in the plant's minimum output level.

Figure 2 shows the percent of hours that each generator runs at various output levels over the past seven years. Lewis & Clark 1 has a minimum output level of 34 MW and a maximum output level of 42 MW. Heskett 1 has a minimum output level of 7 MW and a maximum output level of 21 MW. Heskett 2 has a minimum output level of 50 MW and a maximum output level of 68 MW. As indicated in Figure 2, the generating units are being dispatched at their minimum output levels over 80% of the time. This trend, of the units being dispatched at their minimum output levels, has increased significantly in the last three years which is a direct indication that the units have lost their competitive dispatch position to other resources in the MISO energy market.

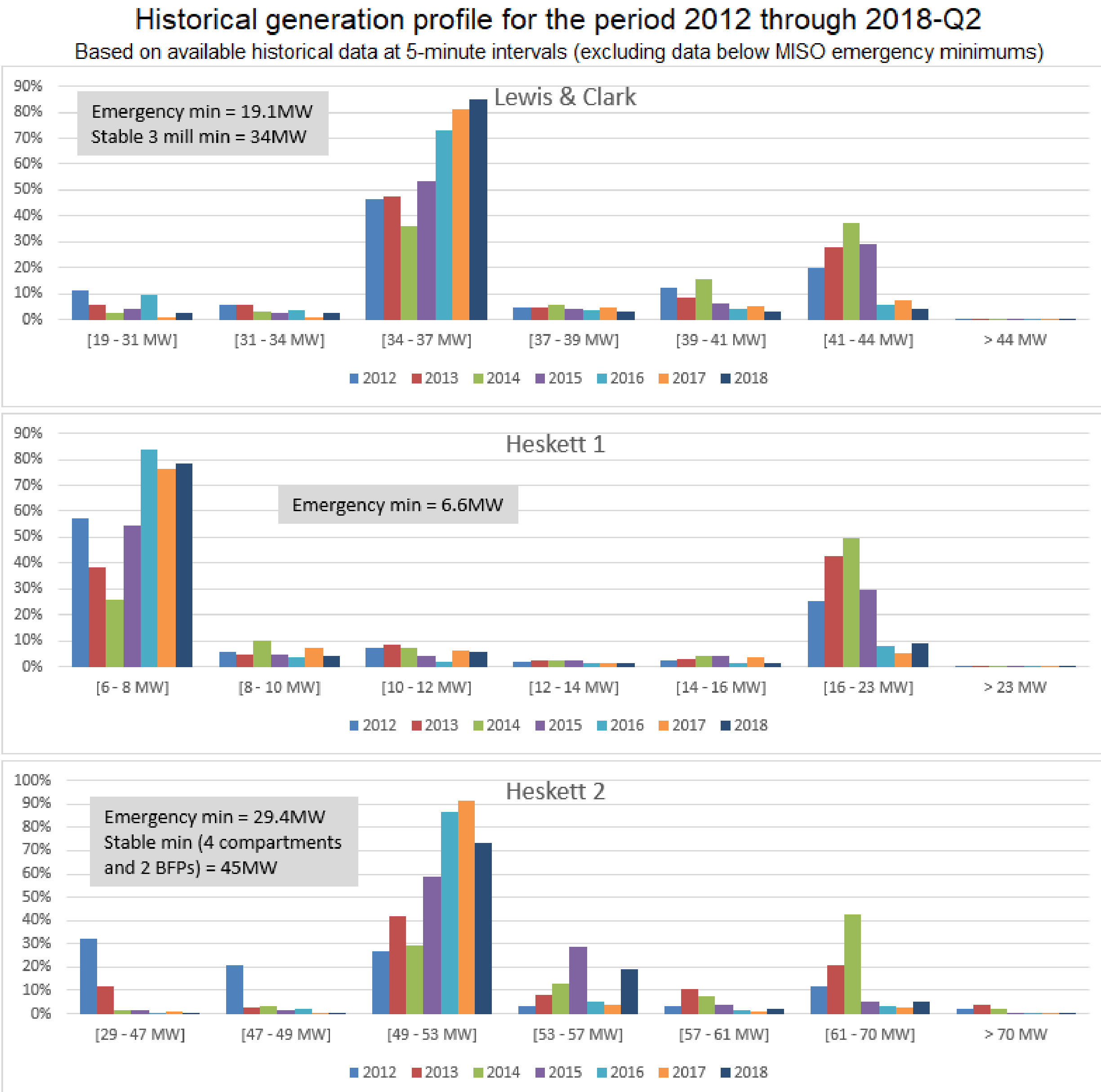

Figure 2 – Percent of Hours at Various Generation Output Levels

Montana-Dakota offers all its generation resources into the MISO energy market and buys all the energy to serve its customer load from the same MISO energy market. (See Attachment H – MISO and RTO Overview for a description of the MISO energy market.)

Economically dispatching the coal-fired units for any generation above their minimum output level saves the customer money as the Company can purchase energy from the MISO market at a lower cost than the variable operating cost to run the units. Montana-Dakota dispatches its coal-fired generation units at their minimum output levels, if the units are available, in order to meet the minimum annual volume provisions of its coal supply agreements. Minimum annual volume or take-or-pay provisions means that the Company must pay for a minimum amount of coal every year whether it is used.

Figure 3 shows the percentage of its energy requirements that Montana-Dakota has purchased from the MISO energy market to serve its customer load obligations, as well as the average purchase price paid for that energy. As shown in Figure 3, MISO energy market prices prior to 2009 were in the $60 per MWh range. However, MISO energy market prices have been very stable and low cost (about $21 to $26 per MWh) in recent years. This trend is expected to continue for the near future.

Figure 3 – MISO Market Energy Prices and Purchases

As part of the IRP Process, Montana-Dakota estimates future MISO market energy prices based on a three-year average of historic MISO pricing with a three percent escalation factor per year for future years. The three percent escalation factor is consistent with the escalation factor used for the IRP's natural gas price forecast which is developed by Montana-Dakota's Gas Supply Department using historic natural gas prices and trading hub index price forecasts. The forecasted prices of the MISO energy market and natural gas have been dropping in recent IRPs and illustrates the economic challenges that Montana-Dakota's older coal-fired generation fleet must compete against in the broader MISO energy market.

As seen in Figures 4 and 5, since 2013 the future forecasts for MISO energy and natural gas prices have been lower in each of the IRPs. These values affect the forecasted dispatch and overall economic competitiveness of Montana-Dakota's generation plants in the IRP model.

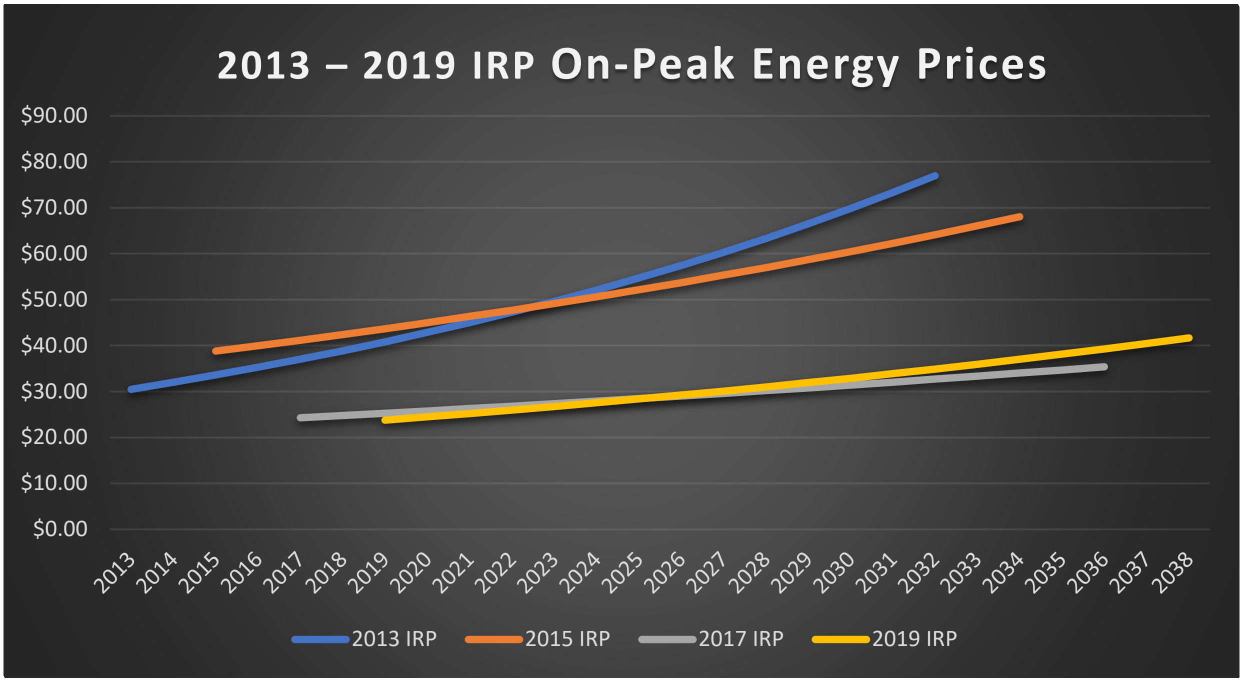

Figure 4 – MISO Market Energy Forecast Prices (2013 – 2019 IRPs)

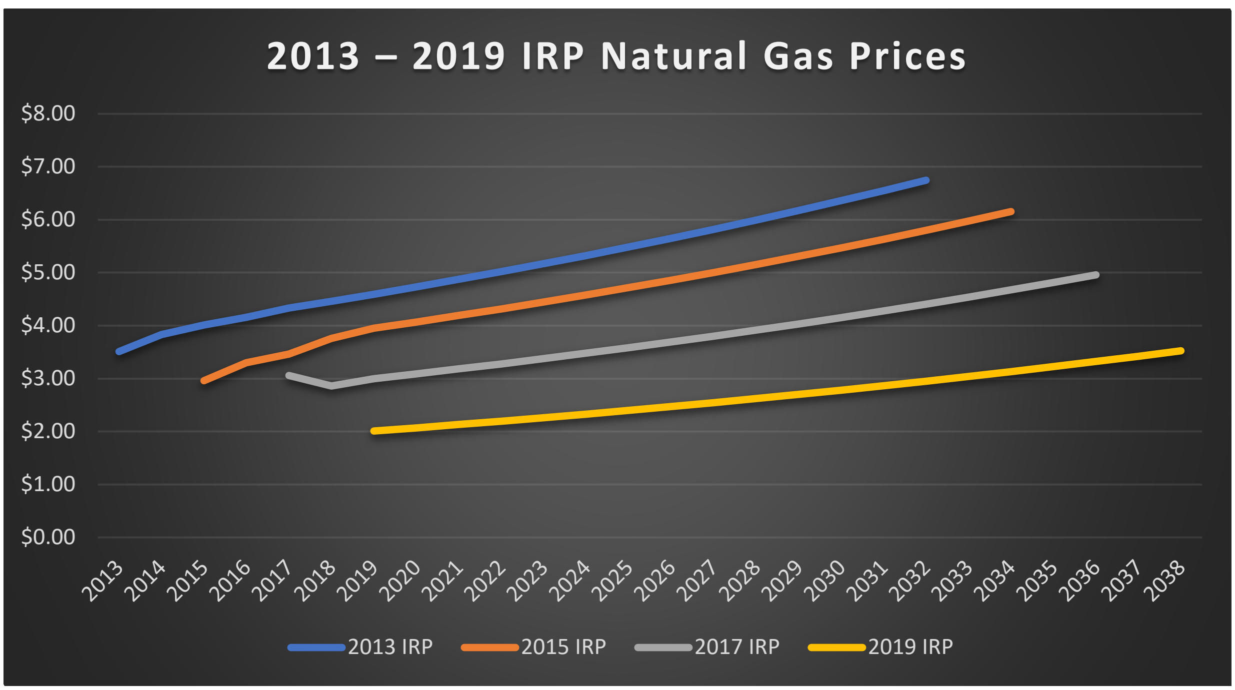

Figure 5 – Natural Gas Commodity Forecast Prices (2013 – 2019 IRPs)

Fuel and Transportation Costs

Lignite coal for the Heskett Station is supplied from Westmoreland Coal Company's Beulah Mine and transported via a rail haul to the power plant. The current coal contract for the Heskett Station runs through December 31, 2021.

Lignite coal for the Lewis & Clark Station is supplied from Westmoreland Coal Company's Savage Mine and transported via truck haul to the power plant. The current coal contract for the Lewis & Clark Station runs through December 31, 2020.

Impacting the competitiveness of the Heskett and Lewis & Clark Stations is rising coal and transportation costs. Figures 6 and 7 show the increase in coal and transportation costs since 2010.

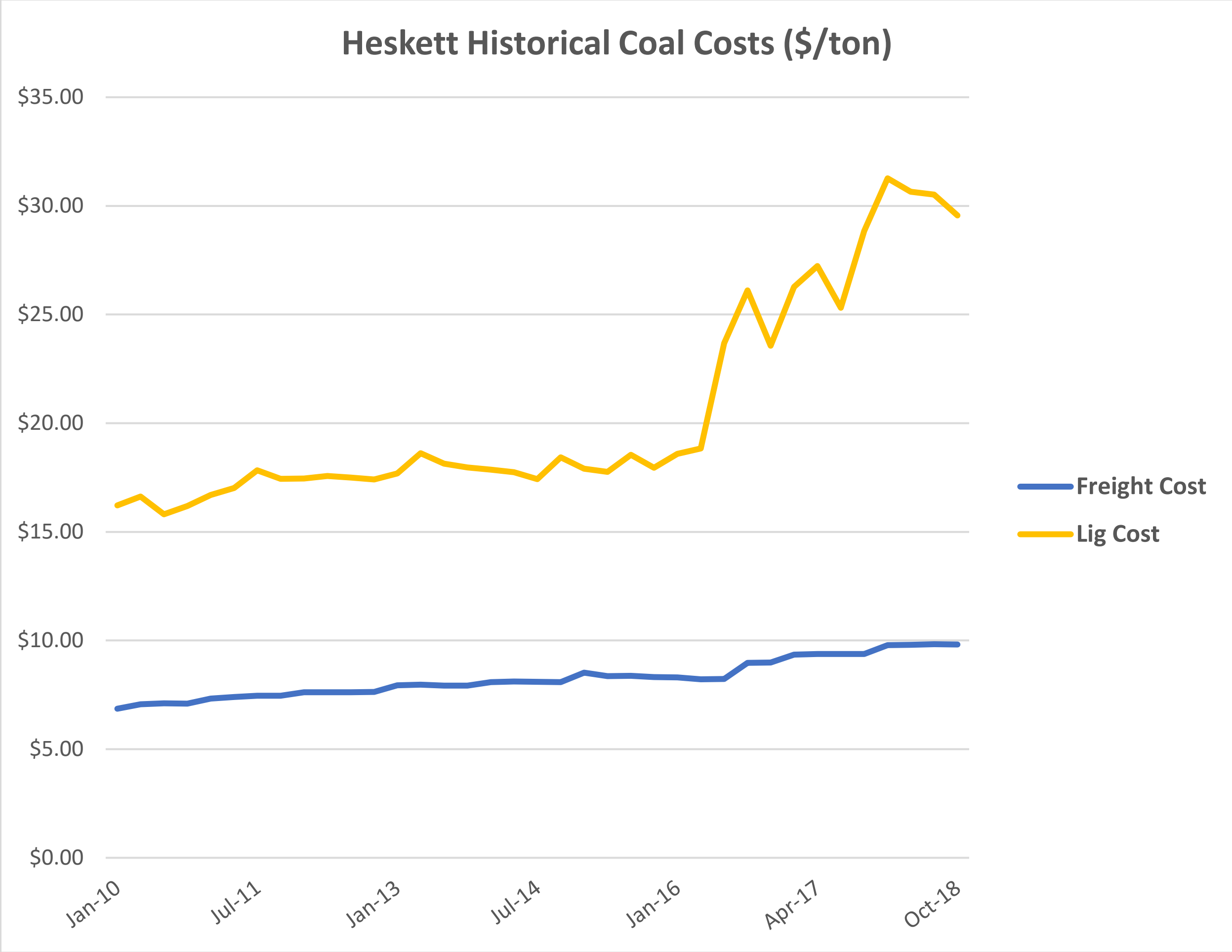

Figure 6 – Heskett Coal and Freight Cost

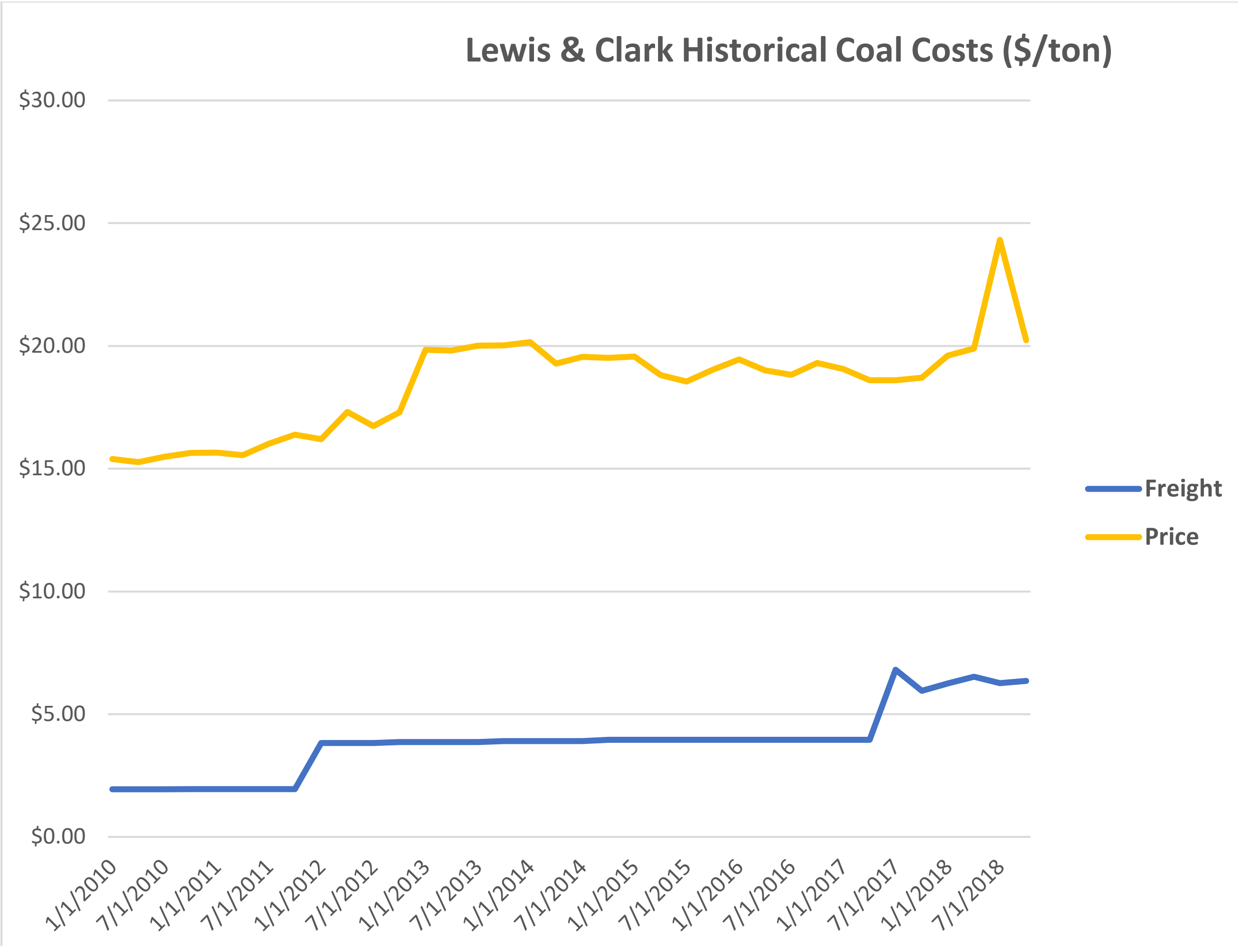

Figure 7 – Lewis & Clark Coal and Freight Cost

These rising coal and freight costs are in contrast with the reduced cost for natural gas and the price of energy available from the MISO energy market which impacts the future economic competitiveness of the units.

Figure 8 is from a MISO presentation on December 7, 2018, to the West Sub-regional planning meeting regarding the MISO Transmission Expansion Plan 2019 (MTEP19) Market Congestion Planning Study (MCPS) Needs Identification. The slide shows MISO's historical coal and natural prices from January 2013 to July 2018. Figure 8 shows coal prices being relatively flat for others in the MISO footprint which is different from Montana-Dakota's experience at the Lewis & Clark and Heskett Stations.

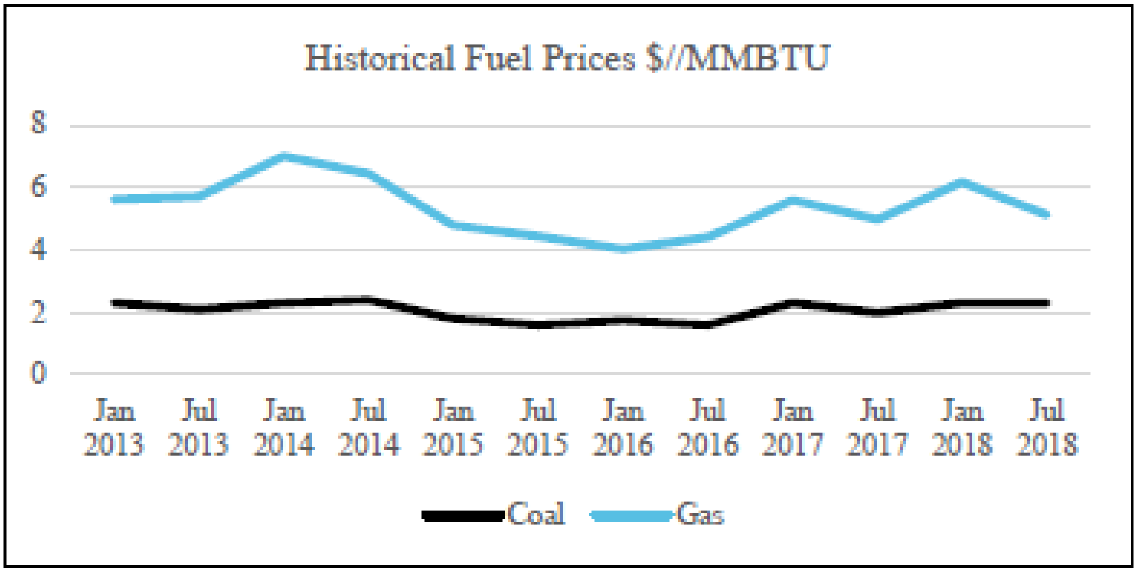

Figure 8 – MISO Historic Coal and Natural Gas Price

An alternate coal supply is not available for the Lewis and Clark Station due to its location and because no rail unloading capability is available on-site.

An alternate coal supply for the Heskett Station is limited, as the plants' environmental pollution control equipment is designed specifically to work with Beulah Mine area lignite coal to ensure environmental permit compliance.

To remain economically viable, fuel and transportation costs for Heskett 1, Heskett 2, and Lewis & Clark 1 would need to be reduced by more than 50 percent, which is unattainable.

Operation and Maintenance (O&M) Costs

Fixed and variable O&M costs have also been increasing at the Heskett 1, Heskett 2, and Lewis & Clark 1 generating stations which impacts the economic competitiveness of the units. Fixed O&M costs are those costs which the Company pays whether the plant is running or not such as labor and maintenance expenses. Variable O&M costs are those costs which are directly related to running the plant such as coal, water and chemical reagents. Figures 9 and 10 show the recent annual operating expenses for the Heskett 1, Heskett 2, and Lewis & Clark 1 generating stations excluding the cost of coal.

To remain economically viable, operations and maintenance costs would need to be reduced for Lewis & Clark 1 to almost zero based upon current fuel prices, which is unattainable. Heskett 1 and Heskett 2 would require a zero-dollar operation and maintenance budget plus a reduction in fuel and transportation costs to remain economically viable, which is unattainable.

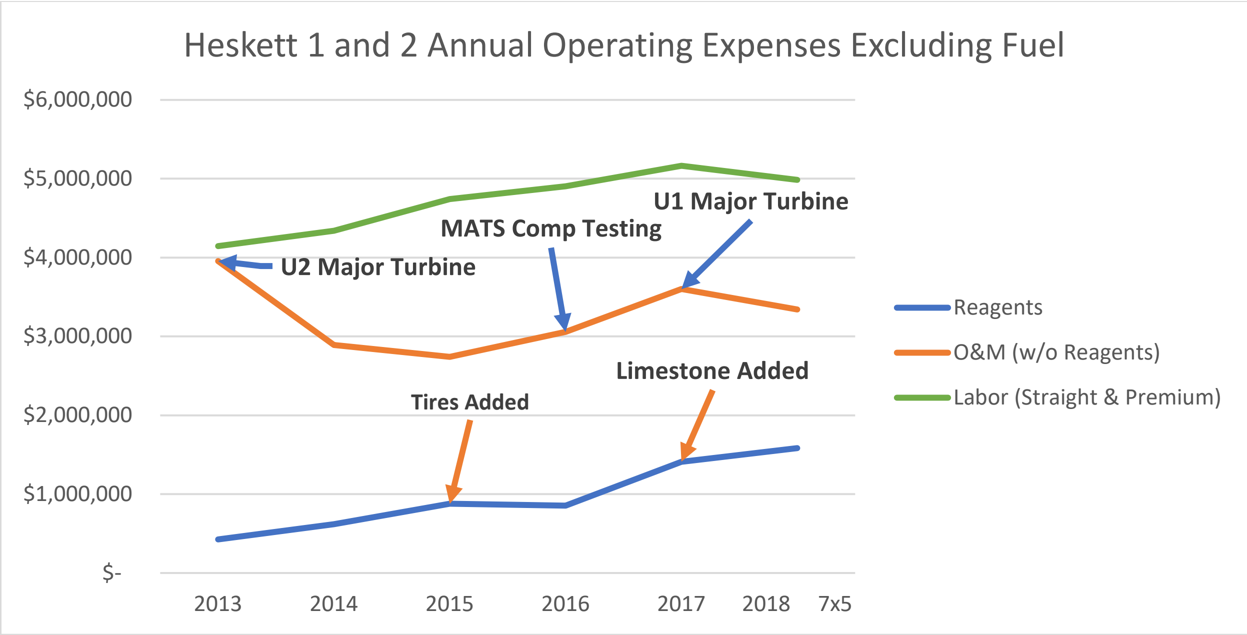

Figure 9 – Heskett 1 and 2 Annual Operating Expenses

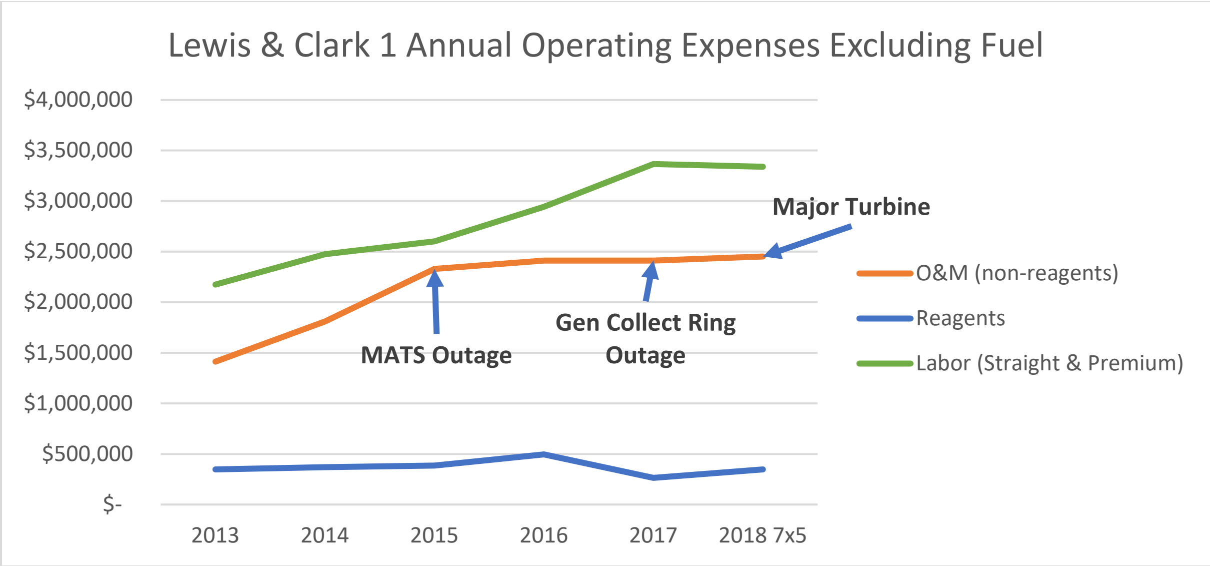

Figure 10 – Lewis & Clark 1 Annual Operating Expenses

Another item to consider related to the future operating expenses for the Heskett 1, Heskett 2, and Lewis & Clark 1 generating units is the next major overhaul dates. Overhauls generally result in significant O&M and capital costs. An average impact on O&M cost for an overhaul based on historical data is $915,000 and capital expenses are specific to the impacted units of property requiring replacing.

Major Unit Outages

	Last	Next
Heskett 1	2017	2023
Heskett 2	2013	2019*
Lewis & Clark 1	2018	2024

* Due to the unit retirement plan, the 2019 overhaul was postponed until 2020 and the scope of the work performed will be limited

Economic Competitiveness Comparison

Montana-Dakota offers its coal-fired generation units into the MISO energy market at the cost of fuel to run the units. This offer price competes against all other generating units within the MISO energy market. A comparison of each unit's fuel cost versus the MISO market price is an indicator of how economically competitive a generation unit is compared to other alternatives.

In 2018, Montana-Dakota's MISO energy market purchase prices averaged $25.85 per MWh. Montana-Dakota's 5-year average MISO energy market purchase price has been $24.44 per MWh.

Figure 11 is a table of fuel, fuel plus variable O&M, and fuel plus all O&M for Montana-Dakota's generating fleet.

	Fuel Cost ($/MWh)	Fuel + Variable O&M ($/MWh)	Fuel + All O&M ($/MWh)	25 Year All-In Cost ($/MWh)
Heskett 1	48.85	55.47	77.28	
Heskett 2	36.98	43.00	52.92	
Lewis & Clark 1	28.82	35.60	53.76	
Big Stone	20.39	22.47	31.54	
Coyote	20.81	22.92	29.68	
MISO Market Purchases		25.85		
Thunder Spirit Wind 2	0	0	5.52	25.63

Figure 11 – Economic Comparison (2018 FERC Form 1)

The all-in-cost of Thunder Spirit Wind 2 represents the levelized 25-year capital and operating and maintenance costs for the project, less production tax credits that the project receives. Costs for Thunder Spirit Wind 2 are included in Figure 11 to show the relative cost of new wind projects.

The age, size and technology of the Heskett 1, Heskett 2, and Lewis & Clark 1 generating units makes these generation resources less competitive than larger and newer units because the units lack economies of scale and operating efficiencies. In addition, Heskett 1, Heskett 2, and Lewis & Clark 1 are not mine-mouth facilities and rely on rail and truck haul to deliver coal to the facilities further increasing the cost of generation from these units.

Figure 12 is a MISO Generation Supply curve from SNL which provides the fuel and variable O&M cost (dispatch cost) for the MISO generation fleet. Colors and symbols represent different fuel types of generation on an economic stacking order. Montana-Dakota's coal-fired generators are identified on this graph. The three vertical lines represent the MISO footprint minimum, average, and maximum load for 2017.[1]

[1] 2017 was used for this illustration because it is the most recent FERC Form 1 data available at this time.

Figure 12 shows that Heskett 1, and Heskett 2, and Lewis & Clark 1 are currently above the MISO maximum system load point because of their high fuel cost and high variable O&M as compared to other generating units within the MISO footprint. Note, the units will still dispatch above their minimum output level at times because of other generating or transmission outages in the area.

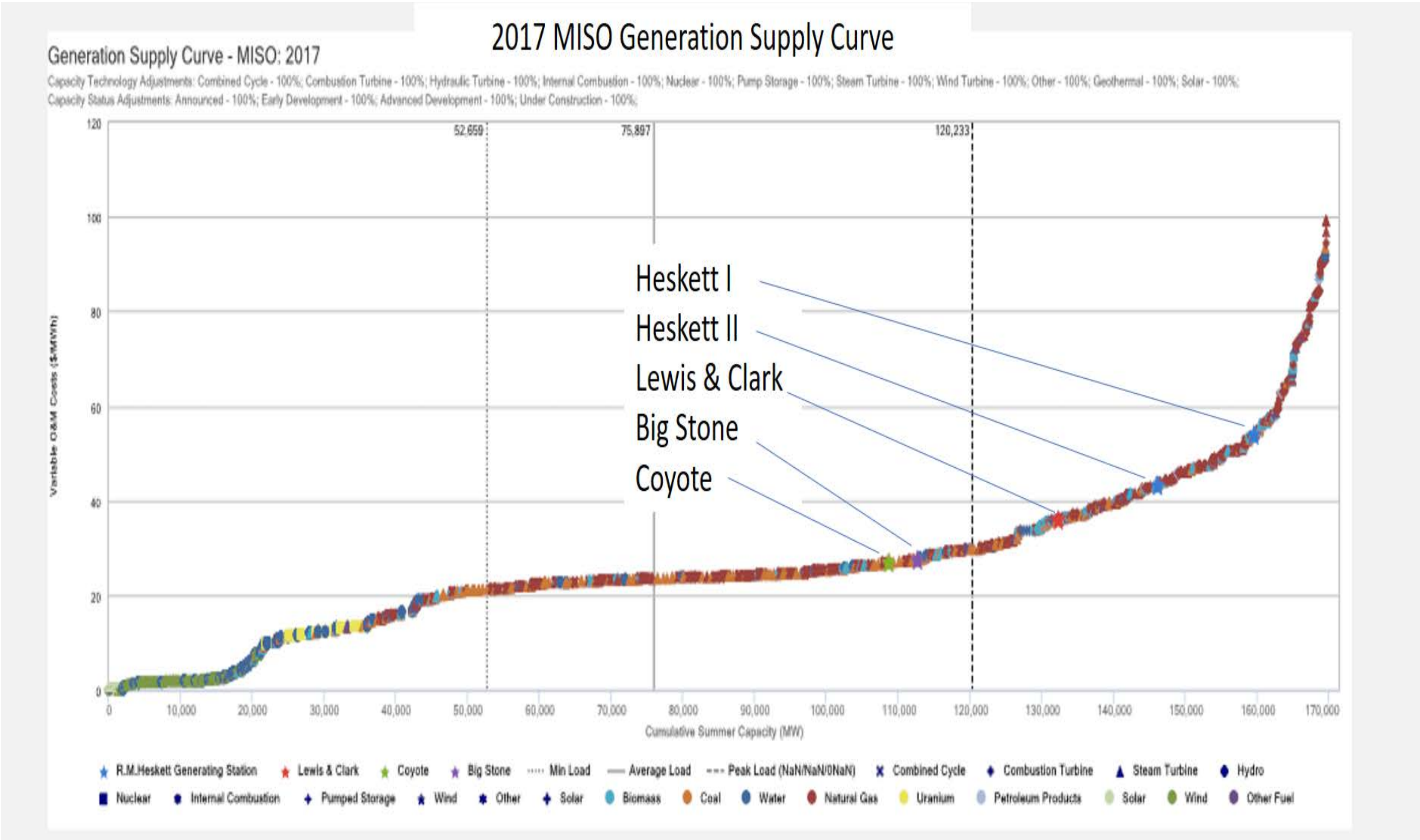

Figure 12 – MISO Generation Supply Curve (SOURCE: S&P Global Market Intelligence)

Retirement Modeling

Specific retirement modeling analysis for Heskett 1, Heskett 2, and Lewis & Clark 1 as part of the 2019 IRP process included: 1) varying the retirement dates for the units in the EGEAS IRP model to compare the total net present value (NPV) of the resource plan over a 50 year period, 2) retiring the units and determining if the EGEAS IRP model selects the units for an additional 5-year period at zero capital costs, and 3) development of a specific revenue requirement model to look at the total net cost impact of retiring the units and replacing that generation with a simple cycle combustion turbine plus market purchases.

Varying retirement dates for Heskett 1, Heskett 2, and Lewis & Clark 1 in the 2019 IRP model from 2029 to 2024 to 2021 show great value in an earlier retire date of 2021 and higher net present value costs to customers if the units continue to run until 2024 or 2029. See Figure 13. The modeled costs to continue to run Heskett 1, Heskett 2, and Lewis & Clark 1 do not include future capital or unit overhaul costs.

Year	**Retire Coal 2021** Plan	**Retire Coal 2024** Plan	**Retire Coal 2029** Plan
2019			
2020			
2021			
2022	Heskett 4, Wind(54 MW), PP(10 MW)	Wind(54 MW), PP(10 MW)	Wind(54 MW), PP(10 MW)
2023	Solar(100 MW)	Solar(100 MW)	Solar(100 MW)
2024			
2025	CC(110 MW)	CC(110 MW)	CC(110 MW)
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034		PP(10 MW)	PP(10 MW)
2035		Heskett 4	Heskett 4
2036			
2037			
2038	Solar(5 MW)	Solar(5 MW)	Solar(5 MW)
NPV ($M)	$2,860.37	$2,866.51	$2,942.92
Difference	0.00%	0.21%	2.89%

Figure 13 – Varying Coal Plant Retirement Dates

In another EGEAS model run, the Heskett 1, Heskett 2 and Lewis & Clark 1 units were assumed to be retired at the end of 2021 with the units allowed to be selected by the model as a future resource with a five-year life beginning in 2022 at zero capital cost and at current fuel and O&M costs for the units. The IRP model did not select any of the retired resources for an additional 5-year life.

A separate model comparing the estimated annual revenue requirement assuming Lewis & Clark 1, Heskett 1, and Heskett 2 continue to run to the estimated annual revenue requirement associated with the post-retirement costs for Lewis & Clark 1, Heskett 1, and Heskett 2 plus the cost of replacing their output with market energy purchases, replacement capacity, and a new combustion turbine to be online in 2023. The post retirement costs included the amortization of employee related retention costs necessary to keep the units running through the retirement date, the amortization of the remaining net book values existing at the time of the retirements amortized over a 15-year period and decommissioning costs amortized over 15 years.

The results of this modeling (provided in Figure 14) showed the total cost of the retirement and replacement option was approximately $20 million less on an annual basis in 2023 compared to the total cost to continue to run the units.

Montana-Dakota also considered the impacts of higher MISO energy and natural gas prices which continued to show the retirement and replacement option as the least cost option for customers.

Figure 14 -Estimated Cost to Run Compared to Cost of Retirement and Replacement Power

(000's)

	2023	
Lewis & Clark Non-Fuel Revenue Requirement	$13,959	
Heskett Non-Fuel Revenue Requirement	19,561	
Subtotal Non-Fuel Revenue Requirement Without Retirements	**$33,520**	
Lewis & Clark Retire 12/2020 - Revenue Requirement	0	1/
Heskett Retire 12/2021 - Revenue Requirement	0	2/
Employee Retention Package Amortized over 5 years	1,413	3/
Net Book Value of Assets at Time of Retirement Amortized over 15 Years	8,815	4/
Plant Decommissioning Revenue Requirement	1,416	5/
Heskett IV Non-Fuel Revenue Requirement	10,642	6/
Subtotal Retirement & Heskett IV	**$22,286**	
Change in Non-Fuel Revenue Requirement	**($11,234)**	
Fuel & Purchased Power - Without Retirements	$79,773	
Fuel & Purchased Power Redispatch after Retirements	68,076	
Capacity Replacement - Retirement	2,867	7/
Change in Fuel/Purchased Power	**($8,830)**	
Net Total Change	**($20,064)**	

1/ End of operation 12/31/2020 - End of coal contract 12/31/2020.

2/ End of operation 12/31/2021 - End of coal contract 12/31/2021.

3/ Employee retention package costs assumed to be amortized over 5 years from retirement date of each plant.

4/ Assumes a 15 year Amortization of remaining balance, plus a return of 9.13% on unamortized balance.

5/ Assumes 25% decommissioning completed year 1, 75% year 2 and 100% year 3
at a 15 year amorization and a return of 9.13%.

6/ Assumes plant in service on 1/1/2023 plus incremental Heskett 4 non-fuel O&M costs.

7/ Capacity purchase at $4 per KW month for capacity needs not met by Heskett 4..

Other Considerations

Heskett 1 and Heskett 2 have value for a future resource if the plants continue to run until a replacement unit is built. MISO allows a generator to keep interconnection rights for another unit at the same point-of-interconnection for a period of three years after a unit is retired. This allows Montana-Dakota to avoid unknown network transmission upgrades and associated costs with a new unit. To utilize this generator replacement provision under the MISO tariff, an existing generating unit must continue to run until at least May 16, 2020. A new air permit at Heskett station will be able to utilize some of the existing emissions from Heskett 1 and Heskett 2 to avoid additional studies and additional pollution control equipment, like an SCR, if the units continue to run until a new air permit is issued.

Conclusion

Heskett 1, Heskett 2, and Lewis & Clark 1 should be retired as soon as possible to save customers the most in rates with the logical times for retirement being at the end of 2020 for Lewis & Clark 1 and at the end of 2021 for Heskett 1 and Heskett 2 which are the end dates of their current coal supply agreements.

The age, size and technology of Heskett 1, Heskett 2 and Lewis & Clark 1 makes them less competitive than larger and newer units because they lack economies of scale and operating efficiencies. Heskett 1, Heskett 2 and Lewis & Clark 1 are not mine-mouth facilities and rely on rail and truck haul to deliver coal to the facilities causing additional costs as compared to other coal-fired generating facilities in the area, which leads to the units not being competitive in MISO energy market. Their age, smaller size, and lack of economies of scale also makes their operating cost higher which impacts the economic competitiveness of the units.

Future of Heskett and Lewis and Clark Stations

At the time of the retirement announcement, there were 77 employees between the two coal-plant locations. Once the coal plants are no longer in operation, approximately 10 employees will be required to operate the two-natural gas-fired combustion turbines at Heskett and the two-natural gas-fired combustion engines at Lewis & Clark. A plan is in place intended to maintain staff until the plant retirements and the Company will offer training for employees who wish to fill open positions in other areas of the Company.

Figure 15 shows the Company's interconnected system generation capacity portfolio before and after retirements based upon nameplate capability:

Fuel Source	2019	2022
Coal	44%	29%
Natural Gas	28%	41%
Renewable	28%	30%

Figure 15 – Montana-Dakota Generation Portfolio Before and After Retirement