



Integrated Resource Plan

2017



Submitted to the
North Dakota Public Service Commission
July 1, 2017

Volume IV: Attachments C-H

Montana-Dakota Utilities Co.
2017 Integrated Resource Plan

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**MONTANA-DAKOTA
UTILITIES CO.**

A Division 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 at this time requires a planning reserve margin (PRM) of 7.8 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, sufficient planning resources are needed to cover the projected yearly MISO non-coincident summer peak demand with a 1.9 percent adder for MISO losses, plus 7.8 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 80.7 percent coincident factor for the 2017-18 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 80.7 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 thermal planning resources

(steam units and combustion turbines) 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:

$$UCAP = ICAP - (1 - XEFOR_d)$$

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

Figure 1-1 shows that, under the current system forecast, Montana-Dakota has adequate capacity to meet its PRMR through 2023. The capacity deficit in 2024 will be 3.7 ZRC and grow to 42.6 ZRC in 2030. As shown in Figure 1-2, under the low-growth forecast, a capacity deficit never occurs. With the high-growth forecast, as shown in Figure 1-3, a capacity deficit of 5.3 ZRC will occur in 2018 and grow to 90.4 ZRC in 2022.

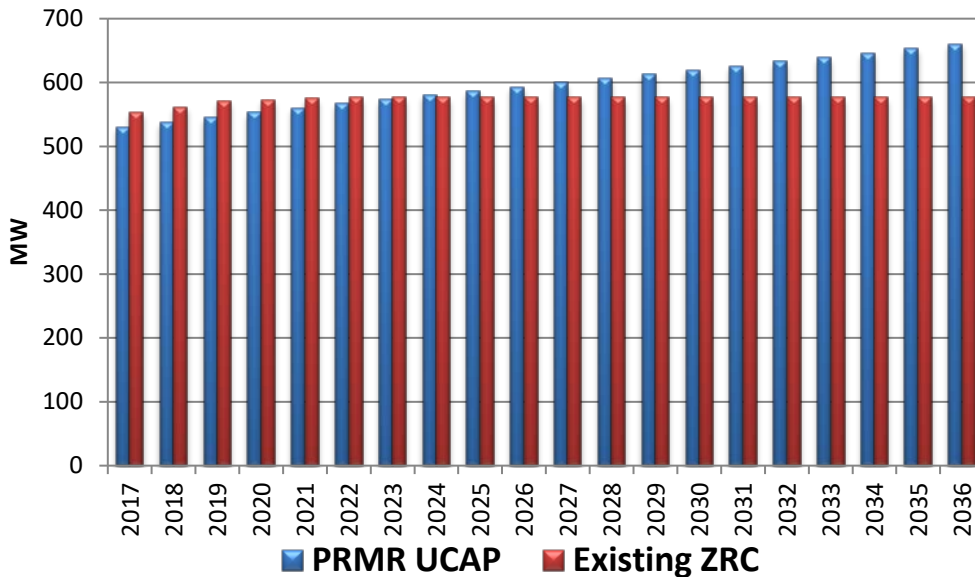


Figure 1-1: Zonal Resource Credit and Planning Reserve Margin Requirement Base Forecast

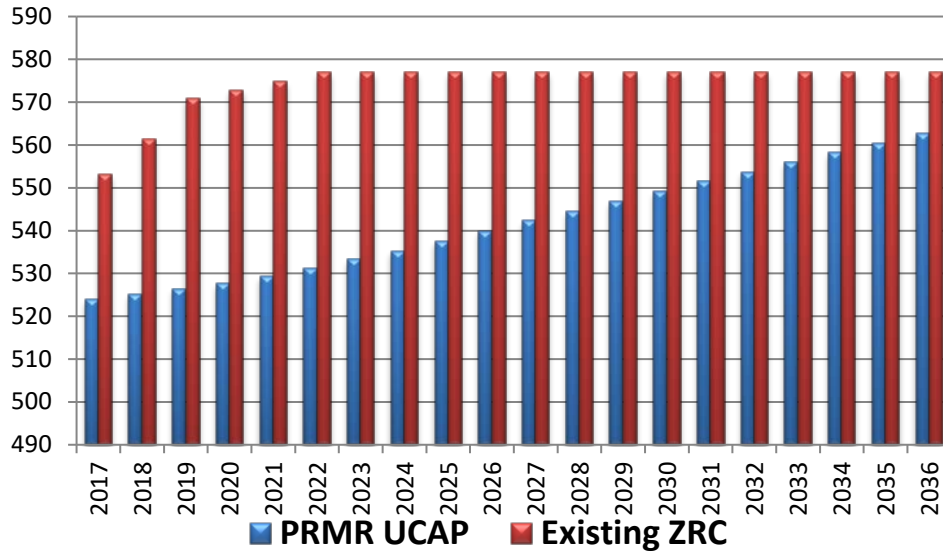


Figure 1-2: Zonal Resource Credit and Planning Reserve Margin Requirement Low Growth Forecast

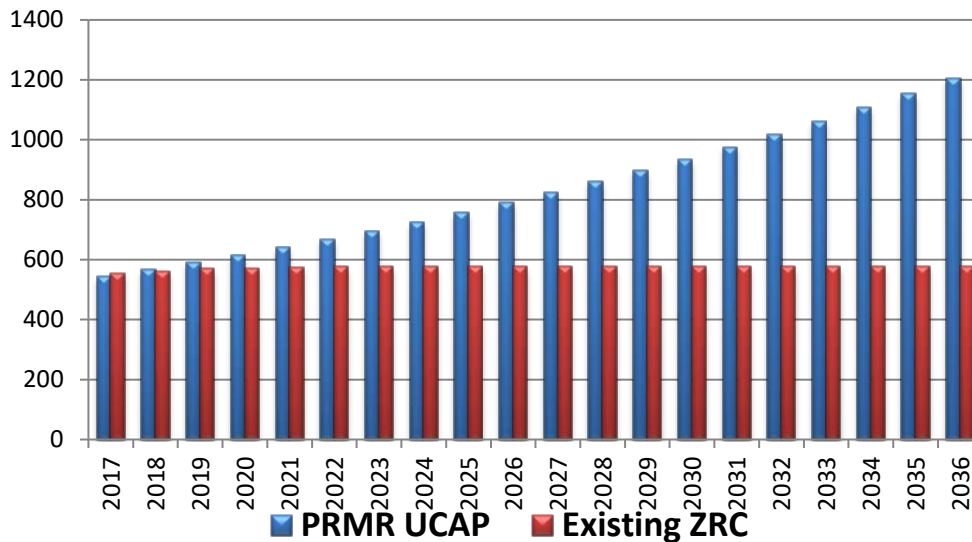


Figure 1-3: Zonal Resource Credit and Planning Reserve Margin Requirement High Growth Forecast

1. Analysis Method

The Electric Generation Expansion Analysis System (EGEAS) version 11.0, 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 2016 with the study period starting in 2017. Costs indicated in this report are in 2016 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2017-2036) in which new resources are allowed to 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 annually examines MISO’s top eight annual summer peaks for the last five years to determine how much wind is actually 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 2017-2018 planning year, the ELCC study concluded that 15.6 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 21.16 percent of its nameplate capacity to ZRCs, Cedar Hills was allowed up to 25.63 percent of its nameplate capacity to ZRCs, and Thunder Spirit was allowed up to 18.76 percent of its nameplate capacity to ZRCs. Diamond Willow, Cedars 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, 5.0, and 20.6 respectively.

2.1. Current Resources

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

2017 MONTANA-DAKOTA ZONAL RESOURCE CREDITS

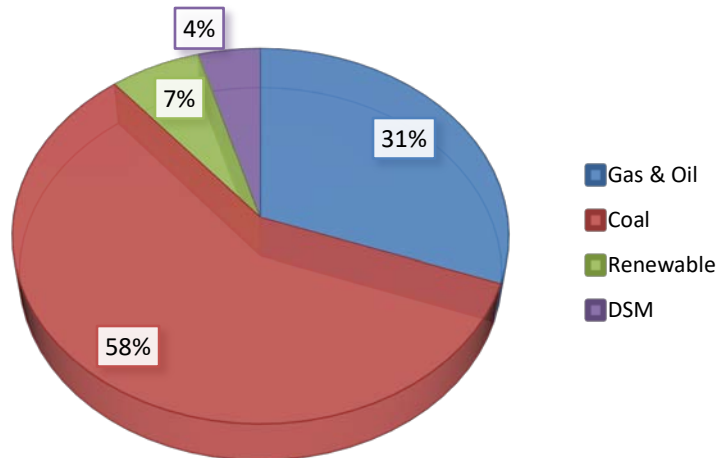


Figure 2-1: Montana-Dakota’s Current Generation Mix by Zonal Resource Credits

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 accounts for 58 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}	107.4	22.33	83.4	29.1	2.8	1.79
Big Stone ³	108.7	6.39	101.8	24.06	6.97	2.28
Heskett 1	25.6	7.9	20.3	78.36	5.79	2.19
Heskett 2	73.1	8.58	66.8	34.99	4.99	2.19
Lewis & Clark 1	52.3	2.61	50.9	80.77	8.48	1.79

1. Based on MISO 2017-18 Planning Year ICAP and XEFOR_d

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 by 2020 to represent a historical XEFOR_d 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 31 percent of Montana-Dakota's existing zonal resource credits. 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)
Glendive 1	34.8	5.62	32.1	5.24	2.5	2.63
Glendive 2	37.9	3.24	36.7	6.07	2.5	2.63
Miles City	21.6	0.35	21.5	7.86	2.5	2.63
Heskett 3 ²	84.3	30.05	59	38.8	2.5	2.63
Lewis & Clark 2	18.5	13.12	16.1	11.76	1.85	2.63
Diesel 1	2	13.12	0	27.42	2.5	23.32
Diesel 2	2.1	13.12	1.9	27.42	2.5	23.32
Diesel 3	2	13.12	1.8	27.42	2.5	23.32

1. Based on MISO 2017-18 Planning Year ICAP and XEFOR_d

2. ZRC was increased in model to 79.6 by 2020 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 three percent of Montana-Dakota’s existing zonal resource credits.

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

<u>Unit</u>	<u>Zonal Resource Credits¹</u>	<u>Fixed O&M (\$/kW-year)</u>	<u>Variable O&M (\$/MWh)</u>	<u>Fuel (\$/MBTU)</u>
Diamond Willow ²	6.3	16.4	-35.85	-
Cedar Hills ²	5	17.06	-35.85	-
Glen Ullin Station 6 ³	4	76.14	7.33	-
Thunder Spirit	20.6	25	-35.85	-

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 2017-18 Planning Year ICAP and XEFOR_d

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 how much would be available in 2017.

- Montana-Dakota Interruptible loads – 14.4 MW
- Commercial DSM – 10.3 MW

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. The model included a 200 MW block of energy for off-peak and on-peak periods.

2.2. Future Capacity Resources (Thunder Spirit Wind Expansion Project)

Montana-Dakota has entered into a contract to purchase the output from or acquire the Thunder Spirit Wind expansion (TSW Phase II) project. This is for an addition of up to 48 MW at the original Thunder Spirit Wind farm near Hettinger, ND, which came out of Montana-Dakota’s 2016 request for proposal (2016 RFP).

Based on an analysis of the 2016 RFP responses and preliminary EGEAS runs, Montana-Dakota entered into a 25 year Power Purchase Agreement (PPA) with Thunder Spirit Wind, LLC and ACE Wind LLC in December 2016 to purchase the output of the additional 48 MW wind project located near Hettinger, ND with an option for Montana-Dakota to purchase the project, under development by Allete Clean Energy (ACE), a subsidiary of Allete, Inc., at the commercial operation date of the project.

The TSW Phase II Project will consist of 14 to 16 Nordex N117/3000 (3.0 MW) wind turbines totaling 42 to 48 MW with a hub height of 91 meters and an estimated capacity factor of 44.5 percent. The Project will interconnect at the adjacent Hettinger 230 kilovolt (kV) Junction Substation owned by Montana-Dakota and also utilized by the first phase of the Thunder Spirit Wind Project. The Project has all of the necessary land agreements and interconnection rights to accommodate a project with a total size of 150 MW.

The TSW Phase II PPA is a 25 year agreement for up to 48 MW of new wind developed from the TSW Phase II Project which contains a purchase option at commercial operation of the Project or the eleventh anniversary date of the Project at Montana-Dakota's sole election. The election of the purchase option at commercial operation of the Project must be made by February 28, 2017.

The PPA includes a negotiated energy purchase price that remains flat over the first ten years of the Project and then increases in year eleven with the end of the eligibility of Project to earn Federal Production Tax Credits (PTCs) for wind generation. Montana-Dakota will receive all of the renewable energy credits and capacity credits that the Project produces at no additional cost.

The PPA contains energy price adjustment mechanisms for final tax equity rates of the Project Owner and any reductions in the federal corporate income tax rates below 30 percent during the first ten years of the Project. The PPA also contains Curtailment Payments to the Project Owner for lost production caused by Buyer Directed or Economic Curtailments. These Curtailment Payments would include any lost energy payments under the PPA plus lost production tax credits associated with the Buyer Directed or Economic Curtailment megawatt (MW) amount.

The analysis of the TSW Phase II ownership option utilized a separate revenue requirement model to develop an annual revenue requirement and \$/MWh cost for the TSW Phase II Project over its 25 year life. The ownership of Thunder Spirit Expansion Project was selected as a least

cost option over the PPA with \$4.77 million in net present value savings over the PPA as seen in Table 3-1 “Least-Cost Resource Expansion Plans for the Studied Scenarios”.

The 25 year levelized ownership cost of the TSW Phase II is \$22.40 per MWh while the annual average Montana-Dakota purchase price of energy over the last 5 years from the MISO Energy Market has been \$24.95 per MWh.

Looking at the difference between the annual revenue requirements in the Thunder Spirit Ownership sensitivity run versus the Base Case EGEAS run, which is summarized in Table 3-1, the following annual cost differences are calculated between the two options:

Annual Cost (\$Millions)				
Year	Thunder Spirit Ownership	Base Case	Difference	
2019	87.6	86.2	1.3	
2020	95.0	94.8	0.2	
2021	97.7	98.5	-0.8	
2022	101.2	102.8	-1.6	
2023	105.0	107.2	-2.2	
2024	108.5	111.3	-2.8	
2025	134.0	137.2	-3.2	
2026	153.6	157.1	-3.5	
2027	157.7	161.4	-3.7	
2028	162.5	166.5	-4.0	
2029	177.7	175.6	2.1	
2030	186.7	184.8	1.9	
2031	192.0	190.2	1.8	
2032	197.6	196.0	1.6	
2033	203.8	202.4	1.5	
2034	210.6	209.2	1.4	

2035	237.9	236.7	1.3
2036	245.3	244.2	1.1
NPV @ 6.12% WACC		-7.26	

Ownership of the TSW Phase II project is a lower cost option to Montana-Dakota’s customers than a PPA. Ownership of the TSW Phase II Project provides Montana-Dakota with control of the project site and equipment along with the ability to capture additional value from the TSW Phase II Project after the expiration of a PPA or if the energy from the TSW Phase II Project exceeds the annual amount of net projected energy under the PPA. The TSW Project has a MISO Large Generator Interconnection Agreement and site leases for a 150 MW project size, which allows for the expansion of TSW under an existing MISO interconnection agreement, existing project permits and site leases. The TSW Phase II Project is scheduled to be online by the end of 2018.

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, and
- Biomass.

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. SCCT's typically have one of the lower capital cost per MW compared to other generating types, and can be installed within a relatively short lead time (two to three years). Two basic types of SCCT exist: aeroderivative (Aero), and heavy-duty Frame (Frame). Aero SCCT's are adapted from jet and turboshaft jet engines, and are usually lighter, 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 problems, and do not normally exceed 100 MW's generating capability in simple cycle form. Frame units are designed to drive stationary generation and process plant equipment. They are usually less expensive than Aero's, more robust, require less frequent inspection and maintenance intervals, and are available in over 500 MW's in simple cycle form. Montana-Dakota has operating experience with three Frame units, and one Aero unit. Three options for the SCCT were analyzed in the resource expansion analysis: 78.4 MW summer net large frame unit, a 90.5 MW summer net aero-hybrid unit, and a 41.3 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 SCCT's of similar power output. Two RICE natural gas fired plants were analyzed in the resource expansion analysis: a 36.5 MW net 4 engine unit, and a 55.3 MW net 3 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 SCCT's. The hot exhaust gases from the SCCT passes through a heat recovery steam generator to produce additional power in a steam turbine. CCCT's can have one of the highest efficiencies 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. However, because they are fueled by natural gas or fuel oil, the units have historically been higher-cost energy producers compared to coal-fired baseload units. There were four natural gas fired CCCTs analyzed in the resource expansion analysis: a 66.1 MW summer net 1x1 Aero unit, a 139.8 MW summer net 2x1 large

frame unit, 265.1 MW summer net 2x1 large frame unit (expansion of Heskett 3), and a 323.0 MW summer net 1x1 large frame unit.

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 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: 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 requires adding other capacity resources to meet the MISO planning reserve margin requirements.

This option represents Montana-Dakota's self-built wind generation. Table 2-5 shows two different options: 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

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 must rely on other capacity resources to meet Montana-Dakota's MISO planning reserve margin requirements. Two types of 50 MW solar options were included in the resource expansion analysis: concentrated and photovoltaic solar. Both projects assume no Federal Earned Income Tax Credits (EITCs) 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 9.3 MW net biomass option was included in the resource expansion analysis.

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

EGEAS Model Input Summary, 2017 \$	Plant Size (MW,net)	ZRC	Capital Cost (\$/kW)	Fixed O&M (\$/kW-month)	Variable O&M (\$/MWh)	Major Maintenance (\$/kW-month)	Fuel Gas Reservation Fee (\$/kW-yr)	Total Fixed O&M (\$/kW-year)	Full Load Heat Rate (BTU/kWh)	Carbon Intensity (ton/GWh)	Fuel Cost (\$/MBtu)
GE 7EA	78.4	74.00	\$1,163.27	\$1.53	\$2.68	\$0.04	\$2.67	\$21.46	11498	672.5	\$2.96
GELMS100PB	90.5	85.42	\$1,326.88	\$1.88	\$4.67	\$0.04	\$1.92	\$24.91	8832	526	\$2.96
GE LM6000PH	41.3	40.85	\$1,546.30	\$2.77	\$4.34	\$0.04	\$2.72	\$36.39	9637	563.5	\$2.96
GE LM6000PH Sprint (CC)	66.1	63.51	\$1,812.47	\$4.87	\$4.63	\$0.43	\$1.83	\$65.41	7834	458	\$2.96
GE 7EA (2x1) Addition to existing	265.1	254.71	\$1,001.68	\$1.97	\$3.98	\$0.43	\$1.45	\$30.23	7694	450	\$2.96
GE 7FA.05 (1X1)	323	310.34	\$1,071.21	\$1.80	\$3.27	\$0.43	\$1.24	\$27.97	6859	401	\$2.96
SIEMENS SGT-800 (2x1)	139.8	134.33	\$1,512.33	\$2.91	\$4.06	\$0.43	\$1.50	\$41.56	7415	433.5	\$2.96
WARTSILA 20V34SG	36.5	36.10	\$1,351.68	\$1.53	\$4.20	\$2.07	\$1.36	\$44.56	8447	494	\$2.96
WARTSILA 18V50SG	55.3	54.70	\$1,382.61	\$1.54	\$4.20	\$2.07	\$1.02	\$44.34	8288	485	\$3.96
BIOMASS	9.3	8.51	\$9,211.23	\$9.90	\$5.92	\$0.39	-	\$123.52	14273	1859	\$6.75
PV SOLAR	50	25.00	\$2,854.74	\$1.55	\$0.00	\$0.00	-	\$18.60	-	-	\$0.00
CONC. SOLAR	50	25.00	\$11,476.47	\$6.01	\$4.37	\$0.39	-	\$76.80	-	-	\$0.00
CFBC WITHOUT CO2 Capture	168	157.26	\$5,623.15	\$19.62	\$13.25	\$0.00	-	\$235.44	9974	973	\$1.91
CFBC WITH CO2 Capture	122	114.20	\$10,308.28	\$26.93	\$21.02	\$0.00	-	\$323.16	13781	124	\$1.91
ND Wind	20	4.16	\$1,542.03	\$3.71	\$0.00	\$2.51	-	\$74.64	-	-	\$0.00
ND Wind	50	10.40	\$1,519.03	\$3.71	\$0.00	\$2.51	-	\$74.64	-	-	\$0.00

2.4. Retirements

Montana-Dakota is modeling the retirement of Heskett 1, Heskett 2, and Lewis & Clark 1 at the end of 2024. The retirements are modeled with the assumption that additional environmental requirements as well as age and condition will result in the closure of these facilities at some point in the future. At this time there is no specific plan in place to retire any of the units.

Additionally, Montana-Dakota's wind projects Diamond Willow, Cedar Hills, and Thunder Spirit are assumed to be retired in the model after a 20 year operating life 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.

As a result of the demand-side analysis in Chapter 3 and Attachment B a new program was modeled again and continues to be found feasible. This is a residential air conditioning cycling (A/C Cycling) program that was modeled in EGEAS as a new supply-side option in all the sensitivity analyses. The amount of demand reduction and costs associated with the air condition cycling program is shown in Table 2-6.

Table 2-6: DSM

<u>Unit</u>	<u>Zonal Resource Credit¹</u>	<u>Total Program Lifetime Cost (\$M)</u>
A/C Cycling	10	\$14.5

1- The program will reach 10 MW by 2022

3. Summaries of Results

Twelve planning scenarios, which include the base case, and eleven 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 Case	Thunder Spirit Ownership	Low Gas Price	High Gas Price	Low Growth	High Growth	High CT and IC Costs	Low Market Price	High Market Price	Limiting Energy Purchases (5 years)	Limiting Energy Purchases (10 years)	90% MISO Coincident Factor	\$30 Carbon Tax
2017												PP(40)	
2018	A/C Cycling	A/C Cycling		A/C Cycling	A/C Cycling		A/C Cycling	A/C Cycling		A/C Cycling	A/C Cycling	PP(30)	
2019	TSW	TSW	TSW	TSW	TSW	TSW	TSW	TSW	TSW	TSW	TSW	TSW, PP(20)	TSW
2020						PP(10)						PP(10)	
2021						CT(78)						PP(20)	
2022										CC-SGT-800(140)		RICE(36)	
2023													
2024						CC-7FA(323)						PP(10)	
2025	Heskett CC	Heskett CC	CC-7FA(323)	CC-SGT-800(140)	CT(78)		CC-SGT-800(140)	Heskett CC	CC-7FA(323)	Heskett CC	Heskett CC, PP(20)	CC-7FA(323)	CC-7FA(323)
2026											CC-SGT-800(140)		
2027													
2028						PP(10)							
2029				PP(10)		CT(78)	PP(10)						
2030				PP(20)	PP(10)	PP(20)	PP(20)						
2031				CT(78)	PP(10)	CC-7FA(323)	CT(78)						
2032					PP(10)					PP(10)	PP(10)		
2033					PP(20)								
2034	PP(10)	PP(10)			PP(20)			PP(10)		RICE(36)	RICE(36)		
2035	CT(41)	CT(41)			RICE(36), PP(10)			CT(41)					
2036				WIND(20)	PP(10)		PP(10)			BIOMASS	BIOMASS		
NPV (\$M)	\$3,021.29	\$3,016.52	\$2,747.38	\$3370.69	\$2,522.62	\$5,237.70	\$3,122.81	\$2,947.19	\$3,228.79	\$3,856.48	\$3,789.61	\$3,148.82	\$3,794.88
Difference	-	-0.16%	-9.07%	11.56%	-16.50%	73.36%	3.36%	-2.45%	6.87%	27.64%	25.43%	4.22%	25.6%

Resources:

- PP(x) - Purchased Capacity with number representing MW value
- A/C Cycling - 10 MW phased in over 5 years
- TSW - 48 MW Phase II of Thunder Spirit Wind
- Heskett CC - Another GE 7EA added with a steam turbine and heat recovery steam generator - 180 MW additional
- CC-7FA(323) - 323 MW GE 7FA (1x1) combined cycle combustion turbine
- CC-SGT-800(140) - 139.8 MW Siemens SGT-800 (2x1) combined cycle combustion turbine
- CT(41) - 41.3 MW GE LM6000PH simple cycle combustion turbine
- CT(78) - 78.4 MW GE7EA simple cycle combustion turbine
- WIND(x) - Self-built wind option
- BIOMASS - 9.3 MW Biomass
- RICE(36) - 36.5 MW Wartsila Reciprocating Internal Combustion Engine (4 units)

3.1. Base Case Plan Results

The Base Case least-cost plan consists of the following resource additions for 2017-2026:

- Purchase the 48 MW Thunder Spirit Wind Expansion Project in 2018;
- Implement the residential A/C Cycling program by 2018 to reach a total of 10 MW in the program by 2022;
- Continue the commercial demand response program to achieve 15 MW by 2019 and achieve 20 MW from Montana-Dakota's interruptible rate by 2019; and
- Install a Combined Cycle unit in 2025.

For the later years an additional 41.3 MW simple cycle unit was identified as needed in 2035. The net present value of the Base Case least-cost plan over the 50-year study period equates to \$3,018.52 million in 2016 dollars, as shown in Attachment C Table 3-1.

3.2. Sensitivity Analysis

The twelve 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, diminishing energy market, and Thunder Spirit Wind Expansion ownership.

3.2.1. Thunder Spirit Wind Expansion Ownership

The Base Case and other sensitivities modeled the purchased power agreement (PPA) price for the TSW Phase II Project over the twenty five year offer period. This sensitivity shows the additional benefits associated with the ownership of the TSW Phase II Project over a PPA, as the NPV over the 50 years decreased by 0.16 percent or \$4.77 million.

3.2.2. 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. For the Base Case, natural gas was priced for delivery at \$3.06/MBTU for 2017, and increasing to \$3.18/MBTU in 2021. After 2021, natural gas prices were escalated by three percent annually. Considering the historical 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 \$3/MBTU and decreased by \$1/MBTU from the Base Case, respectively. The high and low gas price cases were escalated by three percent annually after 2021. The results of the high natural gas price case included a smaller combined cycle option, a larger simple cycle combustion turbine, and an additional 20 MW of wind in the later years. The NPV of the revenue requirement in this scenario increased 11.8 percent over the Base Case. The results of the low natural gas price scenario had a larger combined cycle with nothing selected in the later years, and the A/C cycling program was not selected. This case decreased the NPV of the revenue requirement by 9 percent from the Base Case.

3.2.3. 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 basis for this assumption came from Montana-Dakota's historical growth rate during 1985-1993. The results of this scenario indicate that there is less future capacity and energy needed, resulting in the following resource additions: A/C cycling program, Thunder Spirit Wind Phase II, a simple cycle combustion turbine in 2025, and a RICE unit in 2035. This lowered the NPV by 16.5 percent over the Base Case.

3.2.4. 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 2017. The basis for 4.4 percent per year assumption came from Montana-Dakota's historical growth rate during 1977-1985. The results of this scenario indicate the need for the following resources over the Base Case: an additional combined cycle unit, two larger simple cycle combustion turbines. This increased the NPV by 73.5 percent over the Base Case.

3.2.5. High Combustion Turbine and Internal Combustion Engines Costs

Historically the costs of materials associated with the construction of generation have increased at a rate higher than 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 smaller combined cycle and a larger simple cycle turbine in the later years. The results of this sensitivity case indicate an increase of 3.3 percent in the NPV of the revenue requirement over the Base Case.

3.2.6. 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 case added \$10/MWh to both the on-peak and off-peak market prices of the base year. This resulted in no A/C cycling program and a larger combined cycle compared to the Base Case results, and an increase of 7 percent in NPV of the revenue requirement. The lower market price case decreased the base year on- and off-peak prices to a one year historical value, where the Base Case used a five year average. This resulted in the same results as the Base Case, but lowered the NPV by 2.5 percent.

3.2.7. Diminishing Energy Market

The MISO energy market has been around since 2005, and Montana-Dakota has seen its need to rely on the energy market increase over the years. In the future with potential coal retirements in MISO there is a chance for the energy market to increase in price and /or the availability to purchase energy from the market decrease. These scenarios look at that possibility either at 5 or 10 years that there would be no energy market available and Montana-Dakota would be required to self-supply to its customers. In both scenarios an additional combined cycle was selected, along with a RICE project and a biomass project in the later years. These two scenarios of 5 year and 10 year market diminishing saw an increase of the NPV over the Base Case at 27.8 and 25.6 percent, respectively.

3.2.8. 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 80.7 percent coincident factor. The selected least-cost plan for this scenario was different from the base case with additional capacity purchases, a RICE unit needed to meet the increase

of capacity needed in the early years, and a larger combined cycle being selected. The A/C cycling program was not selected. The results of this scenario indicates an increase of 4.3 percent in the NPV of the revenue requirement over the Base Case.

3.2.9. Carbon Tax

Montana-Dakota analyzes new environmental requirements as information becomes available. Pending rules impacting carbon-dioxide emissions, solid waste, other air emissions and water quality management at the existing plants have been evaluated, although no engineering analysis has been conducted on compliance with these proposed regulations. 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 2024. 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 differed from the Base Case with no A/C cycling being selected and a larger, more efficient combined cycle being selected. The NPV increased by 25.7 percent over the Base Case.

4. Conclusions

Based on the current results of the supply-side and integration analysis, the resource plan resulting from the Base Case with the ownership of the 48 MW Thunder Spirit Wind Expansion Project 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 until 2026:

- Purchase the 48 MW Thunder Spirit Expansion Project in 2018;
- Implement the residential A/C Cycling program in 2018 with an initial 2 MW and increasing the program to 10 MW by 2022;
- Continue the commercial demand response program to achieve 15 MW by 2019 and achieve 20 MW from Montana-Dakota's interruptible rate by 2019;
- Continue the design and engineering work on a natural gas-fired combined cycle combustion turbine resource to be online in or after 2025.

Figure 4-1 and 4-2 show a comparison of the resource mix that Montana-Dakota has available to

serve its customers' needs in 2017, as compared to the least cost plan in 2025. Note a Zonal Resource Credit (ZRC) represents one megawatt of accredited generating capacity under the MISO resource adequacy rules.

2017 MONTANA-DAKOTA ZONAL RESOURCE CREDITS

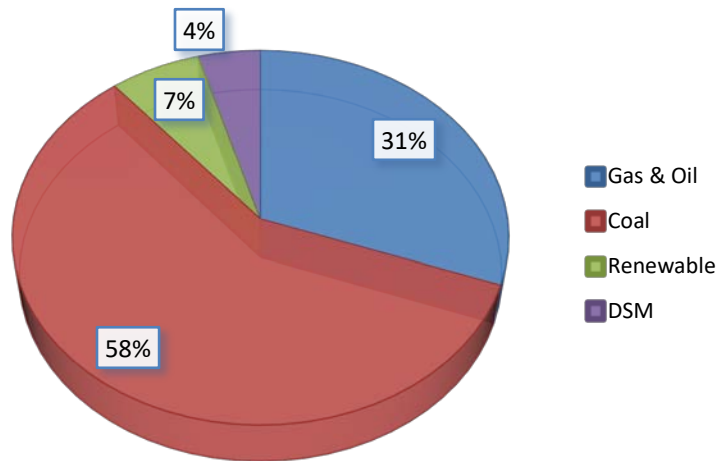


Figure 4-1: 2017 Montana-Dakota Zonal Resource Credits

2025 MONTANA-DAKOTA ZONAL RESOURCE CREDITS

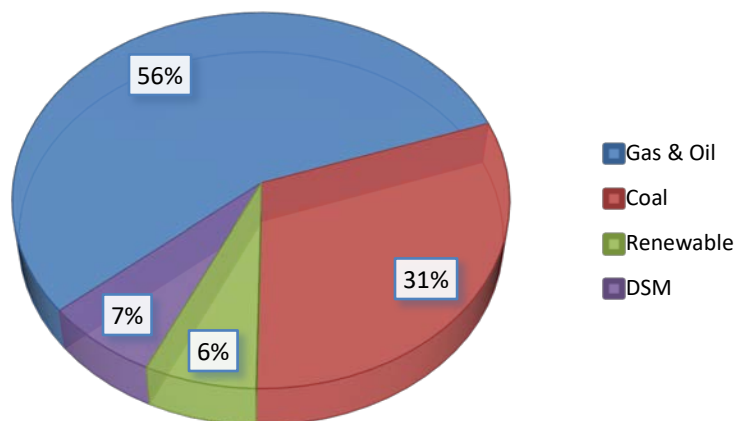


Figure 4-2: 2025 Montana-Dakota Zonal Resource Credits

As shown in Figures 4-1 and 4-2; in 2017 approximately 31 percent of Montana-Dakota's resource capacity comes from natural gas and oil-fired combustion turbines and internal combustion

engines while in 2025, based on the Base Case plan, approximately 56 percent of the Company's resource capacity would be made up by natural gas and oil-fired combustion turbines and internal combustion engines. The resource additions were selected mainly to meet the Company's growing energy requirements on peak.

The sensitivity scenarios show that the largest variations in NPV of supply plans reflect potential carbon tax, high load growth scenarios, diminishing market purchases, 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 resources to meet the requirements identified for the 2017-2026 period:

- Purchase the 48 MW Thunder Spirit Expansion Project in 2018;
- Implement the A/C Cycling program in 2018 with an initial 2 MW and increasing to 10 MW by 2022;
- Continue the commercial demand response program to achieve 15 MW by 2019 and achieve 20 MW from Montana-Dakota's interruptible rate by 2019;
- Continue the design and engineering work on a natural gas-fired combined cycle combustion turbine resource to be online in or after 2025.

Montana-Dakota's recommended resource plan satisfies future customer requirements through a balance of additional wind, increases to the demand response programs, timely unit retirements, and the addition of a large natural gas-fired combined cycle resource timed with potential coal-fired plant retirements. Additional factors that are considered in confirming the best cost new supply-side resource option include, but are not limited to: site location issues, susceptibility to inclement weather and sustained cold temperature operation, fuel delivery requirements and limitations, transmission interconnection options, transmission upgrade requirements, long-term maintenance strategies, synergies with other Company resources, and overall operation and maintenance costs.

6. References

MISO Business Practice Manual-11-r16 Resource Adequacy. (July 15, 2016)

EGEAS User's Guide Version 9.02. New York, New York: Stone & Webster Management Consultants, Inc., June 1999.

MISO Planning Year 2017-2018 Loss of load Expectation Study Report. (December 7, 2016)

MISO Planning Year 2017-2018 Wind Capacity Credit. (December 12, 2016)

Appendix A

EGEAS INPUT DATA FOR THE BASE CASE

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ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

Montana-Dakota Utilities Co.
2017 Model
Base Case Run
-- Data updated for the 2017 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							
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TECHNOLOGY 3	slr16c	1	0				
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	EBPC	130				5.24002.5000				2	0			130				
	EBPD	130	3 6 0 3 1 0 0			0 0 0 5 0 0 0				0	0	0 0		131				
** COMMENT **	*													132				
BASIC PLANT TYPE	EBPA	132	GLENDIVE CT #2	THRM	P	E	GAS	MDU	MONT	100.0	1	2003	99	30				
	EBPB	132	43.0000.80611.0000			0.5000	9176					0.8535		134				
	EBPC	132				6.07002.5000				2	0			135				
	EBPD	132	3 7 0 4 1 0 0			0 0 0 13 0 0 0				0	0	0 0		136				
** COMMENT **	*													137				
BASIC PLANT TYPE	EBPA	134	DIESEL 1	THRM	P	E	GAS	MDU	MONT	100.0	1	2005	99	30				
	EBPB	134	2.0001.00001.0000			0.5000	8687					0.0000		139				
	EBPC	134				27.4202.5000				2	0			140				
	EBPD	134	3 8 0 23 2 0 0			0 0 0 0 0 0 0				0	0	0 0		141				
RECORD COLS	1	2	3	4	5	6	7	8										
1 2345 678 90	1	2345	678 90	1234567890123456789012345678901234567890123456789012	34567890													

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS												ASSIGNED REC. NO.
RECORD COLS				1	2	3	4	5	6	7	8						
1 2345 678 90				12345678901234567890123456789012345678901234567890123456789012												34567890	
** COMMENT **	*																142
BASIC PLANT TYPE		EBPA 136		DIESEL 2		THRM P E	GAS MDU	NDAK 100.0		1	2012 99 30					143	
		EBPB 136		2.1001.00001.0000			0.5000 8687				0.9048					144	
		EBPC 136					27.4202.5000			2	0					145	
		EBPD 136		3 8 0 23 2 0 0			0 0 0 0 0 0 0			0	0 0 0 0					146	
** COMMENT **	*																147
BASIC PLANT TYPE		EBPA 138		DIESEL 3		THRM P E	GAS MDU	NDAK 100.0		1	2012 99 30					148	
		EBPB 138		2.0001.00001.0000			0.5000 8687				0.9000					149	
		EBPC 138					27.4202.5000			2	0					150	
		EBPD 138		3 8 0 23 2 0 0			0 0 0 0 0 0 0			0	0 0 0 0					151	
** COMMENT **	*																152
BASIC PLANT TYPE		EBPA 140		HESKETT #1		THRM B E	COAL MDU	NDAK 100.0		1	1954 71 30					153	
		EBPB 140		27.3000.80591.0000			0.0790 18731				0.7436					154	
		EBPC 140					78.3605.7900			2	0					155	
		EBPD 140		3 9 0 5 3 0 0			0 0 0 14 0 0 0			0	0 0 0 0					156	
		EBPE 140		M 0.0000 0 0			1980 2080									157	
** COMMENT **	*																158
BASIC PLANT TYPE		EBPA 150		HESKETT #2		THRM B E	COAL MDU	NDAK 100.0		1	1963 62 30					159	
		EBPB 150		73.1000.93831.0000			0.0858 12447				0.9138					160	
		EBPC 150					34.9904.9900			2	0					161	
		EBPD 150		3 10 0 6 4 0 0			0 0 0 15 0 0 0			0	0 0 0 0					162	
		EBPE 150		M 0.0000 0 0			1980 2080									163	
** COMMENT **	*																164
BASIC PLANT TYPE		EBPA 152		HESKETT #3		THRM P E	GAS MDU	NDAK 100.0		1	2014 40 25					165	
		EBPB 152		84.3000.83711.0000			0.5000 11482				0.6999					166	
		EBPC 152					38.8002.5000			1	1					167	
		EBPD 152		3 15 0 17 1 0 0			0 0 0 2 0 0 0			27	0 0 0 0					168	
** COMMENT **	*																169
BASIC PLANT TYPE		EBPA 160		LEWIS & CLARK1		THRM B E	COAL MDU	NDAK 100.0		1	1958 67 30					170	
		EBPB 160		52.3000.86041.0000			0.0261 12679				0.9732					171	
		EBPC 160					80.7708.4800			2	0					172	
		EBPD 160		3 11 0 18 5 0 0			0 0 0 16 0 0 0			0	0 0 0 0					173	
		EBPE 160		M 0.0000 0 0			1980 2080									174	
** COMMENT **	*																175
RECORD COLS				1	2	3	4	5	6	7	8						
1 2345 678 90				12345678901234567890123456789012345678901234567890123456789012												34567890	

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.		
RECORD COLS	1	2	3	4	5	6	7	8	9	10				
1234567890	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890								
BASIC PLANT TYPE	EBPA	162			LEWIS & CLARK2	THRM P E	GAS MDU	NDAK	100.0	1	2015	40	25	176
	EBPB	162			18.5000.83711.0000		0.5000	8544					0.8865	177
	EBPC	162					11.7601.8500			1	1			178
	EBPD	162			3	20	0	19	1	0	0	0	0	179
** COMMENT **	*													180
BASIC PLANT TYPE	EBPA	170			BIG STONE	THRM B E	COAL MDU	SDAK	100.0	1	1975	99	30	181
	EBPB	170			107.80.92511.0000		0.0639	10414					0.9443	182
	EBPC	170					24.0606.9700			2	0			183
	EBPD	170			3	12	0	8	6	0	0	0	0	184
	EBPE	170			M		0.0000	0	0				1980	185
** COMMENT **	*													186
BASIC PLANT TYPE	EBPA	180			COYOTE	THRM B E	COAL MDU	NDAK	100.0	1	1981	99	30	187
	EBPB	180			107.30.93681.0000		0.0875	11921					0.7773	188
	EBPC	180					29.1002.8000			2	0			189
	EBPD	180			3	13	0	22	7	0	0	0	0	190
	EBPE	180			M		0.0000	0	0				1980	191
** COMMENT **	*													192
BASIC PLANT TYPE	EBPA	190			DIAMOND WILLOW	NDT B E	WIND MDU	MONT	100.0	1	2008	22	20	193
	EBPB	190			30.0001.00000.3810		0.0000						0.2100	194
	EBPC	190					16.400-35.38			2	1			195
	EBPD	190			3	17	0	10	0	0	0	0	0	196
** COMMENT **	*													197
BASIC PLANT TYPE	EBPA	200			GLEN ULLIN ORMAT	THRM B E	PURC MDU	NDAK	100.0	1	2009	30	20	198
	EBPB	200			7.5000.66670.6667		0.1058	1					0.5333	199
	EBPC	200					76.1407.3300			2	1			200
	EBPD	200			44	18	0	15	8	0	0	0	0	201
	EBPE	200			M		0.0000	0	0				1980	202
** COMMENT **	*													203
BASIC PLANT TYPE	EBPA	210			CEDAR HILLS	NDT B E	WIND MDU	MONT	100.0	1	2010	20	20	204
	EBPB	210			19.5001.00000.3810		0.0000						0.2564	205
	EBPC	210					17.060-35.38			2	1			206
	EBPD	210			3	19	0	10	0	0	0	0	0	207
** COMMENT **	*													208
BASIC PLANT TYPE	EBPA	220			THUNDER SPIRIT	NDT B E	WIND MDU	NDAK	100.0	1	2015	20	20	209
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1234567890	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890								

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8				
1234567890	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012						34567890	
BASIC PLANT TYPE	EBPB	220			107.51.00000.4186		0.0000				0.1879	210
	EBPC	220					25.000-35.38			2	1	211
	EBPD	220			3 32 0 13	0 0	0 0 0 0	2	0 0	0 0 0 0	0	212
** COMMENT **	*											213
BASIC PLANT TYPE	EBPA	230			WAPA PUR-FT PECK HYDR B E HYDR MDU NDAK	100.0		1	2001	50	30	214
	EBPB	230			2.8000.89291.0000	0.0000		14.35			0.0000	215
	EBPC	230			0.000	0.0000	33.250		2	0		216
	EBPD	230			14 0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0		217
	EBPE	230			M	0.0000	0 0		1980	2080		218
	EBPF	230			0.000		0	0.0000				219
	EBPG	230			0.000000000.000000000.000000000							220
** COMMENT **	*											221
BASIC PLANT TYPE	EBPA	310			PURCHASE POWER THRM P G PURC MDU MISO	100.0		1		1	1	222
	EBPB	310			10.0001.00001.0000	0.0000	1			1.0000		223
	EBPC	310			0.000	36.0001000.0			2	0		224
	EBPD	310			21 21 0 0 8 0 0	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0	225	
	EBPF	310			0.000		0	0.0000				226
	EBPG	310			0.000000000.000000000.000000000							227
** COMMENT **	*											228
BASIC PLANT TYPE	EBPA	320			GE 7EA THRM P G GAS MDU NDAK	100.0		1		40	35	229
	EBPB	320			78.4000.83711.0000	0.5000	11498			0.9439		230
	EBPC	320			1163.270	8.729021.4602.6800			1	1		231
	EBPD	320			30 22 60 0 28 1 0 0	0 0 0 0	2 0 0 0	0 0 0 0	0 0 20 0		232	
	EBPF	320			857.000	30 37	0.0000					233
	EBPG	320			0.000000000.000000000.000000000							234
** COMMENT **	*											235
BASIC PLANT TYPE	EBPA	330			GE LMS100PB THRM P G GAS MDU NDAK	100.0		1		40	35	236
	EBPB	330			90.5000.83711.0000	0.5000	8832			0.9436		237
	EBPC	330			1326.880	8.729024.9104.6700			1	1		238
	EBPD	330			30 22 24 0 28 1 0 0	0 0 0 13	0 0 0 0	0 0 0 0	0 0 20 0		239	
	EBPF	330			857.000	30 37	0.0000					240
	EBPG	330			0.000000000.000000000.000000000							241
** COMMENT **	*											242
BASIC PLANT TYPE	EBPA	340			GE LM6000PH THRM P G GAS MDU NDAK	100.0		1		40	35	243
	EBPB	340			41.3000.83711.0000	0.5000	9637			0.9903		244
	EBPC	340			1546.300	8.729036.3904.3400			1	1		245

RECORD COLS 1 2 3 4 5 6 7 8
 1 2345 678 90 12345678901234567890123456789012345678901234567890123456789012 34567890

RECORD DESCRIPTION	C	REC. TYPE	REF. NO.	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.										
RECORD COLS				1	2	3	4	5	6	7	8												
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012							34567890											
BASIC PLANT TYPE		EBPD	340		30	22	62	0	28	1	0	0	0	0	0	13	0	0	0	0	20	0	246
		EBPF	340		850.000					30	37		0.0000										247
		EBPG	340		0.000000000	0.000000000	0.000000000	0.000000000															248
** COMMENT **		*																					249
BASIC PLANT TYPE		EBPA	350		GE LM6000PH	SPRT	THRM	I	G	GAS	MDU	NDAK	100.0	1						40	35		250
		EBPB	350		66.1000	83711.0000				0.0392	7834									0.9607			251
		EBPC	350		1812.470					8.729065	4104.6300			1	1								252
		EBPD	350		30	22	62	0	28	1	0	0	0	0	0	13	0	0	0	0	20	0	253
		EBPF	350		850.000					30	37		0.0000										254
		EBPG	350		0.000000000	0.000000000	0.000000000	0.000000000															255
** COMMENT **		*																					256
BASIC PLANT TYPE		EBPA	370		GE 7EA 2x1	ADD	THRM	I	G	GAS	MDU	NDAK	100.0	1						50	50		257
		EBPB	370		265.10	85711.0000				0.0392	7695									0.9612			258
		EBPC	370		1001.680					8.070030	2303.9800			1	1								259
		EBPD	370		30	22	68	0	21	1	0	0	0	0	0	2	0	0	0	0	20	0	260
		EBPF	370		750.000					30	37		0.0000										261
		EBPG	370		0.000000000	0.000000000	0.000000000	0.000000000															262
** COMMENT **		*																					263
BASIC PLANT TYPE		EBPA	380		GE 7FA.05	1x1	THRM	I	G	GAS	MDU	NDAK	100.0	1						50	50		264
		EBPB	380		323.00	85711.0000				0.0392	6859									0.9607			265
		EBPC	380		1071.210					8.070027	9703.2700			1	1								266
		EBPD	380		30	22	54	0	24	1	0	0	0	0	0	2	0	0	0	0	20	0	267
		EBPF	380		750.000					30	37		0.0000										268
		EBPG	380		0.000000000	0.000000000	0.000000000	0.000000000															269
** COMMENT **		*																					270
BASIC PLANT TYPE		EBPA	400		SMN SGT-800	2x1	THRM	I	G	GAS	MDU	NDAK	100.0	1						50	50		271
		EBPB	400		139.80	85711.0000				0.0392	7415									0.9606			272
		EBPC	400		1512.330					8.070041	5604.0600			1	1								273
		EBPD	400		30	22	69	0	25	1	0	0	0	0	0	2	0	0	0	0	20	0	274
		EBPF	400		750.000					30	37		0.0000										275
		EBPG	400		0.000000000	0.000000000	0.000000000	0.000000000															276
** COMMENT **		*																					277
BASIC PLANT TYPE		EBPA	410		WRTSLA	18V50SG	THRM	P	G	GAS	MDU	NDAK	100.0	1						40	25		278
		EBPB	410		55.3000	83711.0000				0.5000	8288									0.8680			279
		EBPC	410		1382.610					8.729044	3404.2000			1	1								280
		EBPD	410		30	22	56	0	1	1	0	0	0	0	0	1	0	0	0	0	20	0	281
RECORD COLS				1	2	3	4	5	6	7	8												
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012																		34567890

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
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RECORD COLS	1	2	3	4	5	6	7	8
1 2345 678 90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	12 34567890

BASIC PLANT TYPE	EBPF 410	857.000	30 37	0.0000					282
	EBPG 410	0.000000000	0.000000000	0.000000000					283

** COMMENT ** * 284

BASIC PLANT TYPE	EBPA 420	WRTSLA 20V34SG	THRM P G GAS	MDU NDAK 100.0	1	40 25			285
	EBPB 420	36.5000.83711.0000	0.5000 8447			0.8685			286
	EBPC 420	1351.680	8.729044.5604.2000		1 1				287
	EBPD 420	30 22 56 0 28 1 0 0	0 0 0 10 0 0 0 0			0 0 20 0			288
	EBPF 420	857.000	30 37	0.0000					289
	EBPG 420	0.000000000	0.000000000	0.000000000					290

** COMMENT ** * 291

BASIC PLANT TYPE	EBPA 430	BIOMASS	THRM B G BMP	MDU NDAK 100.0	1	40 25			292
	EBPB 430	9.3000.83711.0000	0.0845 14273			0.9140			293
	EBPC 430	9211.230	8.7290123.52-12.54		1 1				294
	EBPD 430	30 22 58 0 28 10 0 0	0 0 0 19 0 0 0 0			0 0 20 0			295
	EBPF 430	857.000	30 37	0.0000					296
	EBPG 430	0.000000000	0.000000000	0.000000000					297

** COMMENT ** * 298

BASIC PLANT TYPE	EBPA 450	PV SOLAR	NDT B G PURC	MDU NDAK 100.0	1	30 25			299
	EBPB 450	50.0000.50000.5000	0.0000			0.5000			300
	EBPC 450	2854.740	9.833018.6000.0000		1 1				301
	EBPD 450	42 22 0 10 0 0	0 0 0 0 4 0 0 0			0 0 0 0			302
	EBPF 450	2558.000	30 38	0.0000					303
	EBPG 450	0.000000000	0.000000000	0.000000000					304

** COMMENT ** * 305

BASIC PLANT TYPE	EBPA 460	CONC SOLAR	NDT B G PURC	MDU NDAK 100.0	1	30 25			306
	EBPB 460	50.0000.50000.5000	0.0000			0.5000			307
	EBPC 460	11475.470	9.833076.8000.0000		1 1				308
	EBPD 460	45 22 0 10 0 0	0 0 0 0 4 0 0 0			0 0 0 0			309
	EBPF 460	2558.000	30 38	0.0000					310
	EBPG 460	0.000000000	0.000000000	0.000000000					311

** COMMENT ** * 312

BASIC PLANT TYPE	EBPA 490	CFBC	THRM B G LIGN	MDU NDAK 100.0	1	50 50			313
	EBPB 490	30.0000.95001.0000	0.0639 9974			0.6934			314
	EBPC 490	5623.150	8.0700235.4413.250		1 1				315
	EBPD 490	30 22 61 0 33 12 0 0	0 0 0 0 0 0 0 0			0 0 20 0			316
	EBPE 490	M 0.0000 0 0	1980 2080						317

RECORD COLS	1	2	3	4	5	6	7	8
1 2345 678 90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	12 34567890	34567890

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS			1	2	3	4	5	6	7	8		
	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012							34567890	
BASIC PLANT TYPE		EBPF 490		3900.000		30 31	0.0000				318	
		EBPG 490		0.000000000.000000000.000000000							319	
** COMMENT **	*										320	
BASIC PLANT TYPE		EBPA 500		CFBC CO2		THRM B G COAL MDU NDAK 100.0		1		50 50	321	
		EBPB 500		30.0000.95001.0000		0.0639 13781				0.9367	322	
		EBPC 500		10308.280		8.0700323.1621.020			1 1		323	
		EBPD 500		30 22 25 0 33 12 0 0		0 0 0 0 0 0 0 0 0 0 0 0 0 0 20 0					324	
		EBPE 500		M		0.0000 0 0				1980 2080	325	
		EBPF 500		3900.000		30 31	0.0000				326	
		EBPG 500		0.000000000.000000000.000000000							327	
** COMMENT **	*										328	
BASIC PLANT TYPE		EBPA 510		WIND20		NDT B G WIND MDU NDAK 100.0		1		25 25	329	
		EBPB 510		20.0001.00000.3810		0.0000				0.2080	330	
		EBPC 510		1542.030		9.833074.640-23.59			1 1		331	
		EBPD 510		30 22 41 0 10		0 0 0 0 0 0 0 0 1 0 0 0 0 0 21 0					332	
		EBPF 510		2400.000		30 38	0.0000				333	
		EBPG 510		0.000000000.000000000.000000000							334	
** COMMENT **	*										335	
BASIC PLANT TYPE		EBPA 520		WIND50		NDT B G WIND MDU NDAK 100.0		1		25 25	336	
		EBPB 520		50.0001.00000.3810		0.0000				0.2080	337	
		EBPC 520		1519.030		9.833074.640-23.59			1 1		338	
		EBPD 520		30 22 41 0 10		0 0 0 0 0 0 0 0 1 0 0 0 0 0 21 0					339	
		EBPF 520		2400.000		30 38	0.0000				340	
		EBPG 520		0.000000000.000000000.000000000							341	
** COMMENT **	*										342	
						== MAINTENANCE CYCLES ==					343	
						Y YBO ----NUMBER OF WEEKS (W) AND STARTING WEEK (S)----					344	
						I RAP 1 2 3 4 5 6 7 8 9 10					345	
						N PST W S W S W S W S W S W S W S W S W S					346	
						+-+-+ +--+ +--+ +--+ +--+ +--+ +--+ +--+ +--+ +--+ +---					347	
											348	
MAINTENANCE CYCLE		EMC	1 1	1 110 2							349	
** COMMENT **	*										350	
MAINTENANCE CYCLE		EMC	2 1	101021 115 913 119 116 116 216 119 117 118 116							351	
** COMMENT **	*										352	
RECORD COLS			1	2	3	4	5	6	7	8		
	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012							34567890	

RECORD DESCRIPTION	C	REC. REF SEQ		DATA FIELDS												ASSIGNED REC. NO.
		TYPE	NO.	NO.	1	2	3	4	5	6	7	8				
RECORD COLS					1	2	3	4	5	6	7	8				
	1	2345	678	90	1234567890123456789012345678901234567890123456789012	34567890										
MAINTENANCE CYCLE		EMC	3	1	101021	117	114	118	118	117	119	117	216	117	118	353
** COMMENT **		*														354
MAINTENANCE CYCLE		EMC	4	1	101021	116	115	1014	117	118	120	216	118	119	115	355
** COMMENT **		*														356
MAINTENANCE CYCLE		EMC	5	1	101022	214	617	118	122	118	116	116	116	113	113	357
		EMC	5	2		241	144	143	141	143	142	537	140	140	137	358
** COMMENT **		*														359
MAINTENANCE CYCLE		EMC	6	1	101022	211	215	214	515	214	218	117	217	220	214	360
		EMC	6	2		242	242	241	242	240	243	242	243	242	539	361
** COMMENT **		*														362
MAINTENANCE CYCLE		EMC	8	1	101022	539	415	637	414	0	219	222	0	615	639	363
		EMC	8	2		0	441	0	440	0	0	0	0	0	0	364
** COMMENT **		*														365
MAINTENANCE CYCLE		EMC	9	1	1 100	1										366
** COMMENT **		*														367
MAINTENANCE CYCLE		EMC	10	1	1 110	1										368
** COMMENT **		*														369
MAINTENANCE CYCLE		EMC	13	1	1 110	1										370
** COMMENT **		*														371
MAINTENANCE CYCLE		EMC	14	1	1 100	1										372
** COMMENT **		*														373
MAINTENANCE CYCLE		EMC	15	1	1 120	1										374
** COMMENT **		*														375
MAINTENANCE CYCLE		EMC	17	1	1 110	1										376
** COMMENT **		*														377
RECORD COLS					1	2	3	4	5	6	7	8				
	1	2345	678	90	1234567890123456789012345678901234567890123456789012	34567890										

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.			
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11				
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890									
MAINTENANCE CYCLE	EMC	18	1	101022	219	217	614	220	220	220	219	220	614	218	378
	EMC	18	2		341	340	339	340	339	341	340	340	341	340	379
** COMMENT **	*														380
MAINTENANCE CYCLE	EMC	19	1	1 110	1										381
** COMMENT **	*														382
MAINTENANCE CYCLE	EMC	21	1	1 110	2										383
** COMMENT **	*														384
MAINTENANCE CYCLE	EMC	22	1	101022	1013	123	122	613	123	123	612	123	122	514	385
	EMC	22	2		137	137	136	136	135	137	137	138	137	0	386
** COMMENT **	*														387
MAINTENANCE CYCLE	EMC	23	1	1 110	2										388
** COMMENT **	*														389
MAINTENANCE CYCLE	EMC	24	1	1 110	2										390
** COMMENT **	*														391
MAINTENANCE CYCLE	EMC	25	1	1 110	2										392
** COMMENT **	*														393
MAINTENANCE CYCLE	EMC	27	1	1 110	1										394
** COMMENT **	*														395
MAINTENANCE CYCLE	EMC	28	1	1 110	2										396
** COMMENT **	*														397
MAINTENANCE CYCLE	EMC	33	1	1 110	3										398
** COMMENT **	*														399
	*														400
	*														401
	*														402
	*														403
	*														404
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890									

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							
** COMMENT **	*			MIN. FUEL TJ SM							405	
	*	EFLB		-----++----							406	
	*			-----							407	
	*										408	
FUEL TYPE	EFLA	1		GAS DKT	1.1400	-1.000000	2.630000	0 33	0 0	GAS	409	
** COMMENT **	*										410	
FUEL TYPE	EFLA	2		OIL2 GAL	39.1700	-1.000000	23.320000	0 34	0 0	OIL2	411	
** COMMENT **	*										412	
FUEL TYPE	EFLA	3		COAL TON	14.2700	-1.000000	2.190000	0 35	0 0	COAL	413	
** COMMENT **	*										414	
FUEL TYPE	EFLA	4		COAL TON	14.2700	-1.000000	2.190000	0 36	0 0	COAL	415	
** COMMENT **	*										416	
FUEL TYPE	EFLA	5		COAL TON	13.2200	-1.000000	1.790000	0 37	0 0	COAL	417	
** COMMENT **	*										418	
FUEL TYPE	EFLA	6		COAL TON	16.4800	-1.000000	2.280000	0 38	0 0	COAL	419	
** COMMENT **	*										420	
FUEL TYPE	EFLA	7		COAL TON	13.6800	-1.000000	1.790000	0 39	0 0	COAL	421	
** COMMENT **	*										422	
FUEL TYPE	EFLA	8		PURC NONE	0.0100	-1.000000	0.000000	0	0 0	PURC	423	
** COMMENT **	*										424	
FUEL TYPE	EFLA	10		BMP TON	14.9000	-1.000000	6.750000	0 63	0 0	BMP	425	
** COMMENT **	*										426	
FUEL TYPE	EFLA	12		COAL TON	14.0700	-1.000000	1.910000	0 43	0 0	COAL	427	
** COMMENT **	*										428	
	*			== PLANNING ALTERNATIVES ==							429	
	*			1ST LAST T EX PREREQ M M R							430	
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							

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RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.			
-----	----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----			
RECORD COLS				1	2	3	4	5	6	7	8					
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012								34567890			
** COMMENT **	*				NAME	BP	YEAR	YEAR	Y	RET	PA	NfR	N	X	Q	431
	*				-----++++		++++	----	+	-----++-		+-		+		432
	*															433
PLANNING ALTERNATIVE	EPA		1	1	GE 7EA	320	2019	2036	0	0	0	00	0-1	0		434
** COMMENT **	*															435
PLANNING ALTERNATIVE	EPA		2	1	WRTSLA 18V50SG	410	2019	2036	0	0	0	00	0-1	0		436
** COMMENT **	*															437
PLANNING ALTERNATIVE	EPA		4	1	AC CYCLING	3	2018	2018	0	0	0	00	0-1	0		438
** COMMENT **	*															439
PLANNING ALTERNATIVE	EPA		5	1	CFBC	490	2023	2036	0	0	0	00	0-1	0		440
** COMMENT **	*															441
PLANNING ALTERNATIVE	EPA		6	1	GE LM6000PH	340	2019	2036	0	0	0	00	0-1	0		442
** COMMENT **	*															443
PLANNING ALTERNATIVE	EPA		7	1	PURCHASE POWER	310	2017	2036	1	0	0	00	0-1	0		444
** COMMENT **	*															445
PLANNING ALTERNATIVE	EPA		8	1	GE 7EA 2x1 ADD	370	2022	2036	0	152	0	00	0-1	0		446
** COMMENT **	*															447
PLANNING ALTERNATIVE	EPA		9	1	GE 7FA.05 1x1	380	2022	2036	0	0	0	00	0-1	0		448
** COMMENT **	*															449
PLANNING ALTERNATIVE	EPA		10	1	BIOMASS	430	2020	2036	0	0	0	00	0-1	0		450
** COMMENT **	*															451
PLANNING ALTERNATIVE	EPA		11	1	CFBC CO2	500	2023	2036	0	0	0	00	0-1	0		452
** COMMENT **	*															453
PLANNING ALTERNATIVE	EPA		12	1	CONC SOLAR	460	2019	2036	0	0	0	00	0-1	0		454
RECORD COLS				1	2	3	4	5	6	7	8					
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012								34567890			

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS					1	2	3	4	5	6	7	8	
1 2345 678 90					12345678901234567890123456789012345678901234567890123456789012								34567890
** COMMENT **	*												455
PLANNING ALTERNATIVE	EPA	13	1		GE LM6000PH SPRT350			2019 2036 0 0 0 00 0-1 0					456
** COMMENT **	*												457
PLANNING ALTERNATIVE	EPA	14	1		GE LMS100PB 330			2019 2036 0 0 0 00 0-1 0					458
** COMMENT **	*												459
PLANNING ALTERNATIVE	EPA	16	1		PV SOLAR 450			2019 2036 0 0 0 00 0-1 0					460
** COMMENT **	*												461
PLANNING ALTERNATIVE	EPA	19	1		SMN SGT-800 2x1 400			2022 2036 0 0 0 00 0-1 0					462
** COMMENT **	*												463
PLANNING ALTERNATIVE	EPA	20	1		WIND20 510			2019 2036 0 0 0 00 0-1 0					464
** COMMENT **	*												465
PLANNING ALTERNATIVE	EPA	22	1		WIND50 520			2019 2036 0 0 0 00 0-1 0					466
** COMMENT **	*												467
PLANNING ALTERNATIVE	EPA	23	1		WRTSLA 20V34SG 420			2019 2036 0 0 0 00 0-1 0					468
** COMMENT **	*												469
PLANNING ALTERNATIVE	EPA	27	1		THUNDER SPIRIT 2 9			2019 2019 0 0 0 00 0-1 0					470
** COMMENT **	*												471
					== TRAJECTORIES ==								472
					T B								473
					Y A N YEAR RATE YEAR RATE YEAR RATE YEAR RATE YEAR RATE								474
					- + -- +----- +----- +----- +----- +-----								475
					*								476
TRAJECTORY	ETJ	1	1		1 1 21 20161.6959 20171.4236 20181.4036 20191.4039 20201.2870								477
	ETJ	1	2		20211.2706 20221.1787 20231.1837 20241.0956 20251.1205								478
	ETJ	1	3		20261.0899 20271.0602 20281.0846 20291.0729 20301.0790								479
	ETJ	1	4		20311.0847 20321.0730 20331.0616 20341.0672 20351.0724								480
	ETJ	1	5		20361.3700								481
** COMMENT **	*												482
RECORD COLS					1	2	3	4	5	6	7	8	
1 2345 678 90					12345678901234567890123456789012345678901234567890123456789012								34567890

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							
TRAJECTORY	ETJ	2	1	1 1 21	20164.3003	20171.6952	20181.6699	20191.6685	20201.4790		483	
	ETJ	2	2		20211.4518	20221.2570	20231.3123	20241.1391	20251.1849		484	
	ETJ	2	3		20261.1552	20271.1550	20281.1598	20291.1593	20301.1636		485	
	ETJ	2	4		20311.1626	20321.1689	20331.1675	20341.1732	20351.1786		486	
	ETJ	2	5		20361.5600						487	
** COMMENT **	*										488	
TRAJECTORY	ETJ	3	1	1 1 1	20163.0000						489	
** COMMENT **	*										490	
TRAJECTORY	ETJ	4	1	1 1 4	201614.444	201726.213	201815.384	2019.00000			491	
** COMMENT **	*										492	
TRAJECTORY	ETJ	5	1	1 1 1	20163.0000						493	
** COMMENT **	*										494	
TRAJECTORY	ETJ	6	1	1 1 1	20163.0000						495	
** COMMENT **	*										496	
TRAJECTORY	ETJ	7	1	1 1 1	20163.0000						497	
** COMMENT **	*										498	
TRAJECTORY	ETJ	8	1	1 1 1	20163.0000						499	
** COMMENT **	*										500	
TRAJECTORY	ETJ	9	1	1 1 1	20163.0000						501	
** COMMENT **	*										502	
TRAJECTORY	ETJ	10	1	1 1 1	20163.0000						503	
** COMMENT **	*										504	
TRAJECTORY	ETJ	11	1	1 1 1	20163.0000						505	
** COMMENT **	*										506	
TRAJECTORY	ETJ	12	1	1 1 1	20163.0000						507	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8	9	10		
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012						34567890	
** COMMENT **	*										508	
TRAJECTORY	ETJ	13	1	1 1 1	20163.0000						509	
** COMMENT **	*										510	
TRAJECTORY	ETJ	14	1	1 1 1	2016.00000						511	
** COMMENT **	*										512	
TRAJECTORY	ETJ	15	1	1 1 1	20163.0000						513	
** COMMENT **	*										514	
TRAJECTORY	ETJ	16	1	1 1 4	201614.285	201715.972	201819.760	2019.00000			515	
** COMMENT **	*										516	
TRAJECTORY	ETJ	17	1	1 1 5	2016.00000	2017-66.67	2018.00000	2019-100.0	2020-0.189		517	
** COMMENT **	*										518	
TRAJECTORY	ETJ	18	1	1 1 6	20161.5006	20171.4784	20181.4569	20191.4360	20201.5444		519	
	ETJ	18	2		20211.5000						520	
** COMMENT **	*										521	
TRAJECTORY	ETJ	19	1	1 1 5	2016.00000	2017.00000	2018.00000	2019-100.0	2020-0.221		522	
** COMMENT **	*										523	
TRAJECTORY	ETJ	20	1	1 1 1	20163.0000						524	
** COMMENT **	*										525	
TRAJECTORY	ETJ	21	1	1 1 1	20163.0000						526	
** COMMENT **	*										527	
TRAJECTORY	ETJ	22	1	1 1 1	20173.0000						528	
** COMMENT **	*										529	
TRAJECTORY	ETJ	23	1	1 1 7	2016.00000	2017.00000	2018100.00	201950.000	202033.333		530	
	ETJ	23	2		202125.000	2022.00000					531	
RECORD COLS	1	2	3	4	5	6	7	8	9	10		
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012						34567890	

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						
** COMMENT **	*										532	
TRAJECTORY	ETJ	24	1	1 1 1	20173.0000						533	
** COMMENT **	*										534	
TRAJECTORY	ETJ	25	1	1 1 1	20173.0000						535	
** COMMENT **	*										536	
TRAJECTORY	ETJ	26	1	1 1 1	20173.0000						537	
** COMMENT **	*										538	
TRAJECTORY	ETJ	27	1	1 1 5	2016.00000	201711.525	201810.182	20199.7931	2020.00000		539	
** COMMENT **	*										540	
TRAJECTORY	ETJ	28	1	1 1 5	2016.00000	20175.8753	20185.4360	20195.2631	2020.00000		541	
** COMMENT **	*										542	
TRAJECTORY	ETJ	29	1	1 1 3	201615.227	20172.0000	20182.0000				543	
** COMMENT **	*										544	
TRAJECTORY	ETJ	30	1	1 1 1	20173.0000						545	
** COMMENT **	*										546	
TRAJECTORY	ETJ	31	1	1 1 1	20163.0000						547	
** COMMENT **	*										548	
TRAJECTORY	ETJ	32	1	1 1 11	2016.00000	2017.00000	2018.00000	2019.00000	2020.00000		549	
	ETJ	32	2		2021.00000	2022.00000	2023.00000	2024.00000	2025-100.0		550	
	ETJ	32	3		2026.00000						551	
** COMMENT **	*										552	
TRAJECTORY	ETJ	33	1	1 1 6	201616.349	2017-6.535	20184.8951	20193.0000	20203.0000		553	
	ETJ	33	2		20213.0000						554	
** COMMENT **	*										555	
TRAJECTORY	ETJ	34	1	1 1 6	2016.30017	20174.9166	20184.7269	20193.0739	20201.0947		556	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						
TRAJECTORY	ETJ	34	2		20213.0000						557	
** COMMENT **	*										558	
TRAJECTORY	ETJ	35	1	1 1 6	201618.721	20175.3846	20182.9197	20193.5461	20203.4246		559	
	ETJ	35	2		20213.0000						560	
** COMMENT **	*										561	
TRAJECTORY	ETJ	36	1	1 1 6	201618.721	20175.3846	20182.9197	20193.5461	20203.4246		562	
	ETJ	36	2		20213.0000						563	
** COMMENT **	*										564	
TRAJECTORY	ETJ	37	1	1 1 6	20161.6759	20172.1978	2018.00000	2019.00000	20201.0752		565	
	ETJ	37	2		20213.0000						566	
** COMMENT **	*										567	
TRAJECTORY	ETJ	38	1	1 1 6	20164.3859	20172.9411	20182.8571	20193.1746	20202.6923		568	
	ETJ	38	2		20213.0000						569	
** COMMENT **	*										570	
TRAJECTORY	ETJ	39	1	1 1 6	20167.2625	20172.0833	20182.0408	20192.5000	2020.00000		571	
	ETJ	39	2		20213.0000						572	
** COMMENT **	*										573	
TRAJECTORY	ETJ	40	1	1 1 15	2016.00000	2017.00000	2018.00000	2019.00000	2020.00000		574	
	ETJ	40	2		2021.00000	2022.00000	2023.00000	2024.00000	2025.00000		575	
	ETJ	40	3		2026.00000	2027.00000	2028-65.00	2029.00000	2030.00000		576	
** COMMENT **	*										577	
TRAJECTORY	ETJ	41	1	1 1 15	2016.00000	2017.00000	2018.00000	2019.00000	2020.00000		578	
	ETJ	41	2		2021.00000	2022.00000	2023.00000	2024.00000	2025.00000		579	
	ETJ	41	3		2026.00000	2027-100.0	2028.00000	2029.00000	2030.00000		580	
** COMMENT **	*										581	
TRAJECTORY	ETJ	42	1	1 1 10	2016-30.00	20173.0003	20182.9997	20198.8857	20208.5677		582	
	ETJ	42	2		202118.845	20223.0002	20232.9999	20242.9998	20253.0000		583	
** COMMENT **	*										584	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012								34567890
TRAJECTORY		ETJ	43	1	1	1	1	20173.0000					585
** COMMENT **		*											586
TRAJECTORY		ETJ	44	1	1	1	1	20163.0000					587
** COMMENT **		*											588
TRAJECTORY		ETJ	45	1	1	1	8	2016-29.94	20173.0000	20183.0000	20198.8856	20208.5676	589
		ETJ	45	2				202118.846	20223.0000	20233.0000			590
** COMMENT **		*											591
TRAJECTORY		ETJ	46	1	1	1	3	201610.316	20172.0000	20182.0000			592
** COMMENT **		*											593
TRAJECTORY		ETJ	47	1	2	1	16	20171.0000	20181.0000	2019.49792	2020.39520	2021.34324	594
		ETJ	47	2				2022.31187	2023.26381	2024.26656	2025.26936	2026.27222	595
		ETJ	47	3				2027.27516	2028.27813	2029.28116	2030.28424	2031.28740	596
		ETJ	47	4				2032.29062					597
** COMMENT **		*											598
TRAJECTORY		ETJ	48	1	1	1	1	20163.0000					599
** COMMENT **		*											600
TRAJECTORY		ETJ	49	1	1	1	1	2016.00000					601
** COMMENT **		*											602
TRAJECTORY		ETJ	54	1	1	1	1	20173.0000					603
** COMMENT **		*											604
TRAJECTORY		ETJ	56	1	1	1	1	20173.0000					605
** COMMENT **		*											606
TRAJECTORY		ETJ	58	1	1	1	13	2017-1.435	2018-1.456	2019-1.559	2020-1.584	2021-1.694	607
		ETJ	58	2				2022-1.810	2023-1.843	2024-1.967	2025-2.007	2026-2.141	608
		ETJ	58	3				2027-2.283	2028-182.1	2029.00000			609
** COMMENT **		*											610
RECORD COLS	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012								34567890

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8	9	10		
1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							
TRAJECTORY	ETJ	59	1	1 1 28	2016.00000	2017.00000	2018.00000	2019.00000	2020.00000	611		
	ETJ	59	2		2021.00000	2022.00000	2023.00000	2024.00000	2025.00000	612		
	ETJ	59	3		2026.00000	2027.00000	202848.780	2029.00000	2030.00000	613		
	ETJ	59	4		2031.00000	2032.00000	2033.00000	2034.00000	2035.00000	614		
	ETJ	59	5		2036.00000	2037.00000	20384.9180	20396.2500	20405.8823	615		
	ETJ	59	6		20415.5555	20425.2631	2043.00000			616		
** COMMENT **	*									617		
TRAJECTORY	ETJ	60	1	1 1 1	20173.0000					618		
** COMMENT **	*									619		
TRAJECTORY	ETJ	61	1	1 1 1	20173.0000					620		
** COMMENT **	*									621		
TRAJECTORY	ETJ	62	1	1 1 1	20173.0000					622		
** COMMENT **	*									623		
TRAJECTORY	ETJ	63	1	1 1 1	20173.0000					624		
** COMMENT **	*									625		
TRAJECTORY	ETJ	68	1	1 1 1	20173.0000					626		
** COMMENT **	*									627		
TRAJECTORY	ETJ	69	1	1 1 1	20173.0000					628		
** COMMENT **	*									629		
	*				== LOADING BLOCKS ==					630		
	*				-A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-					631		
	*				N 1 2 3 4 5					632		
	*				- ++++++-----+++++-----+++++					633		
	*									634		
LOADING BLOCK	ELBA	1	5	0.2325580.2093020.1860470.1860470.186047						635		
	ELBB	1	1	1.8436370.7766110.6303580.7719000.794509						636		
	ELBC	1	1	1.0000000.0000000.0000000.0000000.0000000						637		
** COMMENT **	*									638		
LOADING BLOCK	ELBA	2	5	0.0946750.2130180.2011830.3076920.183432						639		
	ELBB	2	2	3.2613660.8753020.6785150.6585090.903074						640		
RECORD COLS	1	2	3	4	5	6	7	8				
1	2345	678	90	1234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS			1	2	3	4	5	6	7	8		
	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012							34567890	
LOADING BLOCK		ELBC	2	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000			641	
** COMMENT **		*									642	
LOADING BLOCK		ELBA	5	5 0.2535210	1.690140	1.690140	2.253520	1.83099			643	
		ELBB	5	1.6267900	0.7443120	0.7340610	0.7964580	0.864171			644	
		ELBC	5	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000			645	
** COMMENT **		*									646	
LOADING BLOCK		ELBA	7	5 0.2000000	0.2000000	0.2000000	0.2000000	0.2000000			647	
		ELBB	7	1.0000001	0.0000001	0.0000001	0.0000001	0.0000000			648	
		ELBC	7	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000			649	
** COMMENT **		*									650	
LOADING BLOCK		ELBA	10	5 0.2325580	0.2093020	0.1860470	0.1860470	0.186047			651	
		ELBB	10	1.8436370	0.7766110	0.6303580	0.7719000	0.794509			652	
		ELBC	10	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000			653	
** COMMENT **		*									654	
LOADING BLOCK		ELBA	11	5 0.1891890	0.2432430	0.2162160	0.2162160	0.135135			655	
		ELBB	11	1.2196861	0.0994200	0.8953650	0.8801500	0.872659			656	
		ELBC	11	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000			657	
** COMMENT **		*									658	
LOADING BLOCK		ELBA	12	5 0.2777780	0.1587300	0.2380950	0.1190480	0.206349			659	
		ELBB	12	1.6629090	0.1229151	0.1262310	0.7842410	0.761127			660	
		ELBC	12	0.7885320	0.0841890	0.1095830	0.1287550	0.227864			661	
** COMMENT **		*									662	
LOADING BLOCK		ELBA	13	5 0.2325580	0.2093020	0.1860470	0.1860470	0.186047			663	
		ELBB	13	1.8437230	0.7764340	0.6308710	0.7714830	0.794503			664	
		ELBC	13	1.0000000	0.0000000	0.0000000	0.0000000	0.0000000			665	
** COMMENT **		*									666	
LOADING BLOCK		ELBA	14	5 0.2226030	0.1883560	0.2054790	0.2054790	0.178082			667	
		ELBB	14	1.1014360	0.6004480	0.5689500	0.9914581	0.803029			668	
		ELBC	14	0.5990180	0.0967090	0.3117780	0.2505240	0.258642			669	
** COMMENT **		*									670	
RECORD COLS	1	2345	678 90	1234567890123456789012345678901234567890123456789012							34567890	

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.		
RECORD COLS				1	2	3	4	5	6	7	8				
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012						34567890				
LOADING BLOCK		ELBA	15	5	0.3927610	1.970510	1.1340480	1.1340480	1.142091			671			
		ELBB	15		1.0653170	1.9015531	1.1667870	1.9644570	1.832163			672			
		ELBC	15		0.6892410	1.1361860	1.3041380	1.2250420	1.289710			673			
** COMMENT **	*											674			
LOADING BLOCK		ELBA	16	5	0.3632890	1.1147230	1.1147230	1.1720840	1.235182			675			
		ELBB	16		1.1618430	1.9304890	1.8789340	1.8779260	1.932287			676			
		ELBC	16		0.6857320	1.1000710	1.0984190	1.2329840	1.443454			677			
** COMMENT **	*											678			
LOADING BLOCK		ELBA	17	5	0.3157750	1.1571920	1.1483820	1.2225730	1.156079			679			
		ELBB	17		1.1763010	1.9333160	1.8687580	1.8851910	1.998962			680			
		ELBC	17		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			681			
** COMMENT **	*											682			
LOADING BLOCK		ELBA	18	5	0.4213480	1.1310860	1.1217230	1.1966290	1.129213			683			
		ELBB	18		1.1233120	1.8291850	1.7812650	1.7940971	1.290573			684			
		ELBC	18		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			685			
** COMMENT **	*											686			
LOADING BLOCK		ELBA	19	5	0.2325580	1.2093020	1.1860470	1.1860470	1.186047			687			
		ELBB	19		1.8436370	1.7766110	1.6303580	1.7719000	1.794509			688			
		ELBC	19		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			689			
** COMMENT **	*											690			
	*				== ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ==							691			
	*				YEAR OPT	RATE						692			
	*				----	+	-----					693			
A. F. U. D. C.		EZA	1	2017	1	10.500						694			
** COMMENT **	*											695			
	*				=====							696			
	*				== EXPENDITURE PATTERNS - CONSTRUCTION COST AND CAPITAL EXPENS						ES ==	697			
	*				COST PERCENTAGES FOR YEARS BEFORE ON-LINE							698			
	*	YR			1	2	3	4	5	6	7	8	9	10	699
	*	EZCA			+++++-----+++++-----+++++-----+++++-----+++++-----										700
	*				ANNUAL EXPENDITURES FOR YEARS OF OPERATING LIFE										701
	*	YR F TJ			1	2	3	4	5						702
	*	EZCB			+	-----									703
	*				=====										704
	*														705

RECORD COLS	1	2	3	4	5	6	7	8
1	2345	678	90	1234567890123456789012345678901234567890123456789012				34567890

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS					1	2	3	4	5	6	7	8	
CONSTRUCTION EXPEND.	EZCA	31	1	4	1234567890123456789012345678901234567890123456789012	34567890							706
** COMMENT **	*												707
CONSTRUCTION EXPEND.	EZCA	37	1	3	1234567890123456789012345678901234567890123456789012	34567890							708
** COMMENT **	*												709
CONSTRUCTION EXPEND.	EZCA	38	1	1	1234567890123456789012345678901234567890123456789012	34567890							710
** COMMENT **	*												711
													712
													713
													714
													715
RETURN ON RATE BASE	EZR	1	1		201750.0000.000050.00010.000				2.7337.9401.1840				716
** COMMENT **	*												717
													718
													719
					YR	1	2	3	4	5	6	7	720
					--	+++++	-----	+++++	-----	+++++	-----	+++++	721
													722
TAX DEPRECIATION	EZT	20	1	21	3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464								723
	EZT	20	2		4.4624.4624.4624.4624.4624.4624.4624.4624.4624.462								724
	EZT	20	3		2.224								725
** COMMENT **	*												726
TAX DEPRECIATION	EZT	21	1	20	3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464								727
	EZT	21	2		4.4624.4624.4624.4624.4624.4624.4624.4624.4626.686								728
** COMMENT **	*												729
													730
RECORD COLS					1	2	3	4	5	6	7	8	
					1234567890123456789012345678901234567890123456789012	34567890							

```

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

```

HEADER INFORMATION	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
	2017	1	0	6/19/17	16:15:43	2017 IRP	***

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	4					
NUMBER OF YEARS	21					
FIRST CALENDAR YEAR	2016					
LAST CALENDAR YEAR	2036					
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				

SOURCE FILE HEADERS	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
ORTHOGONALIZED LOAD	2017	1	0	6/19/17	16:15:41	2017 IRP	***
HOURLY LOADS							
SYSTEM A	HOURLOAD	1	0				
HOURLY NDT							
TECHNOLOGY 1	wind40cf	1	0				
TECHNOLOGY 2	wind46cf	1	0				
TECHNOLOGY 3	slr16c	1	0				
TECHNOLOGY 4	slr20c	1	0				

ADDITIONAL HOURLY FILE PARAMETERS

SOURCE FILE	HEADER	DUPLICATEFILE YEARS.....																			
	RECORD	RECORD	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	OPTION	OPTION	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
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
TECHNOLOGY 2	0	0	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
TECHNOLOGY 4	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

GENERAL DATA

BASE YEAR 2016
ALL DATA BASE COSTS
ARE IN 2016 DOLLARS

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

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

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

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

BENCHMARK YEAR 2016
BENCHMARK PEAK 484. 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 2016 -
PEAK LOAD 483.5 MW
ENERGY 3206.7 GWH

YEARLY ESCALATION TRAJECTORIES

PEAK LOAD 1
ENERGY 2

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 1: 1, 2016, INITIAL LOAD, 483.5, 302.5, 3206.7, 0.75918779, 0.62561231, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical data representing load duration curve points for 2016.

CUMULANTS

Table with 4 columns of numerical data representing cumulative values for 2016.

Table with 8 columns: 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. Row 2: 2, 2017, INITIAL LOAD, 491.7, 322.5, 3344.6, 0.77863040, 0.65583943, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical data representing load duration curve points for 2017.

CUMULANTS

Table with 4 columns of numerical data representing cumulative values for 2017.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 3: 2018 INITIAL LOAD, 498.7, 328.7, 3401.3, 0.78071576, 0.65908152, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 2018.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for 2018.

Table with 8 columns: 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. Row 4: 2019 INITIAL LOAD, 505.7, 334.9, 3458.1, 0.78276602, 0.66226903, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 2019.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for 2019.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 5: 2020 INITIAL LOAD, 512.8, 341.2, 3515.8, 0.78480820, 0.66544402, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for set 5.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for set 5.

Table with 8 columns: 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. Row 6: 2021 INITIAL LOAD, 519.4, 346.8, 3567.8, 0.78629573, 0.66775666, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for set 6.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for set 6.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 7: 2022 INITIAL LOAD, 526.0, 352.4, 3619.6, 0.78770251, 0.66994375, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for set 7.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for set 7.

Table with 8 columns: 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. Row 8: 2023 INITIAL LOAD, 532.2, 357.0, 3665.1, 0.78831235, 0.67089184, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for set 8.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for set 8.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 9: 2024 INITIAL LOAD, 538.5 MW, 362.1 MW, 3713.2 GWH, 0.78931436, 0.67244965, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 50 points.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for the first table.

Table with 8 columns: 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. Row 10: 2025 INITIAL LOAD, 544.4 MW, 366.4 MW, 3755.5 GWH, 0.78965433, 0.67297821, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 50 points.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for the second table.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 11 shows data for 2026.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical data representing load duration curve points for 2026.

CUMULANTS

Table with 4 columns of numerical data representing cumulative values for 2026.

Table with 8 columns: 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. Row 12 shows data for 2027.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical data representing load duration curve points for 2027.

CUMULANTS

Table with 4 columns of numerical data representing cumulative values for 2027.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 13 shows data for 2028.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 50 points.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data.

Table with 8 columns: 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. Row 14 shows data for 2029.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 50 points.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data.

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 15 shows data for 2030 with initial and load after contracts values.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 50 points.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for the first table.

Table with 8 columns: 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. Row 16 shows data for 2031.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for 50 points.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for the second table.

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	2032	INITIAL LOAD	587.1	399.0	4072.1	0.79395111	0.67965836	SUNDAY
		LOAD AFTER CONTRACTS	587.1	399.0	4072.1	0.79395111	0.67965836	

LOAD DURATION CURVE (50 POINTS)

1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
0.915530847979357	0.830837859341333	0.735973924374361	0.587349993240724	0.421665015742001	0.293683985288416	0.186444315068627
0.293683985288416	0.186444315068627	0.115331079981328	0.062565971254694	0.031567894421769	0.018120199325133	0.008661227350380
0.018120199325133	0.008661227350380	0.002621160908670	0.000683781106612	0.000000000000000		

CUMULANTS

0.793951114249864D+00	0.281839976935601D-02	0.648996390216364D-04	0.132615275760568D-08
-0.129403934244550D-06	-0.234876373199802D-07	-0.379519354992159D-08	-0.651403648115037D-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	2033	INITIAL LOAD	593.4	404.0	4119.7	0.79470407	0.68082899	SUNDAY
		LOAD AFTER CONTRACTS	593.4	404.0	4119.7	0.79470407	0.68082899	

LOAD DURATION CURVE (50 POINTS)

1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
0.920481478373384	0.833568070129619	0.741319735504423	0.592625488515082	0.427374863360596	0.298343155413069	0.190247809248915
0.298343155413069	0.190247809248915	0.115149989808555	0.063719361949400	0.031518327249973	0.018660670285184	0.008647627693136
0.018660670285184	0.008647627693136	0.002617045222925	0.000682707449461	0.000000000000000		

CUMULANTS

0.794704071260863D+00	0.279783975988524D-02	0.641907734017126D-04	0.130614347694088D-08
-0.127057015454301D-06	-0.229773583740324D-07	-0.369916395349368D-08	-0.632652218566057D-10

LOAD CURVES - SYSTEM A

Table with 8 columns: 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. Row 19 shows data for year 2034.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for system A.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for system A.

Table with 8 columns: 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. Row 20 shows data for year 2035.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for system A.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for system A.

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	2036	INITIAL LOAD	612.6	419.5	4266.4	0.79720859	0.68472272	SUNDAY
		LOAD AFTER CONTRACTS	612.6	419.5	4266.4	0.79720859	0.68472272	

LOAD DURATION CURVE (50 POINTS)

1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000	1.0000000000000000
0.940744507126022	0.849054652633952	0.758555494536325	0.609739281143367	0.448933927207164	0.33026595355173
0.309766687469176	0.198728996188866	0.120376245829016	0.066736499579759	0.033026595355173	0.000000000000000
0.019018763532118	0.008996900113998	0.002619350666103	0.000683308869421	0.000000000000000	0.000000000000000

CUMULANTS

0.797208588799573D+00	0.272999128475176D-02	0.618700160127942D-04	0.124361847585874D-08
-0.119493445713069D-06	-0.213459237181573D-07	-0.339460845153233D-08	-0.573403957714666D-10

BASIC PLANT TYPES - 1

DATA SET REF. NO.	3			9			80			90			100		
NAME	AC CYCLING			THUNDER SPIRIT 2			MISO - On peak			MISO - Off peak			INTERRUPTIBLES		
TYPE / LOADING / STATUS /AVD	DTHR	P	G	NDT	B	G	HYDR	P	E	HYDR	P	E	DTHR	P	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	MISO	WIND	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	20		20	25		25	50		50	50		50	30		30
RATED CAPACITY, MW	2.000			48.000			200.000			200.000			12.600		
- RESERVE	1.0000			0.1667			0.0000			0.0000			1.0000		
CAPACITY - OPERATING	1.0000			1.0000			1.0000			1.0000			1.0000		
MULTIPLIERS - EMERGENCY	1.0000			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			0.0000		
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			0.000000			800.000000			800.000000			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			1		
LEVEL. CARRYING CHARGE, PCT	0.00			0.00			0.00			0.00			0.00		
FIXED O+M COST, \$/KW-YR	363.71			0.00			0.00			0.00			50.04		
VARIABLE O+M COST, \$/MWH	100.00			20.50			21.08			18.03			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	1			1			0			0			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	0	47	49	0	0	59	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	23			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		

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
 DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNNT=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.	3			9			80			90			100		
MAINTENANCE REQUIREMENTS	9			27			0			0			14		
FUEL 1 / FUEL 2	8	0		0	0		8	0		8	0		8	0	
LOADING BLOCKS / NDT NO.		0	0		0	2		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		
TRAJECTORY FOR DISPATCH MODIF	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 MULTIP/ TRAJ / SEG MULT	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0
NDT REVENUES / TRAJ	0.00	0		0.00	0		0.00	0		0.00	0		0.00	0	

BASIC PLANT TYPES - 1

DATA SET REF. NO.	110			120			130			132			134		
NAME	COMMERCIAL DSM			MILES CITY C.T.			GLENDIVE CT #1			GLENDIVE CT #2			DIESEL 1		
TYPE / LOADING / STATUS /AVD	DTHR	P	E	THRM	P	E	THRM	P	E	THRM	P	E	THRM	P	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	MISO	GAS	MDU	MONT	GAS	MDU	MONT	GAS	MDU	MONT	GAS	MDU	MONT
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE	1/ 1/2013			1/ 1/1972			1/ 1/1979			1/ 1/2003			1/ 1/2005		
OPERATING/BOOK LIVES, YEARS	30	30		99	30		99	30		99	30		99	30	
RATED CAPACITY, MW	9.000			25.600			37.066			43.000			2.000		
- RESERVE	1.0000			0.8398			0.8660			0.8535			0.0000		
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.			12430.			9176.			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			7.86			5.24			6.07			27.42		
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	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, DNDR=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			134		
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		
TRAJECTORY FOR DISPATCH MODIF	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 MULTIP/ TRAJ / SEG MULT	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0
NDT REVENUES / TRAJ	0.00	0		0.00	0		0.00	0		0.00	0		0.00	0	

BASIC PLANT TYPES - 1

DATA SET REF. NO.	136			138			140			150			152		
NAME	DIESEL 2			DIESEL 3			HESKETT #1			HESKETT #2			HESKETT #3		
TYPE / LOADING / STATUS /AVD	THRM	P	E	THRM	P	E	THRM	B	E	THRM	B	E	THRM	P	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	GAS MDU NDAK			GAS MDU NDAK			COAL MDU NDAK			COAL MDU NDAK			GAS MDU NDAK		
OWNERSHIP PCT. / NO. UNITS	100.0 1			100.0 1			100.0 1			100.0 1			100.0 1		
INSTALLATION DATE	1/ 1/2012			1/ 1/2012			1/ 1/1954			1/ 1/1963			1/ 1/2014		
OPERATING/BOOK LIVES, YEARS	99	30		99	30		71	30		62	30		40	25	
RATED CAPACITY, MW	2.100			2.000			27.300			73.100			84.300		
- RESERVE	0.9048			0.9000			0.7436			0.9138			0.6999		
CAPACITY - OPERATING	1.0000			1.0000			0.8059			0.9383			0.8371		
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			0.0790			0.0858			0.5000		
FULL LOAD HEAT RATE, BTU/KWH	8687.			8687.			18731.			12447.			11482.		
HEAT RATE MULT. - 2ND FUEL	0.0000			0.0000			0.0000			0.0000			0.0000		
ANNUAL ENERGY LIMIT, GWH	0.000000			0.000000			0.000000			0.000000			0.000000		
STORAGE EFFICIENCY, PERCENT	0.00			0.00			0.00			0.00			0.00		
INSTALLATION COST 1, \$/KW	0.00			0.00			0.00			0.00			0.00		
INSTALLATION COST 2, \$/KW	0.00			0.00			0.00			0.00			0.00		
MULTI-UNIT CAPITAL COST OPT.	2			2			2			2			1		
LEVEL. CARRYING CHARGE, PCT	0.00			0.00			0.00			0.00			0.00		
FIXED O+M COST, \$/KW-YR	27.42			27.42			78.36			34.99			38.80		
VARIABLE O+M COST, \$/MWH	2.50			2.50			5.79			4.99			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			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	0	3	8	0	3	8	0	3	9	0	3	10	0	3	15
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	27	0
ENERGY / HEAT RATE	0	0		0	0		0	0		0	0		0	0	
RATED CAPACITY	0			0			0			0			0		
SEGMENT MULT. - CAP / ENERGY	0	0		0	0		0	0		0	0		0	0	
SUBWEEK ENERGY ALLOCATION	0			0			0			0			0		

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
 DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNDDT=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.	136			138			140			150			152		
MAINTENANCE REQUIREMENTS	23			23			5			6			17		
FUEL 1 / FUEL 2	2	0		2	0		3	0		4	0		1	0	
LOADING BLOCKS / NDT NO.		0	0		0	0		14	0		15	0		2	0
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUST RUN / 1ST YR / LAST YR							M 1980 2080			M 1980 2080					
SPIN RSV / 1ST YR / LAST YR															
DISPATCH MODIFIER, \$/MWH	0.00			0.00			0.00			0.00			0.00		
TRAJECTORY FOR DISPATCH MODIF	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 MULTIP/ TRAJ / SEG MULT	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0
NDT REVENUES / TRAJ	0.00	0		0.00	0		0.00	0		0.00	0		0.00	0	

BASIC PLANT TYPES - 1

DATA SET REF. NO.	160			162			170			180			190		
-----	-----			-----			-----			-----			-----		
NAME	LEWIS & CLARK1			LEWIS & CLARK2			BIG STONE			COYOTE			DIAMOND WILLOW		
TYPE / LOADING / STATUS /AVD	THRM	B	E	THRM	P	E	THRM	B	E	THRM	B	E	NDT	B	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	COAL MDU	NDAK		GAS MDU	NDAK		COAL MDU	SDAK		COAL MDU	NDAK		WIND MDU	MONT	
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE	1/ 1/1958			1/ 1/2015			1/ 1/1975			1/ 1/1981			1/ 1/2008		
OPERATING/BOOK LIVES, YEARS		67	30		40	25		99	30		99	30		22	20
RATED CAPACITY, MW	52.300			18.500			107.800			107.300			30.000		
- RESERVE	0.9732			0.8865			0.9443			0.7773			0.2100		
CAPACITY - OPERATING	0.8604			0.8371			0.9251			0.9368			1.0000		
MULTIPLIERS - EMERGENCY	1.0000			1.0000			1.0000			1.0000			0.3810		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0261			0.5000			0.0639			0.0875			0.0000		
FULL LOAD HEAT RATE, BTU/KWH	12679.			8544.			10414.			11921.			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	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			2			2		
LEVEL. CARRYING CHARGE, PCT	0.00			0.00			0.00			0.00			0.00		
FIXED O+M COST, \$/KW-YR	80.77			11.76			24.06			29.10			16.40		
VARIABLE O+M COST, \$/MWH	8.48			1.85			6.97			2.80			-35.38		
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	3	11	0	3	20	0	3	12	0	3	13	0	3	17
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	28	0	0	0	0
ENERGY / HEAT RATE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RATED CAPACITY	0			0			0			0			40		
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, DNDDT=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.	160			162			170			180			190		
MAINTENANCE REQUIREMENTS	18			19			8			22			10		
FUEL 1 / FUEL 2	5	0		1	0		6	0		7	0		0	0	
LOADING BLOCKS / NDT NO.	16	0		11	0		17	0		18	0		0	1	
EMISSIONS / SITE / TAX DEPR.	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		
TRAJECTORY FOR DISPATCH MODIF	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	
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	
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	
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	
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	
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 MULTIP/ TRAJ / SEG MULT	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0
NDT REVENUES / TRAJ	0.00	0		0.00	0		0.00	0		0.00	0		0.00	0	

BASIC PLANT TYPES - 1

DATA SET REF. NO.	200			210			220			230			310		
NAME	GLEN	ULLIN	ORMAT	CEDAR	HILLS		THUNDER	SPIRIT		WAPA	PUR-FT	PECK	PURCHASE	POWER	
TYPE / LOADING / STATUS /AVD	THRM	B	E	NDT	B	E	NDT	B	E	HYDR	B	E	THRM	P	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	NDAK	WIND	MDU	MONT	WIND	MDU	NDAK	HYDR	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	1/ 1/2009			1/ 1/2010			1/ 1/2015			1/ 1/2001					
OPERATING/BOOK LIVES, YEARS	30		20	20		20	20		20	20		50	30		1 1
RATED CAPACITY, MW	7.500			19.500			107.500			2.800			10.000		
- RESERVE	0.5333			0.2564			0.1879			0.0000			1.0000		
CAPACITY - OPERATING	0.6667			1.0000			1.0000			0.8929			1.0000		
MULTIPLIERS - EMERGENCY	0.6667			0.3810			0.4186			1.0000			1.0000		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.1058			0.0000			0.0000			0.0000			0.0000		
FULL LOAD HEAT RATE, BTU/KWH	1.			0.			0.			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			14.350000			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	76.14			17.06			25.00			0.00			36.00		
VARIABLE O+M COST, \$/MWH	7.33			-35.38			-35.38			33.25			1000.00		
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			0			0		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	0	44	18	0	3	19	0	3	32	0	0	14	0	21	21
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	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, DNNT=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.	200			210			220			230			310		
MAINTENANCE REQUIREMENTS	15			10			13			0			0		
FUEL 1 / FUEL 2	8	0		0	0		0	0		0	0		8	0	
LOADING BLOCKS / NDT NO.		0	0		0	1		0	2		0	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	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	
TRAJECTORY FOR DISPATCH MODIF		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
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			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
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			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
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			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
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			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
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			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
MAXIMUM / TRAJ / SEG MULT		100.00	0	0		100.00	0	0			100.00	0	0		100.00
TARGET / TRAJ / SEG MULT		0.00	0	0		0.00	0	0			0.00	0	0		0.00
BID MULTIP/ TRAJ / SEG MULT		1.00	0	0		1.00	0	0			1.00	0	0		1.00
NDT REVENUES / TRAJ		0.00	0		0.00	0		0.00	0		0.00	0		0.00	0

BASIC PLANT TYPES - 1

DATA SET REF. NO.	320			330			340			350			370		
NAME	GE 7EA			GE LMS100PB			GE LM6000PH			GE LM6000PH SPRT			GE 7EA 2x1 ADD		
TYPE / LOADING / STATUS /AVD	THRM	P	G	THRM	P	G	THRM	P	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	40		35	40		35	50		50
RATED CAPACITY, MW	78.400			90.500			41.300			66.100			265.100		
- RESERVE	0.9439			0.9436			0.9903			0.9607			0.9612		
CAPACITY - OPERATING	0.8371			0.8371			0.8371			0.8371			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			0.5000			0.0392			0.0392		
FULL LOAD HEAT RATE, BTU/KWH	11498.			8832.			9637.			7834.			7695.		
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	1163.27			1326.88			1546.30			1812.47			1001.68		
INSTALLATION COST 2, \$/KW	1163.27			1326.88			1546.30			1812.47			1001.68		
MULTI-UNIT CAPITAL COST OPT.	1			1			1			1			1		
LEVEL. CARRYING CHARGE, PCT	8.73			8.73			8.73			8.73			8.07		
FIXED O+M COST, \$/KW-YR	21.46			24.91			36.39			65.41			30.23		
VARIABLE O+M COST, \$/MWH	2.68			4.67			4.34			4.63			3.98		
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	60	30	22	24	30	22	62	30	22	26	30	22	68
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	0	0	0	0	0
RATED CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0	0	0	0	0	0	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, DNDDT=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.	320			330			340			350			370		
MAINTENANCE REQUIREMENTS	28			28			28			28			21		
FUEL 1 / FUEL 2	1	0		1	0		1	0		1	0		1	0	
LOADING BLOCKS / NDT NO.		2	0		13	0		13	0		13	0		2	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		
TRAJECTORY FOR DISPATCH MODIF	0			0			0			0			0		
CONSTRUCTION COST 1, \$/KW	857.00			857.00			850.00			850.00			750.00		
CONSTRUCTION COST 2, \$/KW	857.00			857.00			850.00			850.00			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 MULTIP/ TRAJ / SEG MULT	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0	1.00	0	0
NDT REVENUES / TRAJ	0.00	0		0.00	0		0.00	0		0.00	0		0.00	0	

BASIC PLANT TYPES - 1

DATA SET REF. NO.	380			400			410			420			430		
NAME	GE	7FA.05	1x1	SMN	SGT-800	2x1	WRTSLA	18V50SG	WRTSLA	20V34SG	BIOMASS				
TYPE / LOADING / STATUS /AVD	THRM	I	G	THRM	I	G	THRM	P	G	THRM	P	G	THRM	B	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	GAS	MDU	NDAK	GAS	MDU	NDAK	GAS	MDU	NDAK	GAS	MDU	NDAK	BMP	MDU	NDAK
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE															
OPERATING/BOOK LIVES, YEARS	50		50	50		50	40		25	40		25	40		25
RATED CAPACITY, MW	323.000			139.800			55.300			36.500			9.300		
- RESERVE	0.9607			0.9606			0.8680			0.8685			0.9140		
CAPACITY - OPERATING	0.8571			0.8571			0.8371			0.8371			0.8371		
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	0.0392			0.0392			0.5000			0.5000			0.0845		
FULL LOAD HEAT RATE, BTU/KWH	6859.			7415.			8288.			8447.			14273.		
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	1071.21			1512.33			1382.61			1351.68			9211.23		
INSTALLATION COST 2, \$/KW	1071.21			1512.33			1382.61			1351.68			9211.23		
MULTI-UNIT CAPITAL COST OPT.	1			1			1			1			1		
LEVEL. CARRYING CHARGE, PCT	8.07			8.07			8.73			8.73			8.73		
FIXED O+M COST, \$/KW-YR	27.97			41.56			44.34			44.56			123.52		
VARIABLE O+M COST, \$/MWH	3.27			4.06			4.20			4.20			-12.54		
DEFAULT AFUDC, PCT. OF GBV	0.00			0.00			0.00			0.00			0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00			0.00			0.00			0.00			0.00		
CAPITAL STRUCTURE	1			1			1			1			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	30	22	54	30	22	69	30	22	56	30	22	56	30	22	58
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RATED CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SEGMENT MULT. - CAP / ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBWEEK ENERGY ALLOCATION	0	0	0	0	0	0	0	0	0	0	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, DNDDT=NON-DISPATCHABLE TECHNOLOGY
 B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
 RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

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

BASIC PLANT TYPES - 1

DATA SET REF. NO.	450			460			490			500			510		
-----	-----			-----			-----			-----			-----		
NAME	PV SOLAR			CONC SOLAR			CFBC			CFBC CO2			WIND20		
TYPE / LOADING / STATUS /AVD	NDT	B	G	NDT	B	G	THRM	B	G	THRM	B	G	NDT	B	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	NDAK	PURC	MDU	NDAK	LIGN	MDU	NDAK	COAL	MDU	NDAK	WIND	MDU	NDAK
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE															
OPERATING/BOOK LIVES, YEARS	30		25	30		25	50		50	50		50	25		25
RATED CAPACITY, MW	50.000			50.000			30.000			30.000			20.000		
- RESERVE	0.5000			0.5000			0.6934			0.9367			0.2080		
CAPACITY - OPERATING	0.5000			0.5000			0.9500			0.9500			1.0000		
MULTIPLIERS - EMERGENCY	0.5000			0.5000			1.0000			1.0000			0.3810		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0000			0.0000			0.0639			0.0639			0.0000		
FULL LOAD HEAT RATE, BTU/KWH	0.			0.			9974.			13781.			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	2854.74			11475.47			5623.15			10308.28			1542.03		
INSTALLATION COST 2, \$/KW	2854.74			11475.47			5623.15			10308.28			1542.03		
MULTI-UNIT CAPITAL COST OPT.	1			1			1			1			1		
LEVEL. CARRYING CHARGE, PCT	9.83			9.83			8.07			8.07			9.83		
FIXED O+M COST, \$/KW-YR	18.60			76.80			235.44			323.16			74.64		
VARIABLE O+M COST, \$/MWH	0.00			0.00			13.25			21.02			-23.59		
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	42	22	0	45	22	0	30	22	61	30	22	25	30	22	41
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	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, DNNT=NON-DISPATCHABLE TECHNOLOGY
 B=BASE, I=INTERMEDIATE, P=PEAKING, E=EXISTING, C=COMMITTED, G=GENERIC
 RPS CONTRIBUTIONS ARE SHOWN WITH THE RPS CONSTRAINTS

BASIC PLANT TYPES - 2

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

BASIC PLANT TYPES - 1

DATA SET REF. NO.	520		
-----	-----		
NAME	WIND50		
TYPE / LOADING / STATUS /AVD	NDT	B	G
LOAD COMPONENT FOR DSM			
CLASS / AREA / GENERATING CO.	WIND MDU	NDAK	
OWNERSHIP PCT. / NO. UNITS	100.0		1
INSTALLATION DATE			
OPERATING/BOOK LIVES, YEARS	25		25
RATED CAPACITY, MW	50.000		
- RESERVE	0.2080		
CAPACITY - OPERATING	1.0000		
MULTIPLIERS - EMERGENCY	0.3810		
- CHARGING	0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0000		
FULL LOAD HEAT RATE, BTU/KWH	0.		
HEAT RATE MULT. - 2ND FUEL	0.0000		
ANNUAL ENERGY LIMIT, GWH	0.000000		
STORAGE EFFICIENCY, PERCENT	0.00		
INSTALLATION COST 1, \$/KW	1519.03		
INSTALLATION COST 2, \$/KW	1519.03		
MULTI-UNIT CAPITAL COST OPT.	1		
LEVEL. CARRYING CHARGE, PCT	9.83		
FIXED O+M COST, \$/KW-YR	74.64		
VARIABLE O+M COST, \$/MWH	-23.59		
DEFAULT AFUDC, PCT. OF GBV	0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00		
CAPITAL STRUCTURE	1		
YEARLY TRAJECTORIES			
COSTS-CAPITAL/FIX OM/VAR OM	30	22	41
F.O.R./RESERVE CAP/OPER CAP	0	0	0
ENERGY / HEAT RATE		0	0
RATED CAPACITY		0	
SEGMENT MULT. - CAP / ENERGY	0		0
SUBWEEK ENERGY ALLOCATION		0	

NOTE: SUPPLY-SIDE - THRM=THERMAL, HYDR=HYDRO, STOR=STORAGE, NDT =NON-DISPATCHABLE TECHNOLOGY
 DEMAND-SIDE - DTHR=THERMAL, DHYD=HYDRO, DSTO=STORAGE, DNNT=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.	520		

MAINTENANCE REQUIREMENTS	10		
FUEL 1 / FUEL 2	0	0	
LOADING BLOCKS / NDT NO.	0	0	1
EMISSIONS / SITE / TAX DEPR.	0	0	21
MUST RUN / 1ST YR / LAST YR			
SPIN RSV / 1ST YR / LAST YR			
DISPATCH MODIFIER, \$/MWH	0.00		
TRAJECTORY FOR DISPATCH MODIF	0		
CONSTRUCTION COST 1, \$/KW	2400.00		
CONSTRUCTION COST 2, \$/KW	2400.00		
TRAJECTORY / EXPEND. PATTERN	30	38	
PERCENT CWIP IN RATE BASE	0.00		
STARTING VALUE OF CWIP, \$/KW	0.00		
EQUITY AFUDC, \$/KW	0.00		
DEBT AFUDC, \$/KW	0.00		
DSM CUSTOMER COST / OPT / TJ	0.00	0	0
BK LIFE/CAP STRUCT/TAX DEPR	0	0	0
LEV.CARRYING CHARGE, PCT	0.00		
EXPENDITURE PATTERN	0		
REBOUND BENEFITS / OPT / TJ	0.00	0	0
BK LIFE/CAP STRUCT/TAX DEPR	0	0	0
LEV.CARRYING CHARGE, PCT	0.00		
EXPENDITURE PATTERN	0		
CUSTOMER BENEFITS / OPT / TJ	0.00	0	0
BK LIFE/CAP STRUCT/TAX DEPR	0	0	0
LEV.CARRYING CHARGE, PCT	0.00		
EXPENDITURE PATTERN	0		
TRANS/DISTR COSTS / OPT / TJ	0.00	0	0
BK LIFE/CAP STRUCT/TAX DEPR	0	0	0
LEV.CARRYING CHARGE, PCT	0.00		
EXPENDITURE PATTERN	0		
OTHER COSTS / OPT / TJ	0.00	0	0
BK LIFE/CAP STRUCT/TAX DEPR	0	0	0
LEV.CARRYING CHARGE, PCT	0.00		
EXPENDITURE PATTERN	0		
PERCENTAGE FOR 2ND FUEL			
MINIMUM / TRAJ / SEG MULT	0.00	0	0
MAXIMUM / TRAJ / SEG MULT	100.00	0	0
TARGET / TRAJ / SEG MULT	0.00	0	0
BID MULTIP/ TRAJ / SEG MULT	1.00	0	0
NDT REVENUES / TRAJ	0.00	0	

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE CYCLES		..FIRST PERIOD..		..SECOND PERIOD..	
				MAINTENANCE SPECIFICATION	YEAR	NO. OF WEEKS	START WEEK	NO. OF WEEKS	START WEEK
1	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	2		
2	10	10	2 - BASE YEAR=1	1	- START WEEKS	1	15		
						2	13		
						3	19		
						4	16		
						5	16		
						6	16		
						7	19		
						8	17		
						9	18		
						10	16		
3	10	10	2 - BASE YEAR=1	1	- START WEEKS	1	17		
						2	14		
						3	18		
						4	18		
						5	17		
						6	19		
						7	17		
						8	16		
						9	17		
						10	18		
4	10	10	2 - BASE YEAR=1	1	- START WEEKS	1	16		
						2	15		
						3	14		
						4	17		
						5	18		
						6	20		
						7	16		
						8	18		
						9	19		
						10	15		
5	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	14	2	41
						2	17	1	44
						3	18	1	43
						4	22	1	41
						5	18	1	43
						6	16	1	42
						7	16	5	37
						8	16	1	40
						9	13	1	40
						10	13	1	37

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE CYCLES		..FIRST PERIOD..		..SECOND PERIOD..		
				MAINTENANCE SPECIFICATION	YEAR	NO. OF WEEKS	START WEEK	NO. OF WEEKS	START WEEK	
6	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	2	11	2	42
						2	2	15	2	42
						3	2	14	2	41
						4	5	15	2	42
						5	2	14	2	40
						6	2	18	2	43
						7	1	17	2	42
						8	2	17	2	43
						9	2	20	2	42
						10	2	14	5	39
8	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	5	39	0	0
						2	4	15	4	41
						3	6	37	0	0
						4	4	14	4	40
						5	0	0	0	0
						6	2	19	0	0
						7	2	22	0	0
						8	0	0	0	0
						9	6	15	0	0
						10	6	39	0	0
9	1	1	0 - INSTALLATION	0	- NO. WEEKS ONLY	1	1			
10	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
13	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
14	1	1	0 - INSTALLATION	0	- NO. WEEKS ONLY	1	1			
15	1	1	2 - BASE YEAR=1	0	- NO. WEEKS ONLY	1	1			
17	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
18	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	2	19	3	41
						2	2	17	3	40
						3	6	14	3	39
						4	2	20	3	40
						5	2	20	3	39
						6	2	20	3	41
						7	2	19	3	40
						8	2	20	3	40
						9	6	14	3	41
						10	2	18	3	40
19	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			

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE CYCLES		..FIRST PERIOD..		..SECOND PERIOD..		
				MAINTENANCE SPECIFICATION	YEAR	NO. OF WEEKS	START WEEK	NO. OF WEEKS	START WEEK	
22	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	10	13	1	37
						2	1	23	1	37
						3	1	22	1	36
						4	6	13	1	36
						5	1	23	1	35
						6	1	23	1	37
						7	6	12	1	37
						8	1	23	1	38
						9	1	22	1	37
						10	5	14	0	0
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			
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			
33	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	3			

FUEL TYPES

DATA SET REF. NO.	NAME	MASS UNIT	HEAT CONTENT MBTU/MASS UNIT	..MASS UNITS AVAILABLE..		FUEL COST \$/MBTU	.TRAJECTORIES.			.SEGMENT MULT.		
				MAXIMUM	MINIMUM		MAX.	MIN.	COST	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	2.190000	0	0	35	0	0	0
4	COAL	TON	14.27	-1.00	0.00	2.190000	0	0	36	0	0	0
5	COAL	TON	13.22	-1.00	0.00	1.790000	0	0	37	0	0	0
6	COAL	TON	16.48	-1.00	0.00	2.280000	0	0	38	0	0	0
7	COAL	TON	13.68	-1.00	0.00	1.790000	0	0	39	0	0	0
8	PURC	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
10	BMP	TON	14.90	-1.00	0.00	6.750000	0	0	63	0	0	0
12	COAL	TON	14.07	-1.00	0.00	1.910000	0	0	43	0	0	0

CAPACITY PLANNING ALTERNATIVES

DATA SET REF. NO.	NAME	BASIC PLANT INSTALLED	GENERIC SITE	-AVAILABLE-		TYPE	BASIC PLANT RETIRED	-----PREREQUISITE PLANNING ALTERNATIVE----- DEPENDENCY			LAG MIN	YEAR MAX	REQUIRED OPTION	
				FIRST YEAR	LAST YEAR			PLAN. ALT.	MULTIPLIER NO.	RETIRE. FLAG OPTION				
1	GE 7EA	320	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
2	WRTSLA 18V50SG	410	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
4	AC CYCLING	3	0	2018	2018	0	0	0	0	0	0 - NO	0	-1	0
5	CFBC	490	0	2023	2036	0	0	0	0	0	0 - NO	0	-1	0
6	GE LM6000PH	340	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
7	PURCHASE POWER	310	0	2017	2036	1	0	0	0	0	0 - NO	0	-1	0
8	GE 7EA 2x1 ADD	370	0	2022	2036	0	152	0	0	0	0 - NO	0	-1	0
9	GE 7FA.05 1x1	380	0	2022	2036	0	0	0	0	0	0 - NO	0	-1	0
10	BIOMASS	430	0	2020	2036	0	0	0	0	0	0 - NO	0	-1	0
11	CFBC CO2	500	0	2023	2036	0	0	0	0	0	0 - NO	0	-1	0
12	CONC SOLAR	460	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
13	GE LM6000PH SPRT	350	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
14	GE LMS100PB	330	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
16	PV SOLAR	450	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
19	SMN SGT-800 2x1	400	0	2022	2036	0	0	0	0	0	0 - NO	0	-1	0
20	WIND20	510	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
22	WIND50	520	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
23	WRTSLA 20V34SG	420	0	2019	2036	0	0	0	0	0	0 - NO	0	-1	0
27	THUNDER SPIRIT 2	9	0	2019	2019	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	2016	1.70	2017	1.42	2018	1.40	2019	1.40	2020	1.29
		2021	1.27	2022	1.18	2023	1.18	2024	1.10	2025	1.12
		2026	1.09	2027	1.06	2028	1.08	2029	1.07	2030	1.08
		2031	1.08	2032	1.07	2033	1.06	2034	1.07	2035	1.07
		2036	1.37								
2	1 - RATE	2016	4.30	2017	1.70	2018	1.67	2019	1.67	2020	1.48
		2021	1.45	2022	1.26	2023	1.31	2024	1.14	2025	1.18
		2026	1.16	2027	1.15	2028	1.16	2029	1.16	2030	1.16
		2031	1.16	2032	1.17	2033	1.17	2034	1.17	2035	1.18
		2036	1.56								
3	1 - RATE	2016	3.00								
4	1 - RATE	2016	14.44	2017	26.21	2018	15.38	2019	0.00		
5	1 - RATE	2016	3.00								
6	1 - RATE	2016	3.00								
7	1 - RATE	2016	3.00								
8	1 - RATE	2016	3.00								
9	1 - RATE	2016	3.00								
10	1 - RATE	2016	3.00								
11	1 - RATE	2016	3.00								
12	1 - RATE	2016	3.00								
13	1 - RATE	2016	3.00								
14	1 - RATE	2016	0.00								
15	1 - RATE	2016	3.00								
16	1 - RATE	2016	14.28	2017	15.97	2018	19.76	2019	0.00		
17	1 - RATE	2016	0.00	2017	-66.67	2018	0.00	2019	-100.00	2020	-0.19
18	1 - RATE	2016	1.50	2017	1.48	2018	1.46	2019	1.44	2020	1.54
		2021	1.50								
19	1 - RATE	2016	0.00	2017	0.00	2018	0.00	2019	-100.00	2020	-0.22
20	1 - RATE	2016	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	2016	3.00								
22	1 - RATE	2017	3.00								
23	1 - RATE	2016	0.00	2017	0.00	2018	100.00	2019	50.00	2020	33.33
		2021	25.00	2022	0.00						
24	1 - RATE	2017	3.00								
25	1 - RATE	2017	3.00								
26	1 - RATE	2017	3.00								
27	1 - RATE	2016	0.00	2017	11.52	2018	10.18	2019	9.79	2020	0.00
28	1 - RATE	2016	0.00	2017	5.88	2018	5.44	2019	5.26	2020	0.00
29	1 - RATE	2016	15.23	2017	2.00	2018	2.00				
30	1 - RATE	2017	3.00								
31	1 - RATE	2016	3.00								
32	1 - RATE	2016	0.00	2017	0.00	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	2016	16.35	2017	-6.53	2018	4.90	2019	3.00	2020	3.00
		2021	3.00								
34	1 - RATE	2016	0.30	2017	4.92	2018	4.73	2019	3.07	2020	1.09
		2021	3.00								
35	1 - RATE	2016	18.72	2017	5.38	2018	2.92	2019	3.55	2020	3.42
		2021	3.00								
36	1 - RATE	2016	18.72	2017	5.38	2018	2.92	2019	3.55	2020	3.42
		2021	3.00								
37	1 - RATE	2016	1.68	2017	2.20	2018	0.00	2019	0.00	2020	1.08
		2021	3.00								
38	1 - RATE	2016	4.39	2017	2.94	2018	2.86	2019	3.17	2020	2.69
		2021	3.00								
39	1 - RATE	2016	7.26	2017	2.08	2018	2.04	2019	2.50	2020	0.00
		2021	3.00								

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
40	1 - RATE	2016	0.00	2017	0.00	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	-65.00	2029	0.00	2030	0.00
41	1 - RATE	2016	0.00	2017	0.00	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	-100.00	2028	0.00	2029	0.00	2030	0.00
42	1 - RATE	2016	-30.00	2017	3.00	2018	3.00	2019	8.89	2020	8.57
		2021	18.84	2022	3.00	2023	3.00	2024	3.00	2025	3.00
43	1 - RATE	2017	3.00								
44	1 - RATE	2016	3.00								
45	1 - RATE	2016	-29.94	2017	3.00	2018	3.00	2019	8.89	2020	8.57
		2021	18.85	2022	3.00	2023	3.00				
46	1 - RATE	2016	10.32	2017	2.00	2018	2.00				
47	2 - MULTIPLIER	2017	1.00	2018	1.00	2019	0.50	2020	0.40	2021	0.34
		2022	0.31	2023	0.26	2024	0.27	2025	0.27	2026	0.27
		2027	0.28	2028	0.28	2029	0.28	2030	0.28	2031	0.29
		2032	0.29								
48	1 - RATE	2016	3.00								
49	1 - RATE	2016	0.00								
54	1 - RATE	2017	3.00								
56	1 - RATE	2017	3.00								
58	1 - RATE	2017	-1.43	2018	-1.46	2019	-1.56	2020	-1.58	2021	-1.69
		2022	-1.81	2023	-1.84	2024	-1.97	2025	-2.01	2026	-2.14
		2027	-2.28	2028	-182.10	2029	0.00				
59	1 - RATE	2016	0.00	2017	0.00	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	48.78	2029	0.00	2030	0.00
		2031	0.00	2032	0.00	2033	0.00	2034	0.00	2035	0.00
		2036	0.00	2037	0.00	2038	4.92	2039	6.25	2040	5.88
		2041	5.56	2042	5.26	2043	0.00				
60	1 - RATE	2017	3.00								
61	1 - RATE	2017	3.00								
62	1 - RATE	2017	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
-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
63	1 - RATE	2017	3.00								
68	1 - RATE	2017	3.00								
69	1 - RATE	2017	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	3.261366	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
5	5	1	0.253521	1.626790	1.000000
		2	0.169014	0.744312	0.000000
		3	0.169014	0.734061	0.000000
		4	0.225352	0.796458	0.000000
		5	0.183099	0.864171	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
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	1.219686	1.000000
		2	0.243243	1.099420	0.000000
		3	0.216216	0.895365	0.000000
		4	0.216216	0.880150	0.000000
		5	0.135135	0.872659	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	0.232558	1.843723	1.000000
		2	0.209302	0.776434	0.000000
		3	0.186047	0.630871	0.000000
		4	0.186047	0.771483	0.000000
		5	0.186047	0.794503	0.000000

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER

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	1.161843	0.685732
		2	0.114723	0.930489	0.100071
		3	0.114723	0.878934	0.098419
		4	0.172084	0.877926	0.232984
		5	0.235182	0.932287	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
18	5	1	0.421348	1.123312	1.000000
		2	0.131086	0.829185	0.000000
		3	0.121723	0.781265	0.000000
		4	0.196629	0.794097	0.000000
		5	0.129213	1.290573	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	2017	1 - COMPOUND	10.50

EGEAS EDIT

DATA BASE CONTENTS REPORT

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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								

EGEAS EDIT

DATA BASE CONTENTS REPORT

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RETURN ON RATE BASE

DATA SET REFERENCE NUMBER 1 (DEFAULT)

CALENDAR YEAR	-----CAPITAL STRUCTURE-----			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
	COMMON STOCK PERCENT	PREFERRED STOCK PERCENT	DEBT PERCENT						
2017	50.00	0.00	50.00	10.00	0.00	2.73	37.94	1.18	9.42

TAX DEPRECIATION TABLE

DATA SET REF. NO.	TAX LIFE YEARS	DEPRECIATION		DEPRECIATION		DEPRECIATION		DEPRECIATION		DEPRECIATION	
		YEAR	PERCENT	YEAR	PERCENT	YEAR	PERCENT	YEAR	PERCENT	YEAR	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	NUMBER OF WEEKS	NUMBER OF HOURS
1	13	2184
2	13	2184
3	13	2184
4	13	2184
	--	----
	52	8736

	SUBWEEK	NUMBER OF HOURS
	1	60
	2	60
	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

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MIRROR IMAGE REPORT	PAGE	2
ERROR REPORT	PAGE	26
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Appendix B

EGEAS OUTPUT REPORT FOR THE BASE CASE

EGEAS REPORT VERSION 11.0 2017 IRP BUILD 1 - 7/31/15

EEEEEEEE	GGGGG	EEEEEEEE	AAAAAA	SSSSSS
EEEEEEEE	GGGGGGG	EEEEEEEE	AAAAAAAA	SSSSSSSS
EE	GG GG	EE	AA AA	SS
EEEEEEEE	GG	EEEEEEEE	AAAAAAAA	SSSSSSS
EEEEEEEE	GG GGG	EEEEEEEE	AAAAAAAA	SSSSSSS
EE	GG GG	EE	AA AA	SS
EEEEEEEE	GGGGGGG	EEEEEEEE	AA AA	SSSSSSSS
EEEEEEEE	GGGGG	EEEEEEEE	AA AA	SSSSSS

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

REPORT PROGRAM

Montana-Dakota Utilities Co.
2017 Model
Base Case Run
-- Data updated for the 2017 Model

RPI 1529

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

EGEAS REPORT

CONTROL REPORT

PAGE 1

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	2017	1	0		5/ 2/17	13:47: 2	2017 IRP	1100
EXPANSION PLAN	2017	1	0	1	5/ 2/17	13:47: 5	2017 IRP	1100
SUBPERIOD REPORT	2017	1	0	1	5/ 2/17	13:47: 5	2017 IRP	1100
UNIT REPORT	2017	1	0	1	5/ 2/17	13:47: 5	2017 IRP	1100
UNIT CAPITAL COST REPORT	2017	1	0	1	5/ 2/17	13:47: 5	2017 IRP	1100

EGEAS REPORT MIRROR IMAGE REPORT PAGE 2

RECORD DESCRIPTION	C	TYPE	REC. NO.	REF. NO.	DATA FIELDS	ASSIGNED REC. NO.
RECORD COLS			1		2 3 4 5 6 7 8	
	1	2345	678	90	1234567890123456789012345678901234567890123456789012 34567890	
** COMMENT **	*				Montana-Dakota Utilities Co.	1
	*				2017 Model	2
	*				Base Case Run	3
	*				-- Data updated for the 2017 Model	4
	*					5
	*				CONTROL RECORD	6
	*				SbUnUcc	7
	*					8
	*				C M E S F	9
	*				T I R E I	10
	*				L R R L L	11
	*				+ - + - +	12
CONTROL RECORD	RCC				1 1 3 1 0 2017 IRP	13
** COMMENT **	*					14
	*				--INPUT FILES--	15
	*				NAME V U RUN	16
	*				-----+-----	17
FILE IDENTIFICATION	RFF				2017 1 0 1	18
** COMMENT **	*					19
	*				== PLAN SELECTION ==	20
	*				PLANS C O C E M	21
	*				DR 1 L P M S N O	22
	*				-----+-----	23
PLAN SELECTION	RRA				1 1 1 0 1 3 2 0 18405032 1 2	24
** COMMENT **	*					25
	*				== TIME PERIODS ==	26
	*				--YEARS-- -SG- -SW-	27
	*				1ST LAST 1 L 1 L	28
	*				---- +++ - - - - +	29
TIME PERIOD	RRB				2017 2036 113 1 3	30
** COMMENT **	*					31
	*				== REPORT SELECTION ==	32
	*				-PROD- MNT -STORAGE-- -FL -EM- -ECON INT- -COST-	33
	*				S S S UOBRRSU DOPD -PJ- SU SSU GCF TSTU CUT UCTCA	34
	*				Y U YAFNRLEEYN EPWRS C 1 L YN YIN E+M RYIN OFF NOOOS	35
	*				S M SRLTDKLSST TRKDP E 1 L ST STT NRT NSET PCT. TNTVT	36
	*				- + -	37
RECORD COLS			1		2 3 4 5 6 7 8	
	1	2345	678	90	1234567890123456789012345678901234567890123456789012 34567890	

EGEAS REPORT

MIRROR IMAGE REPORT

PAGE 3

RECORD DESCRIPTION	C	TYPE	NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.		
RECORD COLS				1	2	3	4	5	6	7	8				
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890									
REPORT SELECTION		RRC			1	2	1001101100	00000	0	00	000	001	00000.0000	00100	38
** COMMENT **		*													39
															40
RECORD COLS				1	2	3	4	5	6	7	8				
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890									

```

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

```

RRA 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

RRB FIRST YEAR = 2017 FIRST SEGMENT = 1 FIRST SUBWEEK = 1
LAST YEAR = 2036 LAST SEGMENT = 13 LAST SUBWEEK = 3

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

EXPANSION PLAN SUMMARY = 2 - YES, WITH RESERVE CAPACITY

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

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

COST ANALYSIS REPORTS
UNIT OUTLAYS = 0 - NO
CONSTRUCTION COST = 0 - NO
TOTAL COST = 1 - YES
INTEREST COVERAGE = 0 - NO
EARNING ASSETS = 0 - NO

PLAN 1

YEAR	NEW UNITS ADDED																
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
2017	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2018	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1+	0.
2019	0	0.	1+	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+	0.	0.
2021	0	0.	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+	0.	0.
2023	0	0	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+	0	0
2025	0	1+	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+	0	0
2027	0	0+	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+	0	0
2029	0	0+	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+	0	0
2031	0	0+	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+	0	0
2033	0	0+	0+	0	0	0	0	0	0	0	0	0	0	0	0+	0	0
2034	1	0+	0+	0	0	0	0	0	0	0	0	0	0	0	0+	0	0
2035	0	0+	0+	0	0	0	0	1+	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+	0	0

TOTAL COST, M\$
 --W/O EXT 1563.524
 --WITH EXT 3021.285

UNIT TYPES

1 PA 7	PURCHASE POWER	10.000 MW	2 PA 8	GE 7EA 2x1 ADD	265.100 MW	3 PA 27	THUNDER SPIRIT 2	48.000 MW
4 PA 10	BIOMASS	9.300 MW	5 PA 12	CONC SOLAR	50.000 MW	6 PA 1	GE 7EA	78.400 MW
7 PA 9	GE 7FA.05 1x1	323.000 MW	8 PA 6	GE LM6000PH	41.300 MW	9 PA 16	PV SOLAR	50.000 MW
10 PA 19	SMN SGT-800 2x1	139.800 MW	11 PA 20	WIND20	20.000 MW	12 PA 22	WIND50	50.000 MW
13 PA 2	WRTSLA 18V50SG	55.300 MW	14 PA 23	WRTSLA 20V34SG	36.500 MW	15 PA 4	AC CYCLING	2.000 MW
16 PA 5	CFBC	30.000 MW	17 PA 11	CFBC CO2	30.000 MW			

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2016.
 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
2017	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2018	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2019	0.00	0.00 .	1.00 +	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	1.00 +	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	1.00	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 .	1.00 +	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 .
TOTAL	1.00	1.00	1.00	0.00	0.00	0.00	0.00	1.00	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	265.100 MW	3 PA 27	THUNDER SPIRIT 2	48.000 MW
4 PA 10	BIOMASS	9.300 MW	5 PA 12	CONC SOLAR	50.000 MW	6 PA 1	GE 7EA	78.400 MW
7 PA 9	GE 7FA.05 1x1	323.000 MW	8 PA 6	GE LM6000PH	41.300 MW	9 PA 16	PV SOLAR	50.000 MW
10 PA 19	SMN SGT-800 2x1	139.800 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14	15	16	17
2017	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2018	0.00 .	0.00 .	0.00 .	0.00 .	1.00 +	0.00 .	0.00 .
2019	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 .
2021	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 .
2023	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 .
2025	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 .
2027	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 .
2029	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 .
2031	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 .
2033	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 .
2035	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 .
TOTAL	0.00	0.00	0.00	0.00	1.00	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 20 WIND20	20.000 MW	12 PA 22 WIND50	50.000 MW	13 PA 2 WRTSLA 18V50SG	55.300 MW
14 PA 23 WRTSLA 20V34SG	36.500 MW	15 PA 4 AC CYCLING	2.000 MW	16 PA 5 CFBC	30.000 MW
17 PA 11 CFBC CO2	30.000 MW				

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2017	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	48.000	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	265.100	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	10.000	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	41.300	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
TOTAL	10.000	265.100	48.000	0.000	0.000	0.000	0.000	41.300	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	265.100 MW	3 PA 27	THUNDER SPIRIT 2	48.000 MW
4 PA 10	BIOMASS	9.300 MW	5 PA 12	CONC SOLAR	50.000 MW	6 PA 1	GE 7EA	78.400 MW
7 PA 9	GE 7FA.05 1x1	323.000 MW	8 PA 6	GE LM6000PH	41.300 MW	9 PA 16	PV SOLAR	50.000 MW
10 PA 19	SMN SGT-800 2x1	139.800 MW						

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14	15	16	17
2017	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	2.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	2.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	2.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	2.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	2.000	0.000	0.000
2023	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
2025	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
2027	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
2029	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
2031	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
2033	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
2035	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
TOTAL	0.000	0.000	0.000	0.000	10.000	0.000	0.000

UNIT TYPES

11 PA 20 WIND20	20.000 MW	12 PA 22 WIND50	50.000 MW	13 PA 2 WRTSLA 18V50SG	55.300 MW
14 PA 23 WRTSLA 20V34SG	36.500 MW	15 PA 4 AC CYCLING	2.000 MW	16 PA 5 CFBC	30.000 MW
17 PA 11 CFBC CO2	30.000 MW				

EGEAS REPORT EXPANSION PLAN SUMMARY PAGE 11

PLAN 1

YEAR	PEAK LOAD, MW	ENERGY GWHRATED CAPACITY, MW.....			RESERVE CAPACITY	RESERVE PERCENT	RELATIVE RELIABILITY	..CAPITAL COSTS, M\$..	NEW UNITS	CHANGES
			INSTALLED	RETIRED	CHANGED	TOTAL					
BENCH	483.5	3206.70				1171.3	549.7	14.33	1.0000		
2017	491.7	3344.59	0.0	0.0	3.1	1174.4	552.8	13.08	99.9999	0.000	0.000
2018	498.7	3401.28	2.0	0.0	5.0	1181.4	571.5	15.59	99.9999	0.000	0.000
2019	505.7	3458.10	48.0	0.0	7.3	1236.7	598.3	19.84	99.9999	0.000	0.000
2020	512.8	3515.78	0.0	0.0	2.0	1238.7	612.3	21.09	99.9999	0.000	0.000
2021	519.4	3567.80	0.0	0.0	2.0	1240.7	614.3	19.92	99.9999	0.000	0.000
2022	526.0	3619.60	0.0	0.0	2.0	1242.7	616.3	18.77	99.9999	0.000	0.000
2023	532.2	3665.09	0.0	0.0	0.0	1242.7	616.3	17.26	99.9999	0.000	0.000
2024	538.5	3713.20	0.0	0.0	0.0	1242.7	616.3	15.76	99.9999	0.000	0.000
2025	544.4	3755.47	265.1	237.0	0.0	1270.8	653.5	21.85	3.0271	336.385	0.000
2026	550.5	3799.96	0.0	0.0	0.0	1270.8	653.5	20.38	1.8214	0.000	0.000
2027	556.5	3843.88	0.0	0.0	0.0	1270.8	653.5	18.97	1.8219	0.000	0.000
2028	562.4	3888.29	0.0	0.0	0.0	1270.8	653.5	17.61	1.5953	0.000	0.000
2029	568.5	3933.36	0.0	0.0	-19.5	1251.3	649.4	15.46	1.0510	0.000	0.000
2030	574.6	3978.97	0.0	30.0	0.0	1221.3	642.2	12.77	2.7949	0.000	0.000
2031	580.8	4025.26	0.0	0.0	0.0	1221.3	642.2	11.46	1.8244	0.000	0.000
2032	587.1	4072.08	0.0	0.0	0.0	1221.3	642.2	10.17	1.0186	0.000	0.000
2033	593.4	4119.65	0.0	0.0	0.0	1221.3	642.2	8.90	1.2208	0.000	0.000
2034	599.7	4167.75	10.0	0.0	0.0	1231.3	652.2	9.47	0.9827	0.000	0.000
2035	606.1	4216.65	41.3	117.5	0.0	1155.1	662.9	10.13	1.4467	108.721	0.000
2036	612.6	4266.37	0.0	0.0	0.0	1155.1	662.9	8.87	0.7160	0.000	0.000

.....COST SUMMARY.....

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2017	75.600	0.000	75.600	75.600	71.422	71.422
2018	83.192	0.000	83.192	158.792	74.250	145.673
2019	86.224	0.000	86.224	245.016	72.703	218.376
2020	94.828	0.000	94.828	339.844	75.539	293.915
2021	98.482	0.000	98.482	438.326	74.114	368.029
2022	102.797	0.000	102.797	541.122	73.086	441.115
2023	107.193	0.000	107.193	648.315	71.999	513.115
2024	111.287	0.000	111.287	759.602	70.619	583.733
2025	110.052	27.146	137.199	896.801	82.249	665.982
2026	129.910	27.146	157.056	1053.857	88.950	754.933
2027	134.264	27.146	161.410	1215.267	86.364	841.296
2028	139.327	27.146	166.474	1381.741	84.150	925.446
2029	148.452	27.146	175.599	1557.339	83.857	1009.304
2030	157.606	27.146	184.753	1742.092	83.353	1092.656
2031	163.095	27.146	190.242	1932.334	81.085	1173.741
2032	168.856	27.146	196.002	2128.336	78.924	1252.665
2033	175.211	27.146	202.357	2330.693	76.979	1329.644
2034	182.076	27.146	209.223	2539.916	75.192	1404.837
2035	200.032	36.636	236.669	2776.584	80.355	1485.192
2036	207.569	36.636	244.205	3020.790	78.332	1563.524
EXT.	1293.373	164.389			1457.762	3021.285

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 2016.
 - CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES. SEE RESERVE REPORT FOR DETAILS.

PLAN 1

ENERGY, GWH.....							TOTAL
	GENERATION	DUMP	CHARGING	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	UNMET	
2017	3344.59	0.00	0.00	0.00	0.00	0.00	0.00	3344.59
2018	3401.28	0.00	0.00	0.00	0.00	0.00	0.00	3401.28
2019	3458.10	0.00	0.00	0.00	0.00	0.00	0.00	3458.10
2020	3515.78	0.00	0.00	0.00	0.00	0.00	0.00	3515.78
2021	3567.80	0.00	0.00	0.00	0.00	0.00	0.00	3567.80
2022	3619.60	0.00	0.00	0.00	0.00	0.00	0.00	3619.60
2023	3665.09	0.00	0.00	0.00	0.00	0.00	0.00	3665.09
2024	3713.17	0.00	0.00	0.00	0.00	0.00	0.03	3713.20
2025	3755.05	0.00	0.00	0.00	0.00	0.00	0.42	3755.47
2026	3799.37	0.00	0.00	0.00	0.00	0.00	0.59	3799.96
2027	3843.31	0.00	0.00	0.00	0.00	0.00	0.57	3843.88
2028	3887.62	0.00	0.00	0.00	0.00	0.00	0.66	3888.29
2029	3932.44	0.00	0.00	0.00	0.00	0.00	0.92	3933.36
2030	3978.31	0.00	0.00	0.00	0.00	0.00	0.66	3978.97
2031	4024.44	0.00	0.00	0.00	0.00	0.00	0.83	4025.26
2032	4070.93	0.00	0.00	0.00	0.00	0.00	1.16	4072.08
2033	4118.58	0.00	0.00	0.00	0.00	0.00	1.07	4119.65
2034	4166.58	0.00	0.00	0.00	0.00	0.00	1.18	4167.75
2035	4213.87	0.00	0.00	0.00	0.00	0.00	2.78	4216.65
2036	4262.54	0.00	0.00	0.00	0.00	0.00	3.83	4266.37
EXT.	4262.54	0.00	0.00	0.00	0.00	0.00	3.83	4266.37

NOTE - GENERATION INCLUDES CHARGING OF STORAGE UNITS (IF ANY).

PLAN 1

.....COST, M\$.....										
	FUEL	VARIABLE O+M	FIXED O+M	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	EMISSION COST	ALLOWANCES CREDIT	UNMET ENERGY	TOTAL
2017	33.050	17.554	24.997	0.000	0.000	0.000	0.000	0.000	0.000	75.600
2018	34.495	21.958	26.739	0.000	0.000	0.000	0.000	0.000	0.000	83.192
2019	32.772	25.645	27.807	0.000	0.000	0.000	0.000	0.000	0.000	86.224
2020	36.776	29.295	28.757	0.000	0.000	0.000	0.000	0.000	0.000	94.828
2021	37.238	31.514	29.730	0.000	0.000	0.000	0.000	0.000	0.000	98.482
2022	37.185	34.883	30.728	0.000	0.000	0.000	0.000	0.000	0.000	102.797
2023	40.484	35.268	31.441	0.000	0.000	0.000	0.000	0.000	0.000	107.193
2024	41.433	37.485	32.365	0.000	0.000	0.000	0.000	0.000	0.004	111.287
2025	44.386	38.034	27.561	0.000	0.000	0.000	0.000	0.000	0.071	110.052
2026	46.906	54.531	28.369	0.000	0.000	0.000	0.000	0.000	0.104	129.910
2027	49.387	55.573	29.201	0.000	0.000	0.000	0.000	0.000	0.102	134.264
2028	52.166	56.981	30.058	0.000	0.000	0.000	0.000	0.000	0.123	139.327
2029	56.999	60.808	30.471	0.000	0.000	0.000	0.000	0.000	0.175	148.452
2030	64.018	62.857	30.602	0.000	0.000	0.000	0.000	0.000	0.130	157.606
2031	67.047	64.381	31.500	0.000	0.000	0.000	0.000	0.000	0.167	163.095
2032	70.017	66.172	32.426	0.000	0.000	0.000	0.000	0.000	0.241	168.856
2033	73.949	67.665	33.367	0.000	0.000	0.000	0.000	0.000	0.230	175.211
2034	76.943	69.924	34.949	0.000	0.000	0.000	0.000	0.000	0.260	182.076
2035	91.800	74.419	33.180	0.000	0.000	0.000	0.000	0.000	0.633	200.032
2036	95.883	76.642	34.144	0.000	0.000	0.000	0.000	0.000	0.899	207.569
EXT.	621.399	446.974	219.171	0.000	0.000	0.000	0.000	0.000	5.829	1293.373

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

PLAN 1 YEAR 2017

* 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\$	\$/MWH
DIAMOND WILLOW	NDT		30.000	0.	0.000	39.22	102.79	0.	-3637.	507.	-3130.	-30.45
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	-2364.	343.	-2021.	-30.25
THUNDER SPIRIT	NDT		107.500	0.	0.000	45.19	424.40	0.	-15015.	2768.	-12247.	-28.86
COYOTE	MUST		107.300	11471.	1.920	69.27	649.33	14301.	1873.	3216.	19390.	29.86
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	58.47	38.31	0.	285.	588.	873.	22.79
MISO - Off peak	HYDR		200.000	10500.	0.000	45.79	800.00	0.	15912.	0.	15912.	19.89
MISO - On peak	HYDR		200.000	10500.	0.000	37.88	661.78	0.	16075.	0.	16075.	24.29
HESKETT #2	MUST		73.100	13260.	2.600	32.02	204.46	7049.	1051.	2634.	10734.	52.50
LEWIS & CLARK1	MUST		52.300	14706.	1.820	27.96	127.75	3419.	1116.	4351.	8886.	69.56
BIG STONE	MUST		107.800	12240.	2.380	23.22	218.67	6370.	1570.	2671.	10612.	48.53
HESKETT #1	MUST		27.300	20626.	2.600	14.80	35.29	1893.	210.	2203.	4307.	122.02
LEWIS & CLARK2			18.500	8708.	3.060	0.32	0.52	14.	1.	224.	239.	457.12
GLENDIVE CT #2			43.000	10633.	3.060	0.03	0.11	4.	0.	269.	273.	2388.66
HESKETT #3			84.300	20770.	3.060	0.00	0.01	0.	0.	3369.	3369.	490661.69
INTERRUPTIBLES	D		14.400	1.	0.000	0.00	0.00	0.	0.	742.	742.	796060.06
GLENDIVE CT #1			37.066	13565.	3.060	0.00	0.00	0.	0.	200.	200.	92731.95
MILES CITY C.T.			25.600	15809.	3.060	0.00	0.00	0.	0.	207.	207.	146665.36
DIESEL 1			2.000	8687.	23.390	0.00	0.00	0.	0.	56.	56.	57.526596.69
DIESEL 2			2.100	8687.	23.390	0.00	0.00	0.	0.	59.	59.	59.558640.75
DIESEL 3			2.000	8687.	23.390	0.00	0.00	0.	0.	56.	56.	57.589651.31
COMMERCIAL DSM	D		10.300	1.	0.000	0.00	0.00	0.	0.	531.	531.	*****

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

PLAN 1 YEAR 2018

* 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 K\$	COST \$/MWH
DIAMOND WILLOW	NDT		30.000	0.	0.000	39.22	102.79	0.	-1212.	522.	-690.	-6.71
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	-2364.	353.	-2011.	-30.10
THUNDER SPIRIT	NDT		107.500	0.	0.000	45.19	424.40	0.	-15015.	2851.	-12164.	-28.66
COYOTE	MUST		107.300	11458.	1.960	69.75	653.84	14683.	1942.	3313.	19938.	30.49
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	58.47	38.31	0.	289.	606.	895.	23.36
MISO - Off peak	HYDR		200.000	10500.	0.000	45.79	800.00	0.	16230.	0.	16230.	20.29
MISO - On peak	HYDR		200.000	10500.	0.000	40.49	707.45	0.	17527.	0.	17527.	24.78
HESKETT #2	MUST		73.100	13259.	2.740	32.02	204.48	7429.	1082.	2714.	11225.	54.89
LEWIS & CLARK1	MUST		52.300	14691.	1.860	25.70	117.42	3208.	1056.	4482.	8746.	74.49
BIG STONE	MUST		107.800	12236.	2.450	24.31	228.98	6864.	1693.	2752.	11309.	49.39
HESKETT #1	MUST		27.300	20623.	2.740	16.45	39.23	2217.	241.	2270.	4727.	120.50
LEWIS & CLARK2			18.500	8900.	2.860	0.89	1.43	36.	3.	231.	270.	188.58
GLENDIVE CT #2			43.000	10458.	2.860	0.41	1.54	46.	4.	277.	327.	212.75
HESKETT #3			84.300	15968.	2.860	0.03	0.19	9.	1.	3470.	3479.	18374.04
GLENDIVE CT #1			37.066	13727.	2.860	0.01	0.03	1.	0.	206.	207.	6266.19
AC CYCLING	2018 D		2.000	1.	0.000	0.01	0.00	0.	0.	727.	728.	637527.00
MILES CITY C.T.			25.600	16146.	2.860	0.00	0.01	0.	0.	213.	214.	24597.22
INTERRUPTIBLES	D		16.700	1.	0.000	0.00	0.01	0.	2.	887.	888.	172132.62
DIESEL 1			2.000	8687.	24.540	0.00	0.00	0.	0.	58.	58.	112949.49
DIESEL 2			2.100	8687.	24.540	0.00	0.00	0.	0.	61.	61.	118491.07
DIESEL 3			2.000	8687.	24.540	0.00	0.00	0.	0.	58.	58.	125356.31
COMMERCIAL DSM	D		13.000	1.	0.000	0.00	0.00	0.	0.	690.	691.	419803.12

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	-1212.	538.	-675.	-6.56
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2364.	364.	-2000.	-29.94
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	2937.	-12079.	-28.46
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11543.	2.000	60.11	563.45	13008.	1724.	3412.	18144.	32.20
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	293.	624.	917.	23.95
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	16555.	0.	16555.	20.69
MISO - On peak		HYDR	200.000	10500.	0.000	38.84	678.65	0.	17150.	0.	17150.	25.27
HESKETT #2		MUST	73.100	13258.	2.820	30.03	191.80	7171.	1046.	2795.	11012.	57.41
LEWIS & CLARK1		MUST	52.300	14703.	1.860	27.98	127.85	3496.	1185.	4616.	9297.	72.72
BIG STONE		MUST	107.800	12241.	2.520	23.22	218.65	6745.	1665.	2834.	11244.	51.42
HESKETT #1		MUST	27.300	20611.	2.820	16.47	39.28	2283.	249.	2338.	4869.	123.96
LEWIS & CLARK2			18.500	8755.	3.000	0.59	0.95	25.	2.	238.	265.	277.44
GLENDIVE CT #2			43.000	10657.	3.000	0.30	1.12	36.	3.	285.	324.	288.64
HESKETT #3			84.300	15303.	3.000	0.02	0.13	6.	0.	3574.	3581.	26668.70
AC CYCLING	2018	D	4.000	1.	0.000	0.01	0.00	0.	0.	724.	725.	218318.02
GLENDIVE CT #1			37.066	13810.	3.000	0.01	0.02	1.	0.	212.	213.	9907.67
MILES CITY C.T.			25.600	16010.	3.000	0.01	0.01	1.	0.	220.	220.	19374.53
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.01	0.	2.	1094.	1095.	179755.45
DIESEL 1			2.000	8687.	25.700	0.00	0.00	0.	0.	60.	60.	112321.43
DIESEL 2			2.100	8687.	25.700	0.00	0.00	0.	0.	63.	63.	117476.50
DIESEL 3			2.000	8687.	25.700	0.00	0.00	0.	0.	60.	60.	122197.62
COMMERCIAL DSM		D	15.000	1.	0.000	0.00	0.00	0.	0.	820.	821.	689650.31

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	554.	554.	5.39
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	374.	374.	5.60
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	3025.	-11991.	-28.25
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11559.	2.050	66.29	621.34	14723.	1958.	3514.	20195.	32.50
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	298.	643.	940.	24.55
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	16886.	0.	16886.	21.11
MISO - On peak		HYDR	200.000	10500.	0.000	35.85	626.45	0.	16148.	0.	16148.	25.78
HESKETT #2		MUST	73.100	13260.	2.920	32.02	204.46	7916.	1148.	2879.	11943.	58.41
LEWIS & CLARK1		MUST	52.300	14691.	1.860	28.09	128.35	3507.	1225.	4754.	9487.	73.91
BIG STONE		MUST	107.800	12243.	2.600	27.42	258.22	8219.	2026.	2919.	13164.	50.98
HESKETT #1		MUST	27.300	20625.	2.920	16.44	39.22	2362.	256.	2408.	5025.	128.14
LEWIS & CLARK2			18.500	8737.	3.090	0.51	0.82	22.	2.	245.	269.	326.05
GLENDIVE CT #2			43.000	10366.	3.090	0.15	0.58	19.	2.	294.	314.	541.87
HESKETT #3			84.300	15417.	3.090	0.02	0.14	7.	0.	3681.	3688.	26558.61
GLENDIVE CT #1			37.066	13689.	3.090	0.01	0.02	1.	0.	219.	220.	9802.77
AC CYCLING	2018	D	6.000	1.	0.000	0.00	0.00	0.	0.	862.	863.	938948.50
MILES CITY C.T.			25.600	16176.	3.090	0.00	0.00	0.	0.	226.	227.	76572.52
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	0.	1126.	1127.	*****
DIESEL 1			2.000	8687.	26.490	0.00	0.00	0.	0.	62.	62.	569746.81
DIESEL 2			2.100	8687.	26.490	0.00	0.00	0.	0.	65.	65.	601349.56
DIESEL 3			2.000	8687.	26.490	0.00	0.00	0.	0.	62.	62.	629766.69
COMMERCIAL DSM		D	15.000	0.	0.000	0.00	0.00	0.	0.	845.	845.	0.00

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	570.	570.	5.55
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	386.	386.	5.77
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	3116.	-11900.	-28.04
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11535.	2.050	67.09	628.84	14869.	2041.	3620.	20530.	32.65
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	302.	662.	964.	25.17
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	17224.	0.	17224.	21.53
MISO - On peak		HYDR	200.000	10500.	0.000	38.91	679.79	0.	17873.	0.	17873.	26.29
HESKETT #2		MUST	73.100	13259.	3.020	32.02	204.48	8188.	1183.	2965.	12336.	60.33
LEWIS & CLARK1		MUST	52.300	14674.	1.880	28.24	129.04	3560.	1269.	4897.	9726.	75.37
BIG STONE		MUST	107.800	12241.	2.670	26.38	248.41	8119.	2007.	3007.	13133.	52.87
HESKETT #1		MUST	27.300	20623.	3.020	16.45	39.23	2443.	263.	2480.	5186.	132.22
LEWIS & CLARK2			18.500	8736.	3.183	0.66	1.07	30.	2.	252.	284.	265.25
GLENDIVE CT #2			43.000	10358.	3.183	0.14	0.52	17.	2.	303.	321.	613.36
HESKETT #3			84.300	14987.	3.183	0.03	0.19	9.	1.	3792.	3802.	19789.70
GLENDIVE CT #1			37.066	13580.	3.183	0.01	0.03	1.	0.	225.	227.	7181.99
AC CYCLING	2018	D	8.000	1.	0.000	0.00	0.00	0.	0.	999.	999.	408699.81
MILES CITY C.T.			25.600	16504.	3.183	0.00	0.01	0.	0.	233.	234.	37790.31
DIESEL 1			2.000	8687.	26.780	0.00	0.00	0.	0.	64.	64.	319134.41
DIESEL 2			2.100	8687.	26.780	0.00	0.00	0.	0.	67.	67.	334751.47
DIESEL 3			2.000	8687.	26.780	0.00	0.00	0.	0.	64.	64.	356149.09
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	0.	1160.	1161.	871559.56
COMMERCIAL DSM		D	15.000	0.	0.000	0.00	0.00	0.	0.	870.	870.	0.00

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	587.	587.	5.72
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	397.	397.	5.95
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	3209.	-11806.	-27.82
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11497.	2.111	61.51	576.55	13997.	1928.	3728.	19653.	34.09
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	307.	682.	989.	25.81
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	17568.	0.	17568.	21.96
MISO - On peak		HYDR	200.000	10500.	0.000	44.42	776.12	0.	20814.	0.	20814.	26.82
HESKETT #2		MUST	73.100	13259.	3.111	32.69	208.79	8611.	1244.	3054.	12909.	61.83
LEWIS & CLARK1		MUST	52.300	14585.	1.936	29.05	132.74	3749.	1344.	5044.	10137.	76.37
BIG STONE		MUST	107.800	12239.	2.750	26.40	248.65	8369.	2069.	3097.	13535.	54.44
HESKETT #1		MUST	27.300	20619.	3.111	15.14	36.11	2316.	250.	2554.	5120.	141.80
LEWIS & CLARK2			18.500	8707.	3.278	1.72	2.78	79.	6.	260.	345.	124.36
GLENDIVE CT #2			43.000	10972.	3.278	0.35	1.32	48.	4.	312.	363.	274.75
HESKETT #3			84.300	14385.	3.278	0.04	0.30	14.	1.	3906.	3920.	13209.13
GLENDIVE CT #1			37.066	13439.	3.278	0.02	0.05	2.	0.	232.	234.	4553.34
AC CYCLING	2018	D	10.000	1.	0.000	0.01	0.01	0.	1.	1134.	1135.	155982.64
MILES CITY C.T.			25.600	16050.	3.278	0.01	0.01	1.	0.	240.	241.	17514.89
INTERRUPTIBLES		D	20.000	1.	0.000	0.00	0.00	0.	1.	1195.	1196.	316473.38
DIESEL 1			2.000	8687.	27.583	0.00	0.00	0.	0.	65.	66.	177912.17
DIESEL 2			2.100	8687.	27.583	0.00	0.00	0.	0.	69.	69.	185464.22
DIESEL 3			2.000	8687.	27.583	0.00	0.00	0.	0.	65.	66.	195634.38
COMMERCIAL DSM		D	15.000	1.	0.000	0.00	0.00	0.	0.	896.	896.	*****

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	605.	605.	5.89
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	409.	409.	6.12
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	3305.	-11710.	-27.59
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11505.	2.175	68.07	638.07	15966.	2197.	3840.	22003.	34.48
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	311.	702.	1014.	26.46
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	17919.	0.	17919.	22.40
MISO - On peak		HYDR	200.000	10500.	0.000	42.46	741.78	0.	20291.	0.	20291.	27.35
HESKETT #2		MUST	73.100	13259.	3.204	32.04	204.58	8691.	1256.	3146.	13092.	63.99
LEWIS & CLARK1		MUST	52.300	14533.	1.994	29.60	135.24	3920.	1410.	5195.	10526.	77.83
BIG STONE		MUST	107.800	12228.	2.833	27.57	259.65	8993.	2226.	3190.	14409.	55.49
HESKETT #1		MUST	27.300	20615.	3.204	16.47	39.27	2594.	280.	2631.	5504.	140.16
LEWIS & CLARK2			18.500	8608.	3.377	5.00	8.09	235.	18.	268.	521.	64.42
GLENDIVE CT #2			43.000	10527.	3.377	0.45	1.68	60.	5.	321.	386.	229.32
HESKETT #3			84.300	14123.	3.377	0.06	0.41	19.	1.	4023.	4043.	9936.49
GLENDIVE CT #1			37.066	13326.	3.377	0.02	0.08	3.	0.	239.	243.	3125.45
AC CYCLING	2018	D	10.000	1.	0.000	0.02	0.01	0.	1.	960.	961.	67560.93
MILES CITY C.T.			25.600	15901.	3.377	0.01	0.02	1.	0.	247.	249.	10294.09
INTERRUPTIBLES		D	20.000	1.	0.000	0.01	0.01	0.	4.	1231.	1235.	98962.84
DIESEL 1			2.000	8687.	28.411	0.01	0.00	0.	0.	67.	68.	64037.69
DIESEL 2			2.100	8687.	28.411	0.01	0.00	0.	0.	71.	71.	66656.52
DIESEL 3			2.000	8687.	28.411	0.00	0.00	0.	0.	67.	68.	78492.06
COMMERCIAL DSM		D	15.000	1.	0.000	0.00	0.00	0.	1.	923.	924.	266071.12

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	623.	623.	6.06
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	421.	421.	6.31
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	3404.	-11611.	-27.36
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11482.	2.240	68.99	646.65	16632.	2294.	3955.	22881.	35.38
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	316.	723.	1039.	27.13
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	18278.	0.	18278.	22.85
MISO - On peak		HYDR	200.000	10500.	0.000	45.12	788.34	0.	21996.	0.	21996.	27.90
HESKETT #2		MUST	73.100	13255.	3.300	32.11	205.04	8969.	1296.	3240.	13505.	65.87
LEWIS & CLARK1		MUST	52.300	14154.	2.054	30.79	140.67	4091.	1511.	5351.	10953.	77.86
BIG STONE		MUST	107.800	12178.	2.918	24.83	233.87	8310.	2065.	3286.	13660.	58.41
HESKETT #1		MUST	27.300	20579.	3.300	16.55	39.47	2680.	290.	2710.	5680.	143.90
LEWIS & CLARK2			18.500	8774.	3.478	10.25	16.57	506.	39.	276.	820.	49.49
GLENDIVE CT #2			43.000	10263.	3.478	1.24	4.66	166.	15.	331.	512.	109.81
HESKETT #3			84.300	14203.	3.478	0.16	1.20	59.	4.	4143.	4206.	3505.87
GLENDIVE CT #1			37.066	13222.	3.478	0.08	0.26	12.	1.	246.	259.	999.83
AC CYCLING	2018	D	10.000	1.	0.000	0.08	0.07	0.	7.	970.	976.	14525.08
MILES CITY C.T.			25.600	15725.	3.478	0.04	0.09	5.	0.	255.	260.	2875.92
INTERRUPTIBLES		D	20.000	1.	0.000	0.04	0.07	0.	20.	1268.	1288.	19275.80
DIESEL 1			2.000	8687.	29.263	0.03	0.00	1.	0.	69.	71.	14399.01
DIESEL 2			2.100	8687.	29.263	0.03	0.00	1.	0.	73.	74.	14959.48
DIESEL 3			2.000	8687.	29.263	0.03	0.00	1.	0.	69.	71.	15751.90
COMMERCIAL DSM		D	15.000	1.	0.000	0.02	0.03	0.	8.	951.	959.	35263.68

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	642.	642.	6.25
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	434.	434.	6.50
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	-15015.	3507.	-11509.	-27.12
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11419.	2.307	67.09	628.86	16569.	2297.	4074.	22940.	36.48
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	321.	745.	1066.	27.82
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	18643.	0.	18643.	23.30
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	22768.	0.	22768.	28.46
BIG STONE		MUST	107.800	12187.	3.005	24.75	233.10	8537.	2120.	3384.	14041.	60.24
GE 7EA 2x1 ADD	2025		265.100	11811.	3.582	19.48	451.10	19085.	2274.	10152.	31511.	69.85
LEWIS & CLARK2			18.500	8325.	3.582	0.67	1.08	32.	3.	284.	319.	293.93
GLENDIVE CT #2			43.000	9460.	3.582	0.65	2.46	83.	8.	341.	432.	175.85
AC CYCLING	2018	D	10.000	1.	0.000	0.40	0.35	0.	35.	980.	1015.	2884.42
INTERRUPTIBLES		D	20.000	1.	0.000	0.27	0.48	0.	144.	1306.	1450.	3019.10
GLENDIVE CT #1			37.066	12954.	3.582	0.22	0.70	32.	2.	253.	288.	411.75
MILES CITY C.T.			25.600	15505.	3.582	0.19	0.42	24.	1.	263.	287.	679.15
COMMERCIAL DSM		D	15.000	1.	0.000	0.18	0.24	0.	71.	979.	1050.	4452.09
DIESEL 1			2.000	8687.	30.141	0.17	0.03	8.	0.	72.	80.	2632.56
DIESEL 2			2.100	8687.	30.141	0.17	0.03	8.	0.	75.	83.	2683.50
DIESEL 3			2.000	8687.	30.141	0.17	0.03	8.	0.	72.	79.	2735.60

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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 K\$	COST \$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	661.	661.	6.43
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	447.	447.	6.69
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	3612.	3612.	8.51
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
COYOTE		MUST	107.300	11416.	2.377	58.65	549.76	14915.	2069.	4196.	21180.	38.53
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	326.	767.	1093.	28.53
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	19016.	0.	19016.	23.77
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	23223.	0.	23223.	29.03
BIG STONE		MUST	107.800	12175.	3.095	25.41	239.28	9017.	2241.	3486.	14744.	61.62
GE 7EA 2x1 ADD	2025		265.100	10864.	3.690	24.49	567.10	22731.	2945.	10456.	36132.	63.71
LEWIS & CLARK2			18.500	8487.	3.690	0.83	1.34	42.	3.	292.	338.	251.35
GLENDIVE CT #2			43.000	9435.	3.690	0.74	2.77	97.	9.	351.	457.	164.71
AC CYCLING	2018	D	10.000	1.	0.000	0.52	0.45	0.	45.	990.	1035.	2280.95
INTERRUPTIBLES		D	20.000	1.	0.000	0.36	0.63	0.	190.	1345.	1535.	2418.43
GLENDIVE CT #1			37.066	12910.	3.690	0.27	0.88	42.	3.	261.	306.	349.15
COMMERCIAL DSM		D	15.000	1.	0.000	0.24	0.32	0.	96.	1009.	1105.	3455.05
MILES CITY C.T.			25.600	15471.	3.690	0.24	0.53	31.	2.	270.	303.	566.02
DIESEL 1			2.000	8687.	31.045	0.23	0.04	11.	0.	74.	85.	2132.39
DIESEL 2			2.100	8687.	31.045	0.22	0.04	11.	0.	77.	89.	2172.73
DIESEL 3			2.000	8687.	31.045	0.22	0.04	10.	0.	74.	84.	2207.39

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	681.	681.	6.63
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	460.	460.	6.89
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	3720.	3720.	8.77
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11416.	2.448	71.51	670.28	18730.	2598.	4322.	25651.	38.27
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	331.	790.	1121.	29.26
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	19397.	0.	19397.	24.25
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	23687.	0.	23687.	29.61
BIG STONE		MUST	107.800	12180.	3.188	23.74	223.59	8682.	2157.	3590.	14430.	64.54
GE 7EA 2x1 ADD	2025		265.100	11292.	3.800	21.88	506.66	21742.	2710.	10770.	35222.	69.52
LEWIS & CLARK2			18.500	8516.	3.800	0.80	1.30	42.	3.	301.	347.	266.61
GLENDIVE CT #2			43.000	9461.	3.800	0.70	2.61	94.	9.	361.	464.	177.78
AC CYCLING	2018	D	10.000	1.	0.000	0.49	0.43	0.	43.	1001.	1044.	2427.93
INTERRUPTIBLES		D	20.000	1.	0.000	0.34	0.60	0.	180.	1385.	1566.	2602.93
GLENDIVE CT #1			37.066	12916.	3.800	0.25	0.82	40.	3.	269.	312.	381.96
COMMERCIAL DSM		D	15.000	1.	0.000	0.23	0.30	0.	91.	1039.	1130.	3724.07
DIESEL 1			2.000	8687.	31.977	0.21	0.04	10.	0.	76.	86.	2311.61
DIESEL 2			2.100	8687.	31.977	0.21	0.04	11.	0.	80.	91.	2353.75
DIESEL 3			2.000	8687.	31.977	0.21	0.04	10.	0.	76.	86.	2393.91
MILES CITY C.T.			25.600	15456.	3.800	0.19	0.43	25.	2.	279.	306.	704.51

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	0.	701.	701.	6.82
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	474.	474.	7.10
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	3832.	3832.	9.03
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	3885.	0.	3885.	20.50
COYOTE		MUST	107.300	11416.	2.521	71.55	670.69	19303.	2677.	4452.	26432.	39.41
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	335.	814.	1150.	30.01
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	19785.	0.	19785.	24.73
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	24161.	0.	24161.	30.20
BIG STONE		MUST	107.800	12176.	3.284	24.86	234.12	9361.	2327.	3698.	15385.	65.72
GE 7EA 2x1 ADD	2025		265.100	11004.	3.914	23.31	539.88	23255.	2974.	11093.	37322.	69.13
LEWIS & CLARK2			18.500	8564.	3.914	0.87	1.40	47.	4.	310.	361.	257.99
GLENDIVE CT #2			43.000	9454.	3.914	0.63	2.37	88.	8.	372.	468.	197.56
AC CYCLING	2018	D	10.000	1.	0.000	0.53	0.46	0.	46.	1012.	1058.	2300.25
INTERRUPTIBLES		D	20.000	1.	0.000	0.37	0.65	0.	196.	1427.	1623.	2487.21
GLENDIVE CT #1			37.066	12897.	3.914	0.28	0.89	45.	3.	277.	325.	364.96
COMMERCIAL DSM		D	15.000	1.	0.000	0.26	0.33	0.	100.	1070.	1171.	3495.57
MILES CITY C.T.			25.600	15458.	3.914	0.24	0.55	33.	2.	287.	322.	589.30
DIESEL 1			2.000	8687.	32.936	0.23	0.04	12.	0.	78.	90.	2229.02
DIESEL 2			2.100	8687.	32.936	0.23	0.04	12.	0.	82.	94.	2273.69
DIESEL 3			2.000	8687.	32.936	0.22	0.04	11.	0.	78.	89.	2304.08

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EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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 K\$	COST \$/MWH
DIAMOND WILLOW		NDT	10.500	0.	0.000	39.22	35.98	0.	0.	253.	253.	7.03
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	0.	489.	489.	7.31
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	3947.	3947.	9.30
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11414.	2.597	64.53	604.86	17928.	2487.	4585.	25001.	41.33
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	340.	839.	1179.	30.78
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	20180.	0.	20180.	25.23
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	24644.	0.	24644.	30.81
GE 7EA 2x1 ADD	2025		265.100	10096.	4.032	31.26	723.95	29469.	4108.	11426.	45003.	62.16
BIG STONE		MUST	107.800	12159.	3.382	23.93	225.37	9268.	2307.	3809.	15384.	68.26
LEWIS & CLARK2			18.500	8588.	4.032	1.04	1.68	58.	5.	319.	382.	227.65
GLENDIVE CT #2			43.000	9434.	4.032	0.87	3.27	125.	12.	383.	520.	158.75
AC CYCLING	2018	D	10.000	1.	0.000	0.69	0.61	0.	61.	1023.	1083.	1784.39
INTERRUPTIBLES		D	20.000	1.	0.000	0.50	0.88	0.	263.	1470.	1732.	1979.23
GLENDIVE CT #1			37.066	12862.	4.032	0.35	1.15	60.	4.	285.	349.	304.01
COMMERCIAL DSM		D	15.000	1.	0.000	0.35	0.46	0.	137.	1102.	1239.	2721.29
MILES CITY C.T.			25.600	15433.	4.032	0.32	0.71	44.	3.	295.	342.	482.42
DIESEL 1			2.000	8687.	33.924	0.31	0.05	16.	0.	81.	96.	1804.02
DIESEL 2			2.100	8687.	33.924	0.30	0.06	16.	0.	85.	101.	1831.97
DIESEL 3			2.000	8687.	33.924	0.30	0.05	15.	0.	81.	96.	1859.81

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	4065.	4065.	9.58
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11413.	2.675	71.68	671.95	20513.	2846.	4723.	28082.	41.79
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	346.	864.	1209.	31.57
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	20584.	0.	20584.	25.73
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	25137.	0.	25137.	31.42
GE 7EA 2x1 ADD	2025		265.100	10047.	4.153	33.05	765.33	31930.	4473.	11769.	48172.	62.94
BIG STONE		MUST	107.800	12160.	3.484	28.27	266.20	11277.	2807.	3923.	18006.	67.64
LEWIS & CLARK2			18.500	8576.	4.153	1.03	1.67	59.	5.	329.	393.	235.64
GLENDIVE CT #2			43.000	9373.	4.153	0.90	3.38	131.	13.	395.	539.	159.62
AC CYCLING	2018	D	10.000	1.	0.000	0.57	0.50	0.	50.	1034.	1083.	2183.49
INTERRUPTIBLES		D	20.000	1.	0.000	0.42	0.74	0.	222.	1514.	1736.	2344.28
GLENDIVE CT #1			37.066	12900.	4.153	0.30	0.96	52.	4.	294.	349.	362.61
COMMERCIAL DSM		D	15.000	1.	0.000	0.29	0.38	0.	113.	1135.	1248.	3315.31
MILES CITY C.T.			25.600	15465.	4.153	0.26	0.59	38.	2.	304.	344.	585.35
DIESEL 1			2.000	8687.	34.942	0.11	0.02	6.	0.	83.	89.	4446.90
DIESEL 2			2.100	8687.	34.942	0.11	0.02	6.	0.	87.	93.	4551.95
DIESEL 3			2.000	8687.	34.942	0.11	0.02	6.	0.	83.	89.	4657.90

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

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\$	\$/MWH
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	4187.	4187.	9.87
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11414.	2.755	71.70	672.08	21134.	2932.	4865.	28931.	43.05
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	351.	890.	1240.	32.38
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	20995.	0.	20995.	26.24
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	25640.	0.	25640.	32.05
GE 7EA 2x1 ADD	2025		265.100	9803.	4.277	35.41	820.01	34384.	4937.	12122.	51443.	62.73
BIG STONE		MUST	107.800	12152.	3.588	27.26	256.77	11196.	2788.	4041.	18025.	70.20
LEWIS & CLARK2			18.500	8581.	4.277	1.08	1.75	64.	5.	339.	408.	233.28
GLENDIVE CT #2			43.000	9380.	4.277	0.94	3.52	141.	14.	407.	562.	159.50
AC CYCLING	2018	D	10.000	1.	0.000	0.66	0.58	0.	58.	1045.	1103.	1912.16
INTERRUPTIBLES		D	20.000	1.	0.000	0.50	0.87	0.	262.	1559.	1821.	2084.01
COMMERCIAL DSM		D	15.000	1.	0.000	0.35	0.45	0.	136.	1169.	1305.	2883.01
GLENDIVE CT #1			37.066	12871.	4.277	0.34	1.10	60.	4.	303.	367.	334.69
MILES CITY C.T.			25.600	15438.	4.277	0.30	0.67	44.	3.	313.	360.	540.56
DIESEL 1			2.000	8687.	35.990	0.14	0.02	8.	0.	85.	93.	3826.69
DIESEL 2			2.100	8687.	35.990	0.14	0.02	8.	0.	90.	98.	3913.33
DIESEL 3			2.000	8687.	35.990	0.13	0.02	7.	0.	85.	93.	3998.49

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

PLAN 1 YEAR 2032

* CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST \$/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION COST K\$	\$/MWH
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	4313.	4313.	10.16
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11416.	2.838	64.56	605.13	19602.	2719.	5011.	27332.	45.17
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	356.	916.	1272.	33.21
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	21415.	0.	21415.	26.77
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	26153.	0.	26153.	32.69
GE 7EA 2x1 ADD	2025		265.100	9375.	4.406	40.19	930.69	38442.	5771.	12485.	56698.	60.92
BIG STONE		MUST	107.800	12138.	3.696	27.41	258.12	11579.	2887.	4162.	18628.	72.17
LEWIS & CLARK2			18.500	8590.	4.406	1.20	1.94	73.	6.	349.	428.	221.23
GLENDIVE CT #2			43.000	9391.	4.406	1.01	3.79	157.	15.	419.	591.	155.82
AC CYCLING	2018	D	10.000	1.	0.000	0.82	0.72	0.	72.	1057.	1129.	1570.79
INTERRUPTIBLES		D	20.000	1.	0.000	0.64	1.11	0.	334.	1606.	1940.	1741.90
COMMERCIAL DSM		D	15.000	1.	0.000	0.45	0.59	0.	178.	1204.	1383.	2328.74
GLENDIVE CT #1			37.066	12830.	4.406	0.41	1.34	76.	5.	312.	393.	292.73
MILES CITY C.T.			25.600	15408.	4.406	0.37	0.84	57.	3.	323.	383.	458.07
DIESEL 1			2.000	8687.	37.070	0.18	0.03	10.	0.	88.	99.	3049.53
DIESEL 2			2.100	8687.	37.070	0.18	0.03	11.	0.	92.	103.	3112.33
DIESEL 3			2.000	8687.	37.070	0.18	0.03	10.	0.	88.	98.	3173.32

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

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\$	\$/MWH
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	4442.	4442.	10.47
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11415.	2.923	71.72	672.25	22429.	3111.	5161.	30701.	45.67
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	361.	944.	1305.	34.07
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	21844.	0.	21844.	27.30
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	26676.	0.	26676.	33.34
GE 7EA 2x1 ADD	2025		265.100	9468.	4.538	38.94	901.89	38746.	5760.	12860.	57367.	63.61
BIG STONE		MUST	107.800	12144.	3.807	28.44	267.83	12382.	3086.	4287.	19754.	73.76
LEWIS & CLARK2			18.500	8597.	4.538	1.19	1.92	75.	6.	360.	440.	229.22
GLENDIVE CT #2			43.000	9428.	4.538	1.00	3.76	161.	16.	431.	608.	161.59
AC CYCLING	2018	D	10.000	1.	0.000	0.76	0.67	0.	67.	1057.	1124.	1684.14
INTERRUPTIBLES		D	20.000	1.	0.000	0.59	1.03	0.	309.	1654.	1963.	1904.72
COMMERCIAL DSM		D	15.000	1.	0.000	0.42	0.55	0.	164.	1241.	1405.	2563.87
GLENDIVE CT #1			37.066	12835.	4.538	0.38	1.24	72.	5.	321.	398.	321.46
MILES CITY C.T.			25.600	15413.	4.538	0.35	0.78	55.	3.	333.	390.	499.69
DIESEL 1			2.000	8687.	38.182	0.17	0.03	10.	0.	91.	101.	3373.43
DIESEL 2			2.100	8687.	38.182	0.17	0.03	10.	0.	95.	105.	3443.21
DIESEL 3			2.000	8687.	38.182	0.16	0.03	9.	0.	91.	100.	3511.75

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
THUNDER SPIRIT		NDT	107.500	0.	0.000	45.19	424.40	0.	0.	4575.	4575.	10.78
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11417.	3.010	71.75	672.53	23114.	3206.	5316.	31636.	47.04
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	367.	972.	1339.	34.95
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	22281.	0.	22281.	27.85
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	27209.	0.	27209.	34.01
GE 7EA 2x1 ADD	2025		265.100	9202.	4.674	42.20	977.23	42032.	6429.	13246.	61706.	63.14
BIG STONE		MUST	107.800	12130.	3.921	25.30	238.22	11330.	2827.	4416.	18572.	77.96
LEWIS & CLARK2			18.500	8608.	4.674	1.31	2.12	85.	7.	370.	462.	218.14
GLENDIVE CT #2			43.000	9476.	4.674	1.08	4.04	179.	17.	444.	641.	158.46
AC CYCLING	2018	D	10.000	1.	0.000	0.96	0.84	0.	84.	1057.	1141.	1359.60
INTERRUPTIBLES		D	20.000	1.	0.000	0.76	1.33	0.	399.	1704.	2102.	1582.25
COMMERCIAL DSM		D	15.000	1.	0.000	0.56	0.73	0.	219.	1278.	1497.	2051.25
GLENDIVE CT #1			37.066	12799.	4.674	0.47	1.53	92.	7.	331.	429.	280.10
MILES CITY C.T.			25.600	15379.	4.674	0.43	0.96	69.	4.	343.	416.	431.46
PURCHASE POWER	2034		10.000	1.	0.000	0.41	0.36	0.	613.	613.	1226.	3403.35
DIESEL 1			2.000	8687.	39.327	0.23	0.04	14.	0.	93.	107.	2649.99
DIESEL 2			2.100	8687.	39.327	0.23	0.04	14.	0.	98.	112.	2699.71
DIESEL 3			2.000	8687.	39.327	0.22	0.04	13.	0.	93.	107.	2746.88

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
COYOTE		MUST	107.300	11423.	3.101	67.55	633.16	22426.	3109.	5475.	31010.	48.98
GE 7EA 2x1 ADD	2025		265.100	7977.	4.814	63.77	1476.83	56712.	10007.	13643.	80362.	54.42
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	372.	1001.	1374.	35.86
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	27753.	0.	27753.	34.69
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	22726.	0.	22726.	28.41
BIG STONE		MUST	107.800	12106.	4.039	25.53	240.43	11755.	2939.	4548.	19242.	80.03
LEWIS & CLARK2			18.500	8737.	4.814	3.16	5.11	215.	17.	381.	613.	119.99
GLENDIVE CT #2			43.000	10857.	4.814	1.52	5.72	299.	25.	458.	782.	136.62
AC CYCLING	2018	D	10.000	1.	0.000	1.40	1.22	0.	122.	1057.	1179.	965.52
INTERRUPTIBLES		D	20.000	1.	0.000	1.26	2.20	0.	659.	1755.	2414.	1098.51
COMMERCIAL DSM		D	15.000	1.	0.000	1.02	1.34	0.	401.	1316.	1717.	1283.85
GE LM6000PH	2035		41.300	9537.	4.814	0.62	2.22	102.	16.	2559.	2677.	1203.95
MILES CITY C.T.			25.600	15106.	4.814	0.60	1.33	97.	6.	353.	456.	341.55
GLENDIVE CT #1			37.066	12394.	4.814	0.59	1.91	114.	8.	341.	463.	242.29
DIESEL 1			2.000	8687.	40.507	0.43	0.08	27.	0.	96.	123.	1630.64
DIESEL 2			2.100	8687.	40.507	0.42	0.08	27.	0.	101.	129.	1654.77
DIESEL 3			2.000	8687.	40.507	0.42	0.07	26.	0.	96.	122.	1678.28

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

EGEAS REPORT

PRODUCTION COST - ANNUAL BY UNITS REPORT

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\$	\$/MWH
THUNDER SPIRIT 2	2019	NDT	48.000	0.	0.000	45.19	189.50	0.	5780.	0.	5780.	30.50
GE 7EA 2x1 ADD	2025		265.100	7856.	4.959	68.54	1587.26	61834.	11077.	14053.	86964.	54.79
COYOTE		MUST	107.300	11425.	3.194	58.96	552.69	20168.	2795.	5639.	28602.	51.75
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.67	14.35	0.	477.	0.	477.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	378.	1031.	1409.	36.79
MISO - On peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	28309.	0.	28309.	35.39
MISO - Off peak		HYDR	200.000	10500.	0.000	45.79	800.00	0.	23181.	0.	23181.	28.98
BIG STONE		MUST	107.800	12053.	4.160	26.62	250.73	12571.	3156.	4684.	20412.	81.41
LEWIS & CLARK2			18.500	8700.	4.959	5.03	8.14	351.	27.	393.	771.	94.77
GLENDIVE CT #2			43.000	10284.	4.959	2.81	10.57	539.	48.	471.	1058.	100.11
AC CYCLING	2018	D	10.000	1.	0.000	1.49	1.30	0.	130.	1057.	1187.	910.40
INTERRUPTIBLES		D	20.000	1.	0.000	1.44	2.52	0.	756.	1808.	2563.	1017.45
COMMERCIAL DSM		D	15.000	1.	0.000	1.27	1.66	0.	498.	1356.	1853.	1117.42
MILES CITY C.T.			25.600	15026.	4.959	0.62	1.38	103.	6.	363.	473.	341.96
GLENDIVE CT #1			37.066	12320.	4.959	0.57	1.86	114.	8.	351.	473.	254.33
DIESEL 1			2.000	8687.	41.722	0.56	0.10	35.	0.	99.	135.	1383.76
DIESEL 2			2.100	8687.	41.722	0.55	0.10	37.	0.	104.	141.	1399.15
GE LM6000PH	2035		41.300	9939.	4.959	0.55	1.97	97.	15.	2635.	2748.	1393.66
DIESEL 3			2.000	8687.	41.722	0.54	0.09	34.	0.	99.	134.	1414.53

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2016.

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 GWH	ENERGY-- PCT.
2017	491.7	3344.59	552.8	13.08	1171.9	0.00	0.000000	1103.0	0.00	0.00
2018	498.7	3401.28	571.5	15.59	1178.9	0.00	0.000000	1110.0	0.00	0.00
2019	505.7	3458.10	598.3	19.84	1234.2	0.00	0.000000	1165.3	0.00	0.00
2020	512.8	3515.78	612.3	21.09	1236.2	0.00	0.000000	1167.3	0.00	0.00
2021	519.4	3567.80	614.3	19.92	1238.2	0.00	0.000000	1169.3	0.00	0.00
2022	526.0	3619.60	616.3	18.77	1240.2	0.00	0.000000	1171.3	0.00	0.00
2023	532.2	3665.09	616.3	17.26	1240.2	0.00	0.000000	1171.3	0.00	0.00
2024	538.5	3713.20	616.3	15.76	1240.2	0.00	0.000000	1171.3	0.03	0.00
2025	544.4	3755.47	653.5	21.85	1268.3	0.03	0.000003	1192.3	0.42	0.01
2026	550.5	3799.96	653.5	20.38	1268.3	0.04	0.000005	1192.3	0.59	0.02
2027	556.5	3843.88	653.5	18.97	1268.3	0.04	0.000005	1192.3	0.57	0.01
2028	562.4	3888.29	653.5	17.61	1268.3	0.05	0.000006	1192.3	0.66	0.02
2029	568.5	3933.36	649.4	15.46	1248.8	0.08	0.000009	1172.8	0.92	0.02
2030	574.6	3978.97	642.2	12.77	1218.8	0.03	0.000003	1142.8	0.66	0.02
2031	580.8	4025.26	642.2	11.46	1218.8	0.04	0.000005	1142.8	0.83	0.02
2032	587.1	4072.08	642.2	10.17	1218.8	0.08	0.000009	1142.8	1.16	0.03
2033	593.4	4119.65	642.2	8.90	1218.8	0.07	0.000008	1142.8	1.07	0.03
2034	599.7	4167.75	652.2	9.47	1228.8	0.08	0.000009	1152.8	1.18	0.03
2035	606.1	4216.65	662.9	10.13	1152.6	0.06	0.000006	1069.9	2.78	0.07
2036	612.6	4266.37	662.9	8.87	1152.6	0.11	0.000013	1069.9	3.83	0.09
EXT.	612.6	4266.37	662.9	8.87	1152.6	0.11	0.000013	1069.9	3.83	0.09

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-----				-----RESOURCES-----				RESERVE MARGIN PCT.
	PEAK LOAD MW	PURCH./SALE CONTRACTS	DEMAND-SIDE MANAGEMENT	NET LOADS MW	CAPACITY MW	RESERVE SHARING	PURCH./SALE CONTRACTS	NET RESOURCES MW	
2017	491.7	0.0	-24.7	467.0	528.1	0.0	0.0	528.1	13.08
2018	498.7	0.0	-31.7	467.0	539.8	0.0	0.0	539.8	15.59
2019	505.7	0.0	-39.0	466.7	559.3	0.0	0.0	559.3	19.84
2020	512.8	0.0	-41.0	471.8	571.3	0.0	0.0	571.3	21.09
2021	519.4	0.0	-43.0	476.4	571.3	0.0	0.0	571.3	19.92
2022	526.0	0.0	-45.0	481.0	571.3	0.0	0.0	571.3	18.77
2023	532.2	0.0	-45.0	487.2	571.3	0.0	0.0	571.3	17.26
2024	538.5	0.0	-45.0	493.5	571.3	0.0	0.0	571.3	15.76
2025	544.4	0.0	-45.0	499.4	608.5	0.0	0.0	608.5	21.85
2026	550.5	0.0	-45.0	505.5	608.5	0.0	0.0	608.5	20.38
2027	556.5	0.0	-45.0	511.5	608.5	0.0	0.0	608.5	18.97
2028	562.4	0.0	-45.0	517.4	608.5	0.0	0.0	608.5	17.61
2029	568.5	0.0	-45.0	523.5	604.4	0.0	0.0	604.4	15.46
2030	574.6	0.0	-45.0	529.6	597.2	0.0	0.0	597.2	12.77
2031	580.8	0.0	-45.0	535.8	597.2	0.0	0.0	597.2	11.46
2032	587.1	0.0	-45.0	542.1	597.2	0.0	0.0	597.2	10.17
2033	593.4	0.0	-45.0	548.4	597.2	0.0	0.0	597.2	8.90
2034	599.7	0.0	-45.0	554.7	607.2	0.0	0.0	607.2	9.47
2035	606.1	0.0	-45.0	561.1	617.9	0.0	0.0	617.9	10.13
2036	612.6	0.0	-45.0	567.6	617.9	0.0	0.0	617.9	8.87
EXT.	612.6	0.0	-45.0	567.6	617.9	0.0	0.0	617.9	8.87

PLAN 1

YEAR	FIXED CHARGES	OPERATING COSTS	TOTAL SYSTEM COST	OTHER ELECTRIC REVENUES	SALES GWH	-----SYSTEM AVERAGE RATE-----	
						\$/MWH	PERCENT INCREASE 1 YEAR
2017	0.	75600.	75600.	0.	3344.59	22.604	
2018	0.	83192.	83192.	0.	3401.27	24.459	8.208
2019	0.	86224.	86224.	0.	3458.09	24.934	1.942
2020	0.	94828.	94828.	0.	3515.78	26.972	8.174
2021	0.	98482.	98482.	0.	3567.80	27.603	2.339
2022	0.	102797.	102797.	0.	3619.59	28.400	2.888
2023	0.	107193.	107193.	0.	3665.06	29.247	2.983
2024	0.	111287.	111287.	0.	3713.04	29.972	2.478
2025	27146.	110052.	137199.	0.	3754.40	36.543	21.925
2026	27146.	129910.	157056.	0.	3798.55	41.346	13.143
2027	27146.	134264.	161410.	0.	3842.54	42.006	1.595
2028	27146.	139327.	166474.	0.	3886.84	42.830	1.962
2029	27146.	148452.	175599.	0.	3931.42	44.665	4.285
2030	27146.	157606.	184753.	0.	3977.36	46.451	3.998
2031	27146.	163095.	190242.	0.	4023.36	47.284	1.794
2032	27146.	168856.	196002.	0.	4069.66	48.162	1.856
2033	27146.	175211.	202357.	0.	4117.40	49.147	2.045
2034	27146.	182076.	209223.	0.	4164.86	50.235	2.215
2035	36636.	200032.	236669.	0.	4211.89	56.191	11.855
2036	36636.	207569.	244205.	0.	4260.88	57.313	1.998
TOTAL	344735.	2676055.	3020790.				
						PERCENT INCREASE IN SYSTEM AVERAGE RATE	
PRESENT VALUE REVENUE REQUIREMENTS (THOUSANDS OF 2016 DOLLARS)	151881.	1411643.	1563524.				
LEVELIZED SYSTEM AVERAGE RATE =	35.382	\$/MWH					
				MINIMUM		1.595	
				MAXIMUM		21.925	
				COMPOUND AVERAGE		5.019	

NOTE - ALL COSTS ARE IN THOUSANDS OF CURRENT YEAR DOLLARS EXCEPT PRESENT VALUE TOTALS.
 - ** INDICATES CONSTRAINT WAS NOT SATISFIED.

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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 are taken.

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Director of Environmental

Shawn Nieuwsma	Manager of Gas Supply
Cory Fong	Director of Communications & Public Affairs
Matt Lund	Engineer – Power Production

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

December 13, 2016 Meeting Agenda

2015 IRP Action Plans	Brian Giggee Larry Oswald
Gas Supply Update	Shawn Nieuwsma
Load Forecast	Kayla Kaul
Request for Proposals	Brian Giggee Larry Oswald
Environmental Challenges & Uncertainties	Abbie Krebsbach
Supply-side analysis and modeling	Brian Giggee
Future Customer Outlook	Larry Oswald
Wrap-up	Group Discussion
Meeting Logistics	
Discussion Topics for Future Meetings	
Meeting Schedule for final meeting 2017	

June 7, 2017 Meeting Agenda

Legislative Update	Cory Fong
Environmental Overview	Abbie Krebsbach
DSM and A/C Cycling	Larry Oswald
Load Forecast Recap	Kayla Kaul
Capacity and Energy RFP	Brian Giggee
Supply Side Resources	Matt Lund
IRP Inputs and Results	Brian Giggee

Two Year Action Plan

Darcy Neigum

MISO Market Overview

Darcy Neigum

Wrap-up

IRP Filing Timeline

Feedback from the PAG members

Future PAG membership for 2019 IRP

Attachment E

Supply-Side Resources Study

Montana-Dakota Utilities Co.



Integrated Resource Plan Supply-Side Resources Performance and Cost Analysis Final

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LIST OF ACRONYMS

ATB	Annual Technology Baseline
BOP	Balance-of-Plant
CFBC	Circulating Fluidized Bed Combustion
CEMS	Continuous Emission Monitoring System
DLN	Dry Low NO _x
EGEAS	Electric Generation Expansion Analysis System
EPA	Environmental Protection Agency
FRP	Fiber-Reinforced Polymer
GE	General Electric
HRSG	Heat Recovery Steam Generator
IRP	Integrated Resource Plan
IDC	Interest During Construction
ITC	Investment Tax Credit
MWhs	Megawatt Hours
MISO	Midcontinent Independent System Operator
Montana-Dakota	Montana-Dakota Utilities Co.
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
O&M	Operating and Maintenance
OEM	Original Equipment Manufacturers
OxCat	Oxidation Catalyst
PV	Photovoltaic
PEACE	Plant Engineering and Construction Estimator
PTC	Production Tax Credit
RICE	Reciprocating Internal Combustion Engines
Sega	Sega Inc.
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
CTGs	Combustion Turbine Generators
SPRINT	Spray Inter-Cooled Turbine
Thermoflow	Thermoflow Inc.

TCI - L Total Capital Investment - Loaded
TCI - UL Total Capital Investment - Unloaded
USDA FSA United States Department of Agriculture's Farm Service Agency

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SECTION 1

INTRODUCTION

INTRODUCTION

1.1 PURPOSE

Montana-Dakota Utilities Co. (Montana-Dakota) requested Sega Inc. (Sega) to conduct a performance and cost analysis of resource options to be included in Montana-Dakota's 2017 Integrated Resource Plan (IRP) supply-side alternative resources model. The results of the analysis will be input into the Electric Generation Expansion Analysis System (EGEAS) and used to develop a least cost option for Montana-Dakota's future energy resources.

The following is a list of the analysis deliverables which are EGEAS performance and cost inputs for each supply-side resource option assessed:

1. Summer and Winter Net Plant Output (MW).
2. Capital Cost (\$/kW).
3. Fixed Operating and Maintenance (O&M) Cost (\$/kW-month).
4. Variable O&M Cost (\$/MWh).
5. Major Maintenance (\$/kW-month).
6. Summer and Winter Full Load Heat Rate (Btu/kWh, net, HHV).
7. Summer and Winter Carbon Intensity (lb/MWh).
8. Summer and Winter NO_x (ppmvd at 15 percent O₂).
9. Summer and Winter CO (ppmvd at 15 percent O₂).
10. Summer and Winter PM (lb/hr).

1.2 SUPPLY-SIDE RESOURCES ASSESSED

The supply-side resource options that were investigated include: simple-cycle combustion turbine generators (CTGs), combined-cycle CTGs, reciprocating internal combustion engines (RICE), a biomass boiler, wind turbine generation options, solar generation options, and coal generation options. Both the simple-cycle and combined-cycle CTGs had various operating cases that were explored. The specific generating facility configurations and operating conditions assessed to develop the performance cost related EGEAS inputs are shown in *Figures 1.1* and *Figure 1.2*.

Generating Facility Type	Configuration	Season	Operating Condition		Operating Case Number
			Evaporative Cooling	Duct Firing	
Simple-Cycle CTG (9 Total Cases)	GE 7EA	Summer	On	N/A	Case 1
		Summer	Off	N/A	Case 2
		Winter	Off	N/A	Case 3
	GE LMS100PB	Summer	On	N/A	Case 1
		Summer	Off	N/A	Case 2
		Winter	Off	N/A	Case 3
	GE LM6000PH	Summer	On	N/A	Case 1
		Summer	Off	N/A	Case 2
		Winter	Off	N/A	Case 3
Combined-Cycle CTG (16 Total Cases)	1x1 GE LM6000PH with SPRINT	Summer	On	Off	Case 1
		Summer	On	On	Case 2
		Summer	Off	Off	Case 3
		Winter	Off	Off	Case 4
	1x1 GE 7FA.05	Summer	On	Off	Case 1
		Summer	On	On	Case 2
		Summer	Off	Off	Case 3
		Winter	Off	Off	Case 4
	2x1 GE 7EA (Heskett 3 Expansion)	Summer	On	Off	Case 1
		Summer	On	On	Case 2
		Summer	Off	Off	Case 3
		Winter	Off	Off	Case 4
	2x1 Siemens SGT-800	Summer	On	Off	Case 1
		Summer	On	On	Case 2
		Summer	Off	Off	Case 3
		Winter	Off	Off	Case 4

Figure 1.1 - CTG-Related Generating Facilities and Operating Conditions Assessed in Study

Generating Facility Type	Configuration	Operating Condition (Year-Round)
RICE	4 x Wartsila 20V34SG	Full Load
	3 x Wartsila 18V50SG	Full Load
Renewable - Biomass	Loose Wheat Straw Fueled Stoker Boiler (10 MW)	Full Load
Renewable - Wind	Generic 8 x GE 2.5-116-80m (20 MW) in North Dakota	Full Load
	Generic 20 x GE 2.5-116-80m (50 MW) in North Dakota	Full Load
	15 x Nordex N117 (45 MW Thunder Spirit Expansion)	Full Load
Renewable - Solar	Generic Photovoltaic - Fixed Tilt (50 MW)	Full Load
	Generic Thermal/ Concentrated (50 MW)	Full Load
Coal Fueled Boiler	Generic Circulating Fluidized Bed (With Carbon Capture)	Full Load
	Generic Circulating Fluidized Bed (Without Carbon Capture)	Full Load

Figure 1.2 - Non-CTG Generating Facilities Assessed in Study

1.3 METHOD

Sega utilized thermal engineering/costing software, budgetary quotations from original equipment manufacturers (OEMs), input from Montana-Dakota, published information, and engineering experience to develop performance and cost estimates for the supply-side resources considered. Spreadsheets were developed to list, calculate, adjust, and summarize the performance and costs for each generating option and operating condition assessed. Thermoflow Inc.'s (Thermoflow) thermal engineering software, "GT PRO", was used to perform model runs for seven CTG-related options (total of 25 operating cases) and two RICE options. Thermoflow's "Steam PRO" model was used to model the biomass boiler and provide performance and cost information. Methodologies specific to each generating facility are described in the applicable report section for that facility type.

1.4 PERFORMANCE BASIS

The following assumptions, provided by Montana-Dakota, were used in the Thermoflow models to develop some or all performance characteristics of the CTG-related, RICE, and biomass boiler generating facility options. The site-specific inputs were based on the geography and weather conditions of Bismarck, North Dakota. The temperature and humidity are an average of the previous 10 years of the Midcontinent Independent System Operator (MISO) determined summer and winter coincidence peak.

1. Elevation: 1,695 feet AMSL.
2. Relative Humidity:
 - a. Summer: 41 percent.
 - b. Winter: 70 percent.
3. Dry-Bulb Temperature:
 - a. Summer: 83.5 degrees F.
 - b. Winter: 6.8 degrees F.
4. Generation Power Factor: 0.85.
5. Generator Terminal Voltage: 13.8-kV.
6. Interconnection Voltage: 115-kV.
7. Fuel for Biomass: Loose Wheat Straw (based on an assessment of available biomass fuels in the area).

Montana-Dakota provided the natural gas quality which was input into GT PRO for the CTG and RICE runs. This information can be found in *Figure 1.3*.

Natural Gas Constituent	Mole Percent
CH ₄	89.55
C ₂ H ₆	7.50
C ₃ H ₈	0.60
C ₄ H ₁₀	0.09
C ₅ H ₁₂	0.01
C ₆ H ₁₄₊	0.00
N ₂	1.25
CO ₂	0.85
H ₂	0.13
He (No He in GT PRO - used Argon)	0.02
Total	100
Fuel Gas Temperature (as delivered)	80 degrees F
Fuel Gas Pressure (as delivered)	900 psig
Heating Value (HHV, value calculated)	1,022 MMBtu/scf, dry

Figure 1.3 - Natural Gas Quality for CTG and RICE Analyses

1.5 COST BASIS

Sega utilized thermal engineering/costing software, budgetary quotations from OEMs, input from Montana-Dakota, published information, and engineering experience to develop cost estimates for the supply-side resources considered. Major assumptions that were made throughout the cost analyses for the generation resources are explained in this section. Further explanation and additional assumptions specific to the cost analysis of each resource are described in the respective sections.

1.5.1 GT PRO and Steam PRO

The cost analysis performed for each of the seven CTG generation configurations, the two RICE options, and the biomass boiler utilized Thermoflow's preliminary Plant Engineering and Cost Estimator (PEACE) module for determining capital costs. PEACE uses information from OEMs, material suppliers, engineering firms, and contractors to determine the cost indices contained in the module. The cost indices are refreshed by Thermoflow on a routine basis to reflect current market conditions. The PEACE costs are based on site works, foundations, mechanical installation and materials, electrical installation and materials, and engineering design and startup for specific models of CTG, RICE, and biomass boilers. For example, a CTG requiring a Selective Catalytic Reduction (SCR) system will require additional material and labor for the installation of the SCR and

related equipment. The PEACE economic model was updated with regional North Dakota, union labor pricing data for the CTGs, RICE, and biomass boiler options. These costs were escalated to 2017 dollars at 3 percent per year for each cost analysis. GT PRO and Steam PRO were also used to estimate contractor’s soft costs. The soft cost categories and assumed values are shown in *Figure 1.4*.

	Category	Amount
Contractor’s Soft Costs	Contingency for Labor	25%
	Contingency for Specialized Equipment	3%
	Contingency for Other Equipment	4%
	Contingency for Commodities	6%
	Profit Margin on Labor	25%
	Profit Margin for Specialized Equipment	7%
	Profit Margin on Other Equipment	7%
	Profit Margin on Commodities	7%
	Permits, Licenses, Fee, and Miscellaneous	0%
	Bonds and Insurance	2%
	Spare Parts and Materials	0%
	Contractor’s Fee	5%
Owner’s Soft Costs	0%	Calculated Separately in the Cost Analysis Spreadsheet

Figure 1.4 - GT PRO and Steam PRO’s Soft Cost Breakdown

The equipment assumptions made in Thermoflow affect the costs estimated in each option. Segal used engineering judgement to determine the level of water quality, fuel compression, site-specific constraints, and generator options that would be appropriate for each design case. Equipment options selected are detailed in *Figure 1.5* for each generating category and briefly explained in this section.

Installation and material costs for each category were based on a greenfield site in a cold/northerly climate with packed, or somewhat rocky soil. These assumptions help to develop a conservative, but realistic basis for installation and foundation design in the colder climate of that region.

Basic plant components were included in all design cases. A continuous emissions monitoring system and distributed control system were included in all options. A standard open air cooled generator with electric motor starter was also included in all options studied.

Based on the fuel design pressure specified by Montana-Dakota, Sega assumes a fuel compressor is not required for any of the options studied. At a design pressure of 900 psig, the delivered pressure would be sufficient for both the combustion turbine and reciprocating engine plants.

A make-up water treatment system was included for each CTG and biomass option. Consumption rates are based on a 100 percent make-up system, which is conservative for the installation. Sega assumes a minimal water treatment system would be required for the simple-cycle cases without water injection or intercooling, and a system including only water filtration was specified. Conversely, high water quality is required for all combined-cycle, direct water injected simple cycle, and biomass options. Thermoflow includes the cost of a typical filtration, clarification, and reverse osmosis system for these options.

For the appropriate design cases (combined cycle and biomass), a mechanical draft cooling tower is included in the plant. The type of tower selected in this analysis was a crossflow design, constructed from fiber-reinforced polymer (FRP) material. Sega assumed a medium-fill density and single-speed fans would be sufficient for these applications.

For cases which include an evaporative cooler, Sega assumed the cooler would operate at 85 percent effectiveness based on five cycles of concentration. An estimated air pressure drop of 2 inH₂O across the evaporative cooler is assumed in the analysis.

For the simple-cycle, combined-cycle (with the exception of the Heskett 3 Expansion), RICE, and biomass options, Segal also included a dedicated fire protection system. For simplicity, a dedicated fire protection storage tank with an assumed flow capacity of 1,500 gpm for 120 minutes was included. A fire protection system was not included for the Heskett 3 Expansion since the existing facility is already equipped with a system.

For combined-cycle cases which include duct firing, Segal assumed the same gas turbine fuel would be used in the duct burner. The duct burner was sized based on an exit temperature of 1,200 degrees Fahrenheit, which is typical for these installations.

1.5.2 Total Capital Cost

Total capital cost for each generating option was calculated in the cost analysis spreadsheet by adding in the equipment, installation, engineering, and a range of other capital-related costs such as interconnect costs, land, developer's fees, and other soft costs. A list of what is included in the total capital cost for each of the generating option categories is listed in *Figure 1.5*.

Cost Item	CTGs	RICE	Biomass	Wind	Solar	Coal
Major Equipment	✓	✓	✓**	✓	✓	✓
Water Treatment System	✓*		✓			
Distributed Control System	✓	✓	✓	✓	✓	✓
Continuous Emission Monitoring System (CEMS)	✓	✓	✓			✓
Mechanical Draft Cooling Tower - Crossflow	✓*		✓			
Balance-of-Plant (BOP) / Engineering	✓	✓	✓	✓	✓	✓
Generator Step-Up Transformer	✓	✓	✓	✓	✓	✓
Fire Protection	✓	✓	✓			✓
Fuel Gas Conditioning Skid	✓	✓				
Installation	✓	✓	✓	✓	✓	✓
Transmission Interconnect and MISO Queue Fee	✓	✓	✓	✓	✓	✓
Gas Interconnect	✓	✓				
Water Interconnect	✓		✓		✓	✓
Land	✓	✓	✓	✓	✓	✓
Spare Parts and Materials	✓	✓	✓	✓	✓	✓
Developer's Fee	✓	✓	✓	✓	✓	✓
Engineering Supervision, General, and Administrative Rate	✓	✓	✓	✓	✓	✓
Permits, Licenses, Fees, and Miscellaneous	✓	✓	✓	✓	✓	✓
Legal and Financial Costs	✓	✓	✓	✓	✓	✓
Contractor's Soft Costs	✓	✓	✓	✓	✓	✓
Contingency	✓	✓	✓	✓	✓	✓
*High Quality Water and Mechanical Draft Cooling specified for water injection simple-cycle and combined-cycle cases only.						
**Includes an electrostatic precipitator for particulate control.						

Figure 1.5 - Resource-Specific Costs Included in Total Capital Cost

The transmission interconnect and the MISO queue fee costs were provided as one cost item for this analysis. Montana-Dakota provided Segra with a document that contained the transmission interconnect and MISO queue fee estimates. The costs vary with each generation configuration because the costs are based, in part, on megawatt size. The total transmission interconnect and MISO queue fee shown in the cost analysis tables for each generation configuration is the sum of three payment estimates provided by Montana-Dakota. One of the three payment costs is a transmission upgrade payment estimate based on \$50,000/MW times the net power output of the specific generation configuration. The other two payment estimates are costs for MISO studies and include a non-refundable payment cost of \$5,000 per generation option and a partially refundable payment cost that is based on megawatt size. The sum of these three payment costs is the total transmission interconnect and MISO queue fee that is provided in the cost analysis tables for each generation configuration.

Capital costs were evaluated on a Total Capital Investment - Unloaded (TCI - UL) and a Total Capital Investment - Loaded (TCI - L) basis for all of the resource options. The TCI - L costs were calculated by adding the interest during construction (IDC) to the TCI - UL for each generating option. IDC was calculated by Montana-Dakota for each option based on the generating option project development and construction schedule (by Segra) and the project cash flow (by Segra).

1.5.3 O&M Cost

Fixed O&M costs are those which can be expected to be the same each year based on the type and size of equipment at the plant and are not a function of the number of operating hours. These calculations are made up of labor costs, maintenance costs, and other expenses; such as, administration, taxes, and insurance. Variable O&M costs are those which are expected to be a function of how much the generating resources are operated in terms of the number of megawatt hours (MWhs) generated. These calculations are made up of maintenance costs and chemical/water costs. Major maintenance costs are those which are not included in the fixed or variable costs because they are considered to be large projects and not necessarily performed every year. The fixed and variable O&M costs and

the major maintenance costs for each of the generating options were calculated within the cost analysis spreadsheet developed, and were assessed differently depending on the generating option. These costs are further discussed in each of the generating option sections.

SECTION 2

COMBUSTION TURBINE GENERATOR OPTIONS

COMBUSTION TURBINE GENERATOR OPTIONS

2.1 INTRODUCTION

GT PRO was used to estimate the performance and key capital costs for the CTG options. O&M costs were calculated separately in the cost analysis spreadsheets developed for this study. The spreadsheets for the simple-cycle and combined-cycle options are provided in Appendices A-1 and A-2, respectively. Segra created GT PRO models for the following three simple-cycle and four combined-cycle CTG generation configurations:

1. Simple-Cycle CTGs:
 - a. GE 7EA.
 - b. GE LMS100PB.
 - c. GE LM6000PH.
2. Combined-Cycle CTGs:
 - a. 1x1 GE LM6000PH with SPRINT.
 - b. 1x1 GE 7FA.05.
 - c. 2x1 GE 7EA (expansion of R.M. Heskett Station Unit 3 simple-cycle GE 7EA).
 - d. 2x1 Siemens SGT-800.

The natural gas quality and site conditions specified by Montana-Dakota (see *Figure 1.3* and *Section 1.4*) were utilized for each of the CTG options. The GT PRO performance and cost output values differed between runs depending on the generating facility type, combustion turbine configuration, and operating condition being analyzed. Details of the performance and cost estimations are explained in the following sections for each option.

2.2 SIMPLE-CYCLE CTG PERFORMANCE ANALYSIS

2.2.1 Introduction

The following three operating cases for each of the three simple-cycle CTG configurations were run through GT PRO for a total of nine runs:

Case 1. Summer - Evaporative cooler on.

Case 2. Summer - Evaporative cooler off.

Case 3. Winter - Evaporative cooler off.

Figure 2.1 summarizes the GT PRO performance related inputs and assumptions made for the runs, including key performance information and model descriptions for the three simple-cycle CTG configurations assessed.

Configuration	GT PRO Inputs	Assumptions
GE 7EA	<ul style="list-style-type: none"> Thermoflow model name: GE GT-7E.03 GT PRO model revision: April 14, 2014 PEACE update: May 2015 Dry low NO_x combustor 	<ul style="list-style-type: none"> No SCR No OxCat Low quality produced water (filtration only) Evaporative cooler effectiveness - 85%
GE LMS100PB	<ul style="list-style-type: none"> Thermoflow model name: GE LMS100PB Wet IC GT PRO model revision: December 1, 2011 PEACE update: August 2016 Dry low NO_x combustor Intercooler with wet cooling 	<ul style="list-style-type: none"> SCR (90% reduction) OxCat (80% reduction) Winter case operated at 10°F due to model constraints High quality produced water (RO quality) Evaporative cooler effectiveness - 85%
GE LM6000PH	<ul style="list-style-type: none"> Thermoflow model name: GE LM6000PH GT PRO model revision: December 4, 2009 PEACE update: August 2016 Dry low NO_x combustor 	<ul style="list-style-type: none"> SCR (80% reduction) OxCat (80% reduction) No water injection No Spray Inter-Cooled Turbine (SPRINT) Evaporative cooler effectiveness - 85%

Figure 2.1 - Simple-Cycle CTG GT PRO Inputs / Assumptions Related to Performance

2.2.2 GE 7EA

The GE 7EA CTG utilizes dry low NO_x (DLN) technology to minimize NO_x emissions to less than 9 parts per million by dry volume (ppmvd) at 15 percent O₂. The NO_x emissions are very low, which would result in a relatively high cost to add SCR emission control technology. Therefore, Sega has assumed the SCR would not be needed by the permitting process. Similarly, Sega assumed that an oxidation catalyst (OxCat) for CO emission reduction would not be required based on the relatively low CO emissions and high emission reduction cost effectiveness for adding an OxCat to this simple-cycle CTG.

GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various consumables for each operating case. The NO_x and CO emissions information are based on typical OEM guarantees. PM emissions and carbon intensity were calculated based on factors published by the United States Environmental Protection Agency (EPA). *Figure 2.2* lists the results of the performance analysis for each of the GE 7EA cases.

	Operating Case 1	Operating Case 2	Operating Case 3
Season	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	Off	Off
Gross Plant Output (MW)	79.42	75.23	96.42
Net Plant Output (MW)	78.43	74.28	95.35
Net Full Load Heat Rate (Btu/kWh, HHV)	11,498	11,638	11,074
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	0	0	0
Water Consumption (Gal/hr)	1,060	0	0
Fuel Consumption (MMBtu/hr, HHV)	902	864	1,056
Carbon Intensity (lb/MWh, net)	1,345	1,361	1,295
NO _x Emissions (ppmvd @ 15% O ₂)	9	9	9
CO Emissions (ppmvd @ 15% O ₂)	5	5	5
PM Emissions (lb/hr)	9.0	8.6	10.6

Figure 2.2 - GE 7EA Simple-Cycle Performance Analysis Results

2.2.3 GE LMS100PB

The GE LMS100PB utilizes DLN technology to maintain NO_X emissions to an emission level of 25 ppmvd at 15 percent O₂. Segal concluded that with this NO_X emission level the use of SCR would be required in the permitting process. The SCR NO_X reduction was set to 90 percent. Segal assumed that an OxCat for CO emission reduction would also be required for this CTG because of the relatively high uncontrolled emission level. OxCat pollution reduction was set to 80 percent.

As with the GE 7EA, GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various consumables for each operating case. The NO_X and CO uncontrolled emissions information are based on typical OEM guarantees and emission reduction levels were estimated by Segal for anticipated permitting requirements. As with the GE 7EA, PM emissions and carbon intensity were calculated based on factors published by the EPA. *Figure 2.3* lists the results of the performance analysis for each of the GE LMS100PB cases.

	Operating Case 1	Operating Case 2	Operating Case 3
Season	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	Off	Off
Gross Plant Output (MW)	92.12	89.12	96.63
Net Plant Output (MW)	90.46	87.51	94.97
Net Full Load Heat Rate (Btu/kWh, HHV)	8,832	9,079	8,825
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	20.0	19.6	20.7
Water Consumption (Gal/hr)	15,427	14,957	10,291
Fuel Consumption (MMBtu/hr, HHV)	814	795	838
Carbon Intensity (lb/MWh, net)	1,052	1,062	1,032
NOx Uncontrolled Emissions (ppmvd @ 15% O ₂)	25	25	25
NOx Controlled Emissions (ppmvd @ 15% O ₂)	2.5	2.5	2.5
CO Uncontrolled Emissions (ppmvd @ 15% O ₂)	200	200	200
CO Controlled Emissions (ppmvd @ 15% O ₂)	40	40	40
PM Emissions (lb/hr)	8.1	7.9	8.4

Figure 2.3 - GE LMS100PB Simple-Cycle Performance Analysis Results

2.2.4 GE LM6000PH

The GE LM6000PH utilizes DLN to maintain NO_x emissions to a level of 15 ppmdv at 15 percent O₂. Sega concluded that this uncontrolled NO_x emission level would be high enough to require the use of SCR in the permitting process. The SCR NO_x reduction was set to 80 percent. Sega assumed that an OxCat for CO emission reduction would be required for this CTG because of the relatively high uncontrolled emission level. Emission reduction rate of the OxCat was set to 80 percent. The LM6000PH power augmentation option of Spray Inter-Cooled Turbine (SPRINT) was not included in this simple-cycle configuration. SPRINT would have required the addition of high quality water treatment equipment and water interconnect capital costs.

As with the other simple-cycle CTG options, GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various consumables for each operating case. The NO_x and CO uncontrolled emissions are based on typical OEM guarantees and emission reduction levels were estimated by Segal for anticipated permitting requirements. PM emissions and carbon intensity were calculated based on factors published by the EPA. *Figure 2.4* lists the results of the performance analysis for each of the GE LM6000PH cases.

	Operating Case 1	Operating Case 2	Operating Case 3
Season	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	Off	Off
Gross Plant Output (MW)	41.99	38.15	51.04
Net Plant Output (MW)	41.28	37.48	50.30
Net Full Load Heat Rate (Btu/kWh, HHV)	9,637	9,921	9,253
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	6.3	5.9	7.3
Water Consumption (Gal/hr)	507	0	0
Fuel Consumption (MMBtu/hr, HHV)	398	372	465
Carbon Intensity (lb/MWh, net)	1,127	1,160	1,082
NO _x Uncontrolled Emissions (ppmvd @ 15% O ₂)	15	15	15
NO _x Controlled Emissions (ppmvd @ 15% O ₂)	3	3	3
CO Uncontrolled Emissions (ppmvd @ 15% O ₂)	100	100	100
CO Controlled Emissions (ppmvd @ 15% O ₂)	20	20	20
PM Emissions (lb/hr)	4.0	3.7	4.7

Figure 2.4 - GE LM6000PH Simple-Cycle Performance Analysis Results

2.3 COMBINED-CYCLE CTG PERFORMANCE ANALYSIS

2.3.1 Introduction

The following four operating cases for each of the four combined-cycle CTG configurations were run through GT PRO for a total of 16 runs:

Case 1. Summer - Evaporative cooler on, duct burner off.

Case 2. Summer - Evaporative cooler on, duct burner on.

Case 3. Summer - Evaporative cooler off, duct burner off.

Case 4. Winter - Evaporative cooler off, duct burner off.

Figure 2.5 summarizes the GT PRO performance related inputs and assumptions made for the runs. This includes key performance information and model descriptions for the four combined-cycle CTG configurations assessed.

Configuration	GT PRO Inputs	Assumptions
1x1 GE LM6000PH with SPRINT	<ul style="list-style-type: none"> Thermoflow model name: GE LM6000PH SPRINT GT PRO model revision: December 4, 2009 PEACE update: May 2015 Dry low NO_x combustor HRSG: Single pressure STG: No reheat, condensing turbine 	<ul style="list-style-type: none"> SCR (80% reduction) OxCat (80% reduction) High quality produced water (RO quality) Mechanical draft cooling tower - crossflow, FRP construction, single speed fans Evaporative cooler effectiveness - 85% Duct burner exit temperature - 1,200°F
1x1 GE 7FA.05	<ul style="list-style-type: none"> Thermoflow model name: GE GT-7F.05 GT PRO model revision: July 10, 2014 PEACE update: May 2015 Dry low NO_x combustor HRSG: Triple pressure, reheat before IP STG: Condensing turbine 	<ul style="list-style-type: none"> SCR (80% reduction) OxCat (80% reduction) High quality produced water (RO quality) Mechanical draft cooling tower - crossflow, FRP construction, single-speed fans Evaporative cooler effectiveness - 85% Duct burner exit temperature - 1,200°F
2x1 GE 7EA Heskett 3 Expansion	<ul style="list-style-type: none"> Thermoflow model name: GE GT-7E.03 GT PRO model revision: April 14, 2014 PEACE update: May 2015 Dry low NO_x combustor HRSG: Double pressure, no reheat STG: Condensing turbine No fire protection Includes existing water treatment 	<ul style="list-style-type: none"> SCR (80% reduction) OxCat (80% reduction) High quality produced water (RO quality) Mechanical draft cooling tower - crossflow, FRP construction, single-speed fans Evaporative cooler effectiveness - 85% Duct burner exit temperature - 1,200°F
2x1 Siemens SGT-800	<ul style="list-style-type: none"> Thermoflow model name: Siemens SGT-800-50 GT PRO model revision: May 20, 2015 PEACE update: May 2015 3rd generation DLE combustor HRSG: Single pressure, no reheat STG: Condensing non-reheat ST 	<ul style="list-style-type: none"> SCR (80% reduction) OxCat (80% reduction) High quality produced water (RO quality) Mechanical draft cooling tower - crossflow, FRP construction, single speed fans Evaporative cooler effectiveness - 85% Duct burner exit temperature - 1,200°F

Figure 2.5 - Combined-Cycle CTG GT PRO Inputs / Assumptions Related to Performance

2.3.2 1x1 GE LM6000PH with SPRINT

The combined-cycle 1x1 GE LM6000PH with SPRINT CTG configuration is similar to the simple-cycle CTG configuration except that it includes SPRINT and a 1x1 single-pressure combined-cycle plant with a condensing turbine. SPRINT was included in this case because the demineralized water, which is required for injection, will already be available as part of the steam generation system equipment. As with the simple-cycle case, a SCR system was assumed with a NO_x reduction of 80 percent resulting in an outlet NO_x level of approximately 3 ppmvd at 15 percent O₂. Sega assumed that an OxCat would be required for CO reduction because of the relatively high uncontrolled emission level and based on the relatively low emission reduction cost effectiveness of installing an OxCat in a HRSG. The OxCat was assumed at 80 percent CO reduction.

As with the simple-cycle options, GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various consumables for each operating case. The NO_x and CO uncontrolled emissions information are based on typical OEM guarantees and emission reduction levels were estimated by Sega for anticipated permitting requirements. PM emissions and carbon intensity were calculated based on factors published by the EPA. *Figure 2.6* lists the results of the performance analysis for each of the 1x1 GE LM6000PH with SPRINT cases.

	Operating Case 1	Operating Case 2	Operating Case 3	Operating Case 4
Season	Summer	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	On	Off	Off
Duct Burner (On/Off)	Off	On	Off	Off
Gross Plant Output (MW)	56.89	67.57	52.86	62.89
Net Plant Output (MW)	55.78	66.14	51.79	61.82
Net Full Load Heat Rate (Btu/kWh, HHV)	7,542	7,834	7,639	7,358
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	6.6	6.6	6.2	7.1
Water Consumption (Gal/hr)	13,891	23,892	12,911	8,003
Fuel Consumption (MMBtu/hr, HHV)	421	518	396	455
Carbon Intensity (lb/MWh, net)	882	916	893	860
NOx Uncontrolled Emissions (ppmvd @ 15% O ₂)	15	15	15	15
NOx Controlled Emissions (ppmvd @ 15% O ₂)	3	2.4	3	3
CO Uncontrolled Emissions (ppmvd @ 15% O ₂)	100	100	100	100
CO Controlled Emissions (ppmvd @ 15% O ₂)	20	16.2	20	20
PM Emissions (lb/hr)	4.2	5.2	4.0	4.5

Figure 2.6 - 1x1 GE LM6000PH with SPRINT Combined-Cycle Performance Analysis Results

2.3.3 1x1 GE 7FA.05

The combined-cycle 1x1 GE 7FA.05 configuration was modeled with a triple pressure HRSG with reheat and a condensing steam turbine. The GE 7FA.05 CTG utilizes DLN technology to maintain NO_x emissions to an emission level of the 9 ppmvd at 15 percent O₂. As with the 1x1 GE LM6000, Segra assumed SCR and an OxCat would be required for NO_x and CO reduction, respectively, for the permitting process. The GE 7FA.05 was modeled with a SCR NO_x reduction of 80 percent, resulting in an outlet NO_x level of approximately 2 ppmvd at 15 percent O₂. The OxCat was also set to 80 percent reduction.

GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various consumables for each operating case. The NO_x and CO uncontrolled emissions are based on typical OEM guarantees and emission reduction levels were estimated by Segra for anticipated permitting requirements. PM emissions and carbon intensity were calculated based on factors published by the EPA. *Figure 2.7* lists the results of the performance analysis for the 1x1 GE 7FA.05 cases.

	Operating Case 1	Operating Case 2	Operating Case 3	Operating Case 4
Season	Summer	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	On	Off	Off
Duct Burner (On/Off)	Off	On	Off	Off
Gross Plant Output (MW)	302.85	330.29	297.04	334.82
Net Plant Output (MW)	296.61	322.96	290.86	328.79
Net Full Load Heat Rate (Btu/kWh, HHV)	6,762	6,859	6,760	6,681
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	21.1	21.1	20.8	22.6
Water Consumption (Gal/hr)	77,871	93,453	75,799	48,216
Fuel Consumption (MMBtu/hr, HHV)	2,006	2,215	1,966	2,197
Carbon Intensity (lb/MWh, net)	791	802	791	781
NOx Uncontrolled Emissions (ppmvd @ 15% O ₂)	9	9	9	9
NOx Controlled Emissions (ppmvd @ 15% O ₂)	1.8	1.6	1.8	1.8
CO Uncontrolled Emissions (ppmvd @ 15% O ₂)	5	5	5	5
CO Controlled Emissions (ppmvd @ 15% O ₂)	1	0.9	1	1
PM Emissions (lb/hr)	20.1	22.2	19.7	22.0

Figure 2.7 - 1x1 GE 7FA.05 Combined-Cycle Performance Analysis Results

2.3.4 2x1 GE 7EA (Heskett 3 Expansion)

The 2x1 GE 7EA (Heskett 3 Expansion) combined-cycle is a unique case that incorporates the existing simple-cycle GE 7EA located at the R.M Heskett station into a new 2x1 combined-cycle arrangement. This was modeled to include the output (in MW) of the existing GE 7EA in the total plant output, and was also factored into the \$/kW cost calculations. The 2x1 GE 7EA (Heskett 3 Expansion) was modeled with double pressure HRSGs, no reheat, and a condensing turbine. Segal assumed SCR and an OxCat would be required for NO_x and CO reduction, respectively, for permitting purposes. The 2x1 GE 7EA (Heskett 3 Expansion) was modeled with the NO_x reduction set to 80 percent (outlet NO_x level of approximately 2 ppmvd at 15 percent O₂), and the OxCat was also set to 80 percent reduction.

GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various plant consumables for each operating case. The NO_x and CO uncontrolled emissions are based on typical OEM guarantees and emission reduction levels were estimated by Segal for anticipated permitting requirements. PM emissions and carbon intensity were calculated based on factors published by the EPA. *Figure 2.8* lists the results of the performance analysis for the 2x1 GE 7EA (Heskett 3 Expansion) cases.

	Operating Case 1	Operating Case 2	Operating Case 3	Operating Case 4
Season	Summer	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	On	Off	Off
Duct Burner (On/Off)	Off	On	Off	Off
Gross Plant Output (MW)	243.89	271.65	233.83	285.54
Net Plant Output (MW)	238.40	265.06	228.49	280.18
Net Full Load Heat Rate (Btu/kWh, HHV)	7,583	7,694	7,574	7,566
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	20.5	20.5	19.7	23.8
Water Consumption (Gal/hr)	75,799	94,748	72,000	50,029
Fuel Consumption (MMBtu/hr, HHV)	1,808	2,040	1,731	2,120
Carbon Intensity (lb/MWh, net)	887	900	886	885
NOx Uncontrolled Emissions (ppmvd @ 15% O ₂)	9	9	9	9
NOx Controlled Emissions (ppmvd @ 15% O ₂)	1.8	1.6	1.8	1.8
CO Uncontrolled Emissions (ppmvd @ 15% O ₂)	5	5	5	5
CO Controlled Emissions (ppmvd @ 15% O ₂)	1	0.9	1	1
PM Emissions (lb/hr)	18.1	20.4	17.3	21.2

Figure 2.8 - 2x1 GE 7EA (Heskett 3 Expansion) Combined-Cycle Performance Analysis Results

2.3.5 2x1 Siemens SGT-800

The combined-cycle 2x1 SGT-800 configuration was modeled with single pressure, no reheat HRSGs, and a condensing turbine. The Siemens SGT-800 CTG utilizes DLN technology to maintain NO_x emissions to an uncontrolled emission level of 25 ppmvd at 15 percent O₂. As with the other combined-cycle options, Sega assumed SCR would be necessary for NO_x reduction. The 2x1 Siemens SGT-800 was modeled with 90 percent NO_x reduction (outlet NO_x level of approximately 2.5 ppmvd at 15 percent O₂). It was also determined that an OxCat would be required for CO reduction. The 2x1 Siemens SGT-800 was modeled with the OxCat set to 80 percent reduction.

GT PRO calculated the gross plant output, net plant output, net full load heat rate, and various plant consumables for each operating case. The NO_x and CO uncontrolled emissions are based on typical OEM guarantees and emission reduction levels were estimated by Sega for anticipated permitting requirements. PM emissions and carbon intensity were calculated based on factors published by the EPA. *Figure 2.9* lists the results of the performance analysis for each of the 2x1 Siemens SGT-800 cases.

	Operating Case 1	Operating Case 2	Operating Case 3	Operating Case 4
Season	Summer	Summer	Summer	Winter
Evaporative Cooling (On/Off)	On	On	Off	Off
Duct Burner (On/Off)	Off	On	Off	Off
Gross Plant Output (MW)	129.99	142.78	124.58	148.09
Net Plant Output (MW)	127.44	139.81	122.08	145.56
Net Full Load Heat Rate (Btu/kWh, HHV)	7,318	7,415	7,324	7,291
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	23.1	23.1	22.2	26.2
Water Consumption (Gal/hr)	32,413	43,010	30,911	20,167
Fuel Consumption (MMBtu/hr, HHV)	933	1,037	894	1,061
Carbon Intensity (lb/MWh, net)	856	867	857	853
NOx Uncontrolled Emissions (ppmvd @ 15% O ₂)	25	25	25	25
NOx Controlled Emissions (ppmvd @ 15% O ₂)	2.5	2.2	2.5	2.5
CO Uncontrolled Emissions (ppmvd @ 15% O ₂)	10	10	10	10
CO Controlled Emissions (ppmvd @ 15% O ₂)	2	1.8	2	2
PM Emissions (lb/hr)	9.3	10.4	8.9	10.6

Figure 2.9 - 2x1 Siemens SGT-800 Combined-Cycle Performance Analysis Results

2.4 CTG COST ANALYSIS

2.4.1 Introduction

This section describes, for each CTG generation option, the process used to develop each option's capital costs, fixed O&M, major maintenance, and variable O&M. A complete listing of the cost analysis tables is provided in Appendices A-1 and A-2 for reference through the following sections.

2.4.2 Total Capital Investment

Equipment, installation, SCR, OxCat, evaporative cooler, duct burner, generator step-up transformer, fire protection, Balance of Plant (BOP), and engineering costs are included in the Contractor's Internal Cost (CIC) determined by GT PRO. The general approach, assumptions, and basis of the GT PRO modeling is described in Section 1.5.1. This section describes the process specific to the CTG options. GT PRO calculated the CIC in 2015 dollars for all of the simple-cycle and combined-cycle CTGs, except for the simple-cycle GE LMS100PB and the simple-cycle GE LM6000PH which were calculated in 2016 dollars. The CIC amount for each option was escalated to 2017 dollars based on a 3 percent escalation rate each year. *Figure 2.10* details the multipliers and/or rate/basis for each of the items included in the TCI - UL. The multipliers and rate/basis for each category were provided by either GT PRO or Segal, in consultation with Montana-Dakota. The rate/basis shown for each cost category was multiplied by the appropriate values in order to obtain a dollar amount for each CTG option. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. Appendices A-1 and A-2 display the complete results of cost analysis for the TCI - UL costs for each of the simple-cycle and combined-cycle CTG options, respectively.

	2017\$ or Multiplier	Rate / Basis
Contractor's Internal Cost (CIC)/Major Equipment	--	\$
Installation	--	\$ (Included in CIC)
BOP/Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fuel Gas Conditioning Skid	515,917	Escalated Cost of Heskett 3 (\$515,917)*(Fuel Consumption Option/Fuel Consumption GE7EA SC)^0.6
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	4,000	\$/Dkt/hr Consumed
Water Interconnect	20	\$/Gallon/hr Consumed
Land	1%	% of CIC
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	2%	% of CIC
Legal and Financial Costs	2%	% of CIC
Contractor's Soft Costs	--	Escalated 2015\$
Contingency	20%	% of TCI - UL before Contingency

Figure 2.10 - Costs Included in TCI - UL for Simple-Cycle and Combined-Cycle CTG Options

Figure 2.11 summarizes the resulting TCI - UL for each simple-cycle and combined-cycle CTG option, as well as the calculated \$/kW value for each operating case modeled. An IDC cost was calculated by Montana-Dakota based on the TCI - UL cash flow over the plant construction period. The project schedules and cash flow diagrams are located in Appendices B and C, respectively. The TCI - L cost was calculated for each CTG option by adding the IDC to the TCI - UL cost. The IDC and TCI - L cost are also listed for each CTG option in Figure 2.11.

CTG Generation Option	TCI - UL (\$)	TCI - UL (\$/kW)				IDC (\$)	TCI - L (\$)
		Case 1	Case 2	Case 3	Case 4		
GE 7EA	90,221,511	1,150	1,215	946	--	1,018,527	91,240,038
GE LMS100PB	118,678,444	1,312	1,356	1,250	--	1,352,836	120,031,280
GE LM6000PH	63,119,959	1,529	1,684	1,255	--	711,258	63,831,217
1x1 GE LM6000PH with SPRINT	117,356,552	2,104	1,774	2,266	1,898	2,512,778	119,869,330
1x1 GE 7FA.05	338,863,114	1,142	1,049	1,165	1,031	7,097,945	345,961,059
2x1 GE 7EA (Heskett 3 Expansion)	260,106,490	1,091	981	1,138	928	5,399,636	265,506,126
2x1 Siemens SGT-800	207,038,044	1,625	1,481	1,696	1,422	4,394,329	211,432,373

Figure 2.11 - Simple-Cycle and Combined-Cycle CTG TCI - UL and TCI - L Costs (2017\$)

2.4.3 Fixed O&M

2.4.3.1 *Introduction*

The fixed O&M costs for the CTG generation options are broken into three major categories; labor, maintenance, and other expenses. This section describes the methods and assumptions for calculating the costs for each category. Appendices A-1 and A-2 display the complete build-up of fixed O&M for the simple-cycle and combined-cycle generation options, respectively.

2.4.3.2 Labor Fixed O&M Costs

The annual fixed labor cost is the cost of the number of full-time equivalent (FTE) operating staff required at the plant to perform the duties necessary to run the plant. *Figure 2.12* shows cost assumptions that were provided by Montana-Dakota for the fixed O&M calculations.

	Value	Units
Labor Rate	70.14	\$/hr
FTE Hours	2,080	hr/yr
FTE Cost	145,891	\$/yr

Figure 2.12 – Labor Cost (2017\$) Provided by Montana-Dakota for Fixed O&M for CTG Options

Figure 2.13 lists the subcategories included in the labor costs for the fixed O&M costs for various CTG options. The number of FTE for each category was provided by Segal, in consultation with Montana-Dakota, and are based on actual experience, engineering estimate, or as a result of research. The number of FTE shown for a labor cost category was multiplied by the FTE labor cost and then divided by the net plant output to determine a \$/kW-month value for each operating case.

	FTE
Site Management (CTG)	1
Site Management (HRSG, STG)	2
O&M (CTG)	2.25
Technical Services (CTG)	0.75
O&M (HRSG, STG)	6
Technical Services (HRSG, STG)	3
SCR O&M	0.25
Water Treatment O&M	1
Water Injection O&M (LM6000 with SPRINT Options Only)	0.5
Intercooling O&M (LMS100PB Options Only)	0.9
Aeroderivative & Aero-hybrid O&M	0.2
Aeroderivative & Aero-hybrid Technical Services	0.1
Multi-unit O&M (CTG)	1

Figure 2.13 - Basis for Labor Portion of Fixed O&M for CTG Options

Some of the subcategories may not apply to certain types of CTGs or in certain operating cases. Therefore, it should be noted that not every item that is listed in *Figure 2.13* will be applicable to each simple-cycle and combined-cycle CTG option. For example, Technical Service (HRSG, STG) applies to the combined-cycle options because of the steam cycle equipment, but not simple-cycle options because there is no steam. Technical Services (CTG) applies to both simple-cycle and combined-cycle options because each has CTG technical service requirements. Similarly, SCR O&M is applied to only operating cases with SCR installed. The cost analysis tables in Appendices A-1 and A-2 show how these labor categories are applied to all CTG options assessed.

2.4.3.3 Maintenance Fixed O&M Costs

The annual fixed maintenance cost is the cost to perform regular maintenance of the equipment at the plant, including regular contracted services, and is not a function of the number of operating hours. *Figure 2.14* lists the various subcategories included in the maintenance costs for the fixed O&M costs for the CTG options. The maintenance rate for each category was provided by either GT PRO or Sega, in consultation with Montana-Dakota, and are based on actual experience, engineering estimate, or as a result of research. The maintenance rate was provided as a \$/MW-year value and converted to the required units of measure, \$/kW-month, for each operating case for each CTG option. The one exception is that the SCR maintenance cost item was provided by GT PRO as a percent of the capital cost of only the SCR. The percent provided by GT PRO was multiplied by the capital cost of the SCR and then divided by the net plant output.

	2017 \$/MW-year
I&C and Electric Plant (CTG)	246
Contracted Services (CTG)	308
Steam Cycle Maintenance	5,632
SCR Maintenance	1.5% of SCR \$
Water Treatment	1,856
Water Injection (Water) (LM6000 with SPRINT Options Only)	30.8
Water Injection (Wastewater Treatment) (LM6000 with SPRINT Options Only)	24.4
Intercooling (Heat Rejection) (LMS100PB Options Only)	123.1
Intercooling (I&C) (LMS100PB Options Only)	61.5
Aeroderivative & Aero-hybrid (CTG)	123.1
Aeroderivative & Aero-hybrid (I&C)	61.5
Mult-unit (CTG)	123.1

Figure 2.14 - Basis for Maintenance Costs of Fixed O&M for CTG Options

It should be noted that, like with the labor costs, not every item that is listed in *Figure 2.14* will be applicable to each simple-cycle and combined-cycle CTG option. This is clarified in the applicable spreadsheets in Appendices A-1 and A-2.

2.4.3.4 *Other Expenses Fixed O&M Costs*

The annual fixed cost for other expenses is the cost associated with administration, property tax, and insurance. As shown in *Figure 2.15*, the administration cost was provided as a fixed rate in \$/MW-year by Segal, in consultation with Montana-Dakota, and are based on actual experience. This rate was converted to the required units of measure, \$/kW-month. The administration cost will be the same for all CTG and operating cases, because it is based on a flat \$/MW-year value. The property tax and insurance were provided by Montana-Dakota as a percent of the TCI - L. The percent values for the property tax and insurance were multiplied by the TCI - L, in \$/kW, for each operating case for each CTG option and divided by the number of months of operation to obtain the required units of measure. Appendices A-1 and A-2 show the calculation of this subcategory of fixed O&M costs.

	2017\$ or Multiplier	Rate / Basis
Administration	492.3	\$/MW-year
Property Taxes, per year	0.389	% of TCI - L
Insurance, per year	0.14	% of TCI - L
Aeroderivative and Aero-hybrid Insurance, per year	0.11	% of TCI - L

Figure 2.15 - Basis for Other Expenses of Fixed O&M for CTGs

2.4.4 Major Maintenance

The major maintenance for CTGs includes the overhaul of the turbines (both CTG and STG). *Figure 2.16* lists these major maintenance items that are included in the cost analysis for the CTG options. The combustion turbine overhaul category applies to all of the CTG options, whereas the steam turbine overhaul cost is applied only to the combined-cycle CTGs. The rate for the combustion turbine overhaul category was provided by Sega, in consultation with Montana-Dakota, and the rate for the steam turbine overhaul category was provided by Sega based on actual experience or engineering estimates. Both rates were converted to the required units of measure, \$/kW-month, for each CTG option. Appendices A-1 and A-2 show the calculations for the major maintenance costs.

	2017\$ or Multiplier	Rate / Basis
Combustion Turbine Overhaul	430.7	\$/MW-year
Steam Turbine Overhaul	4,711	\$/MW-year

Figure 2.16 - Basis for Major Maintenance Cost for CTG Options

2.4.5 Variable O&M

2.4.5.1 *Introduction*

The variable O&M costs for the CTGs are broken down into two major categories; maintenance and chemicals. This section describes the methods and assumptions for calculating the cost for each category. Appendices A-1 and A-2 display the complete build-up of variable O&M for the simple-cycle and combined-cycle generation options, respectively.

2.4.5.2 *Maintenance Variable O&M Costs*

Figure 2.17 lists the various subcategories included in the maintenance costs for the variable O&M costs for the CTG options. The maintenance cost (in units of \$/MWh) is the cost to perform the particular maintenance activities which are needed after operating for a certain number of MWhs. The cost rate for each category was provided by Sega, in consultation with Montana-Dakota, and are based on actual experience, engineering

estimates, or as a result of research. The rate was provided in the required units of measure, therefore, no further calculations were necessary to determine a \$/MWh value for each CTG option.

	2017\$ or Multiplier	Rate / Basis
Combustion Turbine Generator	2.40	\$/MWh
SCR Catalyst Replacement	0.202	\$/MWh
Aeroderivative and Aeroybrid (CTG)	1.23	\$/MWh
Multi-Unit (CTG)	0.615	\$/MWh

Figure 2.17 - Basis for Maintenance Portion of Variable O&M for CTG Options

It should be noted that not every item that is listed in *Figure 2.17* will be applicable to every simple-cycle and combined-cycle CTG option. For example, the SCR catalyst replacement cost does not apply to the CTG options which do not have SCR (e.g., GE 7EA simple-cycle). This is clarified in Appendices A-1 and A-2.

2.4.5.3 Chemicals / Water Variable O&M Costs

Figure 2.18 lists the various subcategories included in the chemicals/water costs for the variable O&M costs for the CTG options. The chemicals/water cost is the cost of chemicals and water to operate the plant. The rates for the “All Models”, “Water Treatment”, and “Intercooling Heat Rejection Equipment” categories were provided by Sega, in consultation with Montana-Dakota. The rates were provided in the required units of measure (\$/MWh), therefore, no further calculations were necessary to determine a \$/MWh value for each CTG option. The rates for the “SCR Ammonia Consumption” and “Water Consumption” were provided by Sega, in consultation with Montana-Dakota, in units of \$/gal and \$/1,000 gal, respectively. In order to obtain the required unit of measure (\$/MWh) for “SCR Ammonia Consumption” the rate was multiplied by the ammonia consumption that was provided by GT PRO for each operating case and then divided by the net plant output for that operating case. For “Water Consumption”, the rate was multiplied by the water consumption that was provided by GT PRO for each case and then divided by the net plant output for that case.

	2017\$ or Multiplier	Rate / Basis
All Models	0.024	\$/MWh
SCR Ammonia Consumption (19% Aqueous Solution)	1.49	\$/gal
Water Consumption	1.1	\$/1,000 gal
Water Treatment	0.25	\$/MWh
Intercooling Heat Rejection Equipment (LMS100PB Option Only)	0.0615	\$/MWh

Figure 2.18 - Costs Included in Chemicals Costs of Variable O&M for CTGs

As with the maintenance variable O&M category, not every subcategory that is listed in *Figure 2.18* will be applicable to every operating case or each single-cycle and combined-cycle CTG option. Appendices A-1 and A-2 show the calculations of this subcategory of variable O&M costs.

SECTION 3

RECIPROCATING INTERNAL COMBUSTION ENGINE OPTIONS

RECIPROCATING INTERNAL COMBUSTION ENGINE OPTIONS

3.1 INTRODUCTION

GT PRO runs were performed and the OEM, Wartsila, was contacted to gather necessary information to develop performance and cost input for the IRP for the following RICE generation configurations:

1. 4 x Wartsila 20V34SG.
2. 3 x Wartsila 18V50SG.

The same natural gas quality that was specified by Montana-Dakota (see *Figure 1.3*) for the CTGs was assumed for each RICE option. The site-specific assumptions listed in Section 1.4 and the information described in the following sections were modeled in GT PRO. Unlike the CTG generation options, only one operating condition was modeled for the RICE since performance, emissions, and cost are not as directly impacted by ambient temperature as they are for CTGs.

3.2 RICE PERFORMANCE ANALYSIS

3.2.1 Introduction

The performance analysis information was provided by Wartsila. Wartsila provided the gross plant output, net plant output, net full load heat rate, and fuel consumption for both of the RICE configurations assessed. The RICE were assumed to meet federal regulations, such as the New Source Performance Standards (NSPS) and the National Emission Standards for Hazardous Air Pollutants (NESHAPs). *Figure 3.1* summarizes the GT PRO performance related inputs and assumptions made for the runs, including key performance information and model descriptions for the RICE options assessed. Complete details of the performance related information are provided in Appendix A-3.

Configuration	GT PRO Inputs	Assumptions
4 x Wartsila 20V34SG	<ul style="list-style-type: none"> PEACE Update: May 2015 	<ul style="list-style-type: none"> Natural gas 4 Engines SCR OxCat
3 x Wartsila 18V50SG	<ul style="list-style-type: none"> PEACE Update: May 2015 	<ul style="list-style-type: none"> Natural gas 3 Engines SCR OxCat

**Figure 3.1 - RICE GT PRO Inputs / Assumptions
Related to Performance**

3.2.2 4 x Wartsila 20V34SG

Sega requested performance information from Wartsila for a four engine Wartsila 20V34SG model facility. Because the RICE was assumed to meet NSPS and NESHAP emission standards it was assumed and quoted to have both SCR and an OxCat installed as part of the base package. The NO_x, CO, and PM emissions, provided by Wartsila, are the controlled emissions due to the SCR and OxCat installed on the RICE. The carbon intensity was calculated based on emission factors published by the EPA. *Figure 3.2* lists the results of the performance analysis for the 4 x Wartsila 20V34SG configuration.

	4 x Wartsila 20V34SG
Season	Summer (assumed similar for Winter)
Gross Plant Output (MW)	37.5
Net Plant Output (MW)	36.5
Net Full Load Heat Rate (Btu/kWh, HHV)	8,447
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	2.48
Fuel Consumption (MMBtu/hr, HHV)	82.68
Carbon Intensity (lb/MWh, net)	987.9
NO _x Emissions (ppmvd @ 15% O ₂)	5
CO Emissions (ppmvd @ 15% O ₂)	15
PM Emissions (lb/hr)	8.4

Figure 3.2 - 4 x Wartsila 20V34SG Facility Performance Analysis Results

3.2.3 3 x Wartsila 18V50SG

Sega requested performance information from Wartsila for a three engine Wartsila 18V50SG model configuration. The Wartsila 18V50SG model RICE was assumed to meet NSPS and NESHAPs, and therefore, the RICE were assumed and quoted to have both SCR and an OxCat installed as part of the base package. The NO_x, CO, and PM emissions, provided by Wartsila, are the controlled emissions due to the SCR and OxCat installed on the RICE. The carbon intensity was calculated based on emission factors published by the EPA. *Figure 3.3* lists the results of the performance analysis for the 3 x Wartsila 18V50SG configuration.

	3 x Wartsila 18V50SG
Season	Summer (assumed similar for Winter)
Gross Plant Output (MW)	56.5
Net Plant Output (MW)	55.3
Net Full Load Heat Rate (Btu/kWh, HHV)	8,288
Aqueous Ammonia Consumption (Gal/hr, 19% Solution)	3.70
Fuel Consumption (MMBtu/hr, HHV)	125.2
Carbon Intensity (lb/MWh, net)	969.2
NOx Emissions (ppmvd @ 15% O ₂)	5
CO Emissions (ppmvd @ 15% O ₂)	15
PM Emissions (lb/hr)	12.6

Figure 3.3 - 3 x Wartsila 18V50SG Facility Performance Analysis Results

3.3 RICE COST ANALYSIS

3.3.1 Introduction

This section describes for each RICE option the process used to develop each option’s capital costs, fixed O&M, major maintenance, and variable O&M. A complete listing of the cost analysis table is provided in Appendix A-3 for reference through the following sections.

3.3.2 Total Capital Investment

Budgetary quotations for capital and operational costs for the 4 x Wartsila 20V34SG and 3 x 18V50SG models were provided by Wartsila. The CIC for the RICE options were calculated by adding the major equipment cost that was provided by Wartsila and the BOP and engineering costs that were provided by GT PRO. The general approach, basis, and assumptions for the GT PRO modeling is described in Section 1.5.1. This section describes the process specific to the RICE options. GT PRO calculated the BOP and engineering costs

in 2015 dollars, therefore, the amount was escalated to 2017 dollars based on a 3 percent escalation rate each year. *Figure 3.4* lists what was included in the TCI - UL. The rate or basis for each category included in the TCI - UL was provided by either Wartsila, GT PRO, or Sega, in consultation with Montana-Dakota. The rate or basis shown for each cost category was multiplied by the appropriate values in order to obtain a dollar amount for each RICE option. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. Appendix A-3 displays the complete results of cost analysis for the TCI - UL costs for each RICE facility.

	2017\$ or Multiplier	Rate / Basis
CIC/Wartsila Major Equipment	--	OEM Proposal
Installation	--	OEM Proposal (Included in CIC)
BOP / Engineering	--	Escalated 2015\$
Generator Step-Up Transformer	--	Escalated 2015\$ (Included in BOP / Engineering cost)
Fire Protection	--	Included in CIC
Fuel Gas Conditioning Skid	515,917	Escalated Cost of Heskett 3 (\$515,917)*(Fuel Consumption Option/Fuel Consumption GE7EA SC)^0.6
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	4,000	\$/Dkt/hr Consumed
Water Interconnect	--	\$/Gallon/hr Consumed
Land	1%	% of CIC
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	2%	% of CIC
Legal and Financial Costs	2%	% of CIC
Contractor's Soft Costs	--	Escalated 2015\$
Contingency	15%	% of TCI - UL before Contingency

Figure 3.4 - Costs Included in TCI - UL for RICE Options

Figure 3.5 summarizes the resulting TCI - UL for each RICE option as well as the calculated \$/kW value based on the net plant output. An IDC cost was calculated by Montana-Dakota based on the TCI - UL cash flow over the plant construction period. The project schedules and cash flow diagrams are in Appendices B and C, respectively. The TCI - L cost was calculated for each RICE option by adding the IDC to the TCI - UL cost. The IDC and TCI - L cost are also listed for each RICE option in Figure 3.5.

RICE Generation Option	TCI - UL (\$)	TCI - UL (\$/kW)	IDC (\$)	TCI - L (\$)
4 x Wartsila 20V34SG	48,662,803	1,333	695,267	49,358,070
3 x Wartsila 18V50SG	75,350,478	1,363	1,078,975	76,429,453

Figure 3.5 - RICE TCI - UL and TCI - L Costs (2017\$)

3.3.3 Fixed O&M

The annual fixed O&M cost includes labor and maintenance costs and other expenses, and is expressed in units of \$/kW-month. The other expenses category includes cost associated with administration, property tax, and insurance. Figure 3.6 lists the basis for the fixed O&M costs for the RICE options. The labor and maintenance rate, in \$/kW-year, was provided by the OEM. The value provided by the OEM was in 2015 dollars, and therefore, was escalated to 2017 dollars based on a 3 percent escalation rate annually. As shown in Figure 3.7, the administration cost was provided as a fixed rate in \$/MW-year by Segal, in consultation with Montana-Dakota. This rate was converted to the required units of measure, \$/kW-month, for each RICE option. The property tax and insurance were provided by Montana-Dakota as a percent of the TCI - L. The percent values for the property tax and insurance were multiplied by the TCI - L, in \$/kW, and divided by the number of months of operation to obtain the required units of measure for each RICE option and included in the appropriate line item in Appendix A-3.

	2017\$ or Multiplier	Rate / Basis
Labor and Maintenance	10.7	Escalated 2015\$
Other Expenses – Administration, per year	492.3	Escalated 2015\$
Other Expenses - Property Taxes, per year	0.389	% of TCI - L
Other Expenses – Insurance, per year	0.14	% of TCI - L

Figure 3.6 - Basis for Labor, Maintenance, and Other Cost Categories of Fixed O&M for RICE Options

3.3.4 Major Maintenance

The major maintenance for the RICE options includes the periodic overhaul of major engine items. *Figure 3.7* shows the major maintenance rate that was provided by the OEM. Major maintenance is performed at set, regular intervals, the length of which will be set based on the running profile of the engine. Engine major maintenance costs were separately provided by Wartsila for each running profile of 2,000, 3,000, and 4,000 hours per year. Segra selected the major maintenance cost associated with a running profile of 2,000 hours per year because it is a realistic expectation for the current energy marketplace. The rate was converted to the required unit of measure, \$/kW-month, for each RICE option and included in the appropriate line item in Appendix A-3.

	2017\$	Rate / Basis
Engine Major Maintenance	2.88	\$/MWh

Figure 3.7 - Basis for Major Maintenance Cost for RICE Options

3.3.5 Variable O&M

The variable O&M costs for the RICE options include maintenance costs and chemical costs and is expressed in units of \$/MWh. The maintenance cost is the cost to perform the particular maintenance activities which are needed after operating for a certain number of MWhs. As shown in *Figure 3.8*, these costs include scheduled BOP maintenance, scheduled minor maintenance, and SCR catalyst replacement. The cost rate for each category was provided by the OEM. The rate was provided in the required units of measure, therefore,

no further calculations were necessary to determine a \$/MWh value for each RICE option. The SCR catalyst replacement cost rate in \$/MWh will depend on the engine running profile. SCR catalyst replacement rates were provided separately for engine running profiles of 2,000, 3,000, and 4,000 hours per year. Sega selected the catalyst replacement rate associated with 2,000 hours per year profile because it is a realistic expectation for the current energy marketplace.

	2017\$ or Multiplier	Rate / Basis
Scheduled BOP Maintenance (OEM Equipment)	0.62	\$/MWh
Scheduled Minor Maintenance	1.88	\$/MWh
SCR Catalyst Replacement	0.21	\$/MWh

Figure 3.8 - Basis for Maintenance Cost Portion of Variable O&M for RICE Options

The chemicals cost is the cost of chemicals to operate the plant. *Figure 3.9* lists the two items included in the chemical cost portion for the variable O&M costs for the RICE options. These costs include SCR ammonia consumption and lube oil. The cost rate for each category was provided by the OEM. The rate was provided in the required units of measure, therefore, no further calculations were necessary to determine a \$/MWh value for each RICE option. Variable O&M is included in the appropriate line items in Appendix A-3.

	2017\$ or Multiplier	Rate / Basis
SCR Ammonia Consumption (19% Aqueous Solution)	0.9	\$/MWh
Lube Oil	0.59	\$/MWh

Figure 3.9 - Basis for Chemical Cost Portion of Variable O&M for RICE Options

SECTION 4

BIOMASS OPTION

BIOMASS OPTION

4.1 INTRODUCTION

Steam PRO was used to estimate the performance and key capital costs for the biomass generating option. O&M costs were calculated separately in the cost analysis spreadsheet developed for this study. Refer Appendix A-4 for the performance and cost analysis results for the biomass configuration.

Research was performed prior to performing the Steam PRO run in order to develop certain assumptions necessary for the analysis of this generating option. For example, the appropriate biomass fuel and boiler size were chosen based on the available fuel in the North Dakota area. After the assumptions were set then Steam PRO and calculations were made to estimate the biomass performance, capital costs, and O&M costs.

4.2 BACKGROUND RESEARCH

4.2.1 Introduction

This section discusses the selection process for the biomass fuel and boiler size. A summary of this research is provided for reference in Appendix D.

4.2.2 Biomass Source

Montana-Dakota provided to Sega a recent study, “Great Plains Institute Feasibility of Biomass Co-Firing Study” which was used as a basis for the biomass research. Agricultural products were determined to be the best fuel choice, since availability of woody biomass is limited in the area. Sega selected wheat straw as the biomass fuel source based on information provided by the United States Department of Agriculture’s Farm Service Agency (USDA FSA). Wheat straw is the plant residue left behind after a wheat crop is harvested. Although wheat straw is not the only biomass possibility, the estimated accessibility of the product within a 50 mile radius of Bismarck, North Dakota and

available product information in the Steam PRO software made it an ideal choice for this study. In order to stay within the 50 mile or less transportation distance benchmark, only biomass sources within Burleigh County were analyzed.

4.2.3 Feasible Boiler Size

Once a biomass fuel source was selected, a feasible boiler size was calculated. Segal assumed that loose wheat straw, as opposed to densified straw, would be burned because the transportation of large square bales of loose wheat straw is simple and money is saved because a densification process is not required. A possible boiler size for a biomass plant in Bismarck, North Dakota is 10 MW. Segal based this size selection on the wheat straw fuel consumption, fuel availability (within 50 miles), whether the fuel would be densified prior to transport, and limiting the number of truck deliveries to site per day to less than 10. These calculations are provided in Appendix D. The calculations show that the available amount of wheat straw would support approximately a 10-MW biomass-fired steam generating plant assuming 40 percent of the material is removed from each agricultural area. The calculations further show that this 10 MW plant could be fueled with less than 10 truck deliveries per day.

4.3 BIOMASS PERFORMANCE ANALYSIS

The performance analysis for the biomass boiler generation option was completed through research and use of Steam PRO with the PEACE module. Danish wheat straw was chosen from Steam PRO's fuel library for Montana-Dakota because the properties are most similar to the properties of North Dakota wheat straw described in the "Great Plains Institute Feasibility of Biomass Co-Firing Study". The properties of the Danish wheat straw from Steam PRO are listed in *Figure 4.1*.

Constituent		
Moisture	% wt	10.3
Ash	% wt	4.2
Carbon	% wt	42.45
Hydrogen	% wt	5.27
Nitrogen	% wt	0.52
Chlorine	% wt	0.15
Sulfur	% wt	0.06
Oxygen	% wt	37.05
Higher Heating Value	Btu/lb	7,309
Square Bale Density	lb/cf	13-16

Figure 4.1 - Danish Wheat Straw Properties from Steam PRO

Sega selected a mass-burn grate boiler for this application complete with non-reheat condensing steam turbine and electrostatic precipitator in addition to the other plant components included in all options run through Thermoflow (see Section 1.5.1). The grate style boiler is ideally suited for this size category and handling of the loose wheat straw material. To keep transportation costs low, Sega assumed the loose wheat straw would be transported in large-to-midsized square bales in a 4,050 cf truck size.

Steam PRO calculated the gross plant output, net plant output, net full load heat rate, and fuel consumption for the biomass boiler generation option. The carbon intensity was calculated based on factors published by the EPA and the PM emission was determined based on the EPA's Area Source Boiler Maximum Achievable Control Technology regulation. The NO_x emissions and the CO emissions were determined by Sega based on engineering assessment and past biomass boiler permits that have been issued. No SCR or OxCat was added to the biomass boiler. *Figure 4.2* lists the results of the performance analysis for the biomass boiler. These are also listed in the cost analysis table in Appendix A-4.

	Biomass Boiler
Season	Summer (assumed similar for Winter)
Gross Plant Output (MW)	9.998
Net Plant Output (MW)	9.301
Net Full Load Heat Rate (Btu/kWh, HHV)	14,273
Fuel Consumption (MMBtu/hr, HHV)	132.75
Water Consumption (Gal/hr)	10,999
Carbon Intensity (lb/MWh, net)	3,718
NOx Emissions (ppmvd @ 15% O ₂)	70
CO Emissions (ppmvd @ 15% O ₂)	76
PM Emissions (lb/hr)	9.3

Figure 4.2 - Biomass Boiler Performance Analysis Results

4.4 BIOMASS COST ANALYSIS

4.4.1 Introduction

This section describes, for the biomass-fired generation option, the process used to develop the capital costs, fuel cost, fixed O&M, major maintenance, variable O&M, and tax credits. A complete listing of the cost analysis table is provided in Appendix A-4 for reference through the following sections.

4.4.2 Total Capital Investment

Equipment, installation, generator step-up transformer, fire protection, BOP, and engineering costs are included in the CIC determined by Steam PRO. The general approach, assumptions, and basis of the Steam PRO modeling is described in Section 1.5.1. This section describes the process specific to the biomass option. Steam PRO calculated the CIC in 2014 dollars, therefore, the amount was escalated to 2017 dollars based on a

3 percent escalation rate each year. *Figure 4.3* details the multipliers and/or rate/basis for each of the items included in the TCI - UL. The multipliers and rate/basis for each category were provided by either Steam PRO or Segal, in consultation with Montana-Dakota. The rate/basis shown for each cost category was multiplied by the appropriate values in order to obtain a dollar amount for the biomass-fired generation option. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. Appendix A-4 displays the complete results of cost analysis for the TCI - UL costs.

	2017\$ or Multiplier	Rate / Basis
CIC/Major Equipment	--	\$
Installation	--	\$ (Included in CIC)
BOP/Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fire Protection	--	\$ (Included in CIC)
Fuel Gas Conditioning Skid	--	N/A for this Option
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	--	N/A for this Option
Water Interconnect	20	\$/Gallon/hr Consumed
Land	1%	% of CIC
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	2%	% of CIC
Legal and Financial Costs	2%	% of CIC
Contractor's Soft Costs	--	Escalated 2015\$
Contingency	20%	% of TCI - UL before Contingency

Figure 4.3 - Costs Included in TCI - UL for Biomass Boiler Option

Figure 4.4 summarizes the resulting TCI - UL for the biomass boiler option, as well as, the calculated \$/kW value based on the net plant output. An IDC cost was calculated by Montana-Dakota based on the TCI - UL cash flow over the plant construction period. The project schedules and cash flow diagrams are in Appendices B and C, respectively. The TCI - L cost was calculated for each CTG option by adding the IDC to the TCI - UL cost. The IDC and TCI - L cost are also listed for the biomass option in Figure 4.4.

Generation Option	TCI - UL (\$)	TCI - UL (\$/kW)	IDC (\$)	TCI - L (\$)
Biomass	84,006,051	9,032	1,667,644	85,673,695

Figure 4.4 - Biomass TCI - UL and TCI - L Costs (2017\$)

4.4.3 Fuel Cost

Fuel cost for the wheat straw boiler was determined using pricing described in the “Great Plains Institute Feasibility of Biomass Co-Firing Study” and escalating the cost to 2017 dollars based on a 3 percent escalation rate each year. The results of the calculations are shown in Figure 4.5. See Appendix D for more information.

	2017\$ / ton	2017\$ / MMBtu
Total Biomass Fuel Cost	60.02	4.11

Figure 4.5 - Basis for Fuel Cost for Biomass

4.4.4 Fixed O&M

The fixed O&M costs for this analysis were derived from the U.S. Energy Information Administrations’ Assumptions to the Annual Energy Outlook 2015 (Energy Outlook) which provides up-to-date cost estimates for a range of generation technologies. The fixed O&M costs were reported in 2013 dollars (2013\$/kW-yr). Therefore, the cost value was escalated to 2017 dollars at 3 percent annual rate, and converted to obtain the required units of measure (\$/kW-month). Figure 4.6 shows the value from the Energy Outlook and the calculated fixed O&M for the biomass plant.

	Value from Energy Outlook (2013\$/kW-yr)	Calculated Value (2017\$/kW-month)
Fixed O&M	105.58	9.90

Figure 4.6 - Basis for Fixed O&M Cost for Biomass Boiler Option

4.4.5 Major Maintenance

The major maintenance for the biomass plant includes the periodic steam turbine overhaul. This steam turbine overhaul was considered to be similar to the steam turbine overhaul that would take place for the combined-cycle combustion turbines, so the cost basis from Section 2.4.4 was used for the biomass major maintenance cost shown in *Figure 4.7*.

	Provided by Sega (\$/MW-yr)	Calculated (2017\$ / kW-month)
Steam Turbine Overhaul	4,711	0.393

Figure 4.7 - Basis for Major Maintenance Cost for Biomass Boiler Option

4.4.6 Variable O&M

The variable O&M cost for this analysis was derived from the Energy Outlook. The variable O&M costs were reported in 2013 dollars (2013\$/MWh). The cost value was escalated to 2017 dollars at 3 percent annual rate as shown in *Figure 4.8*.

	Value from Energy Outlook (2013\$/MWh)	Calculated Value (2017\$/MWh)
Variable O&M	5.26	5.92

Figure 4.8 - Basis for Variable O&M Cost for Biomass Boiler Option

4.4.7 Tax Credits

The government offers a federal renewable electricity production tax credit (PTC) for electricity generated by qualified energy resources. The duration of the credit is 10 years after the facility is placed in service. The biomass plant was assumed to use open-loop biomass which means the PTC would be \$0.012/kWh. Closed-loop biomass is organic material that is planted specifically to be used at a facility utilizing the biomass to produce electricity. Since wheat straw is the waste left over from a wheat crop yield, the biomass would be considered open-loop because it was not grown for the purposes of being used to

produce electricity. It should be noted that the PTC for the tax years 2017 through 2019 would depend on the inflation-adjustment factor used by the IRS in the respective tax years. The tax credits are included in the cost analysis table in Appendix A-4. Tax credits are listed for reference only, and were not included in the overall cost analysis.

SECTION 5

WIND OPTIONS

WIND OPTIONS

5.1 INTRODUCTION

Montana-Dakota provided information for the performance and cost analysis for the non-fuel, renewable wind energy options. Based on this information provided, capital and O&M costs were calculated separately in the spreadsheet developed for this study. The results of the performance and cost analysis are shown in Appendix A-5. The performance and cost analysis were performed for the following wind generation configurations:

1. 20 MW GE 2.5-116-80m located in North Dakota.
2. 50 MW GE 2.5-116-80m located in North Dakota.
3. 45 MW Nordex N117 (Thunder Spirit Wind Expansion, North Dakota).

5.2 WIND PERFORMANCE ANALYSIS

Montana-Dakota provided performance information specific to these wind turbine options. *Figure 5.1* lists the performance analysis results. Because no combustion takes place with this resource option, the net full load heat rate is not applicable and the carbon intensity, NO_x, CO, and PM emissions would be zero for all the wind resource options.

	20 MW GE 2.5-116-80m	50 MW GE 2.5-116-80m	45 MW Nordex N117
Number of Turbines	8	20	15
Gross Plant Output (MW)	N/A	N/A	N/A
Net Plant Output (MW)	20	50	45
Net Full Load Heat Rate (Btu/kWh, HHV)	N/A	N/A	N/A
Carbon Intensity (lb/MWh, net)	0	0	0
NOx Emissions (ppmvd @ 15% O ₂)	0	0	0
CO Emissions (ppmvd @ 15% O ₂)	0	0	0
PM Emissions (lb/hr)	0	0	0

Figure 5.1 - Wind Performance Analysis Results

5.3 WIND COST ANALYSIS

5.3.1 Introduction

This section describes the process used to develop the capital costs, fixed O&M, major maintenance, variable O&M, and tax credits for the wind related generation options. A complete listing of the cost analysis table is provided in Appendix A-5 for reference through the following sections.

5.3.2 Total Capital Investment

Montana-Dakota provided wind turbine major equipment cost, as well as additional costs that were taken into consideration when calculating the TCI - UL and the TCI - L. The wind turbine major equipment cost did not include the installation cost of the turbines. Due to the ease of erection and recent installation experience, an installation cost equivalent to 28 percent of the equipment cost was selected.

The CIC for the wind facilities located in North Dakota were calculated by adding the wind turbine major equipment cost that was provided by Montana-Dakota to the calculated installation cost, which also included the BOP, engineering costs, and contractor's soft costs. The rate or basis for each category included in the TCI - UL was provided by Segal, in

consultation with Montana-Dakota. The same percentages that were provided by GT PRO for the permits, licenses, fees, and miscellaneous and the legal and financial costs categories for the CTG, RICE, and biomass boiler options were used for the wind options for consistency between the analyses. The rate or basis shown for each cost category was multiplied by the appropriate values in order to obtain a dollar amount for each wind option. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. *Figure 5.2* lists what was included in TCI - UL costs for the new wind facility configurations and not the Thunder Spirit Wind Expansion.

	2017\$ or Multiplier	Rate / Basis
CIC/Major Equipment	--	OEM Proposal
Installation	28%	% of Wind Turbine Major Equipment
BOP / Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fire Protection	--	N/A for this Option
Fuel Gas Conditioning Skid	--	N/A for this Option
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	--	N/A for this Option
Water Interconnect	--	N/A for this Option
Land	1%	% of CIC
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	2%	% of CIC
Legal and Financial Costs	2%	% of CIC
Contractor's Soft Costs	--	\$ (Included in CIC)
Contingency	15%	% of TCI - UL before Contingency

Figure 5.2 - Costs Included in TCI - UL for the New Wind Facility Options (Not Including 45 MW Thunder Spirit Wind Expansion)

Montana-Dakota provided the cost for the Thunder Spirit Wind Expansion to Sega as an all-in cost. The transmission interconnect and MISO queue fee, as well as the remainder of the costs that make up the TCI - UL cost, is considered to be included in the CIC. *Figure 5.3* lists what was included in TCI - UL cost for the Thunder Spirit Wind Expansion. Appendix A-5 displays the complete results of cost analysis for the TCI - UL costs for the new wind facility configurations and the Thunder Spirit Wind Expansion.

	2017\$ or Multiplier	Rate / Basis
CIC/Major Equipment	--	\$
Installation	--	\$ (Included in CIC)
BOP / Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fire Protection	--	N/A for this Option
Fuel Gas Conditioning Skid	--	N/A for this Option
Transmission Interconnect and MISO Queue Fee	--	\$ (Included in CIC)
Gas Interconnect	--	N/A for this Option
Water Interconnect	--	N/A for this Option
Land	--	\$ (Included in CIC)
Spare Parts and Material	--	\$ (Included in CIC)
Developer's Fee	--	\$ (Included in CIC)
Engineering Supervision, General, and Administrative Rate	--	\$ (Included in CIC)
Permits, Licenses, Fees, and Miscellaneous	--	\$ (Included in CIC)
Legal and Financial Costs	--	\$ (Included in CIC)
Contractor's Soft Costs	--	\$ (Included in CIC)
Contingency	--	\$ (Included in CIC)

**Figure 5.3 - Costs Included in TCI - UL for the 45 MW
Thunder Spirit Wind Expansion Option**

Figure 5.4 summarizes the resulting TCI - UL for each wind option as well as the calculated \$/kW value based on the net plant output. An IDC cost was calculated by Montana-Dakota based on the TCI - UL cash flow over the plant construction period. The project schedules and cash flow diagrams are in Appendices B and C, respectively. The TCI - L cost was calculated for each wind option by adding the IDC to the TCI - UL cost. The IDC and TCI - L cost are also listed for each wind option in Figure 5.4.

Wind Generation Option	TCI - UL (\$)	TCI - UL (\$/kW)	IDC (\$)	TCI - L (\$)
20 MW GE 2.5-116-80m	30,643,714	1,532	196,938	30,840,652
50 MW GE 2.5-116-80m	75,467,807	1,509	483,747	75,951,554
45 MW Nordex N117	78,750,000	1,750	0	78,750,000

Figure 5.4 - Wind TCI - UL and TCI - L Costs (2017\$)

5.3.3 Fixed O&M

The fixed O&M costs for the analysis of the two new options were derived from the Energy Outlook literature. The fixed O&M cost for the Thunder Spirit Wind Expansion option was provided by Montana-Dakota as \$1.12/kW-month. The costs from the Energy Outlook literature were reported in 2013 dollars (2013\$/kW-yr). The fixed O&M cost for the two new wind options was escalated to 2017 dollars at 3 percent annual rate and then converted to obtain the required units of measure (\$/kW-month). Figure 5.5 shows the value from the Energy Outlook in 2013 dollars and the calculated fixed O&M for the wind facilities in 2017 dollars. The calculations for the fixed O&M costs can be found in Appendix A-5.

	Value from Energy Outlook (2013\$/kW-yr)	Calculated Value for New Wind Options (2017\$/kW-month)	Value for Thunder Spirit Expansion (2017\$/kW-month)
Fixed O&M	39.53	3.71	1.12

Figure 5.5 - Basis for Fixed O&M Cost for Wind Generation Options

5.3.4 Major Maintenance

The major maintenance for the two new wind options includes the gear box replacement and other major maintenance items. *Figure 5.6* shows the major maintenance rate that was provided by an OEM. The calculations for the major maintenance costs can be found in Appendix A-5. The major maintenance cost for the Thunder Spirit Wind Expansion option was provided by Montana-Dakota as \$0/kW-month.

	Value for New Wind Options (2017\$/kW-month)	Value for Thunder Spirit Expansion (2017\$/kW-month)
Gear Box Replacement and Other Major Maintenance	2.51	0.00

Figure 5.6 - Basis for Major Maintenance Cost for Wind Options

5.3.5 Variable O&M

The variable O&M cost for this analysis was assumed to be zero based on cost information in the Energy Outlook and information provided by Montana-Dakota.

5.3.6 Tax Credits

The wind facilities would be eligible for the PTC for electricity generated by qualified energy resources. The duration of the credit is 10 years after the facility is placed in service as with the biomass facility. The PTC for wind facilities for the year 2016 is \$0.023/kWh. The tax credit is phased down for wind facilities commencing construction after December 31, 2016. For the purposes of this IRP, it was assumed that the wind turbine facilities would commence construction in 2017. The PTC is reduced by 20 percent for the 2017 year and would result in a \$0.018/kWh credit. It should be noted that the PTC for the tax years 2017 through 2019 would depend on the inflation-adjustment factor used by the IRS in the respective tax years. The tax credits are included in the cost analysis table Appendix A-5. Values listed are for reference only and were not included in the cost build up for this option.

SECTION 6

SOLAR OPTIONS

SOLAR OPTIONS

6.1 INTRODUCTION

Sega researched types and sizes of solar generation options for this study and performed a performance and cost analysis on two configurations selected. The selected types and sizes are as follows:

1. 50-MW Photovoltaic (PV) Solar.
2. 50-MW Concentrated Solar.

This section describes the background research and analysis of performance and cost.

6.2 BACKGROUND RESEARCH

6.2.1 Introduction

This section discusses the selection process for solar options and describes the assumptions for the analysis. A summary of this research is provided for reference in Appendix E.

6.2.2 PV Solar

PV solar converts direct sunlight into electricity using semiconducting materials on an array of panels. Sega determined that a 50-MW fixed tilt PV solar facility is a feasible option for Montana-Dakota based on information from actual experience, engineering judgement, and research through the National Renewable Energy Laboratory (NREL). NREL considers the annual average PV solar resource for the North Dakota area as middle range for this technology, which is the rating given to the Missouri area. Sega has previous project experience with a PV solar project in the Missouri area, and believes that equivalent success would be achieved in North Dakota based on this information.

6.2.3 Concentrated Solar

As compared to PV solar, which directly converts sunlight into electricity, concentrated solar uses an array of mirrors (heliostats) to focus incident solar energy to heat a working fluid which in turn creates steam for a traditional steam turbine generator system. Two major types of concentrated solar technology are central tower (also known as power tower) and parabolic trough. Concentrated solar technologies are configured to either have no storage capabilities or account for a certain number of hours of energy storage. Segal believes energy storage would be included in a new installation of this type. As compared to PV style technology, NREL lists the annual average concentrated solar direct resource in the low range for the North Dakota area. Despite this, Segal still believes concentrated solar to be a technically viable generation option for further study of performance and cost as a comparison to PV solar and other renewable generation options. A 50-MW central tower configuration with 10 hours of storage was selected for analysis for the Bismarck, North Dakota area.

6.3 SOLAR PERFORMANCE ANALYSIS

Based on the design information from NREL for the two solar options and the assumptions that were made for the analysis as shown in Appendix E, the resulting performance information is shown in *Figure 6.1*.

Because no combustion takes place with this resource option, the net full load heat rate is not applicable and the carbon intensity, NO_x, CO, and PM emissions would be zero for both solar resource options.

	PV Solar	Concentrated Solar
Type	Fixed Tilt	Central Tower with Storage
Gross Plant Output (MW)	N/A	N/A
Net Plant Output (MW)	50	50
Net Full Load Heat Rate (Btu/kWh, HHV)	N/A	N/A
Water Consumption (Gal/hr)	N/A	50,000
Carbon Intensity (lb/MWh, net)	0	0
NOx Emissions (ppmvd @ 15% O ₂)	0	0
CO Emissions (ppmvd @ 15% O ₂)	0	0
PM Emissions (lb/hr)	0	0

Figure 6.1 - Solar Performance Analysis Results

6.4 SOLAR COST ANALYSIS

6.4.1 Introduction

This section describes the process used to develop the capital costs, fixed O&M, major maintenance, variable O&M, and tax credits for the two solar related generation options. NREL produces an Annual Technology Baseline (ATB) report each year. The 2016 ATB report was the source of the majority of the cost information for the analysis. Segal, in consultation with Montana-Dakota, provided the remainder of the economic information necessary to complete the analysis. A complete listing of the cost analysis tables is provided in Appendix A-6 for reference through the following sections.

6.4.2 Total Capital Investment

The CIC for the 50 MW fixed tilt PV solar facility was determined by using the capital cost information that was provided by the NREL 2016 ATB report for a 100 MW fixed tilt PV solar facility with a 20 percent capacity factor. The ATB report calculated the CIC in 2014 dollars on a \$/kW-year basis. This basis was escalated to 2017 dollars based on a 3 percent annual escalation rate and adjusted for a 50-MW capacity. The CIC value that was provided by the ATB report includes the following:

1. Modules:
 - a. Module supply.
 - b. Power electronics.
 - c. Racking.
 - d. Foundation.
 - e. AC and DC materials and installation.
2. BOP:
 - a. Land acquisition.
 - b. Site preparation.
 - c. Installation of underground utilities.
 - d. Access roads.
 - e. Fencing.
 - f. Buildings for O&M.
 - g. Electrical infrastructure (such as transformers, switchgear and electrical system connecting modules to each other and to control center).
 - h. Project indirect costs (including engineering, distributable labor and materials).
 - i. Construction management startup and commissioning.
 - j. Contractor overhead costs.
 - k. Fees and profit.

3. Financial Costs:
 - a. Owner's costs (such as development costs).
 - b. Preliminary feasibility and engineering studies.
 - c. Environmental studies and permitting.
 - d. Legal fees.
 - e. Insurance costs.
 - f. Property taxes during construction.
 - g. On site electrical equipment.
 - h. Nominal-distance spur line.
 - i. Necessary upgrades at a transmission substation.

Figure 6.2 lists what was included in the TCI - UL for the PV solar option. In contrast to the other generation options, many of the TCI - UL cost categories are included in the CIC from the ATB report, as noted in *Figure 6.2*. Other Owner's costs determined by Segal, in consultation with Montana-Dakota, were added to the CIC provided by the ATB report to calculate the total TCI - UL. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. A complete breakdown of the calculations can be found in the cost analysis table in Appendix A-6.

	2017\$ or Multiplier	Rate / Basis
CIC/PV Solar Major Equipment	2,161	ATB Report (Escalated 2014\$)
Installation	--	\$ (Included in CIC)
BOP / Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fire Protection	--	N/A for this Option
Fuel Gas Conditioning Skid	--	N/A for this Option
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	--	N/A for this Option
Water Interconnect	--	N/A for this Option
Land	--	\$ (Included in CIC)
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	--	\$ (Included in CIC)
Legal and Financial Costs	--	\$ (Included in CIC)
Contractor's Soft Costs	--	\$ (Included in CIC)
Contingency	25%	% of TCI - UL before Contingency

Figure 6.2 - Costs Included in TCI - UL for PV Solar Option

The CIC for concentrated solar was determined by using the NREL 2016 ATB report for a 100-MW, class 1, central tower concentrated solar facility with 10 hours of storage. The report calculated the CIC in 2014\$/kW-year, therefore, the amount was escalated to 2017 dollars based on a 3 percent annual escalation rate, and adjusted for a 50 MW facility. The CIC value that was provided by the ATB report includes the following:

1. CSP Generation Plant:
 - a. Installed solar collectors.
 - b. Solar receiver.
 - c. Piping and heat-transfer fluid system.
 - d. Power block-heat exchangers.
 - e. Power turbine.
 - f. Generator.
 - g. Cooling system.
 - h. Thermal energy storage system.
 - i. Installation.
2. Balance of System:
 - a. Land acquisition.
 - b. Site preparation.
 - c. Installation of underground utilities.
 - d. Access roads.
 - e. Fencing.
 - f. Buildings for operations and maintenance.
 - g. Electrical infrastructure (such as transformers, switchgear and electrical system connecting modules to each other and to control center).
 - h. Generator voltage is 13.8-kV.
 - i. Step-up transformer will be 13.8/230-kV.

- j. Transmission tie line will be 230-kV.
 - k. Project indirect costs (including engineering distributable labor and materials).
 - l. Construction management startup and commissioning.
 - m. Contractor overhead costs.
 - n. Fees and profit.
3. Financial Costs:
- a. Owner's costs (such as development costs, preliminary feasibility and engineering studies).
 - b. Environmental studies and permitting.
 - c. Legal fees.
 - d. Insurance costs.
 - e. Property taxes during construction.
 - f. On site electrical equipment.
 - g. Nominal-distance spur line.
 - h. Necessary upgrades at a transmission substation.

Figure 6.3 lists what was included in the TCI - UL. Similar to the PV solar calculations, many of the TCI - UL cost categories are included in the CIC from the ATB report, as noted in *Figure 6.3*. Other Owner's costs determined by Sega, in consultation with Montana-Dakota, were added to the CIC provided by the ATB report to calculate the total TCI - UL. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. A complete breakdown of the calculations can be found in the cost analysis table in Appendix A-6.

	2017\$ or Multiplier	Rate / Basis
CIC/Concentrated Solar Major Equipment	8,769	ATB Report (Escalated 2014\$)
Installation	--	\$ (Included in CIC)
BOP / Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fire Protection	--	N/A for this Option
Fuel Gas Conditioning Skid	--	N/A for this Option
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	--	N/A for this Option
Water Interconnect	20	\$/Gallon/hr Consumption
Land	--	\$ (Included in CIC)
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	--	\$ (Included in CIC)
Legal and Financial Costs	--	\$ (Included in CIC)
Contractor's Soft Costs	--	\$ (Included in CIC)
Contingency	25%	% of TCI - UL before Contingency

Figure 6.3 - Costs Included in TCI - UL for Concentrated Solar Option

Figure 6.4 summarizes the resulting TCI - UL for the PV solar and concentrated solar options, as well as the calculated \$/kW value based on the net plant output. An IDC cost was calculated by Montana-Dakota based on the TCI - UL cash flow over the plant construction period. The project schedules and cash flow diagrams are in Appendices B and C, respectively. The TCI - L cost was calculated for each solar option by adding the IDC to the TCI - UL cost. The IDC and TCI - L cost are also listed for each solar option in Figure 6.4.

Generation Option	TCI - UL (\$)	TCI - UL (\$/kW)	IDC (\$)	TCI - L (\$)
PV Solar	141,410,768	2,828	1,325,983	142,736,751
Concentrated Solar	563,902,929	11,278	9,920,805	573,823,734

Figure 6.4 - PV Solar and Concentrated Solar TCI - UL and TCI - L Costs (2017\$)

6.4.3 Fixed O&M

The fixed O&M cost for this analysis was derived from the NREL 2016 ATB report. The fixed O&M costs were reported in 2014 dollars (2014\$/kW-yr). The cost value was escalated to 2017 dollars at 3 percent annual rate and then divided by the months of operation to obtain the required units of measure (2017\$/kW-month). Figure 6.5 shows the value from the NREL 2016 ATB report and the calculated fixed O&M for the PV solar and concentrated solar facilities in 2017 dollars. The calculations for the fixed O&M costs can be found in Appendix A-6.

	Value from NREL (2014\$/kW-yr)	Calculated Value (2017\$/kW-month)
PV Solar	17	1.55
Concentrated Solar	66	6.01

Figure 6.5 - Basis for Fixed O&M Costs for Solar Generation Options

6.4.4 Major Maintenance

The major maintenance cost for PV solar was set to zero based on an assumption that the maintenance cost is included in the fixed O&M category.

The major maintenance for the concentrated solar plant includes the periodic steam turbine overhaul because there is steam production with this solar option as opposed to the PV solar option. This steam turbine overhaul was considered to be similar to the steam turbine overhaul that would take place for the combined-cycle options, so the cost basis from Section 2.4.4 was used for the concentrated solar option major maintenance cost shown in *Figure 6.6*. The calculations for the major maintenance costs can be found in Appendix A-6.

	Provided by Sega (\$/MW-yr)	Calculated (2017\$ / kW-month)
Steam Turbine Overhaul	4,711	0.393

Figure 6.6 - Basis for Major Maintenance Cost for Concentrated Solar Generation Option

6.4.5 Variable O&M

The variable O&M cost for PV solar was assumed to be zero based on cost information by NREL.

Unlike PV solar, concentrated solar does have variable O&M costs due to the steam production equipment. The variable O&M costs were reported by NREL in 2014 dollars (2014\$/MWh). The cost value was escalated to 2017 dollars at 3 percent annual rate. *Figure 6.7* shows the value from NREL and the calculated variable O&M for the concentrated solar facility. The calculations for the variable O&M costs can be found in Appendix A-6.

	Value from NREL (2014\$/MWh)	Calculated Value (2017\$/MWh)
Variable O&M	4.00	4.37

Figure 6.7 - Basis for Variable O&M Costs for Concentrated Solar Generation Option

6.4.6 Tax Credits

The government does not offer a federal renewable electricity PTC for solar energy resources, but instead offers an Investment Tax Credit (ITC). This tax credit would be applicable for both PV and concentrated solar. The ITC is currently a 30 percent federal tax credit, and is applied as a reduction in the income taxes. The 30 percent reduction is applicable to eligible properties which have commenced construction through 2019. The ITC steps down in 2020 and even further in the years following. For the purpose of this IRP, the solar facilities were assumed to commence construction prior to 2019. The tax credits are included in the cost analysis table in Appendix A-6. Tax credits are listed for reference only and were not included in the cost build up for the option.

SECTION 7

COAL OPTIONS

COAL OPTIONS

7.1 INTRODUCTION

Montana-Dakota provided the information necessary for the performance and the cost analysis for the following two coal boiler generation configurations:

1. Circulating Fluidized Bed Combustion (CFBC) with carbon capture.
2. CFBC without carbon capture.

Capital and O&M costs were calculated separately in the spreadsheet developed for this study. The results of the performance and cost analysis can be seen in Appendix A-7.

7.2 BACKGROUND

For the performance analysis of new coal-fired power plant options, Montana-Dakota used the results of a 2012 study completed by WorleyParsons called “A Study of Advanced Generation Technology Systems”. This study evaluated advanced generation technology alternatives viable for a generating station burning North Dakota lignite coal. Four technologies were selected and a comparative evaluation based on performance and cost was completed. The evaluation examined these technologies with and without CO₂ capture. Technologies included in the evaluation were:

1. Subcritical atmospheric fluidized bed combustion,
2. Pressurized fluidized bed combustion,
3. Gasification, and
4. Oxycombustion CFBC.

The criteria that were assessed in the study included, but were not limited to: lignite experience, technology development and risk, permit ability, environmental impact, performance, emissions, capital cost, and operating cost. The results of the study ranked subcritical CFBC technology the best among all other technologies evaluated for both including and not including CO₂ capture. Therefore, the CFBC technology with and without carbon capture were selected as the configurations to assess performance and cost.

7.3 COAL PERFORMANCE ANALYSIS

7.3.1 Circulating Fluidized Bed Combustion with Carbon Capture

Montana-Dakota provided Segra with the performance data for a CFBC with carbon capture. The information provided included the gross plant output, net plant output, and net full load heat rate. The emissions information gathered from the WorleyParsons' study was also provided by Montana-Dakota. The NO_X and CO emissions were provided in two different units, ppmvd at 15 percent O₂ and lb/MWh-gross, while the PM emissions were provided in lb/hr and lb/MWh-gross. The CO₂ emissions were also provided in two different units, lb/MMBtu and lb/MWh-gross. The NO_X value from the study is a controlled emissions value and reflects selective non-catalytic reduction (SNCR) with a 60 percent reduction. The PM value is also a controlled value and reflects a fabric filter before the stack. Sulfur dioxide emissions are not included in the model; however, this option assumes sulfur dioxide is removed in the fluidized bed and polished in a flue gas desulfurization system. *Figure 7.1* lists the results of the performance analysis for the CFBC with carbon capture technology.

	CFBC with Carbon Capture
Gross Plant Output (MWe)	146
Net Plant Output (MWe)	122
Net Full Load Heat Rate (Btu/kWh)	13,781
NO _x Emissions (ppmvd @ 15% O ₂ , lb/MWh-gross)	14.4, 0.69
CO Emissions (ppmvd @ 15% O ₂ , lb/MWh-gross)	39.4, 1.16
PM Emissions (lb/hr, lb/MWh-gross)	<18.7, <7.0x10 ⁻³
CO ₂ Emissions (lb/MMBtu, lb/MWh-gross)	22, 248

Figure 7.1 - CFBC with Carbon Capture Performance Analysis Results

7.3.2 CFBC without Carbon Capture

Information that was provided by Montana-Dakota for a CFBC without carbon capture included the gross plant output, net plant output, and net full load heat rate. The emissions information gathered from the WorleyParsons' study was also provided by Montana-Dakota. The NO_x, CO, PM, and CO₂ emissions were provided with the same units as for the CFBC with carbon capture technology unit. The NO_x value from the study is a controlled emissions value and reflects selective non-catalytic reduction with a 60 percent reduction. The PM value is also a controlled value and reflects a fabric filter before the stack. Sulfur dioxide emissions are not included in the model; however, this option assumes sulfur dioxide is removed in the fluidized bed and polished in a flue gas desulfurization system. *Figure 7.2* lists the results of the performance analysis for the CFBC without carbon capture technology.

	CFBC without Carbon Capture
Gross Plant Output (MWe)	185
Net Plant Output (MWe)	168
Net Full Load Heat Rate (Btu/kWh)	9,974
NOx Emissions (ppmvd @ 15% O ₂ , lb/MWh-gross)	14.4, 0.54
CO Emissions (ppmvd @ 15% O ₂ , lb/MWh-gross)	39.4, 0.90
PM Emissions (lb/hr, lb/MWh-gross)	<18.7, <7.0x10 ⁻³
CO ₂ Emissions (lb/MMBtu, lb/MWh-gross)	215, 1,945

Figure 7.2 - CFBC without Carbon Capture Performance Analysis Results

7.4 COAL COST BASIS

7.4.1 Total Capital Investment

The CIC for the coal boiler options were calculated by multiplying the total plant capital cost by the net power generation provided by Montana-Dakota based on the WorleyParsons study. The costs associated with CO₂ sequestration for the CFBC with carbon capture option were not evaluated in the analysis. *Figure 7.3* lists what was included in the TCI - UL. The rate or basis for each category included in the TCI - UL was provided by Sega, in consultation with Montana-Dakota. The same percentages that were provided by GT PRO for the permits, licenses, fees and miscellaneous and the legal and financial costs categories for the CTG, RICE, and biomass boiler options were used for the coal generation options for consistency between the analyses. As described in Section 1.5.2, the transmission interconnect and MISO queue fee costs are comprised of transmission upgrades, studies, and fee estimates provided by Montana-Dakota for each generation configuration. A complete breakdown of the calculations can be found in the cost analysis table in Appendix A-7.

	2017\$ or Multiplier	Rate / Basis
CIC/Major Equipment	--	WorleyParsons Study
Installation	--	\$ (Included in CIC)
BOP / Engineering	--	\$ (Included in CIC)
Generator Step-Up Transformer	--	\$ (Included in CIC)
Fire Protection	--	\$ (Included in CIC)
Fuel Gas Conditioning Skid	--	N/A for this Option
Transmission Interconnect and MISO Queue Fee	\$50,000/MW	Upgrades Cost Rate, Total Cost Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
	--	Studies/Fees, Varies for Each Generation Configuration Based on MW. Basis is MISO Queue Fee Estimates Document from Montana-Dakota
Gas Interconnect	--	N/A for this Option
Water Interconnect	20	\$/Gallon/hr Consumption
Land	1%	% of CIC
Spare Parts and Material	1%	% of CIC
Developer's Fee	1%	% of CIC
Engineering Supervision, General, and Administrative Rate	21.15%	% of First \$1 Million
Permits, Licenses, Fees, and Miscellaneous	2%	% of CIC
Legal and Financial Costs	2%	% of CIC
Contractor's Soft Costs	--	\$ (Included in CIC)
Contingency	20%	% of TCI - UL before Contingency

Figure 7.3 - Costs Included in TCI - UL for Coal Generation Options

Figure 7.4 summarizes the resulting TCI - UL for the coal generation options as well as the calculated \$/kW value based on the net plant output. An IDC cost was calculated by Montana-Dakota based on the TCI - UL cash flow over the plant construction period. The project schedules and cash flow diagrams are in Appendix B and C, respectively. The TCI - L cost was calculated for each coal option by adding the IDC to the TCI - UL cost. The IDC and TCI - L cost are also listed for each coal option in Figure 7.4.

Generation Option	TCI - UL (\$)	TCI - UL (\$/kW-net)	IDC (\$)	TCI - L (\$)
CFBC with Carbon Capture	1,215,030,667	9,959	42,579,962	1,257,610,629
CFBC without Carbon Capture	920,684,084	5,480	24,005,757	944,689,841

Figure 7.4 - Coal Generation Options TCI - UL and TCI - L Costs (2017\$)

7.4.2 Fixed O&M, Variable O&M, and Major Maintenance

The annual fixed and variable O&M, as well as, the major maintenance costs were also provided by Montana-Dakota based on the 2012 WorleyParsons study. The fixed O&M cost was calculated based on a 100 percent capacity factor assumption. Figure 7.5 lists the fixed and variable O&M and the major maintenance costs for the coal generation options. Appendix A-7 displays the results of the fixed and variable O&M costs and the major maintenance costs for each of the coal boiler options.

	CFBC with Carbon Capture	CFBC without Carbon Capture
Fixed O&M (\$/kW-month)	26.93	19.62
Variable Non-Fuel O&M (\$/MWh-net)	21.02	13.25
Major Maintenance (\$/kW-month)	0	0

Figure 7.5 - Basis for Fixed and Variable O&M and Major Maintenance Cost for Coal Generation Options

SECTION 8

RESULTS

RESULTS

8.1 INTRODUCTION

Montana-Dakota requested Segra conduct a performance and cost analysis of resource options to be included in Montana-Dakota's 2017 IRP supply-side alternative resources model. The results of the analysis will be input into the EGEAS and used to develop a least cost option for Montana-Dakota's future energy resources. Segra researched and gathered information to conduct a performance and cost analyses for several supply-side resource options. Segra utilized Thermoflow, a thermal engineering and costing software, budgetary quotations from OEMs, input from Montana-Dakota, published literature, and engineering experience to develop performance and cost estimates for each of the resources considered. The supply-side resource options that were investigated include: simple-cycle CTGs, combined-cycle CTGs, RICE, a biomass boiler, wind turbine generation options, solar generation options, and coal generation options. Both the simple-cycle and combined-cycle CTGs had various operating cases that were explored. Segra developed a spreadsheet to summarize the information and perform calculations for each option.

8.2 RESULTS

The EGEAS performance and cost inputs determined for each supply-side resource option assessed are listed below:

1. Summer and Winter Net Plant Output (MW).
2. Capital Cost (\$/kW).
3. Fixed O&M Cost (\$/kW-month).
4. Variable O&M Cost (\$/MWh).
5. Major maintenance (\$/kW-month).
6. Summer and Winter Full Load Heat Rate (Btu/kWh, net, HHV).
7. Summer and Winter Carbon Intensity (lb/MWh).
8. Summer and Winter NO_x (ppmvd at 15 percent O₂).

9. Summer and Winter CO (ppmvd at 15 percent O₂).
10. Summer and Winter PM (lb/hr).

The results of the performance and cost analysis, the schedules, and the cash flows for each generation options can be seen in Appendices A, B, and C, respectively. *Figures 8.1, 8.2, and 8.3* summarize the results of the performance and cost analysis that will be input into the EGEAS and used by Montana-Dakota for the IRP.

Simple-Cycle Configuration	Season	Operating Condition		Plant Output (MW, net)	Loaded Capital Cost (\$/kW)	Fixed O&M (\$/kW-month)	Variable O&M (\$/MWh)	Major Maintenance (\$/kW-month)	Full Load Heat Rate (Btu/kWh, net, HHV)	Carbon Intensity (lb/MWh)	NO _x (ppmvd@15% O ₂)	CO (ppmvd@15%O ₂)	PM (lb/hr)
		Evaporative Cooling	Duct Firing										
GE 7EA	Summer	On	N/A	78.4	1,163	1.53	2.68	0.036	11,498	1,345	9	5	9.0
	Summer	Off	N/A	74.3	1,228	1.60	2.67		11,638	1,361			8.6
	Winter	Off	N/A	95.4	957	1.30	2.67		11,074	1,295			10.6
GE LMS100PB	Summer	On	N/A	90.5	1,327	1.88	4.67	0.036	8,832	1,052	2.5	40	8.1
	Summer	Off	N/A	87.5	1,372	1.94	4.68		9,079	1,062			7.9
	Winter	Off	N/A	95.0	1,264	1.81	4.60		8,825	1,032			8.4
GE LM6000PH	Summer	On	N/A	41.3	1,546	2.77	4.34	0.036	9,637	1,127	3	20	4.0
	Summer	Off	N/A	37.5	1,703	3.03	4.33		9,921	1,160			3.7
	Winter	Off	N/A	50.3	1,269	2.32	4.32		9,253	1,082			4.7

Figure 8.1 - 2017 Simple-Cycle Combustion Turbine Generating Facility EGEAS Model Input Summary

Combined-Cycle Configuration	Season	Operating Condition		Plant Output (MW, net)	Loaded Capital Cost (\$/kW)	Fixed O&M (\$/kW-month)	Variable O&M \$/MWh	Major Maintenance (\$/kW-month)	Full Load Heat Rate (Btu/kWh, net, HHV)	Carbon Intensity (lb/MWh)	NO _x (ppmvd@15% O ₂)	CO (ppmvd@15%O ₂)	PM (lb/hr)
		Evaporative Cooling	Duct Firing										
1x1 GE LM6000PH with SPRINT	Summer	On	Off	55.8	2,149	5.64	4.54	0.428	7,542	882	3.0	20.0	4.2
	Summer	On	On	66.1	1,812	4.87	4.63		7,834	916	2.4	16.2	5.2
	Summer	Off	Off	51.8	2,315	6.02	4.54		7,639	893	3.0	20.0	4.0
	Winter	Off	Off	61.8	1,939	5.16	4.41		7,358	860	3.0	20.0	4.5
1x1 GE 7FA.05	Summer	On	Off	296.6	1,166	1.90	3.25	0.428	6,762	791	1.8	1.0	20.1
	Summer	On	On	323.0	1,071	1.80	3.27		6,859	802	1.6	0.9	22.2
	Summer	Off	Off	290.9	1,189	1.93	3.25		6,760	791	1.8	1.0	19.7
	Winter	Off	Off	328.8	1,052	1.79	3.13		6,681	781	1.8	1.0	22.0
2x1 GE 7EA (Heskett 3 Expansion)	Summer	On	Off	238.4	1,114	2.11	3.95	0.428	7,583	887	1.8	1.0	18.1
	Summer	On	On	265.1	1,002	1.97	3.98		7,694	900	1.6	0.9	20.4
	Summer	Off	Off	228.5	1,162	2.17	3.95		7,574	886	1.8	1.0	17.3
	Winter	Off	Off	280.2	948	1.91	3.80		7,566	885	1.8	1.0	21.2
2x1 Siemens SGT-800	Summer	On	Off	127.4	1,659	3.13	4.03	0.428	7,318	856	2.5	2.0	9.3
	Summer	On	On	139.8	1,512	2.91	4.06		7,415	867	2.2	1.8	10.4
	Summer	Off	Off	122.1	1,732	3.23	4.03		7,324	857	2.5	2.0	8.9
	Winter	Off	Off	145.6	1,453	2.83	3.90		7,291	853	2.5	2.0	10.6

Figure 8.2 - 2017 Combined-Cycle Combustion Turbine Generating Facility EGEAS Model Input Summary

Generating Facility Type	Configuration	Fuel	Plant Output (MW, net)	Loaded Capital Cost (\$/kW)	Fixed O&M (\$/kW-month)	Variable O&M (\$/MWh)	Major Maintenance (\$/kW-month)	Full Load Heat Rate (Btu/kWh, net, HHV)	Carbon Intensity (lb/MWh)	NO _x (ppmvd@15% O ₂)	CO (ppmvd@15%O ₂)	PM (lb/hr)
RICE	4 x Wartsila 20V34SG	Natural Gas	36.5	1,352	1.53	4.20	2.07	8,447	988	5	15	8.4
	3 x Wartsila 18V50SG	Natural Gas	55.3	1,383	1.54	4.20	2.07	8,288	969	5	15	12.6
Renewable - Biomass	Stoker Boiler	Loose Wheat Straw	9.3	9,211	9.90	5.92	0.39	14,273	3,718	70	76	9.3
Renewable - Wind	Generic 8 x GE 2.5-116-80m (20 MW in North Dakota)	N/A	20.0	1,542	3.71	0.00	2.51	N/A	0	0	0	0.0
	Generic 20 x GE 2.5-116-80m (50 MW in North Dakota)	N/A	50.0	1,519	3.71	0.00	2.51	N/A	0	0	0	0.0
	15 x Nordex N117 (45 MW Thunder Spirit Expansion)	N/A	45.0	1,750	1.12	0.00	0.00	N/A	0	0	0	0.0
Renewable - Solar	Generic Photovoltaic - Fixed Tilt (50 MW)	N/A	50.0	2,855	1.55	0.00	0.00	N/A	0	0	0	0.0
	Generic Thermal / Concentrated (50 MW)	N/A	50.0	11,476	6.01	4.37	0.39	N/A	0	0	0	0.0
Coal	Generic Circulating Fluidized Bed (with Carbon Capture)	Coal-Lignite	122.0	10,308	26.93	21.02	0.00	13,781	248	14.4	39.4	<18.7
	Generic Circulating Fluidized Bed (without Carbon Capture)	Coal-Lignite	168.0	5,623	19.62	13.25	0.00	9,974	1,945	14.4	39.4	<18.7

Figure 8.3 - 2017 Non-Combustion Turbine Generating Facility EGEAS Model Input Summary

SECTION 9

APPENDICES

APPENDIX A

COST TABLES

SIMPLE-CYCLE COMBUSTION TURBINES COST ANALYSIS TABLE

	20175 or Multiplier	Rate / Basis	Final Units	GE 7EA			GE LMS100PB			GE LM6000PH		
Fuel	--	--	--	Natural Gas			Natural Gas			Natural Gas		
Model Description	--	--	--	Thermoflow GE GT-7E.03. GT Pro Model Revised 04-14-2014. PEACE updated May 2015. Dry Low NOx Combustor. Raw Water Quality: Low TDS/ Low NTU			Thermoflow GE LMS100PB Wet IC GT Pro Model Revised 12-01-2011. PEACE updated August 2016. Dry Low NOx Combustor. Intercooler with Wet Cooling. Raw Water Quality: High TDS/High NTU. Compressor Inlet Temperature below minimum 10F for winter case. Winter operated at 10F.			Thermoflow GE LM6000PH. No Water Injection. GT Pro Model Revised 12-04-2009. PEACE updated August 2016. Dry Low NOx Combustor. Raw Water Quality: Low TDS/Low NTU.		
CTG Type	--	--	--	Frame			Aero-hybrid			Aero-derivative		
Uncontrolled NOx Emissions	--	OEM Data	ppmvd @ 15% O2	9 ppmvd			25 ppmvd			15 ppmvd		
SCR	--	--	--	Yes			Yes			Yes		
SCR Percent Reduction	--	--	--	0%			90%			80%		
SCR Capital Cost	--	Escalated 2015\$ (Thermoflow)	\$	--			2,709,930			1,864,300		
Uncontrolled CO Emissions	--	OEM Data	ppmvd @ 15% O2	5 ppmvd			200 ppmvd			100 ppmvd		
Oxidation Catalyst	--	--	--	Yes			Yes			Yes		
Oxidation Catalyst Percent Reduction	--	--	--	0%			80%			80%		
Estimated Construction Time (Mobilization to End; Calendar Days)	--	--	days	363			363			363		
Operating Case	--	--	--	Summer			Winter			Summer		
Evaporative Cooling	--	Yes (On) / No (Off)	--	Yes	No	No	Yes	No	No	Yes	No	No
Duct Burner	--	Yes (On) / No (Off)	--	--	--	--	--	--	--	--	--	--
Gross Plant Output	--	Thermoflow	MW	79.42	75.23	96.42	92.12	89.12	96.63	41.99	38.15	51.04
Net Plant Output	--	Thermoflow	MW	78.43	74.28	95.35	90.46	87.51	94.97	41.28	37.48	50.30
Net Full Load Heat Rate	--	Thermoflow	Btu/kWh HHV	11,498	11,638	11,074	8,832	9,079	8,825	9,637	9,921	9,253
Consumables	--	--	--	--	--	--	--	--	--	--	--	--
Aqueous Ammonia Consumption (19% Solution)	--	Thermoflow (b/hr)	Gal/hr	0	0	0	20.0	19.6	20.7	6.3	5.9	7.3
Water Consumption	--	Thermoflow (lbs)	Gal/hr	1,060	0	0	15,427	14,957	10,291	507	0	0
Fuel Consumption	--	Thermoflow (kBu/hr HHV)	MMBtu/hr HHV	902	864	1,056	814	795	838	398	372	465
Emissions Information (Outlet)	--	--	--	--	--	--	--	--	--	--	--	--
Carbon Intensity	53.06	40 CFR 98 Table C-1 (kg CO2 / MMBtu)	lb/MWh_net	1,345	1,361	1,295	1,052	1,062	1,032	1,127	1,180	1,082
NOx Emissions	--	Inlet OEM Data / % Reduction	ppmvd @ 15% O2	2.5			2.5			3		
CO Emissions	--	Inlet OEM Data / % Reduction	ppmvd @ 15% O2	5			40			20		
PM Emissions	0.01	(b/MMBtu) EPA, AP-42	b/hr	9.0	8.6	10.6	8.1	7.9	8.4	4.0	3.7	4.7
Unloaded Capital Cost												
Contractor's Internal Cost (CIC)	CIC	Thermoflow (Includes Equipment, Installation, SCR / Ox. Cat / Evap. Cooler, and Duct Burner Costs) Escalated (2015\$)	\$	51,597,932			70,754,820			37,398,270		
Generator Step Up Transformer	--	Thermoflow	\$	(Included in CIC)			(Included in CIC)			(Included in CIC)		
Fire Protection	--	Thermoflow	\$	(Included in CIC)			(Included in CIC)			(Included in CIC)		
Existing Water Treatment Capacity (Tanks, System)	--	Thermoflow	\$	--			--			--		
Gas Turbine Bridge Crane	--	Thermoflow	\$	(397,137)			--			--		
Fuel Gas Conditioning Skid	515,917	Escalated Cost of Heskett (\$515,917)/(FuelConsumption_option/Fuel Consumption GE EA SS'/0.6	\$	515,917			449,155			315,567		
Transmission Interconnect & MISO Queue Fee	--	MISO GIP	\$	4,985,000			4,985,000			2,735,000		
Gas Interconnect	4,000	\$/DKt/hr Consumed	\$	4,223,452			3,352,444			1,861,460		
Water Interconnect	20	\$/Gallon/hr Consumed	\$	308,547			308,547			373,983		
Land	1%	% of CIC	\$	515,979			707,548			373,983		
Spares Parts and Materials	1%	% of CIC	\$	515,979			707,548			373,983		
Developer's Fee	1%	% of CIC	\$	515,979			707,548			373,983		
Engineering Supervision & General & Administrative Rate	21.15%	% of First \$1 Million	\$	211,500			211,500			211,500		
Permits, Licenses, Fees & Miscellaneous	2%	% of CIC (Thermoflow)	\$	1,031,959			1,415,096			747,965		
Legal and Financial Costs	2%	% of CIC (Thermoflow)	\$	1,031,959			1,415,096			747,965		
Contractor's Soft Costs	--	Escalated 2015\$ (Thermoflow)	\$	10,436,073			13,884,400			7,460,290		
Subtotal - TCI-UL Without Contingency	--	\$	\$	75,184,593			98,898,703			52,599,966		
Contingency	20%	\$	\$	15,036,919			19,779,741			10,519,993		
Total Capital Investment - Unloaded, With Contingency	--	\$	\$	90,221,511			118,678,444			63,119,959		
Total Capital Investment - Unloaded	TCI - UL	TCI-UL	\$/kW	1,150	1,215	946	1,312	1,356	1,250	1,529	1,684	1,255
Loaded Capital Cost												
Interest During Construction	--	Based on TCI-UL over Construction Period.	\$	1,018,527			1,352,836			711,258		
Total Capital Investment - Loaded, with Contingency	--	\$	\$	91,240,038			120,031,280			63,831,217		
Total Capital Investment - Loaded	TCI - L	TCI-L	\$/kW	1,163	1,228	957	1,327	1,372	1,264	1,546	1,703	1,269
Fixed O&M Costs												
Labor												
Site Management (CTG)	1	X FTE	\$/kW-month	0.2	0.2	0.1	0.1	0.1	0.1	0.3	0.3	0.2
Site Management (HRSG, STG)	2	X FTE	\$/kW-month	--	--	--	--	--	--	--	--	--
Operations & Maintenance (CTG)	2.25	X FTE	\$/kW-month	0.3	0.4	0.3	0.3	0.3	0.3	0.7	0.7	0.5
Technical Services (CTG)	0.75	X FTE	\$/kW-month	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Operations & Maintenance (HRSG, STG)	6	X FTE	\$/kW-month	--	--	--	--	--	--	--	--	--
Technical Services (HRSG, STG)	3	X FTE	\$/kW-month	--	--	--	--	--	--	--	--	--
SCR O&M	0.25	X FTE	\$/kW-month	--	--	--	0.0	0.0	0.0	0.1	0.1	0.1
Water Treatment O&M	1	X FTE	\$/kW-month	0.2	0.2	0.1	0.1	0.1	0.1	0.3	0.3	0.2
SPRINT Water Injection O&M	0.5	X FTE	\$/kW-month	--	--	--	--	--	--	--	--	--
Intercooling O&M	0.9	X FTE	\$/kW-month	--	--	--	0.1	0.1	0.1	--	--	--
Aero derivative & Aero-hybrid O&M	0.2	X FTE	\$/kW-month	--	--	--	0.0	0.0	0.0	0.1	0.1	0.0
Aero derivative & Aero-hybrid TS	0.1	X FTE	\$/kW-month	--	--	--	0.0	0.0	0.0	0.0	0.0	0.0
Multi-unit O&M (CTG)	1	X FTE	\$/kW-month	--	--	--	--	--	--	--	--	--
Maintenance												
I&O and Electric Plant (CTG)	246	Escalated 2015\$ (\$/MW-year)	\$/kW-month	0.021			0.021			0.021		
Contracted Services (CTG)	308	Escalated 2015\$ (\$/MW-year)	\$/kW-month	0.026			0.026			0.026		
Steam Cycle Maintenance	5,632	\$/MW-year	\$/kW-month	--			--			--		
SCR Maintenance	1.5%	% of SCR-only TEC (Thermoflow)	\$/kW-month	0	0	0	0.037	0.039	0.036	0.056	0.062	0.046
Water Treatment	1,856	\$/MW-year	\$/kW-month	0.15			0.15			0.15		
SPRINT Water Injection (Water)	30.8	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			--			--		
SPRINT Water Injection (Wastewater Treatment)	24.4	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			--			--		
Intercooling (Heat Rejection)	123.1	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			0.010			0.010		
Intercooling (I&C)	61.5	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			0.005			0.005		
Aero derivative & Aero-hybrid (CTG)	123.1	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			0.010			0.010		
Aero derivative & Aero-hybrid (I&C)	61.5	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			0.005			0.005		
Multi-unit (CTG)	123.1	Escalated 2015\$ (\$/MW-year)	\$/kW-month	--			--			--		
Other Expenses												
Administration	492.3	Escalated 2015\$ (\$/MW-year)	\$/kW-month	0.041			0.041			0.041		
Property Taxes	0.369%	% of TCI-Loaded	\$/kW-month	0.377	0.398	0.510	0.430	0.445	0.410	0.501	0.552	0.411
Insurance	0.14%	% of TCI-Loaded	\$/kW-month	0.136	0.143	0.112	0.155	0.160	0.147	0.180	0.199	0.148
Aero derivative & Aero-hybrid Insurance	0.11%	% of TCI-Loaded	\$/kW-month	--	--	--	0.122	0.126	0.116	0.142	0.156	0.116
Total Fixed O&M Cost	F - O&M	O&M - Fixed	\$/kW-month	1.53	1.60	1.30	1.88	1.94	1.81	2.77	3.03	2.32
Major Maintenance Cost												
Combustion Turbine Overhaul	430.7	Escalated 2015\$ (\$/MW-year)	\$/kW-month	0.036			0.036			0.036		
Steam Turbine Overhaul	4,711	\$/MW-year	\$/kW-month	--			--			--		
Total Major Maintenance Cost	MM	Major Maintenance	\$/kW-month	0.036			0.036			0.036		
Variable O&M Costs												
Maintenance												
Combustion Turbine Generator	2.40	Escalated 2015\$ (\$/MWh)	\$/MWh	2.40			2.40			2.40		
Steam Cycle Maintenance	--	\$/MWh	\$/MWh	--			--			--		
SCR Catalyst Replacement	0.202	Escalated 2015\$ (\$/MWh)	\$/MWh	--			0.202			0.202		
Aero derivative & Aero hybrid (CTG)	1.23	Escalated 2015\$ (\$/MWh)	\$/MWh	--			1.230			1.230		
Multi-Unit (CTG)	0.615	Escalated 2015\$ (\$/MWh)	\$/MWh	--			--			--		
Chemicals												
All Models	0.024	Escalated 2015\$ (\$/MWh)	\$/MWh	0.024			0.024			0.024		
SCR Ammonia Consumption (19% Aqueous Solution)	1.49	Escalated 2015\$ (\$/gal) (Consumption - Thermoflow)	\$/MWh	--	--	--	0.33	0.33	0.32	0.23	0.23	0.21
Water Consumption	1.1	Escalated 2015\$ (\$/1000 gal) (Consumption - Thermoflow)	\$/MWh	0.01	0.00	0.00	0.18	0.18	0.11	0.01	0.00	0.00
Water Treatment	0.25	Escalated 2015\$ (\$/MWh)	\$/MWh	0.25			0.25			0.25		
Intercooling Heat Rejection Equipment	0.0615	Escalated 2015\$ (\$/MWh)	\$/MWh	0.0615			0.0615			0.0615		
Total Variable O&M Cost	V - O&M	O&M - Variable	\$/MWh	2.68	2.67	2.67	4.67	4.68	4.60	4.34	4.33	4.32

COMBINED-CYCLE COMBUSTION TURBINES COST ANALYSIS TABLE

RICE COST ANALYSIS TABLE

	2017\$ or Multiplier	Rate / Basis	Final Units	Wartsila 20V34SG	Wartsila 18V50SG
Fuel	--	--	--	Natural Gas	Natural Gas
Number of Engines	--	--	--	4	3
SCR	Included Per Engine	OEM Uncontrolled NOx Value / Reduction	--	Yes	Yes
Oxidation Catalyst	Included Per Engine	OEM Uncontrolled CO Value / Reduction	--	Yes	Yes
Estimated Construction Time (Mobilization to End; Calendar Days)	--	--	days	392	392
Operating Case					
	--	--	--	Summer	Summer
Gross Plant Output	--	OEM Proposal	MW	37.5	56.5
Net Plant Output	--	OEM Proposal	MW	36.5	55.3
Net Full Load Heat Rate	--	OEM Proposal	Btu/kWh HHV	8,447	8,288
Consumables					
Fuel Consumption	--	OEM Proposal	MMBtu/hr	82.68	125.2
Emissions Information (Outlet)					
Carbon Intensity	53.06	40 CFR 98 Table C-1 (kg CO2 / MMBtu)	lb/MWh	987.9	969.2
NOx Emissions	--	Inlet OEM Data / % Reduction	ppmvd @ 15% O2	5	5
CO Emissions	--	Inlet OEM Data / % Reduction	ppmvd @ 15% O2	15	15
PM Emissions	--	Inlet OEM Data / % Reduction	lb/hr	8.4	12.6
Unloaded Capital Cost					
Contractor's Internal Cost (CIC)	CIC	Wartsila Major Equipment + BOP/Engineering	\$	32,245,803	50,387,937
Wartsila Major Equipment	--	OEM Proposal	\$	20,790,000	32,680,000
BOP / Engineering	--	Escalated 2015\$ (Thermoflow)	\$	11,455,803	17,707,937
Generator Step Up Transformer	--	Escalated 2015\$ (Thermoflow)	\$	(Included in BOP)	(Included in BOP)
Fuel Gas Conditioning Skid	515,917	Escalated Cost of Heskett (\$515,917)*(Fuel Consumption Option/Fuel Consumption GE7EA SS)^0.6	\$	111,907	143,516
Transmission Interconnect & MISO Queue Fee	--	MISO GIP	\$	1,975,000	2,985,000
Gas Interconnect	4,000	\$/Dkt/hr Consumed	\$	330,720	500,654
Water Interconnect	--	\$/Gallon/hr Consumed	\$	--	--
Land	1%	% of CIC	\$	322,458	503,879
Spare Parts and Materials	1%	% of CIC	\$	322,458	503,879
Developer's Fee	1%	% of CIC	\$	322,458	503,879
Engineering Supervision & General & Administrative Rate	21.15%	% of First \$1 Million	\$	211,500	211,500
Permits, Licenses, Fees & Miscellaneous	2%	% of CIC (Thermoflow)	\$	644,916	1,007,759
Legal and Financial Costs	2%	% of CIC (Thermoflow)	\$	644,916	1,007,759
Contractor's Soft Costs (BOP / Engineering)	--	Escalated 2015\$ (Thermoflow)	\$	5,183,345	7,766,392
Subtotal - TCI-UL Without Contingency	--	\$	\$	42,315,481	65,522,154
Contingency	15%	\$	\$	6,347,322	9,828,323
Total Capital Investment - Unloaded, With Contingency	--	\$	\$	48,662,803	75,350,478
Total Capital Investment - Unloaded	TCI - UL	TCI-UL	\$/kW	1,333	1,363
Loaded Capital Cost					
Interest During Construction	--	Based on TCI-UL over Construction Period	\$	695,267	1,078,975
Total Capital Investment - Loaded, With Contingency	--	\$	\$	49,358,070	76,429,453
Total Capital Investment - Loaded	TCI - L	TCI-L	\$/kW	1,352	1,383
Fixed O&M Costs					
Labor & Maintenance	10.7	Escalated 2015\$ (OEM Provided) (\$/kW-yr)	\$/kW-month	0.892	0.892
Other Expenses					
Administration	492.3	Escalated 2015\$ (\$/MW-year)	\$/kW-month	0.041	0.041
Property Taxes	0.389%	% of TCI-Loaded	\$/kW-month	0.438	0.448
Insurance	0.14%	% of TCI-Loaded	\$/kW-month	0.158	0.161
Total Fixed O&M Cost	F - O&M	O&M - Fixed	\$/kW-month	1.53	1.54
Major Maintenance Cost					
Engine Maintenance	2.88	2017\$ OEM Proposal (\$/MWh) - 2,000 Hours	\$/kW-month	2.07	2.07
Total Major Maintenance Cost	MM	Major Maintenance	\$/kW-month	2.07	2.07
Variable O&M Costs					
Maintenance					
Scheduled BOP (OEM Equipment) Maintenance	0.62	2017\$ OEM Proposal (\$/MWh)	\$/MWh	0.62	0.62
Scheduled Minor Maintenance	1.88	2017\$ OEM Proposal (\$/MWh)	\$/MWh	1.88	1.88
SCR Catalyst Replacement	0.21	2017\$ OEM Proposal (\$/MWh) - 2,000 Hours	\$/MWh	0.21	0.21
Chemicals					
SCR Ammonia Consumption (19% Aqueous Solution)	0.9	2017\$ OEM Proposal (\$/MWh)	\$/MWh	0.9	0.9
Lube Oil	0.59	2017\$ OEM Proposal (\$/MWh)	\$/MWh	0.59	0.59
Total Variable O&M Cost	V - O&M	O&M - Variable	\$/MWh	4.20	4.20

BIOMASS COST ANALYSIS TABLE

	2017\$ or Multiplier	Rate / Basis	Final Units	Biomass
Fuel	--	--	--	Loose Wheat Straw
Boiler Type	--	--	--	Mass Burn Grate Boiler
SCR	--	Yes (On) / No (Off)	--	No
Estimated Construction Time (Mobilization to End; Calendar Days)	--	--	days	630
Operating Case	--	--	--	Summer
Gross Plant Output	--	Thermoflow	MW	9,998
Net Plant Output	--	Thermoflow	MW	9,301
Net Full Load Heat Rate	--	Thermoflow	Btu/kWh HHV	14,273
Consumables				
Fuel Consumption	--	Thermoflow (Btu/s)	Btu/hr	132,753,600
Water Consumption	--	Thermoflow (lb/s)	Gal/hr	10,999
Emissions				
Carbon Intensity	118.17	40 CFR 98 Table C-1 (kg CO ₂ / MMBtu)	lb/MWh, net	3,718
NOx Emissions	--	Engineering Assessment	ppmvd @ 15% O ₂	70
CO Emissions	--	Engineering Assessment	ppmvd @ 15% O ₂	76
PM Emissions	0.07	Area Source MACT Limit (lb/MMBtu)	lb/hr	9.3
Unloaded Capital Cost				
Contractor's Internal Cost (CIC)	CIC	Thermoflow (10MW), Escalated 2014\$	\$	55,522,552
Transmission Interconnect & MISO Queue Fee	--	MISO GIP	\$	555,000
Water Interconnect	20	\$/Gallon/hr Consumed	\$	219,971
Land	1%	% of CIC	\$	555,226
Spare parts and Materials	1%	% of CIC	\$	555,226
Developer's Fee	1%	% of CIC	\$	555,226
Engineering Supervision & General & Administrative Rate	21.15%	% of First \$1 Million	\$	211,500
Permits, Licenses, Fees & Miscellaneous	2%	% of CIC (Thermoflow)	\$	1,110,451
Legal and Financial Costs	2%	% of CIC (Thermoflow)	\$	1,110,451
Contractor's Soft Costs	--	Escalated 2014\$ (Thermoflow)	\$	9,609,441
Subtotal - TCI-UL Without Contingency			\$	70,005,043
Contingency	20%	\$	\$	14,001,009
Total Capital Investment - Unloaded, With Contingency	--	\$	\$	84,006,051
Total Capital Investment - Unloaded	TCI - UL	\$/kW	\$	9,032
Loaded Capital Cost				
Interest During Construction	--	Based on TCI-UL over Construction Period	\$	1,667,644
Total Capital Investment, Loaded, With Contingency	--	\$	\$	85,673,695
Total Capital Investment, Loaded	TCI - L	TCI - L	\$/kW	9,211
Fixed O&M Costs				
Fixed O&M	118.8	Escalated 2013\$/kW-yr - 50MW Unit (2015 Energy Outlook)	\$/kW-month	9.90
Total Fixed O&M Cost	F- O&M	O&M - Fixed	\$/kW-month	9.90
Major Maintenance Cost				
Steam Turbine Overhaul	4,711	\$/MW-year	\$/kW-month	0.393
Total Major Maintenance Cost	MM	Major Maintenance	\$/kW-month	0.393
Variable O&M Costs				
Variable O&M Cost	5.92	Escalated 2013\$/MWh - 50MW Unit (2015 Energy Outlook)	\$/MWh	5.92
Total Variable O&M Cost	V- O&M	O&M - Variable	\$/MWh	5.92
Tax Credits:				
Production Tax Credit	--	Energy.gov	\$/kWh	0.012
Investment Tax Credit	--	Energy.gov	\$/kW	N/A

WIND COST ANALYSIS TABLE

	2017\$ or Multiplier	Rate / Basis	Final Units	20MW Wind - ND	50MW Wind - ND	Thunder Spirit Wind Expansion
Location	--	--	--	North Dakota	North Dakota	North Dakota
Wind Turbine Model	--	--	--	GE 2.5-116-80m	GE 2.5-116-80m	Nordex N117
Number of Turbines	--	--	--	8	20	15
Estimated Construction Time (Mobilization to End; Calendar Days)	--	--	days	223	223	223
Operating Case				Summer	Summer	Summer
Gross Plant Output	--	--	MW	N/A	N/A	N/A
Net Plant Output	--	--	MW	20	50	45
Net Full Load Heat Rate	--	--	Btu/kWh HHV	N/A	N/A	N/A
Emissions						
Carbon Intensity	--	--	lb/MWh, net	0	0	0
NOx Emissions	--	--	ppmvd @ 15% O2	0	0	0
CO Emissions	--	--	ppmvd @ 15% O2	0	0	0
PM Emissions	--	--	lb/hr	0	0	0
Unloaded Capital Cost						
Contractor's Internal Cost (CIC)	CIC	--	\$	23,654,400	58,624,000	78,750,000
Wind Turbine Major Equipment	--	OEM Proposal	\$	18,480,000	45,800,000	78,750,000
Installation	0.28	% of Wind Turbine Major Equipment	\$	5,174,400	12,824,000	--
Transmission Interconnect & MISO Queue Fee	--	MISO GIP	\$	1,125,000	2,685,000	--
Water Interconnect	--	\$/Gallon/hr Consumed	\$	--	--	--
Land	1%	% of CIC	\$	236,544	586,240	--
Spare parts and Materials	1%	% of CIC	\$	236,544	586,240	--
Developer's Fee	1%	% of CIC	\$	236,544	586,240	--
Engineering Supervision & General & Administrative Rate	21.15%	% of First \$1 Million	\$	211,500	211,500	--
Permits, Licenses, Fees & Miscellaneous	2%	% of CIC (Thermoflow)	\$	473,088	1,172,480	--
Legal and Financial Costs	2%	% of CIC (Thermoflow)	\$	473,088	1,172,480	--
Contractor's Soft Costs	--	(Included in Installation)	\$	--	--	--
Subtotal - TCI-UL Without Contingency			\$	26,646,708	65,624,180	78,750,000
Contingency	15%	\$	\$	3,997,006	9,843,627	--
Total Capital Investment - Unloaded, With Contingency	--	\$	\$	30,643,714	75,467,807	78,750,000
Total Capital Investment - Unloaded	TCI - UL	\$/kW	\$	1,532	1,509	1,750
Loaded Capital Cost						
Interest During Construction	--	Based on TCI-UL over Construction Period	\$	196,938	483,747	0.0
Total Capital Investment, Loaded, With Contingency	--	\$	\$	30,840,652	75,951,554	78,750,000
Total Capital Investment, Loaded	TCI - L	TCI - L	\$/kW	1,542	1,519	1,750
Fixed O&M Costs						
Fixed O&M	44.49	Escalated 2013\$/kW-yr - 100MW (2015 Energy Outlook)	\$/kW-month	3.71	3.71	1.12
Total Fixed O&M Cost	F- O&M	O&M - Fixed	\$/kW-month	3.71	3.71	1.12
Major Maintenance Cost						
Gear Box Replacement & Other Major Maintenance	2.51	2017\$/kW-month (OEM)	\$/kW-month	2.51	2.51	0.00
Total Major Maintenance Cost	MM	Major Maintenance	\$/kW-month	2.51	2.51	0.00
Variable O&M Costs						
Variable O&M Cost	0	2015 Energy Outlook	\$/MWh	0.00	0.00	0.00
Total Variable O&M Cost	V- O&M	O&M - Variable	\$/MWh	0.00	0.00	0.00
Tax Credits: (Note 1)						
Production Tax Credit	--	Energy.gov	\$/kWh	0.018	0.018	0.018
Investment Tax Credit	--	Energy.gov	\$/kW	N/A	N/A	N/A
(1) Calculated assuming construction commencing in 2017. Phase-down 20% in 2017 from \$0.023/kWh in 2016						

SOLAR COST ANALYSIS TABLE

	2017\$ or Multiplier	Rate / Basis	Final Units	PV Fixed Tilt Solar	Concentrated Solar With Storage
Location	--	--	--	Bismarck, ND	Bismarck, ND
Type	--	--	--	PV - Fixed Tilt	Central Tower With Storage
Acres Required	--	--	Acres	250	
Estimated Construction Time (Mobilization to End; Calendar Days)	--	--	days	294	644
Operating Case	--	--	--	Summer	Summer
Gross Plant Output	--	--	MW	N/A	N/A
Net Plant Output	--	--	MW	50	50
Net Full Load Heat Rate	--	--	Btu/kWh HHV	N/A	N/A
Consumables					
Water Consumption	1,000	NREL Technical Report (gal/MWh) - Wet Cooled System	Gal/hr	--	50,000
Emissions					
Carbon Intensity	--	--	lb/MWh, net	0	0
NOx Emissions	--	--	ppmvd @ 15% O2	0	0
CO Emissions	--	--	ppmvd @ 15% O2	0	0
PM Emissions	--	--	lb/hr	0	0
Unloaded Capital Cost					
Contractor's Internal Cost (CIC)	CIC	--	\$	108,070,700	438,456,709
Concentrated Thermal Equipment	8,769	Escalated 2014\$/kW - 100MW (NREL)	\$	--	438,456,709
PV Equipment	2,161	Escalated 2014\$/kW - 100MW (NREL)	\$	108,070,700	--
Transmission Interconnect & MISO Queue Fee	--	MISO GIP	\$	2,685,000	2,685,000
Water Interconnect	20	\$/Gallon/hr Consumed	\$	--	1,000,000
Land	--	Included in Equipment Cost	\$	--	--
Spare parts and Materials	1%	% of CIC	\$	1,080,707	4,384,567
Developer's Fee	1%	% of CIC	\$	1,080,707	4,384,567
Engineering Supervision & General & Administrative Rate	21.15%	% of First \$1 Million	\$	211,500	211,500
Permits, Licenses, Fees & Miscellaneous	--	Included in Equipment Cost	\$	--	--
Legal and Financial Costs	--	Included in Equipment Cost	\$	--	--
Contractor's Soft Costs	--	Included in Equipment Cost	\$	--	--
Subtotal - TCI-UL Without Contingency			\$	113,128,614	451,122,343
Contingency	25%	\$	\$	28,282,154	112,780,586
Total Capital Investment - Unloaded, With Contingency	--	\$	\$	141,410,768	563,902,929
Total Capital Investment - Unloaded	TCI - UL	\$/kW	\$	2,828	11,278
Loaded Capital Cost					
Interest During Construction	--	Based on TCI-UL over Construction Period	\$	1,325,983	9,920,805
Total Capital Investment, Loaded, With Contingency	--	\$	\$	142,736,751	573,823,734
Total Capital Investment, Loaded	TCI - L	TCI - L	\$/kW	2,855	11,476
Fixed O&M Costs					
Concentrated Thermal Fixed O&M	72.12	Escalated 2014\$/kW-yr - 100MW (NREL)	\$/kW-month	--	6.01
PV Fixed O&M	18.58	Escalated 2014\$/kW-yr - 100MW (NREL)	\$/kW-month	1.55	--
Total Fixed O&M Cost	F- O&M	O&M - Fixed	\$/kW-month	1.55	6.01
Major Maintenance Cost					
Steam Turbine Overhaul	4,711	\$/MW-year	\$/kW-month	0	0.393
Total Major Maintenance Cost	MM	Major Maintenance	\$/kW-month	0	0.39
Variable O&M Costs					
Concentrated Thermal Variable O&M	4.37	Escalated 2014\$/MWh - 100MW (NREL)	\$/MWh	--	4.37
PV Variable O&M	0.00	Escalated 2014\$/kW-yr - 100MW (NREL)	\$/MWh	0.00	--
Total Variable O&M Cost	V- O&M	O&M - Variable	\$/MWh	0.00	4.37
Tax Credits: (Note 1)					
Production Tax Credit	--	Solar Energies Industries Association	\$/kWh	N/A	N/A
Investment Tax Credit	30%	% of TCI-L (Solar Energies Industries Association)	\$/kW	856	3,443

COAL COST ANALYSIS TABLE

Technology:	Circulating Fluidized Bed Combustion (CFBC) With Carbon Capture	Circulating Fluidized Bed Combustion (CFBC) Without Carbon Capture
Performance at Full Load:		
Gross Power Generation (Mwe):	146	185
Net Power Generation (Mwe):	122	168
Net Heat Rate (Btu/kWh):	13,781	9,974
Estimated Construction Time (Mobilization to End; Calendar Days)	1,302	966
Controlled Emissions:		
NOx ppmvd@15% O2 (lb/MWh-gross):	14.4 (0.69) [Note 2]	14.4 (0.54) [Note 2]
CO ppmvd@15% O2 (lb/MWh-gross):	39.4 (1.16)	39.4 (0.90)
PM lb/hr (lb/MWh-gross):	<18.7 (<7.0E-03) [Note 3]	<18.7 (<7.0E-03) [Note 3]
CO2 lb/MMBtu (lb/MWh-gross):	22 (248)	215 (1,945)
Estimated Cost (2017 dollars):		
Total Plant Capital Cost (\$/kW-net):	7,678	4,198
Contractor's Internal Cost (\$)	936,710,608	705,319,189
Transmission Interconnect & MISO Queue Fee (MISO GIP (MDU))	6,375,000	8,675,000
Water Interconnect Steam Options Only (\$20/Gal/hr Consumed)	3,658,705	3,658,705
Land (1%)	9,367,106	7,053,192
Spare Parts & Materials (1%)	9,367,106	7,053,192
Developer's Fee (1%)	9,367,106	7,053,192
Engineering Supervision & General & Administrative Rate (21.15% of first \$1Million)	211,500	211,500
Permits, Licenses, Fees & Miscellaneous (2%)	18,734,212	14,106,384
Legal and Financial Costs (2%)	18,734,212	14,106,384
Total Capital Investment - Unloaded Without Contingency (\$)	1,012,525,556	767,236,737
Total Capital Investment - Unloaded Without Contingency (\$/kW-net)	8,299	4,567
20% Contingency (\$/kW-net)	1,660	913
Total Capital Investment - Unloaded with Contingency (\$/kW-net)	9,959	5,480
Interest During Construction (\$/kW-net)	349	143
Total Capital Investment - Loaded with Contingency (\$/kW-net)	10,308	5,623
Fixed O&M Cost (\$/kW-month) [Note 5]:	26.93	19.62
Variable Non-Fuel O&M Cost (\$/MWh-net):	21.02	13.25
Major Maintenance (\$/kW-month):	0	0

*From 2012 Worley Parsons 'A Study of Advanced Generation Technology Systems'

*Sequestration is not included in the cost estimates.

[1] Treated reflects sulfur removal in fluid bed and polishing in FGD system

[2] Treated reflects SNCR, 60% reduction

[3] Treated reflects bag filter before stack

[4] Hg control via carbon bed (IGCC) and activated carbon injection (combustion technologies)

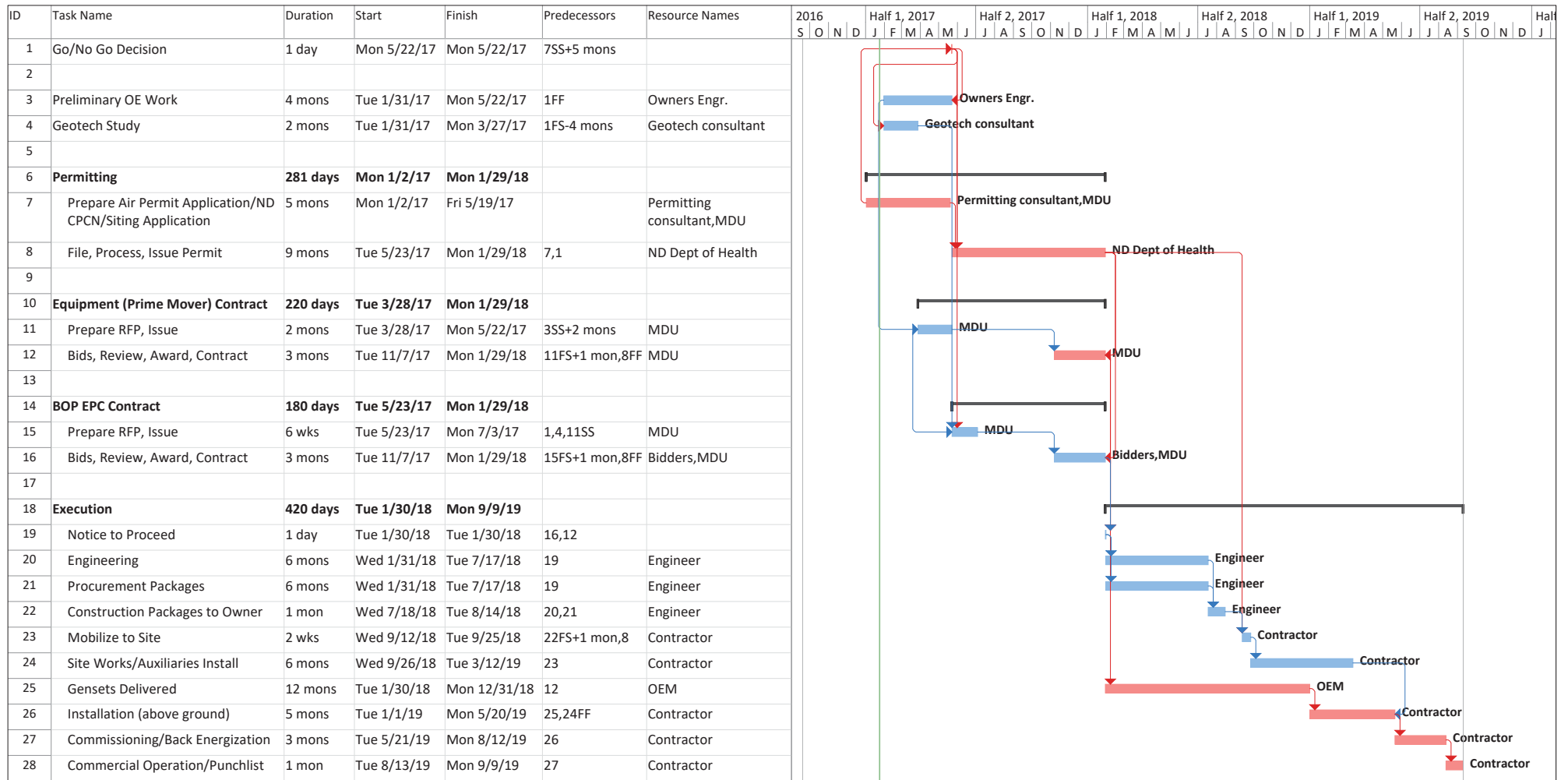
[5] \$/kW-month are the required units for the EGEAS model. To calculate this number, a 100% capacity factor was assumed (The EGEAS model does not take into consideration the capacity factor of thermal units because all units are dispatched based on economics). The Fixed O&M (1000 \$/yr) was divided by the months in a year and divided by the net power generation.

lb/MMBtu to ppm Conversion		
NOx	lb/MMBtu	0.06
CO	lb/MMBtu	0.1
Lignite Fd	dscf/MMBtu	9860
Conversion Factor NOx	lb/scf	1.19E-07
Conversion Factor CO	lb/scf	7.27E-08
ppm NOx at 15% O2	ppm	14.39
ppm CO at 15% O2	ppm	39.41

APPENDIX B

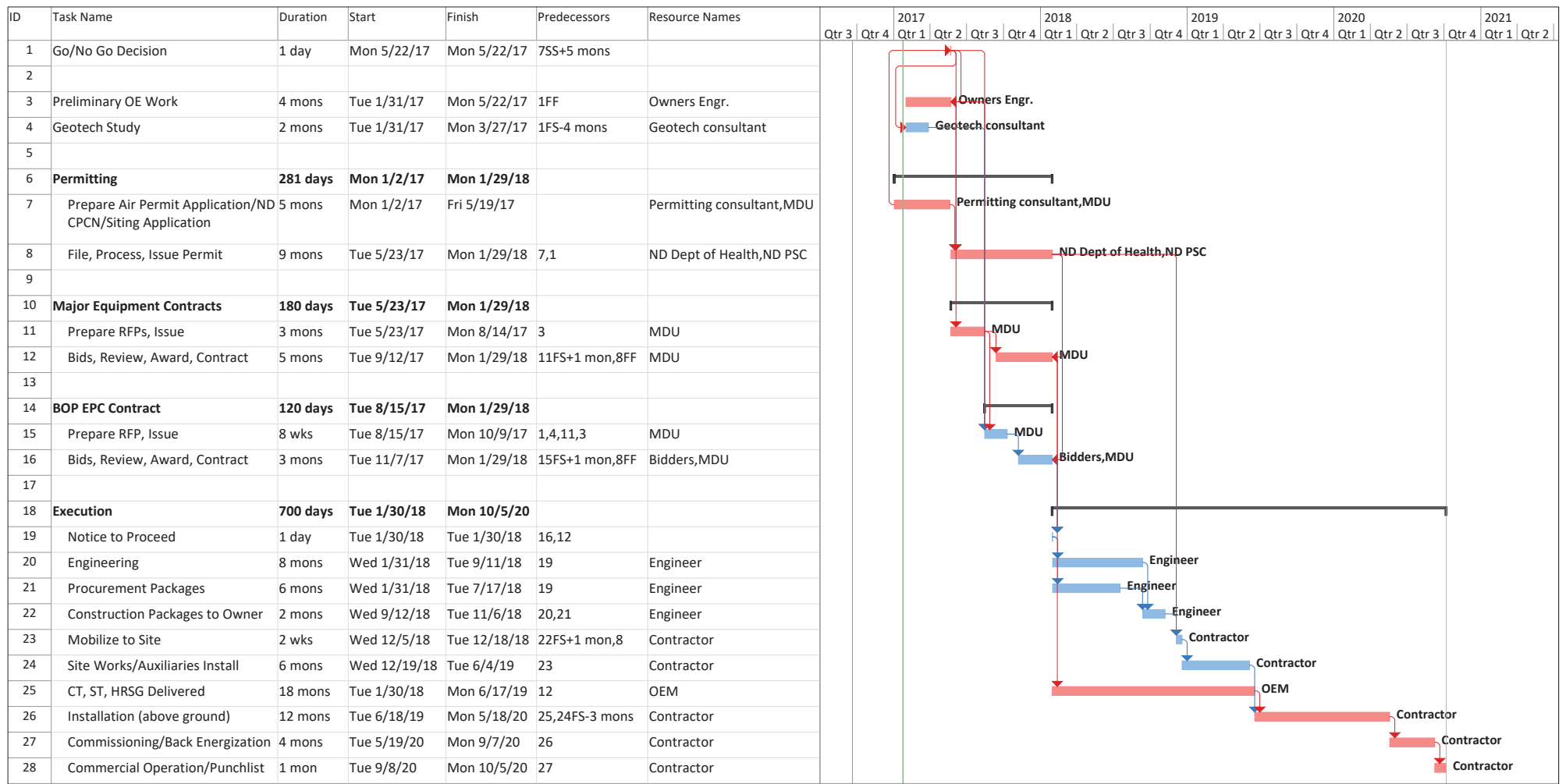
SCHEDULES

SIMPLE-CYCLE COMBUSTION TURBINES



Project: Montana-Dakota Simple-Cycle CTs Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

COMBINED-CYCLE COMBUSTION TURBINES



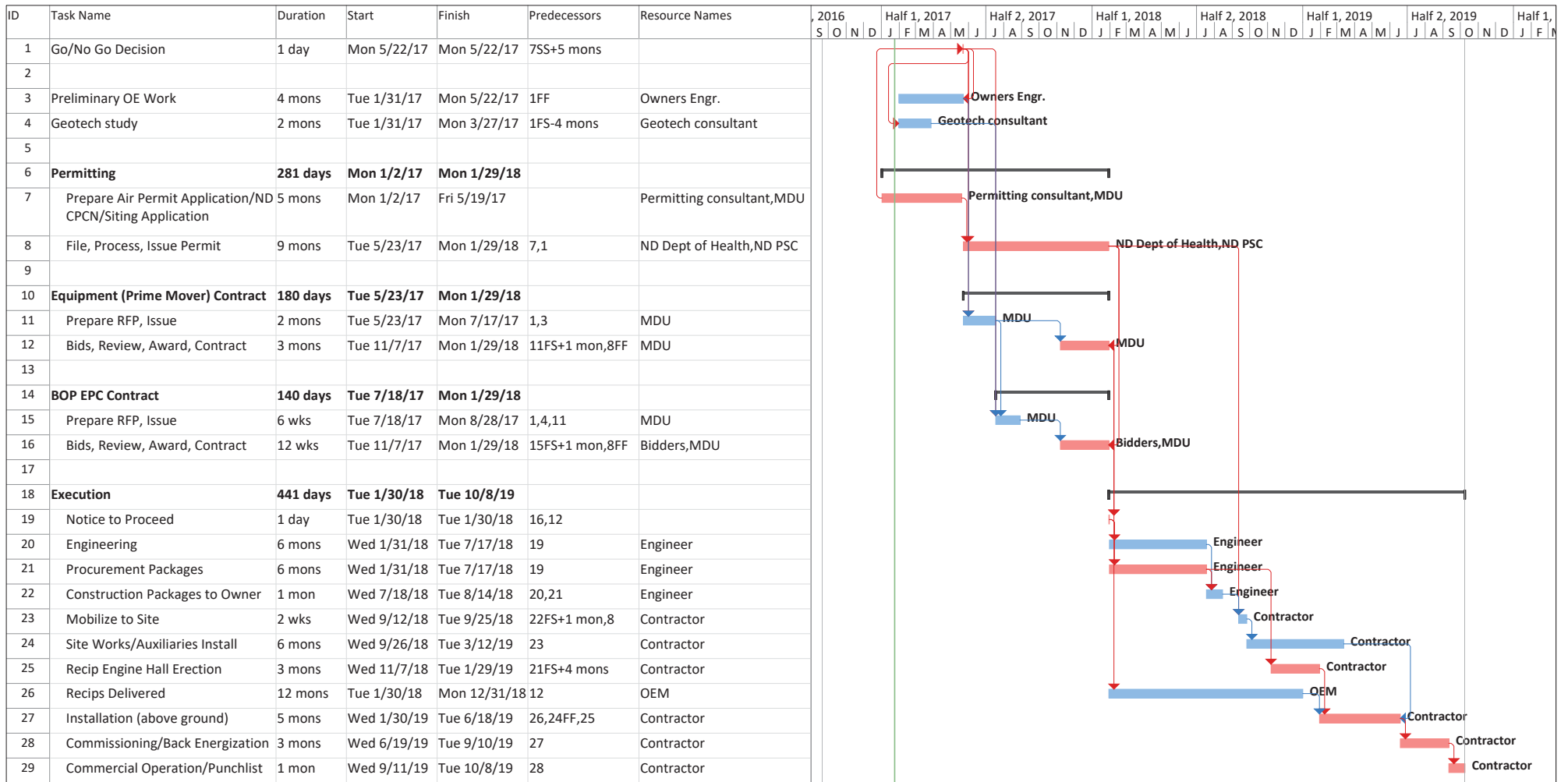
Project: Montana-Dakota Combined-Cycle CTs Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

COMBINED-CYCLE COMBUSTION TURBINES - HESKETT

ID	Task Name	Duration	Start	Finish	Predecessors	Resource Names	2017	2018	2019	2020	2021						
							Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
1	Go/No Go Decision	1 day	Mon 5/22/17	Mon 5/22/17	7SS+5 mons												
2																	
3	Preliminary OE Work	4 mons	Tue 1/31/17	Mon 5/22/17	1FF	Owners Engr.											
4	Geotech Study	3 mons	Tue 1/3/17	Mon 3/27/17	1FS-5 mons	Geotech consultant											
5																	
6	Permitting	281 days	Mon 1/2/17	Mon 1/29/18													
7	Prepare Air Permit Application/ND CPCN/Siting Application	5 mons	Mon 1/2/17	Fri 5/19/17		Permitting consultant,MDU											
8	File, Process, Issue Permit	9 mons	Tue 5/23/17	Mon 1/29/18	7,1	ND Dept of Health,ND PSC											
9																	
10	Major Equipment Contracts	180 days	Tue 5/23/17	Mon 1/29/18													
11	Prepare RFPs, Issue	3 mons	Tue 5/23/17	Mon 8/14/17	3	MDU											
12	Bids, Review, Award, Contract	5 mons	Tue 9/12/17	Mon 1/29/18	11FS+1 mon,8FF	MDU											
13																	
14	BOP EPC Contract	140 days	Tue 7/18/17	Mon 1/29/18													
15	Prepare RFP, Issue	8 wks	Tue 7/18/17	Mon 9/11/17	1,4,11SS+2 mons	MDU											
16	Bids, Review, Award, Contract	3 mons	Tue 11/7/17	Mon 1/29/18	15FS+1 mon,8FF	Bidders,MDU											
17																	
18	Execution	680 days	Tue 1/30/18	Mon 9/7/20													
19	Notice to Proceed	1 day	Tue 1/30/18	Tue 1/30/18	16,12												
20	Engineering	8 mons	Wed 1/31/18	Tue 9/11/18	19	Engineer											
21	Procurement Packages	6 mons	Wed 1/31/18	Tue 7/17/18	19	Engineer											
22	Construction Packages to Owner	2 mons	Wed 9/12/18	Tue 11/6/18	20,21	Engineer											
23	Mobilize to Site	2 wks	Wed 12/5/18	Tue 12/18/18	22FS+1 mon,8	Contractor											
24	Site Works/Auxiliaries Install	5 mons	Wed 12/19/18	Tue 5/7/19	23	Contractor											
25	CT, ST, HRSNG Delivered	18 mons	Tue 1/30/18	Mon 6/17/19	12	OEM											
26	Installation (above ground)	11 mons	Tue 6/18/19	Mon 4/20/20	25,24FS-3 mons	Contractor											
27	Commissioning/Back Energization	4 mons	Tue 4/21/20	Mon 8/10/20	26	Contractor											
28	Commercial Operation/Punchlist	1 mon	Tue 8/11/20	Mon 9/7/20	27	Contractor											

Project: Montana-Dakota Combined-Cycle CTs - Heskett Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

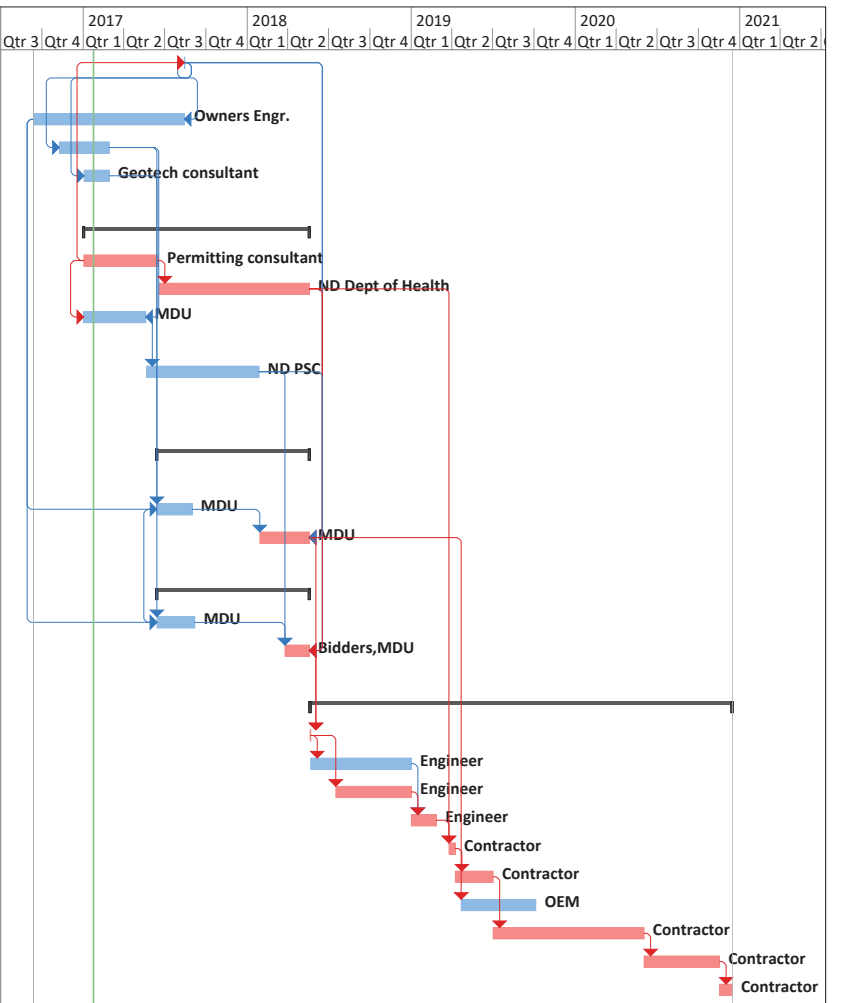
RECIPROCATING ENGINES



Project: Montana-Dakota Reciprocating Engines Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

WHEAT STRAW BIOMASS

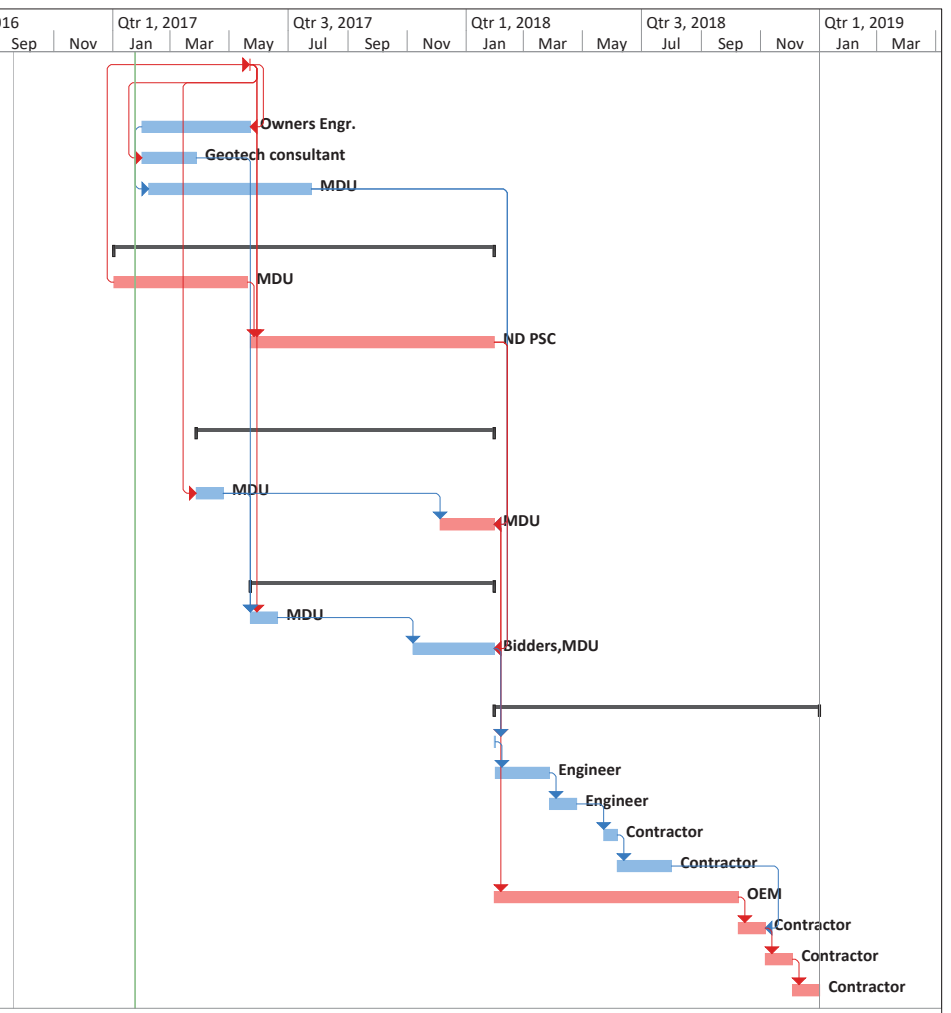
ID	Task Name	Duration	Start	Finish	Predecessors	Resource Names	2017	2018	2019	2020	2021								
							Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	
1	Go/No Go Decision	1 day	Mon 8/14/17	Mon 8/14/17	8SS+8 mons														
2																			
3	Preliminary OE Work	12 mons	Tue 9/13/16	Mon 8/14/17	1SF	Owners Engr.													
4	Fuel & Fuel Handling Study	4 mons	Wed 11/9/16	Mon 2/27/17	1FS-10 mons														
5	Geotech Study	2 mons	Tue 1/3/17	Mon 2/27/17	1FS-8 mons	Geotech consultant													
6																			
7	Permitting	360 days	Mon 1/2/17	Fri 5/18/18															
8	Prepare Air Permit Application	6 mons	Mon 1/2/17	Fri 6/16/17		Permitting consultant													
9	File, Process, Issue Permit	12 mons	Mon 6/19/17	Fri 5/18/18	8	ND Dept of Health													
10	Prepare ND CPCN and Siting Application	5 mons	Mon 1/2/17	Fri 5/19/17	8SS,4FF	MDU													
11	Approval of ND CPCN and Siting Application	9 mons	Mon 5/22/17	Fri 1/26/18	10	ND PSC													
12																			
13	Major Equipment Contracts (Boiler, STG, AQCS, Fuel Handling)	243 days	Wed 6/14/17	Fri 5/18/18															
14	Prepare RFPs, Issue	2.8 mons	Wed 6/14/17	Wed 8/30/17	3SS+9 mons,4	MDU													
15	Bids, Review, Award, Contract	4 mons	Mon 1/29/18	Fri 5/18/18	14FS+1 mon,1FF+1 mon,11FF+1 mon,9FF	MDU													
16																			
17	BOP EPC Contract	243 days	Wed 6/14/17	Fri 5/18/18															
18	Prepare RFP, Issue	3 mons	Wed 6/14/17	Tue 9/5/17	5,3SS+9 mons,14SS	MDU													
19	Bids, Review, Award, Contract	2 mons	Mon 3/26/18	Fri 5/18/18	18FS+1 mon,1FF+1 mon,9FF,11FS+1 mon	Bidders,MDU													
20																			
21	Execution	671 days	Mon 5/21/18	Mon 12/14/20															
22	Notice to Proceed	1 day	Mon 5/21/18	Mon 5/21/18	19,15														
23	Engineering	8 mons	Tue 5/22/18	Mon 12/31/18	22	Engineer													
24	Procurement Packages (other eqt)	6 mons	Tue 7/17/18	Mon 12/31/18	22FS+2 mons	Engineer													
25	Construction Packages to Owner	2 mons	Tue 1/1/19	Mon 2/25/19	23FS-2 mons,24	Engineer													
26	Mobilize to Site	2 wks	Tue 3/26/19	Mon 4/8/19	25FS+1 mon,9	Contractor													
27	Site Works/Auxiliaries Install	3 mons	Tue 4/9/19	Mon 7/1/19	26	Contractor													
28	Major Equipment Delivered	6 mons	Mon 4/22/19	Fri 10/4/19	15FS+12 mons	OEM													
29	Installation (above ground)	12 mons	Tue 7/2/19	Mon 6/1/20	27	Contractor													
30	Commissioning/Back Energization	6 mons	Tue 6/2/20	Mon 11/16/20	29	Contractor													
31	Commercial Operation/Punchlist	1 mon	Tue 11/17/20	Mon 12/14/20	30	Contractor													



Project: Montana-Dakota Wheat Straw Biomass Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

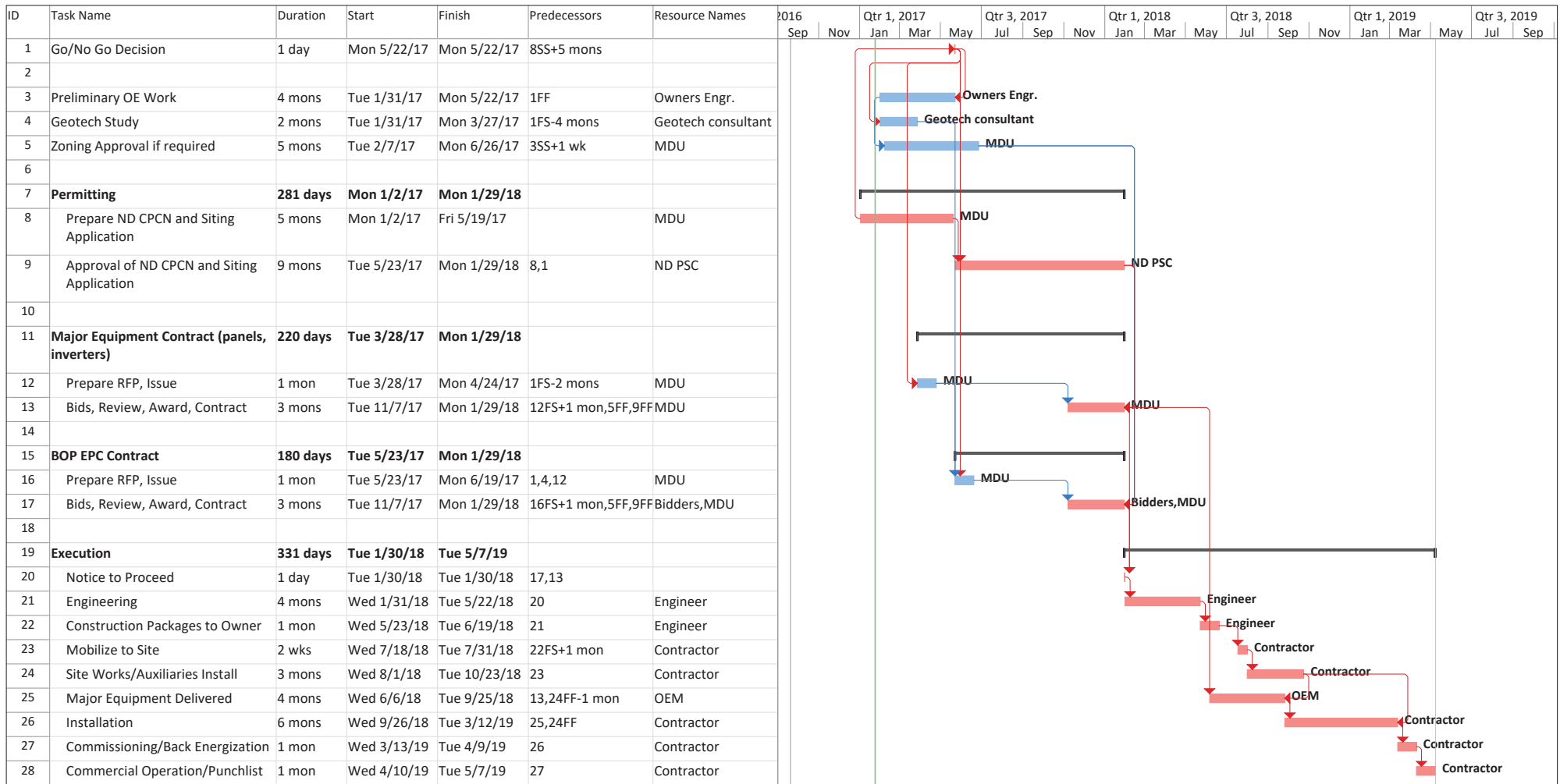
GENERIC WIND

ID	Task Name	Duration	Start	Finish	Predecessors	Resource Names	2016		Qtr 1, 2017			Qtr 3, 2017			Qtr 1, 2018			Qtr 3, 2018			Qtr 1, 2019	
							Sep	Nov	Jan	Mar	May	Jul	Sep	Nov	Jan	Mar	May	Jul	Sep	Nov	Jan	Mar
1	Go/No Go Decision	1 day	Mon 5/22/17	Mon 5/22/17	8SS+5 mons																	
2																						
3	Preliminary OE Work	4 mons	Tue 1/31/17	Mon 5/22/17	1FF	Owners Engr.																
4	Geotech Study	2 mons	Tue 1/31/17	Mon 3/27/17	1FS-4 mons	Geotech consultant																
5	Zoning Approval if required	6 mons	Tue 2/7/17	Mon 7/24/17	3SS+1 wk	MDU																
6																						
7	Permitting	281 days	Mon 1/2/17	Mon 1/29/18																		
8	Prepare ND CPCN and Siting Application	5 mons	Mon 1/2/17	Fri 5/19/17		MDU																
9	Approval of ND CPCN and Siting Application	9 mons	Tue 5/23/17	Mon 1/29/18	8,1	ND PSC																
10																						
11	Major Equipment Contract (nacelles/blades/towers)	220 days	Tue 3/28/17	Mon 1/29/18																		
12	Prepare RFP, Issue	1 mon	Tue 3/28/17	Mon 4/24/17	1FS-2 mons	MDU																
13	Bids, Review, Award, Contract	2 mons	Tue 12/5/17	Mon 1/29/18	12FS+1 mon,5FF,9FF	MDU																
14																						
15	BOP EPC Contract	180 days	Tue 5/23/17	Mon 1/29/18																		
16	Prepare RFP, Issue	1 mon	Tue 5/23/17	Mon 6/19/17	1,4FS+2 mons,12	MDU																
17	Bids, Review, Award, Contract	3 mons	Tue 11/7/17	Mon 1/29/18	16FS+1 mon,5FF,9FF	Bidders,MDU																
18																						
19	Execution	240 days	Tue 1/30/18	Mon 12/31/18																		
20	Notice to Proceed	1 day	Tue 1/30/18	Tue 1/30/18	17,13																	
21	Engineering	2 mons	Wed 1/31/18	Tue 3/27/18	20	Engineer																
22	Construction Packages to Owner	1 mon	Wed 3/28/18	Tue 4/24/18	21	Engineer																
23	Mobilize to Site	2 wks	Wed 5/23/18	Tue 6/5/18	22FS+1 mon	Contractor																
24	Site Works/Auxiliaries Install	2 mons	Wed 6/6/18	Tue 7/31/18	23	Contractor																
25	Major Equipment Delivered	9 mons	Tue 1/30/18	Mon 10/8/18	13	OEM																
26	Installation	1 mon	Tue 10/9/18	Mon 11/5/18	25,24FF	Contractor																
27	Commissioning/Back Energization	1 mon	Tue 11/6/18	Mon 12/3/18	26	Contractor																
28	Commercial Operation/Punchlist	1 mon	Tue 12/4/18	Mon 12/31/18	27	Contractor																



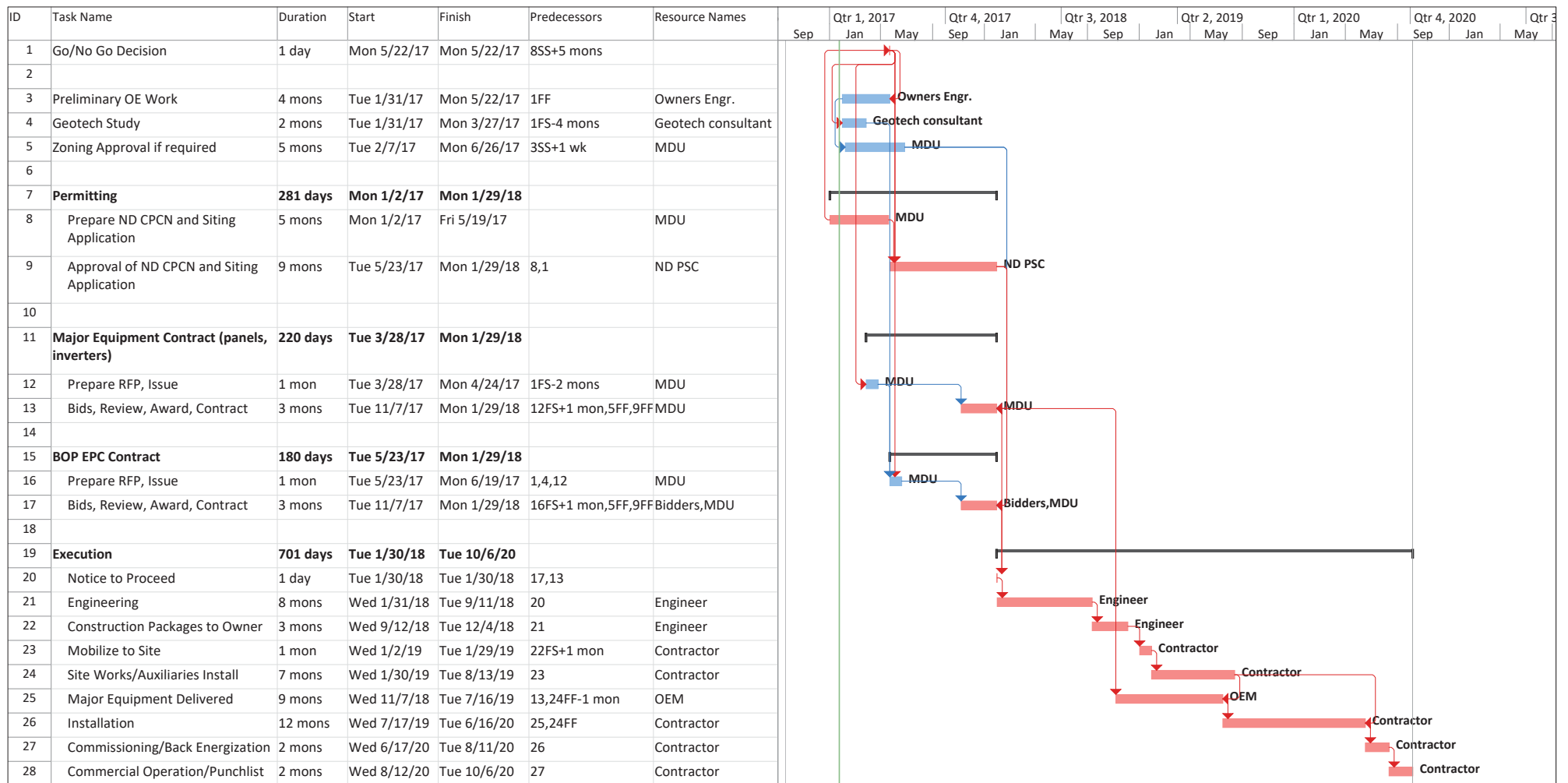
Project: Montana-Dakota Generic Wind Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

PV SOLAR



Project: Montana-Dakota PV Solar Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

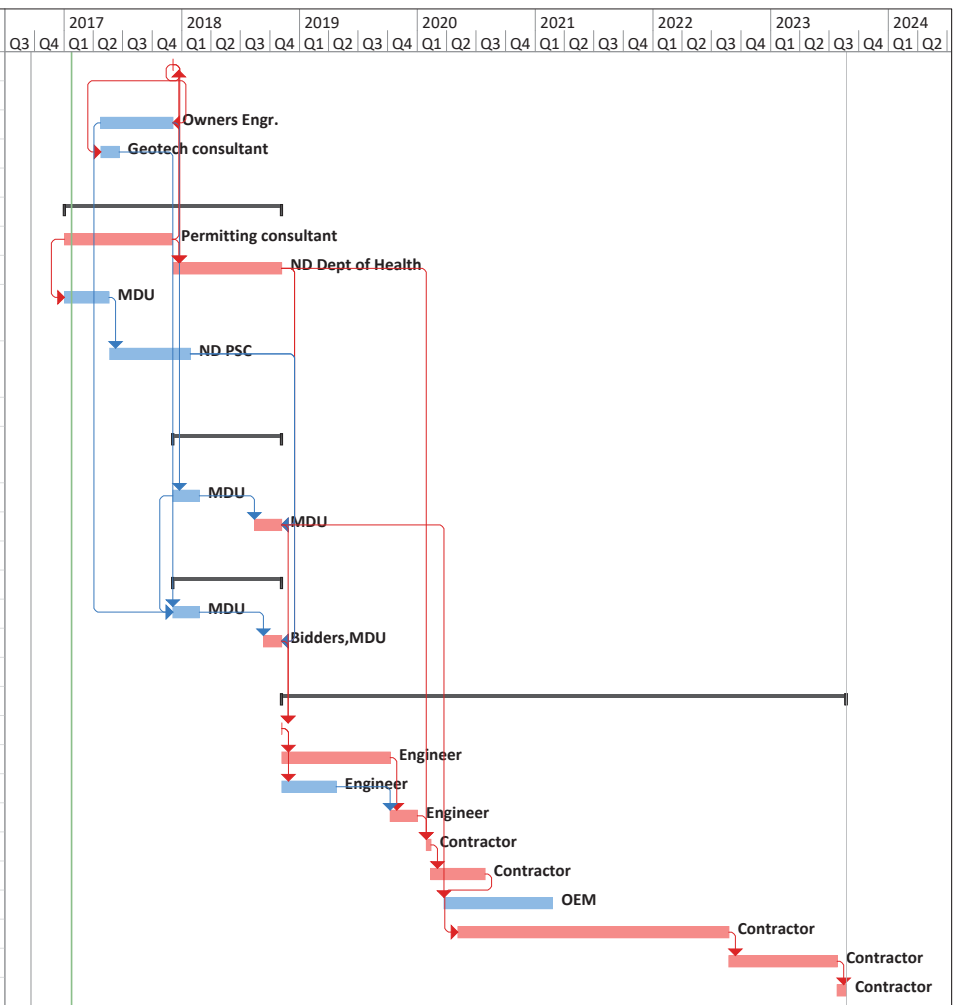
CONCENTRATED SOLAR



Project: Montana-Dakota Concentrated Solar Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

COAL WITH CARBON CAPTURE

ID	Task Name	Duration	Start	Finish	Predecessors	Resource Names	2017	2018	2019	2020	2021	2022	2023	2024		
							Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
1	Go/No Go Decision	1 day	Mon 12/4/17	Mon 12/4/17	7											
2																
3	Preliminary OE Work	8 mons	Mon 4/24/17	Mon 12/4/17	1SF	Owners Engr.										
4	Geotech Study	2 mons	Tue 4/25/17	Mon 6/19/17	1FS-8 mons	Geotech consultant										
5																
6	Permitting	481 days	Mon 1/2/17	Mon 11/5/18												
7	Prepare Air Permit Application	12 mons	Mon 1/2/17	Fri 12/1/17		Permitting consultant										
8	File, Process, Issue Permit	12 mons	Tue 12/5/17	Mon 11/5/18	7,1	ND Dept of Health										
9	Prepare ND CPCN and Siting Application	5 mons	Mon 1/2/17	Fri 5/19/17	7SS	MDU										
10	Approval of ND CPCN and Siting Application	9 mons	Mon 5/22/17	Fri 1/26/18	9	ND PSC										
11																
12	Major Equipment Contracts (Boiler, STG, AQCS)	241 days	Mon 12/4/17	Mon 11/5/18												
13	Prepare RFPs, Issue	3 mons	Mon 12/4/17	Fri 2/23/18	3	MDU										
14	Bids, Review, Award, Contract	3 mons	Tue 8/14/18	Mon 11/5/18	13FS+1 mon,8FF,10FF	MDU										
15																
16	BOP EPC Contract	241 days	Mon 12/4/17	Mon 11/5/18												
17	Prepare RFP, Issue	3 mons	Mon 12/4/17	Fri 2/23/18	4,3SS+3 mons,13SS	MDU										
18	Bids, Review, Award, Contract	2 mons	Tue 9/11/18	Mon 11/5/18	17FS+1 mon,8FF,10FF	Bidders,MDU										
19																
20	Execution	1251 days	Tue 11/6/18	Tue 8/22/23												
21	Notice to Proceed	1 day	Tue 11/6/18	Tue 11/6/18	18,14											
22	Engineering	12 mons	Wed 11/7/18	Tue 10/8/19	21	Engineer										
23	Procurement Packages (other eqt)	6 mons	Wed 11/7/18	Tue 4/23/19	21	Engineer										
24	Construction Packages to Owner	3 mons	Wed 10/9/19	Tue 12/31/19	22,23	Engineer										
25	Mobilize to Site	2 wks	Wed 1/29/20	Tue 2/11/20	24FS+1 mon,8	Contractor										
26	Site Works/Auxiliaries Install	6 mons	Wed 2/12/20	Tue 7/28/20	25	Contractor										
27	Major Equipment Delivered	12 mons	Tue 3/24/20	Mon 2/22/21	14FS+18 mons	OEM										
28	Installation (above ground)	30 mons	Wed 5/6/20	Tue 8/23/22	26FS-3 mons	Contractor										
29	Commissioning/Back Energization	12 mons	Wed 8/24/22	Tue 7/25/23	28	Contractor										
30	Commercial Operation/Punchlist	1 mon	Wed 7/26/23	Tue 8/22/23	29	Contractor										



Project: Montana-Dakota Coal w/ CO2 Capture Date: December 16, 2016	Task		External Tasks		Manual Task		Finish-only		Manual Progress
	Split		External Milestone		Duration-only		Deadline		
	Milestone		Inactive Task		Manual Summary Rollup		Critical		
	Summary		Inactive Milestone		Manual Summary		Critical Split		
	Project Summary		Inactive Summary		Start-only		Progress		

COAL WITHOUT CARBON CAPTURE

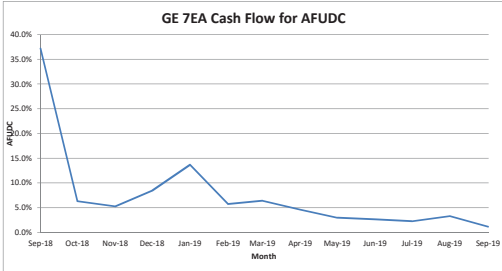
APPENDIX C

CASH FLOWS

SIMPLE-CYCLE COMBUSTION TURBINES

1 x GE 7EA

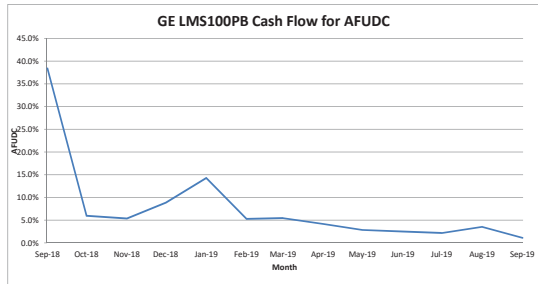
I x GE 7EA																																						
Scope	Totals	Month																																				
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33				
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19				
Engineering (incl. geotech)	\$ 2,129,915 100.0%		\$ 21,299 1.0%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 21,299 1.0%	\$ 21,299 1.0%				\$ 21,299 1%	\$ 21,299 1%	\$ 21,299 1%	\$ 149,094 7%	\$ 212,992 10%	\$ 319,487 15%	\$ 319,487 15%	\$ 255,590 12%	\$ 170,393 8%	\$ 63,897 3%	\$ 21,299 1%	\$ 31,949 1.5%	\$ 21,299 1%	\$ 42,598 2%	\$ 42,598 2%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 31,949 1.5%	\$ 21,299 1%					
Major Equipment (CT only)	\$ 32,039,810 100%														\$ 5,446,768 17%	\$ 1,922,389 6%	\$ 1,922,389 6%	\$ 1,922,389 6%	\$ 1,601,990 5%	\$ 1,601,990 5%	\$ 1,601,990 5%	\$ 1,601,990 5%	\$ 1,601,990 5%	\$ 1,601,990 5%	\$ 3,203,981 10%	\$ 6,407,962 20%						\$ 1,601,990 5%						
Fuel Gas Conditioning Skid	\$ 515,917 100%																					\$ 103,183 20%	\$ 103,183 20%	\$ 103,183 20%	\$ 103,183 20%	\$ 103,183 20%												
MISO Queue Fees and Network Upgrades	\$ 4,985,000 100%	\$ 569,000 11%				\$ 96,000 2%		\$ 480,000 10%																		\$ 960,000 19%	\$ 960,000 19%	\$ 960,000 19%	\$ 960,000 19%									
Gas Interconnect	\$ 4,223,432 100%																					\$ 1,055,863 25%	\$ 1,055,863 25%	\$ 1,055,863 25%										\$ 1,055,863 25%				
Water Interconnect	\$ - 0%																						\$ - -	\$ - -														
Land	\$ 515,979 100%					\$ 515,979 100%																																
Spare Parts and Marls	\$ 515,979 100%																									\$ 515,979 100%												
Developers Fee	\$ 515,979 100%												\$ 515,979 100%																									
Ingr Supv G&A	\$ 211,500 100%																										\$ 211,500 100%											
Permits, Licences, Fees	\$ 1,031,959 100%												\$ 1,031,959 100%																									
Legal/Financial	\$ 1,031,959 100%												\$ 515,980 50%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ - 0%	\$ 10,320 1%	\$ 10,320 1%	\$ 10,320 1%	\$ 20,639 2%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%	\$ 30,959 3%				
Contractor's Soft Costs	\$ 10,436,073 100%													\$ 313,082 3%	\$ 313,082 3%							\$ 521,804 5%	\$ 730,525 7%	\$ 834,886 8%	\$ 939,247 9%	\$ 1,043,607 10%	\$ 1,252,329 12%	\$ 1,043,607 10%	\$ 939,247 9%	\$ 834,886 8%	\$ 730,525 7%	\$ 626,164 6%	\$ 313,082 3%	\$ 313,082 3%	\$ 313,082 3%			
Contractor Internal Costs	\$ 17,021,070 100%												\$ 510,922 3%	\$ 510,922 3%								\$ 851,553 5%	\$ 1,192,175 7%	\$ 1,362,406 8%	\$ 1,532,796 9%	\$ 1,703,107 10%	\$ 2,043,728 12%	\$ 1,703,107 10%	\$ 1,532,796 9%	\$ 1,362,406 8%	\$ 1,192,175 7%	\$ 1,021,864 6%	\$ 510,922 3%	\$ 510,922 3%	\$ 510,922 3%			
Contingency (20%)	\$ 15,036,918 100%	\$ 113,800 0.8%	\$ 4,260 0.0%	\$ 6,390 0.0%	\$ 6,390 0.0%	\$ 128,786 0.9%	\$ 4,260 0.0%	\$ 100,260 0.7%				\$ 4,260 0.0%	\$ 4,260 0.0%	\$ 417,043 2.8%	\$ 1,280,167 8.6%	\$ 433,268 2.9%	\$ 454,567 3.0%	\$ 454,567 3.0%	\$ 377,708 2.5%	\$ 360,668 2.4%	\$ 550,542 3.7%	\$ 879,630 5.8%	\$ 949,329 6.3%	\$ 790,961 5.3%	\$ 1,273,749 8.5%	\$ 2,058,283 13.7%	\$ 859,731 5.7%	\$ 960,969 6.4%	\$ 694,862 4.6%	\$ 447,928 3.0%	\$ 395,058 2.6%	\$ 342,187 2.3%	\$ 497,782 3.3%	\$ 175,254 1.2%				
Checksum	\$ 90,221,510	\$ 682,800	\$ 25,559	\$ 38,338	\$ 38,338	\$ 772,713	\$ 25,559	\$ 601,559	\$ -	\$ -	\$ -	\$ 25,559	\$ 25,559	\$ 2,502,260	\$ 7,741,002	\$ 2,599,607	\$ 2,727,402	\$ 2,727,402	\$ 2,266,247	\$ 2,164,011	\$ 3,303,252	\$ 5,277,782	\$ 5,695,971	\$ 4,745,764	\$ 7,642,492	\$ 12,340,700	\$ 5,158,387	\$ 5,765,815	\$ 4,169,173	\$ 2,687,568	\$ 2,370,345	\$ 2,053,123	\$ 2,986,695	\$ 1,051,521				
Monthly	0.8%	0.0%	0.0%	0.0%	0.9%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	8.6%	2.9%	3.0%	3.0%	2.5%	2.4%	3.7%	5.8%	6.3%	5.3%	8.5%	13.7%	5.7%	6.4%	4.6%	3.0%	2.6%	2.3%	3.3%	1.2%				
Cumulative	0.8%	0.8%	0.8%	0.9%	1.7%	1.8%	2.4%	2.4%	2.4%	2.4%	2.4%	2.5%	5.3%	13.8%	16.7%	19.7%	22.8%	25.3%	27.7%	31.3%	37.2%	43.5%	48.8%	57.2%	70.9%	76.6%	83.0%	87.6%	90.6%	93.2%	95.5%	98.8%	100.0%					
AFUDC Cash Flow																																						



SIMPLE-CYCLE COMBUSTION TURBINES

1 x GE LMS100PB

I x GE LMS100PB																																			
Scope	Totals	Month																																	
		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	31	32	33	
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	
Engineering (incl. geotech)	\$ 2,328,830		\$ 23,288	\$ 34,932	\$ 34,932	\$ 34,932	\$ 23,288	\$ 23,288	\$ 23,288				\$ 23,288	\$ 23,288	\$ 23,288	\$ 163,018	\$ 232,883	\$ 349,325	\$ 349,325	\$ 279,460	\$ 186,306	\$ 69,865	\$ 23,288	\$ 34,932	\$ 23,288	\$ 46,577	\$ 46,577	\$ 46,577	\$ 34,932	\$ 34,932	\$ 34,932	\$ 34,932	\$ 34,932	\$ 23,288	
Major Equipment (CT only)	\$ 47,703,420		1.0%	1.3%	1.5%	1.5%	1.0%	1.0%			1%		1%	1%		\$ 8,109,581	\$ 2,862,205	\$ 2,862,205	\$ 2,862,205	\$ 2,862,205	\$ 2,385,171	\$ 2,385,171	\$ 2,385,171	\$ 2,385,171	\$ 2,385,171	\$ 4,770,342	\$ 9,540,684						\$ 2,385,171		
Fuel Gas Conditioning Skid	\$ 449,155															17%	6%	6%	6%	5%	5%	5%	\$ 89,831	\$ 89,831	\$ 89,831	\$ 89,831	\$ 89,831							5%	
MISO Queue Fees and Network Upgrades	\$ 4,985,000	\$ 569,000			\$ 96,000			\$ 480,000																		\$ 960,000	\$ 960,000	\$ 960,000	\$ 960,000						
Gas Interconnect	\$ 3,352,444					2%		10%													\$ 838,111	\$ 838,111	\$ 838,111											19%	
Water Interconnect	\$ 308,547																					\$ 77,137	\$ 77,137	\$ 77,137		\$ 77,137	\$ 77,137	\$ 77,137						25%	
Land	\$ 707,548				\$ 707,548																														100%
Spare Parts and Mat'ls	\$ 707,548																									\$ 707,548									100%
Developers Fee	\$ 707,548												\$ 707,548																						100%
Ingr Supv G&A	\$ 211,500																						\$ 211,500												100%
Permits, Licences, Fees	\$ 1,415,096												\$ 1,415,096																						100%
Legal/Financial	\$ 1,415,096											\$ 707,548	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	\$ 42,453	50%	
Contractor's Soft Costs	\$ 13,884,400											\$ 416,532	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	\$ 694,220	\$ 971,908	\$ 1,110,752	\$ 1,249,596	\$ 1,388,440	\$ 1,666,128	\$ 1,888,440	\$ 1,249,596	\$ 1,110,752	\$ 971,908	\$ 694,220	\$ 416,532	3%
Contractor Internal Costs	\$ 20,722,570											\$ 621,677	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	\$ 1,036,129	\$ 1,450,580	\$ 1,657,806	\$ 1,865,031	\$ 2,072,257	\$ 2,486,708	\$ 2,072,257	\$ 1,865,031	\$ 1,450,580	\$ 1,036,129	\$ 621,677	3%	
Contingency (20%)	\$ 19,779,740	\$ 113,800	\$ 4,658	\$ 6,986	\$ 6,986	\$ 167,696	\$ 4,658	\$ 100,658			\$ 4,658	\$ 4,658	\$ 570,696	\$ 1,870,652	\$ 627,508	\$ 650,797	\$ 650,797	\$ 541,417	\$ 522,786	\$ 667,120	\$ 1,079,568	\$ 1,178,025	\$ 1,061,860	\$ 1,754,276	\$ 2,828,048	\$ 1,047,310	\$ 1,077,006	\$ 824,742	\$ 563,528	\$ 497,144	\$ 430,761	\$ 700,153	\$ 220,790		
	\$ 118,678,442	0.6%	0.0%	0.0%	0.0%	0.8%	0.0%	0.5%			0.0%	0.0%	2.9%	9.5%	3.2%	3.3%	3.3%	2.7%	2.6%	3.4%	5.5%	6.0%	5.4%	8.9%	14.3%	5.3%	5.4%	4.2%	2.8%	2.5%	2.2%	3.5%	1.1%		
Checksum	\$ 118,678,442	\$ 682,800	\$ 27,946	\$ 41,919	\$ 41,919	\$ 1,006,177	\$ 27,946	\$ 603,946	\$ -	\$ -	\$ -	\$ 27,946	\$ 27,946	\$ 3,424,176	\$ 11,223,914	\$ 3,765,049	\$ 3,904,779	\$ 3,904,779	\$ 3,248,500	\$ 3,136,716	\$ 4,002,720	\$ 6,477,407	\$ 7,068,148	\$ 6,371,161	\$ 10,525,653	\$ 16,968,290	\$ 6,283,860	\$ 6,462,034	\$ 4,948,453	\$ 3,381,169	\$ 2,982,867	\$ 2,584,564	\$ 4,200,919	\$ 1,324,740	
Monthly		0.6%	0.0%	0.0%	0.0%	0.8%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	2.9%	9.5%	3.2%	3.3%	3.3%	2.7%	2.6%	3.4%	5.5%	6.0%	5.4%	8.9%	14.3%	5.3%	5.4%	4.2%	2.8%	2.5%	2.2%	3.5%	1.1%		
Cumulative		0.6%	0.6%	0.6%	0.7%	1.5%	1.5%	2.0%	2.0%	2.0%	2.1%	2.1%	5.0%	14.4%	17.6%	20.9%	24.2%	26.9%	29.6%	32.9%	38.4%	44.4%	49.7%	58.6%	72.9%	78.2%	83.6%	87.8%	90.7%	93.2%	95.3%	98.9%	100.0%		
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

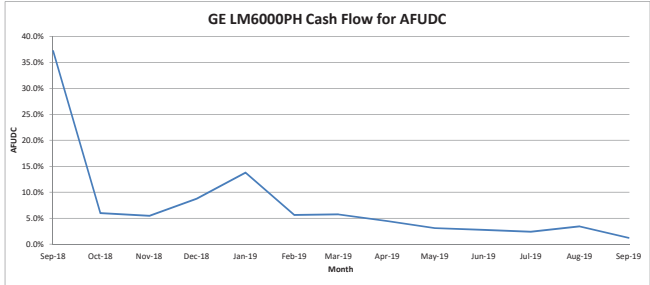


SIMPLE-CYCLE COMBUSTION TURBINES

1 x GE LM6000PH

1 x GE LM6000PH

Scope	Totals	Month																																					
		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	31	32	33					
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19					
Engineering (incl. geotech)	\$ 1,616,070		\$ 16,161	\$ 24,241	\$ 24,241	\$ 24,241	\$ 16,161	\$ 16,161			\$ 16,161	\$ 16,161	\$ 16,161	\$ 113,125	\$ 161,607	\$ 242,411	\$ 242,411	\$ 193,928	\$ 129,286	\$ 48,482	\$ 16,161	\$ 24,241	\$ 16,161	\$ 32,321	\$ 32,321	\$ 32,321	\$ 24,241	\$ 24,241	\$ 24,241	\$ 24,241	\$ 24,241	\$ 24,241	\$ 16,161	\$ 16,161					
Major Equipment (CT only)	\$ 23,083,330		1.0%	1.5%	1.5%	1.0%	1.0%				1%	1%	1%	7%	10%	15%	15%	12%	8%	3%	1%	1.5%	1%	2%	2%	2%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%				
Fuel Gas Conditioning Skid	\$ 315,567													\$ 3,924,166	\$ 1,385,000	\$ 1,385,000	\$ 1,385,000	\$ 1,154,167	\$ 1,154,167	\$ 1,154,167	\$ 1,154,167	\$ 1,154,167	\$ 1,154,167	\$ 2,308,333	\$ 4,616,666								\$ 1,154,167	5%					
MISO Queue Fees and Network Upgrades	\$ 2,735,000	\$ 389,000			\$ 51,000								\$ 255,000													\$ 510,000	\$ 510,000	\$ 510,000	\$ 510,000										
Gas Interconnect	\$ 1,861,460																			\$ 465,365	\$ 465,365	\$ 465,365																	
Water Interconnect	\$ -																				\$ -	\$ -	\$ -				\$ -	\$ -	\$ -										
Land	\$ 373,983				\$ 373,983																																		
Spare Parts and Mar's	\$ 373,983																								\$ 373,983														
Developers Fee	\$ 373,983												\$ 373,983																										
Engr Supv G&A	\$ 211,500																								\$ 211,500														
Permits, Licences, Fees	\$ 747,965												\$ 747,965																										
Legal/Financial	\$ 747,965												\$ 373,983	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430	\$ 22,430		
Contractor's Soft Costs	\$ 7,460,290													\$ 223,809								\$ 373,015	\$ 522,220	\$ 596,823	\$ 671,426	\$ 746,029	\$ 895,235	\$ 746,029	\$ 671,426	\$ 596,823	\$ 522,220	\$ 447,617	\$ 223,809	\$ 223,809	\$ 223,809	\$ 223,809			
Contractor Internal Costs	\$ 12,698,870												\$ 380,966									\$ 634,944	\$ 888,921	\$ 1,015,910	\$ 1,142,898	\$ 1,269,887	\$ 1,523,864	\$ 1,269,887	\$ 1,142,898	\$ 1,015,910	\$ 888,921	\$ 761,932	\$ 380,966	\$ 380,966	\$ 380,966	\$ 380,966			
Contingency (20%)	\$ 10,519,993	\$ 77,800	\$ 3,232	\$ 4,848	\$ 4,848	\$ 89,845	\$ 3,232	\$ 54,232		\$ 3,232	\$ 3,232	\$ 302,418	\$ 932,901	\$ 313,809	\$ 329,970	\$ 329,970	\$ 274,107	\$ 261,178	\$ 338,091	\$ 588,141	\$ 628,093	\$ 573,722	\$ 922,903	\$ 1,452,091	\$ 592,284	\$ 604,600	\$ 471,209	\$ 328,891	\$ 290,668	\$ 251,246	\$ 361,124	\$ 128,675	\$ 128,675	\$ 128,675	\$ 128,675				
	\$ 63,119,959	\$ 466,800	\$ 19,393	\$ 29,089	\$ 29,089	\$ 539,069	\$ 19,393	\$ 325,393	\$ -	\$ -	\$ -	\$ 19,393	\$ 19,393	\$ 1,814,509	\$ 5,597,406	\$ 1,382,855	\$ 1,979,819	\$ 1,979,819	\$ 1,644,641	\$ 1,567,069	\$ 2,028,543	\$ 3,528,843	\$ 3,768,559	\$ 3,442,335	\$ 5,537,417	\$ 8,712,547	\$ 3,553,705	\$ 3,627,602	\$ 2,827,254	\$ 1,973,344	\$ 1,740,410	\$ 1,507,476	\$ 2,166,746	\$ 772,049	\$ 772,049				
Monthly		0.7%	0.0%	0.0%	0.0%	0.9%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	2.9%	8.9%	3.0%	3.1%	3.1%	2.6%	2.5%	3.2%	5.6%	6.0%	5.5%	8.8%	13.8%	5.6%	5.7%	4.5%	3.1%	2.8%	2.4%	3.4%	1.2%	1.2%				
Cumulative		0.7%	0.8%	0.8%	0.9%	1.7%	1.7%	2.3%	2.3%	2.3%	2.3%	2.3%	5.2%	14.1%	17.0%	20.2%	23.3%	25.9%	28.4%	31.6%	37.2%	43.2%	48.6%	57.4%	71.2%	76.8%	82.6%	87.1%	90.2%	93.0%	95.3%	98.8%	100.0%	100.0%	100.0%				
AFUDC Cash Flow																																							

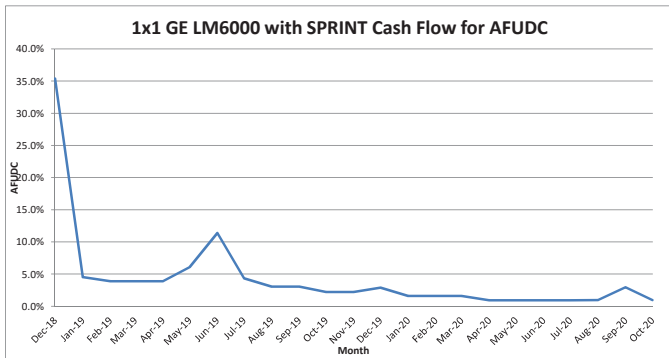


COMBINED-CYCLE COMBUSTION TURBINES

1 x 1 GE LM6000 with SPRINT

1 x 1 GE LM6000 with SPRINT

Scope	Totals	Month																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Engineering (incl. geotech)	\$ 5,218,693 100%	\$ 52,187 1%	\$ 78,280 1.5%	\$ 78,280 1.5%	\$ 78,280 1.5%	\$ 52,187 1%	\$ 52,187 1%				\$ 52,187 1%	\$ 52,187 1%	\$ 52,187 1%	\$ 365,308 7%	\$ 417,495 8%	\$ 626,243 12%	\$ 678,430 13%	\$ 521,869 10%	\$ 313,122 6%	\$ 156,561 3%	\$ 52,187 1%	\$ 78,280 1.5%	\$ 52,187 1%	\$ 104,374 2%	
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 39,401,429 100%													\$ 5,122,186 13%	\$ 1,970,071 5%	\$ 1,970,071 5%	\$ 1,576,057 4%	\$ 1,576,057 4%	\$ 1,576,057 4%	\$ 1,576,057 4%	\$ 1,576,057 4%	\$ 1,576,057 4%	\$ 1,576,057 4%	\$ 1,576,057 4%	
Fuel Gas Conditioning Skid	\$ 336,573 100%																							\$ 48,082 14%	
MISO Queue Fees and Network Upgrades	\$ 3,535,000 100%					\$ 453,000 13%					\$ 67,000 2%		\$ 335,000 9%												
Gas Interconnect	\$ 2,072,528 100%																						\$ 518,132 25%	\$ 518,132 25%	
Water Interconnect	\$ 477,842 100%																							\$ 119,461 25%	
Land	\$ 718,526 100%				\$ 718,526 100%																				
Spare Parts and Mat'ls	\$ 718,526 100%																								
Developers Fee	\$ 718,526 100%												\$ 718,526 100%												
Engr Supv G&A	\$ 211,500 100%																							\$ 211,500 100%	
Permits, Licences, Fees	\$ 1,437,053 100%												\$ 1,437,053 100%												
Legal/Financial	\$ 1,437,053 100%											\$ 718,527 50%	\$ 43,112 3%	\$ 28,741 2%	\$ 28,741 2%	\$ 28,741 2%	\$ 28,741 2%	\$ 28,741 2%	\$ 28,741 2%	\$ 28,741 2%	\$ 14,371 1%	\$ 14,371 1%	\$ 14,371 1%	\$ 14,371 1%	
Contractor's Soft Costs	\$ 14,446,275 100%													\$ 288,926 2%											\$ 722,314 5%
Contractor Internal Costs	\$ 27,067,601 100%													\$ 541,352 2%											\$ 1,353,380 5%
Contingency (20%)	\$ 19,559,425 100%	\$ 10,437 0.1%	\$ 15,656 0.1%	\$ 15,656 0.1%	\$ 159,361 0.8%	\$ 101,037 0.5%	\$ 10,437 0.1%				\$ 23,837 0.1%	\$ 10,437 0.1%	\$ 652,258 3.3%	\$ 1,272,177 6.5%	\$ 483,262 2.5%	\$ 525,011 2.7%	\$ 456,646 2.3%	\$ 425,333 2.2%	\$ 383,584 2.0%	\$ 352,272 1.8%	\$ 328,523 1.7%	\$ 333,742 1.7%	\$ 432,149 2.2%	\$ 933,534 4.8%	
Checksum	\$ 117,356,550	\$ -	\$ 62,624	\$ 93,936	\$ 93,936	\$ 956,168	\$ 606,224	\$ 62,624	\$ -	\$ -	\$ -	\$ 143,024	\$ 62,624	\$ 3,913,551	\$ 7,633,060	\$ 2,899,570	\$ 3,150,067	\$ 2,739,874	\$ 2,552,001	\$ 2,301,504	\$ 2,113,631	\$ 1,971,138	\$ 2,002,450	\$ 2,592,896	\$ 5,601,204
Monthly	0.0%	0.1%	0.1%	0.1%	0.8%	0.5%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	3.3%	6.5%	2.5%	2.7%	2.3%	2.2%	2.0%	1.8%	1.7%	1.7%	2.2%	4.8%	
Cumulative	0.0%	0.1%	0.1%	0.2%	1.0%	1.5%	1.6%	1.6%	1.6%	1.6%	1.7%	1.8%	5.1%	11.6%	14.1%	16.8%	19.1%	21.3%	23.2%	25.0%	26.7%	28.4%	30.6%	35.4%	
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.4%	



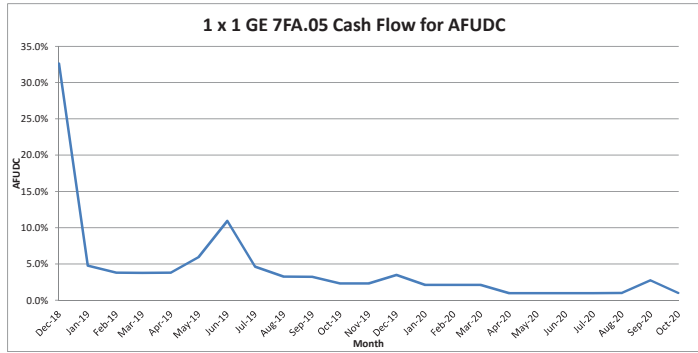
1 x 1 GE LM6000 with SPRINT

Scope	Totals	Month																							
		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20		
Engineering (incl. geotech)	\$ 5,218,693	\$ 78,280	\$ 78,280	\$ 78,280	\$ 78,280	\$ 78,280	\$ 78,280	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187	\$ 52,187		
	100%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%		
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 39,401,429	\$ 1,576,057	\$ 1,576,057	\$ 1,576,057	\$ 1,576,057	\$ 2,758,100	\$ 6,698,243															\$ 1,970,071			
	100%	4%	4%	4%	4%	7%	17%															5%			
Fuel Gas Conditioning Skid	\$ 336,573	\$ 48,082	\$ 48,082	\$ 48,082	\$ 48,082	\$ 48,082	\$ 48,082																		
	100%	14%	14%	14%	14%	14%	14%																		
MISO Queue Fees and Network Upgrades	\$ 3,535,000											\$ 670,000	\$ 670,000	\$ 670,000	\$ 670,000										
	100%											19%	19%	19%	19%										
Gas Interconnect	\$ 2,072,528	\$ 518,132					\$ 518,132																		
	100%	25%					25%																		
Water Interconnect	\$ 477,842	\$ 119,461				\$ 119,461	\$ 119,461																		
	100%	25%				25%	25%																		
Land	\$ 718,526																								
	100%																								
Spare Parts and Mat'ls	\$ 718,526						\$ 718,526																		
	100%						100%																		
Developers Fee	\$ 718,526																								
	100%																								
Engr Supv G&A	\$ 211,500																								
	100%																								
Permits, Licences, Fees	\$ 1,437,053																								
	100%																								
Legal/Financial	\$ 1,437,053	\$ 14,371	\$ -	\$ -	\$ 14,371	\$ 14,371	\$ 28,741	\$ 28,741	\$ 28,741	\$ 14,371	\$ 14,371	\$ 14,371	\$ 14,371	\$ 14,371	\$ 14,371	\$ 14,371	\$ 14,371	\$ 14,371	\$ 28,741	\$ 28,741	\$ 43,112	\$ 43,112			
	100%	1%	0%	0%	1%	1%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%			
Contractor's Soft Costs	\$ 14,446,275	\$ 722,314	\$ 722,314	\$ 722,314	\$ 722,314	\$ 1,011,239	\$ 1,011,239	\$ 1,444,628	\$ 1,011,239	\$ 1,011,239	\$ 722,314	\$ 722,314	\$ 722,314	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926	\$ 288,926		
	100%	5%	5%	5%	5%	7%	7%	10%	7%	7%	5%	5%	5%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%		
Contractor Internal Costs	\$ 27,067,601	\$ 1,353,380	\$ 1,353,380	\$ 1,353,380	\$ 1,353,380	\$ 1,894,732	\$ 1,894,732	\$ 2,706,760	\$ 1,894,732	\$ 1,894,732	\$ 1,353,380	\$ 1,353,380	\$ 1,353,380	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352	\$ 541,352		
	100%	5%	5%	5%	5%	7%	7%	10%	7%	7%	5%	5%	5%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%		
Contingency (20%)	\$ 19,559,425	\$ 886,015	\$ 755,623	\$ 755,623	\$ 758,497	\$ 1,184,853	\$ 2,223,087	\$ 846,463	\$ 597,380	\$ 594,506	\$ 428,450	\$ 428,450	\$ 562,450	\$ 313,367	\$ 313,367	\$ 313,367	\$ 179,367	\$ 179,367	\$ 182,241	\$ 182,241	\$ 185,115	\$ 579,130			
	100%	4.5%	3.9%	3.9%	3.9%	6.1%	11.4%	4.3%	3.1%	3.0%	2.2%	2.2%	2.9%	1.6%	1.6%	1.6%	0.9%	0.9%	0.9%	0.9%	0.9%	3.0%			
	\$ 117,356,550																								
Checksum	\$ 117,356,550	\$ 5,316,092	\$ 4,533,736	\$ 4,533,736	\$ 4,550,981	\$ 7,109,118	\$ 13,338,523	\$ 5,078,779	\$ 3,584,279	\$ 3,567,035	\$ 2,570,702	\$ 2,570,702	\$ 3,374,702	\$ 1,880,202	\$ 1,880,202	\$ 1,880,202	\$ 1,076,202	\$ 1,076,202	\$ 1,093,447	\$ 1,093,447	\$ 1,110,691	\$ 3,474,777			
		4.5%	3.9%	3.9%	3.9%	6.1%	11.4%	4.3%	3.1%	3.0%	2.2%	2.2%	2.9%	1.6%	1.6%	1.6%	0.9%	0.9%	0.9%	0.9%	0.9%	3.0%			
Monthly		4.5%	3.9%	3.9%	3.9%	6.1%	11.4%	4.3%	3.1%	3.0%	2.2%	2.2%	2.9%	1.6%	1.6%	1.6%	0.9%	0.9%	0.9%	0.9%	0.9%	3.0%			
Cumulative		39.9%	43.8%	47.7%	51.5%	57.6%	69.0%	73.3%	76.3%	79.4%	81.6%	83.8%	86.6%	88.2%	89.8%	91.4%	92.4%	93.3%	94.2%	95.1%	96.1%	99.1%			
AFUDC Cash Flow		4.5%	3.9%	3.9%	3.9%	6.1%	11.4%	4.3%	3.1%	3.0%	2.2%	2.2%	2.9%	1.6%	1.6%	1.6%	0.9%	0.9%	0.9%	0.9%	0.9%	3.0%			

COMBINED-CYCLE COMBUSTION TURBINES

1 x 1 GE 7FA.05

1 x 1 GE 7FA.05																									
Scope	Totals	Month																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Engineering (incl. geotech)	\$ 12,245,011 100%	\$ 61,225 0.5%	\$ 122,450 1%	\$ 122,450 1%	\$ 61,225 0.5%	\$ 61,225 0.5%	\$ 61,225 0.5%				\$ 122,450 1%	\$ 122,450 1%	\$ 244,900 2%	\$ 857,151 7%	\$ 979,601 8%	\$ 1,469,401 12%	\$ 1,591,851 13%	\$ 1,224,501 10%	\$ 734,701 6%	\$ 367,350 3%	\$ 244,900 2%	\$ 244,900 2%	\$ 122,450 1%	\$ 244,900 2%	
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 99,182,184 100%													\$ 12,893,684 13%	\$ 4,959,109 5%	\$ 4,959,109 5%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	
Fuel Gas Conditioning Skid	\$ 804,779 100%																							\$ 114,968 14%	
MISO Queue Fees and Network Upgrades	\$ 16,775,000 100%					\$ 1,641,000 10%					\$ 329,000 2%		\$ 1,645,000 10%												
Gas Interconnect	\$ 8,861,264 100%																							\$ 2,215,316 25%	\$ 2,215,316 25%
Water Interconnect	\$ 1,869,065 100%																								\$ 467,266 25%
Land	\$ 1,988,466 100%				\$ 1,988,466 100%																				
Spare Parts and Mat'ls	\$ 1,988,466 100%																								
Developers Fee	\$ 1,988,466 100%												\$ 1,988,466 100%												
Engr Supv G&A	\$ 211,500 100%																								\$ 211,500 100%
Permits, Licences, Fees	\$ 3,976,932 100%												\$ 3,976,932 100%												
Legal/Financial	\$ 3,976,932 100%												\$ 1,988,466 50%	\$ 119,308 3%	\$ 79,539 2%	\$ 79,539 2%	\$ 79,539 2%	\$ 79,539 2%	\$ 79,539 2%	\$ 79,539 2%	\$ 79,539 2%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%
Contractor's Soft Costs	\$ 41,418,597 100%													\$ 828,372 2%											\$ 2,070,930 5%
Contractor Internal Costs	\$ 87,099,267 100%													\$ 1,741,985 2%											\$ 4,354,963 5%
Contingency (20%)	\$ 56,477,186 100%	\$ 12,245 0.0%	\$ 24,490 0.0%	\$ 24,490 0.0%	\$ 409,938 0.7%	\$ 340,445 0.6%	\$ 12,245 0.0%				\$ 90,290 0.2%	\$ 24,490 0.0%	\$ 1,968,753 3.5%	\$ 3,288,100 5.8%	\$ 1,203,650 2.1%	\$ 1,301,610 2.3%	\$ 1,127,735 2.0%	\$ 1,054,265 1.9%	\$ 956,305 1.7%	\$ 882,835 1.6%	\$ 850,391 1.5%	\$ 850,391 1.5%	\$ 1,268,965 2.2%	\$ 2,737,380 4.8%	
	\$ 338,863,114																								
Checksum	\$ 338,863,114	\$ -	\$ 73,470	\$ 146,940	\$ 146,940	\$ 2,459,629	\$ 2,042,670	\$ 73,470	\$ -	\$ -	\$ -	\$ 541,740	\$ 146,940	\$ 11,812,517	\$ 19,728,600	\$ 7,221,898	\$ 7,809,659	\$ 6,766,413	\$ 6,325,592	\$ 5,737,832	\$ 5,297,012	\$ 5,102,348	\$ 5,102,348	\$ 7,613,787	\$ 16,424,281
Monthly		0.0%	0.0%	0.0%	0.0%	0.7%	0.6%	0.0%	0.0%	0.0%	0.2%	0.0%	3.5%	5.8%	2.1%	2.3%	2.0%	1.9%	1.7%	1.6%	1.5%	1.5%	2.2%	4.8%	
Cumulative		0.0%	0.0%	0.1%	0.1%	0.8%	1.4%	1.5%	1.5%	1.5%	1.6%	1.7%	5.1%	11.0%	13.1%	15.4%	17.4%	19.3%	21.0%	22.5%	24.0%	25.5%	27.8%	32.6%	
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	



1 x 1 GE 7FA.05

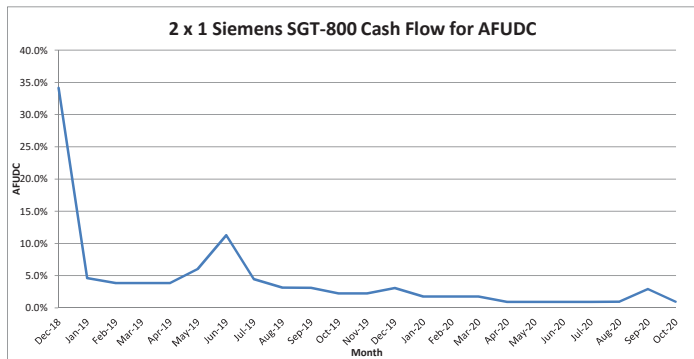
Scope	Totals	Month																							
		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20		
Engineering (incl. geotech)	\$ 12,245,011 100%	\$ 244,900 2%	\$ 244,900 2%	\$ 183,675 1.5%	\$ 183,675 1.5%	\$ 183,675 1.5%	\$ 183,675 1.5%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%	\$ 122,450 1%		
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 99,182,184 100%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 3,967,287 4%	\$ 6,942,753 7%	\$ 16,860,971 17%																\$ 4,959,109 5%		
Fuel Gas Conditioning Skid	\$ 804,779 100%	\$ 114,968 14%	\$ 114,968 14%	\$ 114,968 14%	\$ 114,968 14%	\$ 114,968 14%	\$ 114,968 14%																		
MISO Queue Fees and Network Upgrades	\$ 16,775,000 100%											\$ 3,290,000 20%	\$ 3,290,000 20%	\$ 3,290,000 20%	\$ 3,290,000 20%										
Gas Interconnect	\$ 8,861,264 100%	\$ 2,215,316 25%					\$ 2,215,316 25%																		
Water Interconnect	\$ 1,869,065 100%	\$ 467,266 25%				\$ 467,266 25%	\$ 467,266 25%																		
Land	\$ 1,988,466 100%																								
Spare Parts and Mar'ls	\$ 1,988,466 100%						\$ 1,988,466 100%																		
Developers Fee	\$ 1,988,466 100%																								
Engr Supv G&A	\$ 211,500 100%																								
Permits, Licences, Fees	\$ 3,976,932 100%																								
Legal/Financial	\$ 3,976,932 100%	\$ 39,769 1%	\$ - 0%	\$ - 0%	\$ 39,769 1%	\$ 39,769 1%	\$ 79,539 2%	\$ 79,539 2%	\$ 79,539 2%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 39,769 1%	\$ 79,539 2%	\$ 79,539 2%	\$ 119,308 3%	\$ 119,308 3%	\$ 119,308 3%		
Contractor's Soft Costs	\$ 41,418,597 100%	\$ 2,070,930 5%	\$ 2,070,930 5%	\$ 2,070,930 5%	\$ 2,070,930 5%	\$ 2,899,302 7%	\$ 2,899,302 7%	\$ 4,141,860 10%	\$ 2,899,302 7%	\$ 2,899,302 7%	\$ 2,070,930 5%	\$ 2,070,930 5%	\$ 2,070,930 5%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	\$ 828,372 2%	
Contractor Internal Costs	\$ 87,099,267 100%	\$ 4,354,963 5%	\$ 4,354,963 5%	\$ 4,354,963 5%	\$ 4,354,963 5%	\$ 6,096,949 7%	\$ 6,096,949 7%	\$ 8,709,927 10%	\$ 6,096,949 7%	\$ 6,096,949 7%	\$ 4,354,963 5%	\$ 4,354,963 5%	\$ 4,354,963 5%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	\$ 1,741,985 2%	
Contingency (20%)	\$ 56,477,186 100%	\$ 2,695,080 4.8%	\$ 2,150,610 3.8%	\$ 2,138,365 3.8%	\$ 2,146,319 3.8%	\$ 3,348,936 5.9%	\$ 6,181,290 10.9%	\$ 2,610,755 4.6%	\$ 1,839,648 3.3%	\$ 1,831,694 3.2%	\$ 1,317,623 2.3%	\$ 1,317,623 2.3%	\$ 1,975,623 3.5%	\$ 1,204,515 2.1%	\$ 1,204,515 2.1%	\$ 1,204,515 2.1%	\$ 546,515 1.0%	\$ 546,515 1.0%	\$ 554,469 1.0%	\$ 554,469 1.0%	\$ 562,423 1.0%	\$ 1,554,245 2.8%	\$ 562,423 1.0%		
Checksum	\$ 338,863,114	\$ 16,170,481	\$ 12,903,659	\$ 12,830,189	\$ 12,877,912	\$ 20,093,619	\$ 37,087,743	\$ 15,664,530	\$ 11,037,887	\$ 10,990,164	\$ 7,905,735	\$ 7,905,735	\$ 11,853,735	\$ 7,227,092	\$ 7,227,092	\$ 7,227,092	\$ 3,279,092	\$ 3,279,092	\$ 3,326,815	\$ 3,326,815	\$ 3,374,538	\$ 9,325,469	\$ 3,374,538		
Monthly		4.8%	3.8%	3.8%	3.8%	5.9%	10.9%	4.6%	3.3%	3.2%	2.3%	2.3%	3.5%	2.1%	2.1%	2.1%	1.0%	1.0%	1.0%	1.0%	1.0%	2.8%	1.0%		
Cumulative		37.4%	41.2%	45.0%	48.8%	54.7%	65.7%	70.3%	73.6%	76.8%	79.1%	81.5%	85.0%	87.1%	89.2%	91.4%	92.3%	93.3%	94.3%	95.3%	96.3%	99.0%	100.0%		
AFUDC Cash Flow		4.8%	3.8%	3.8%	3.8%	5.9%	10.9%	4.6%	3.3%	3.2%	2.3%	2.3%	3.5%	2.1%	2.1%	2.1%	1.0%	1.0%	1.0%	1.0%	1.0%	2.8%	1.0%		

COMBINED-CYCLE COMBUSTION TURBINES

2 x 1 Siemens SGT-800

2 x 1 Siemens SGT-800

Scope	Totals	Month																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Engineering (incl. geotech)	\$ 7,529,771 100%	\$ 75,298 1%	\$ 112,947 1.5%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%				\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 527,084 7%	\$ 602,382 8%	\$ 903,572 12%	\$ 978,870 13%	\$ 752,977 10%	\$ 451,786 6%	\$ 225,893 3%	\$ 75,298 1%	\$ 150,595 2%	\$ 75,298 1%	\$ 150,595 2%	
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 67,167,396 100%													\$ 8,731,762 13%	\$ 3,358,370 5%	\$ 3,358,370 5%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	
Fuel Gas Conditioning Skid	\$ 517,512 100%																							\$ 73,930 14%	
MISO Queue Fees and Network Upgrades	\$ 7,575,000 100%					\$ 859,000 11%					\$ 146,000 2%		\$ 730,000 10%												
Gas Interconnect	\$ 4,245,236 100%																						\$ 1,061,309 25%	\$ 1,061,309 25%	
Water Interconnect	\$ 860,201 100%																							\$ 215,050 25%	
Land	\$ 1,250,080 100%				\$ 1,250,080 100%																				
Spare Parts and Mat'ls	\$ 1,250,080 100%																								
Developers Fee	\$ 1,250,080 100%												\$ 1,250,080 100%												
Engr Supv G&A	\$ 211,500 100%																							\$ 211,500 100%	
Permits, Licences, Fees	\$ 2,500,159 100%												\$ 2,500,159 100%												
Legal/Financial	\$ 2,500,159 100%												\$ 1,250,080 50%	\$ 75,005 3%	\$ 50,003 2%	\$ 50,003 2%	\$ 50,003 2%	\$ 50,003 2%	\$ 50,003 2%	\$ 50,003 2%	\$ 50,003 2%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	
Contractor's Soft Costs	\$ 25,558,142 100%													\$ 511,163 2%											\$ 1,277,907 5%
Contractor Internal Costs	\$ 50,116,387 100%													\$ 1,002,328 2%											\$ 2,505,819 5%
Contingency (20%)	\$ 34,506,341 100%	\$ 15,060 0.0%	\$ 22,589 0.1%	\$ 15,060 0.0%	\$ 265,076 0.8%	\$ 186,860 0.5%	\$ 15,060 0.0%				\$ 44,260 0.1%	\$ 15,060 0.0%	\$ 1,161,123 3.4%	\$ 2,169,468 6.3%	\$ 802,151 2.3%	\$ 862,389 2.5%	\$ 743,114 2.2%	\$ 697,935 2.0%	\$ 637,697 1.8%	\$ 592,518 1.7%	\$ 557,399 1.6%	\$ 572,459 1.7%	\$ 769,661 2.2%	\$ 1,641,562 4.8%	
	\$ 207,038,044																								
Checksum	\$ 207,038,044	\$ -	\$ 90,357	\$ 135,536	\$ 90,357	\$ 1,590,453	\$ 1,121,157	\$ 90,357	\$ -	\$ -	\$ -	\$ 265,557	\$ 90,357	\$ 6,966,739	\$ 13,016,809	\$ 4,812,906	\$ 5,174,335	\$ 4,458,683	\$ 4,187,611	\$ 3,826,182	\$ 3,555,111	\$ 3,344,394	\$ 3,434,751	\$ 4,617,965	\$ 9,849,371
Monthly		0.0%	0.0%	0.1%	0.0%	0.8%	0.5%	0.0%	0.0%	0.0%	0.1%	0.0%	3.4%	6.3%	2.3%	2.5%	2.2%	2.0%	1.8%	1.7%	1.6%	1.7%	2.2%	4.8%	
Cumulative		0.0%	0.0%	0.1%	0.2%	0.9%	1.5%	1.5%	1.5%	1.5%	1.5%	1.6%	1.7%	5.0%	11.3%	13.7%	16.2%	18.3%	20.3%	22.2%	23.9%	25.5%	27.2%	29.4%	34.2%
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34.2%	



2 x 1 Siemens SGT-800

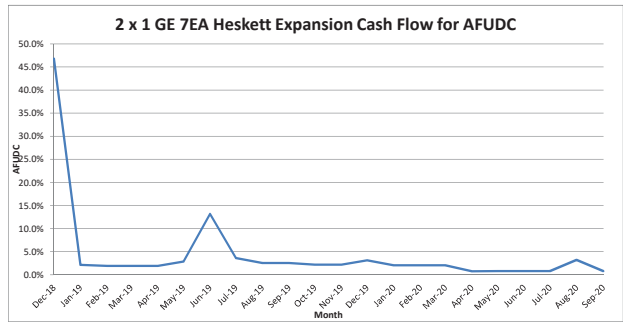
Scope	Totals	Month																							
		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20		
Engineering (incl. geotech)	\$ 7,529,771 100%	\$ 150,595 2%	\$ 112,947 1.5%	\$ 112,947 1.5%	\$ 112,947 1.5%	\$ 112,947 1.5%	\$ 112,947 1.5%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%	\$ 75,298 1%		
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 67,167,396 100%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 2,686,696 4%	\$ 4,701,718 7%	\$ 11,418,457 17%															\$ 3,358,370 5%			
Fuel Gas Conditioning Skid	\$ 517,512 100%	\$ 73,930 14%	\$ 73,930 14%	\$ 73,930 14%	\$ 73,930 14%	\$ 73,930 14%	\$ 73,930 14%																		
MISO Queue Fees and Network Upgrades	\$ 7,575,000 100%											\$ 1,460,000 19%	\$ 1,460,000 19%	\$ 1,460,000 19%	\$ 1,460,000 19%										
Gas Interconnect	\$ 4,245,236 100%	\$ 1,061,309 25%				\$ 1,061,309 25%																			
Water Interconnect	\$ 860,201 100%	\$ 215,050 25%			\$ 215,050 25%	\$ 215,050 25%																			
Land	\$ 1,250,080 100%																								
Spare Parts and Mat'ls	\$ 1,250,080 100%					\$ 1,250,080 100%																			
Developers Fee	\$ 1,250,080 100%																								
Engr Supv G&A	\$ 211,500 100%																								
Permits, Licences, Fees	\$ 2,500,159 100%																								
Legal/Financial	\$ 2,500,159 100%	\$ 25,002 1%	\$ - 0%	\$ - 0%	\$ 25,002 1%	\$ 25,002 1%	\$ 50,003 2%	\$ 50,003 2%	\$ 50,003 2%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 25,002 1%	\$ 50,003 2%	\$ 50,003 2%	\$ 75,005 3%	\$ 75,005 3%	\$ 75,005 3%		
Contractor's Soft Costs	\$ 25,558,142 100%	\$ 1,277,907 5%	\$ 1,277,907 5%	\$ 1,277,907 5%	\$ 1,277,907 5%	\$ 1,789,070 7%	\$ 1,789,070 7%	\$ 2,555,814 10%	\$ 1,789,070 7%	\$ 1,789,070 7%	\$ 1,277,907 5%	\$ 1,277,907 5%	\$ 1,277,907 5%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	\$ 511,163 2%	
Contractor Internal Costs	\$ 50,116,387 100%	\$ 2,505,819 5%	\$ 2,505,819 5%	\$ 2,505,819 5%	\$ 2,505,819 5%	\$ 3,508,147 7%	\$ 3,508,147 7%	\$ 5,011,639 10%	\$ 3,508,147 7%	\$ 3,508,147 7%	\$ 2,505,819 5%	\$ 2,505,819 5%	\$ 2,505,819 5%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	\$ 1,002,328 2%	
Contingency (20%)	\$ 34,506,341 100%	\$ 1,599,262 4.6%	\$ 1,331,460 3.9%	\$ 1,331,460 3.9%	\$ 1,336,460 3.9%	\$ 2,085,173 6.0%	\$ 3,895,799 11.3%	\$ 1,538,551 4.5%	\$ 1,084,504 3.1%	\$ 1,079,503 3.1%	\$ 776,805 2.3%	\$ 776,805 2.3%	\$ 1,068,805 3.1%	\$ 614,758 1.8%	\$ 614,758 1.8%	\$ 614,758 1.8%	\$ 322,758 0.9%	\$ 322,758 0.9%	\$ 327,758 0.9%	\$ 327,758 0.9%	\$ 327,758 0.9%	\$ 332,759 1.0%	\$ 1,004,433 2.9%	\$ 332,759 1.0%	
	\$ 207,038,044																								
Checksum	\$ 207,038,044	\$ 9,595,571	\$ 7,988,759	\$ 7,988,759	\$ 8,018,761	\$ 12,511,036	\$ 23,374,792	\$ 9,231,305	\$ 6,507,022	\$ 6,477,020	\$ 4,660,831	\$ 4,660,831	\$ 6,412,831	\$ 3,688,548	\$ 3,688,548	\$ 3,688,548	\$ 1,936,548	\$ 1,936,548	\$ 1,966,550	\$ 1,966,550	\$ 1,996,552	\$ 6,026,595	\$ 1,996,552		
Monthly		4.6%	3.9%	3.9%	3.9%	6.0%	11.3%	4.5%	3.1%	3.1%	2.3%	2.3%	3.1%	1.8%	1.8%	1.8%	0.9%	0.9%	0.9%	0.9%	0.9%	1.0%	2.9%	1.0%	
Cumulative		38.8%	42.7%	46.5%	50.4%	56.4%	67.7%	72.2%	75.3%	78.4%	80.7%	82.9%	86.0%	87.8%	89.6%	91.4%	92.3%	93.3%	94.2%	95.2%	96.1%	99.0%	100.0%		
AFUDC Cash Flow		4.6%	3.9%	3.9%	3.9%	6.0%	11.3%	4.5%	3.1%	3.1%	2.3%	2.3%	3.1%	1.8%	1.8%	1.8%	0.9%	0.9%	0.9%	0.9%	0.9%	1.0%	2.9%	1.0%	

COMBINED-CYCLE COMBUSTION TURBINES

2 x 1 GE 7EA Heskett Expansion

2 x 1 GE 7EA Heskett Expansion

Scope	Totals	Month																									
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24		
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18		
Engineering (incl. geotech)	\$ 10,329,288 100%	\$ 51,646 0.5%	\$ 51,646 0.5%	\$ 51,646 0.5%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%				\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 723,050 7%	\$ 826,343 8%	\$ 1,239,515 12%	\$ 1,342,807 13%	\$ 1,032,929 10%	\$ 619,757 6%	\$ 309,879 3%	\$ 103,293 1%	\$ 206,586 2%	\$ 103,293 1%	\$ 206,586 2%	\$ 206,586 2%		
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 104,201,697 100%												\$ 17,714,289 17%	\$ 6,252,102 6%	\$ 6,252,102 6%	\$ 6,252,102 6%	\$ 5,210,085 5%	\$ 5,210,085 5%	\$ 5,210,085 5%	\$ 5,210,085 5%	\$ 5,210,085 5%	\$ 5,210,085 5%	\$ 5,210,085 5%	\$ 10,420,170 10%	\$ -		
Fuel Gas Conditioning Skid	\$ 783,785 100%																									\$ 111,969 14%	
MISO Queue Fees and Network Upgrades	\$ 14,375,000 100%					\$ 1,449,000 10%					\$ 281,000 2%		\$ 1,405,000 10%														
Gas Interconnect	\$ - 0%																									\$ -	
Water Interconnect	\$ 1,894,964 100%																									\$ 473,741 25%	
Land	\$ - 0%				\$ -																						
Spare Parts and Mat'ls	\$ 1,487,880 100%																										
Developers Fee	\$ 1,487,880 100%												\$ 1,487,880 100%														
Engr Supv G&A	\$ 211,500 100%																									\$ 211,500 100%	
Permits, Licences, Fees	\$ 2,975,761 100%												\$ 2,975,761 100%														
Legal/Financial	\$ 2,975,761 100%												\$ 1,487,881 50%	\$ 89,273 3%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	
Contractor's Soft Costs	\$ 42,036,041 100%													\$ 840,721 2%													\$ 2,101,802 5%
Contractor Internal Costs	\$ 33,995,851 100%													\$ 679,917 2%													\$ 1,699,793 5%
Contingency (20%)	\$ 43,351,082 100%	\$ 10,329 0.0%	\$ 10,329 0.0%	\$ 10,329 0.0%	\$ 20,659 0.0%	\$ 310,459 0.7%	\$ 20,659 0.0%				\$ 76,859 0.2%	\$ 20,659 0.0%	\$ 5,034,821 11.6%	\$ 1,717,013 4.0%	\$ 1,427,592 3.3%	\$ 1,510,226 3.5%	\$ 1,322,482 3.1%	\$ 1,260,506 2.9%	\$ 1,177,871 2.7%	\$ 1,115,896 2.6%	\$ 1,068,627 2.5%	\$ 1,089,286 2.5%	\$ 1,089,286 2.5%	\$ 2,110,644 4.9%	\$ 967,030 2.2%		
Checksum	\$ 260,106,490	\$ -	\$ 61,976	\$ 61,976	\$ 123,951	\$ 1,862,751	\$ 123,951	\$ -	\$ -	\$ -	\$ 461,151	\$ 123,951	\$ 30,208,923	\$ 10,302,075	\$ 8,565,552	\$ 9,061,358	\$ 7,934,889	\$ 7,563,035	\$ 7,067,229	\$ 6,695,374	\$ 6,411,762	\$ 6,535,714	\$ 6,535,714	\$ 12,663,864	\$ 5,802,178		
Monthly		0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	11.6%	4.0%	3.3%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	2.5%	2.5%	4.9%	2.2%		
Cumulative		0.0%	0.0%	0.0%	0.1%	0.1%	0.8%	0.9%	0.9%	0.9%	1.1%	1.1%	12.7%	16.7%	20.0%	23.5%	26.5%	29.4%	32.1%	34.7%	37.2%	39.7%	44.6%	46.8%			
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	46.8%		



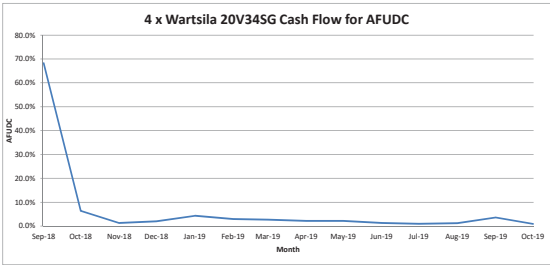
2 x 1 GE 7EA Heskett Expansion

Scope	Totals	Month																							
		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45			
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20			
Engineering (incl. geotech)	\$ 10,329,288 100%	\$ 206,586 2%	\$ 206,586 2%	\$ 206,586 2%	\$ 206,586 2%	\$ 206,586 2%	\$ 206,586 2%	\$ 154,939 1.5%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%	\$ 103,293 1%		
Major Equipment (CT, ST, and Heat Recovery Boiler)	\$ 104,201,697 100%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20,840,339 20%															\$ 5,210,085 5%			
Fuel Gas Conditioning Skid	\$ 783,785 100%	\$ 111,969 14%	\$ 111,969 14%	\$ 111,969 14%	\$ 111,969 14%	\$ 111,969 14%	\$ 111,969 14%																		
MISO Queue Fees and Network Upgrades	\$ 14,375,000 100%											\$ 2,810,000 20%	\$ 2,810,000 20%	\$ 2,810,000 20%	\$ 2,810,000 20%										
Gas Interconnect	\$ - 0%	\$ -					\$ -																		
Water Interconnect	\$ 1,894,964 100%	\$ 473,741 25%			\$ 473,741 25%	\$ 473,741 25%																			
Land	\$ - 0%																								
Spare Parts and Mat'ls	\$ 1,487,880 100%					\$ 1,487,880 100%																			
Developers Fee	\$ 1,487,880 100%																								
Engr Supv G&A	\$ 211,500 100%																								
Permits, Licences, Fees	\$ 2,975,761 100%																								
Legal/Financial	\$ 2,975,761 100%	\$ 29,758 1%	\$ - 0%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 59,515 2%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%	\$ 29,758 1%		
Contractor's Soft Costs	\$ 42,036,641 100%	\$ 2,101,802 5%	\$ 2,101,802 5%	\$ 2,101,802 5%	\$ 2,101,802 5%	\$ 2,942,523 7%	\$ 2,942,523 7%	\$ 4,203,604 10%	\$ 2,942,523 7%	\$ 2,942,523 7%	\$ 2,522,162 6%	\$ 2,522,162 6%	\$ 2,101,802 5%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	\$ 840,721 2%	
Contractor Internal Costs	\$ 33,995,851 100%	\$ 1,699,793 5%	\$ 1,699,793 5%	\$ 1,699,793 5%	\$ 1,699,793 5%	\$ 2,379,710 7%	\$ 2,379,710 7%	\$ 3,399,585 10%	\$ 2,379,710 7%	\$ 2,379,710 7%	\$ 2,039,751 6%	\$ 2,039,751 6%	\$ 1,699,793 5%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	\$ 679,917 2%	
Contingency (20%)	\$ 43,351,082 100%	\$ 924,730 2.1%	\$ 824,030 1.9%	\$ 829,981 1.9%	\$ 829,981 1.9%	\$ 1,228,857 2.8%	\$ 5,700,453 13.1%	\$ 1,563,529 3.6%	\$ 1,097,008 2.5%	\$ 1,097,008 2.5%	\$ 938,993 2.2%	\$ 938,993 2.2%	\$ 1,348,929 3.1%	\$ 892,738 2.1%	\$ 892,738 2.1%	\$ 892,738 2.1%	\$ 330,738 0.8%	\$ 336,689 0.8%	\$ 336,689 0.8%	\$ 336,689 0.8%	\$ 336,689 0.8%	\$ 1,384,658 3.2%	\$ 342,641 0.8%		
Checksum	\$ 260,106,490	\$ 5,548,378	\$ 4,944,180	\$ 4,979,889	\$ 4,979,889	\$ 7,373,143	\$ 34,202,716	\$ 9,381,172	\$ 6,582,049	\$ 6,582,049	\$ 5,633,957	\$ 5,633,957	\$ 8,093,574	\$ 5,356,426	\$ 5,356,426	\$ 5,356,426	\$ 1,984,426	\$ 2,020,135	\$ 2,020,135	\$ 2,020,135	\$ 2,020,135	\$ 8,307,946	\$ 2,055,844		
Monthly	2.1%	1.9%	1.9%	1.9%	1.9%	2.8%	13.1%	3.6%	2.5%	2.5%	2.2%	2.2%	3.1%	2.1%	2.1%	2.1%	0.8%	0.8%	0.8%	0.8%	0.8%	3.2%	0.8%		
Cumulative		48.9%	50.8%	52.7%	54.6%	57.5%	70.6%	74.2%	76.8%	79.3%	81.5%	83.6%	86.7%	88.8%	90.9%	92.9%	93.7%	94.5%	95.2%	96.0%	99.2%	100.0%			
AFUDC Cash Flow	2.1%	1.9%	1.9%	1.9%	1.9%	2.8%	13.1%	3.6%	2.5%	2.5%	2.2%	2.2%	3.1%	2.1%	2.1%	2.1%	0.8%	0.8%	0.8%	0.8%	0.8%	3.2%	0.8%		

RECIPROCATING INTERNAL COMBUSTION ENGINES

4 x Wartsila 20V34SG

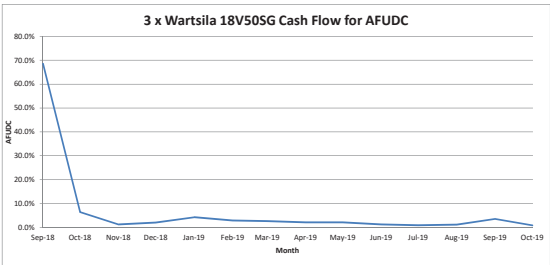
4 x Wartsila 20V34SG																																					
Scope	Totals	Month																																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34		
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19		
Engineering (incl. geotech)	\$ 11,455,803																																				
Major Equipment	\$ 20,790,000																																				
Fuel Gas Conditioning Skid	\$ 111,907																																				
MISO Queue Fees and Network Upgrades	\$ 1,975,000	\$ 273,000																																			
Gas Interconnect	\$ 330,720	14%																																			
Water Interconnect	\$ -																																				
Land	\$ 322,458																																				
Spare Parts and Marls	\$ 322,458																																				
Developers Fee	\$ 322,458																																				
Engr Supv G&A	\$ 211,500																																				
Permits, Licences, Fees	\$ 644,916																																				
Legal/Financial	\$ 644,916																																				
Contractor's Soft Costs	\$ 5,183,345																																				
Contractor Internal Costs (already included in major equipment and engineering costs)	\$ -																																				
Contingency (15%)	\$ 6,347,322	\$ 40,950	\$ 8,592	\$ 17,184	\$ 17,184	\$ 62,511	\$ 8,592	\$ 36,342					\$ 17,184	\$ 17,184	\$ 678,434	\$ 146,513	\$ 265,112	\$ 697,248	\$ 533,686	\$ 361,849	\$ 140,372	\$ 846,480	\$ 435,479	\$ 403,754	\$ 79,502	\$ 127,871	\$ 274,302	\$ 186,070	\$ 171,428	\$ 136,668	\$ 137,635	\$ 82,135	\$ 57,994	\$ 73,544	\$ 228,501	\$ 57,026	
	\$ 48,662,803	0.6%	0.1%	0.3%	0.3%	1.0%	0.1%	0.6%					0.3%	0.3%	10.7%	2.3%	4.2%	11.0%	8.4%	5.7%	2.2%	13.3%	6.9%	6.4%	1.3%	2.0%	4.3%	2.9%	2.2%	2.2%	1.3%	0.9%	1.2%	3.6%	0.9%		
Checksum	\$ 48,662,803	\$ 313,950	\$ 65,871	\$ 131,742	\$ 131,742	\$ 479,248	\$ 65,871	\$ 278,621					\$ 131,742	\$ 131,742	\$ 5,201,324	\$ 1,123,267	\$ 2,032,523	\$ 5,345,566	\$ 4,091,594	\$ 2,774,177	\$ 1,076,183	\$ 6,489,682	\$ 3,338,671	\$ 3,095,446	\$ 609,514	\$ 980,341	\$ 2,102,081	\$ 1,426,535	\$ 1,314,279	\$ 1,047,788	\$ 1,055,203	\$ 629,705	\$ 444,617	\$ 563,834	\$ 1,751,843	\$ 437,201	
Monthly		0.6%	0.1%	0.3%	0.3%	1.0%	0.1%	0.6%	0.0%	0.0%	0.0%	0.3%	0.3%	10.7%	2.3%	4.2%	11.0%	8.4%	5.7%	2.2%	13.3%	6.9%	6.4%	1.3%	2.0%	4.3%	2.9%	2.2%	2.2%	1.3%	0.9%	1.2%	3.6%	0.9%			
Cumulative		0.6%	0.8%	1.1%	1.3%	2.3%	2.4%	3.0%	3.0%	3.0%	3.3%	3.6%	14.2%	16.6%	20.7%	31.7%	40.1%	45.8%	48.0%	61.4%	68.2%	74.6%	78.8%	77.9%	82.2%	85.1%	87.8%	90.0%	92.1%	93.4%	94.3%	95.5%	99.1%	100.0%			
AFUDC Cash Flow																																					



RECIPROCATING INTERNAL COMBUSTION ENGINES

3 x Wartsila 18V50SG

3 x Wartsila 18V50SG																																					
Scope	Totals	Month																																			
		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	31	32	33	34		
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19		
Engineering (incl. geotech)	\$ 17,707,937																																				
Major Equipment	\$ 32,680,000																																				
Fuel Gas Conditioning Skid	\$ 143,316																																				
MISO Queue Fees and Network Upgrades	\$ 2,985,000	\$ 409,000																																			
Gas Interconnect	\$ 500,454																																				
Water Interconnect	\$ -																																				
Land	\$ 503,879																																				
Spare Parts and Marls	\$ 503,879																																				
Developers Fee	\$ 503,879																																				
Engr Supv G&A	\$ 211,500																																				
Permits, Licences, Fees	\$ 1,007,759																																				
Legal/Financial	\$ 1,007,759																																				
Contractor's Soft Costs	\$ 7,766,392																																				
Contractor Internal Costs (already included in major equipment and engineering costs)	\$ -																																				
Contingency (15%)	\$ 9,828,223	\$ 61,350	\$ 13,281	\$ 26,562	\$ 26,562	\$ 97,263	\$ 13,281	\$ 55,281																													
	\$ 75,350,477	0.6%	0.1%	0.3%	0.3%	1.0%	0.1%	0.6%																													
Checksum	\$ 75,350,477	\$ 470,350	\$ 101,821	\$ 203,641	\$ 203,641	\$ 745,681	\$ 101,821	\$ 423,821	\$ -	\$ -	\$ -	\$ -	\$ 203,641	\$ 203,641	\$ 8,158,780	\$ 1,226,197	\$ 3,167,178	\$ 8,350,867	\$ 4,326,100	\$ 1,663,908	\$ 10,185,130	\$ 5,066,089	\$ 4,823,764	\$ 921,626	\$ 1,501,087	\$ 3,247,284	\$ 2,157,812	\$ 1,986,535	\$ 1,586,249	\$ 1,597,835	\$ 953,835	\$ 673,267	\$ 852,014	\$ 2,719,525	\$ 661,798		
Monthly		0.6%	0.1%	0.3%	0.3%	1.0%	0.1%	0.6%	0.0%	0.0%	0.0%	0.3%	0.3%	10.8%	2.3%	4.2%	11.1%	8.4%	5.7%	2.2%	13.5%	6.7%	6.4%	1.2%	2.0%	4.3%	2.9%	2.6%	2.1%	2.1%	1.3%	0.9%	1.1%	3.6%	0.9%		
Cumulative		0.6%	0.8%	1.0%	1.3%	2.3%	2.4%	3.0%	3.0%	3.0%	3.0%	3.3%	3.5%	14.4%	16.0%	20.9%	31.9%	40.4%	46.1%	48.3%	61.8%	68.6%	75.0%	76.2%	78.2%	82.5%	85.4%	88.0%	90.1%	92.2%	93.5%	94.4%	95.5%	99.1%	100.0%		
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		

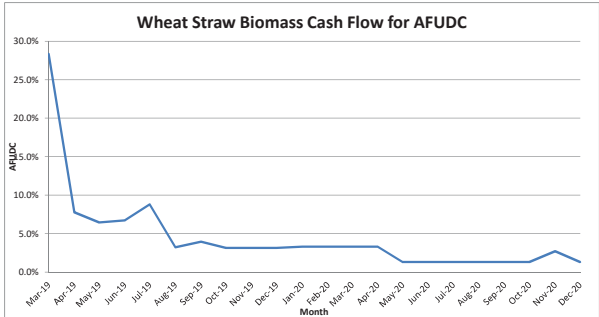


BIOMASS

Wheat Straw Biomass (10 MW)

Wheat Straw Biomass (10 MW)

Scope	Totals	Month																												
		1 Sep-16	2 Oct-16	3 Nov-16	4 Dec-16	5 Jan-17	6 Feb-17	7 Mar-17	8 Apr-17	9 May-17	10 Jun-17	11 Jul-17	12 Aug-17	13 Sep-17	14 Oct-17	15 Nov-17	16 Dec-17	17 Jan-18	18 Feb-18	19 Mar-18	20 Apr-18	21 May-18	22 Jun-18	23 Jul-18	24 Aug-18	25 Sep-18	26 Oct-18	27 Nov-18	28 Dec-18	
Engineering (incl. geotech)	\$ 2,529,068 100%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%										\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 177,035 7%	\$ 202,325 8%	\$ 227,616 9%	\$ 303,488 12%	\$ 227,616 9%	
Major Equipment (Boiler and Steam Turbine Package)	\$ 19,236,519 100%																							\$ 2,500,748 13%	\$ 961,826 5%	\$ 961,826 5%	\$ 769,461 4%	\$ 961,826 5%	\$ 961,826 5%	\$ 961,826 5%
Fuel Gas Conditioning Skid	\$ - 0%																													
MISO Queue Fees and Network Upgrades	\$ 555,000 100%									\$ 95,000 17%					\$ 10,000 2%	\$ 50,000 9%														
Gas Interconnect	\$ - 0%																													
Water Interconnect	\$ 219,971 100%																													
Land	\$ 555,226 100%																\$ 555,226 100%													
Spare Parts and Mat'ls	\$ 555,226 100%																													
Developers Fee	\$ 555,226 100%																					\$ 555,226 100%								
Engr Supv G&A	\$ 211,500 100%																													
Permits, Licences, Fees	\$ 1,110,451 100%																													
Legal/Financial	\$ 1,110,451 100%																						\$ 555,226 50%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	
Contractor's Soft Costs	\$ 9,609,441 100%																							\$ 192,189 2%						
Contractor Internal Costs	\$ 33,756,964 100%																						\$ 675,139 2%							
Contingency (20%)	\$ 14,001,009 100%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 5,058 0.0%				\$ 19,000 0.1%				\$ 2,000 0.0%	\$ 126,103 0.9%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 5,058 0.0%	\$ 449,239 3.2%	\$ 683,115 4.9%	\$ 201,865 1.4%	\$ 232,214 1.7%	\$ 198,799 1.4%	\$ 242,330 1.7%	\$ 257,505 1.8%	\$ 242,330 1.7%		
Checksum	\$ 84,006,053	\$ 30,349	\$ 30,349	\$ 30,349	\$ 30,349	\$ 30,349	\$ 30,349	\$ -	\$ -	\$ -	\$ 114,000	\$ -	\$ -	\$ -	\$ -	\$ 12,000	\$ -	\$ 756,620	\$ 30,349	\$ 30,349	\$ 30,349	\$ 30,349	\$ 2,695,432	\$ 4,098,690	\$ 1,211,191	\$ 1,393,284	\$ 1,192,794	\$ 1,453,981	\$ 1,545,028	\$ 1,453,981
Monthly		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	3.2%	4.9%	1.4%	1.7%	1.4%	1.7%	1.8%	1.7%	
Cumulative		0.0%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	1.3%	1.3%	1.3%	1.4%	4.6%	9.5%	10.9%	12.6%	14.0%	15.7%	17.6%	19.3%		
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	



Wheat Straw Biomass (10 MW)

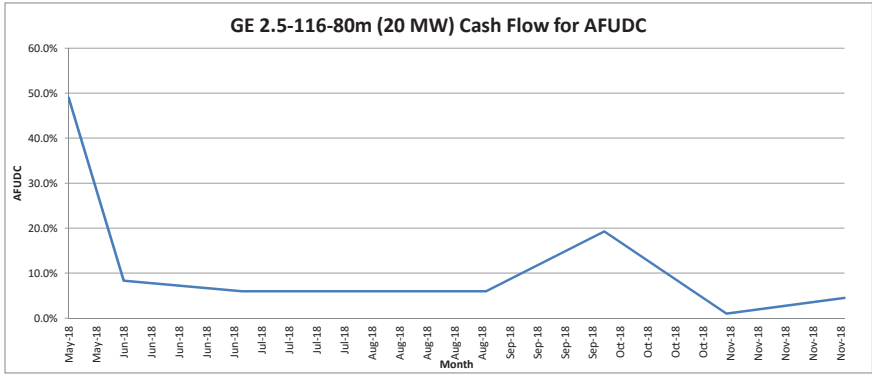
Scope	Totals	Month																							
		29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Engineering (incl. geotech)	\$ 2,529,068 100%	\$ 126,453 5%	\$ 75,872 3%	\$ 75,872 3%	\$ 75,872 3%	\$ 75,872 3%	\$ 75,872 3%	\$ 75,872 3%	\$ 75,872 3%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	\$ 25,291 1%	
Major Equipment (Boiler and Steam Turbine Package)	\$ 19,236,519 100%	\$ 961,826 5%	\$ 961,826 5%	\$ 961,826 5%	\$ 961,826 5%	\$ 961,826 5%	\$ 1,538,922 8%	\$ 3,847,304 20%																\$ 961,826 5%	
Fuel Gas Conditioning Skid	\$ - 0%																								
MISO Queue Fees and Network Upgrades	\$ 555,000 100%												\$ 100,000 18%	\$ 100,000 18%	\$ 100,000 18%	\$ 100,000 18%									
Gas Interconnect	\$ - 0%																								
Water Interconnect	\$ 219,971 100%			\$ 54,993 25%	\$ 54,993 25%		\$ 54,993 25%	\$ 54,993 25%																	
Land	\$ 555,226 100%																								
Spare Parts and Mat'ls	\$ 555,226 100%								\$ 555,226 100%																
Developers Fee	\$ 555,226 100%																								
Engr Supv G&A	\$ 211,500 100%			\$ 211,500 100%																					
Permits, Licences, Fees	\$ 1,110,451 100%																								
Legal/Financial	\$ 1,110,451 100%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ - 0%	\$ - 0%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 11,105 1%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%	\$ 22,209 2%
Contractor's Soft Costs	\$ 9,609,441 100%			\$ 672,661 7%	\$ 960,944 10%	\$ 768,755 8%	\$ 672,661 7%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 480,472 5%	\$ 192,189 2%	\$ 192,189 2%	\$ 192,189 2%	\$ 192,189 2%	\$ 192,189 2%	\$ 192,189 2%	\$ 192,189 2%
Contractor Internal Costs	\$ 33,756,964 100%			\$ 2,362,988 7%	\$ 3,375,696 10%	\$ 2,700,557 8%	\$ 2,362,988 7%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 1,687,848 5%	\$ 675,139 2%	\$ 675,139 2%	\$ 675,139 2%	\$ 675,139 2%	\$ 675,139 2%	\$ 675,139 2%	\$ 675,139 2%
Contingency (20%)	\$ 14,001,009 100%	\$ 219,877 1.6%	\$ 209,761 1.5%	\$ 870,189 6.2%	\$ 1,088,087 7.8%	\$ 903,623 6.5%	\$ 941,087 6.7%	\$ 1,229,298 8.8%	\$ 451,059 3.2%	\$ 551,988 3.9%	\$ 440,943 3.1%	\$ 440,943 3.1%	\$ 440,943 3.1%	\$ 460,943 3.3%	\$ 463,164 3.3%	\$ 463,164 3.3%	\$ 463,164 3.3%	\$ 182,966 1.3%	\$ 182,966 1.3%	\$ 182,966 1.3%	\$ 182,966 1.3%	\$ 182,966 1.3%	\$ 182,966 1.3%	\$ 182,966 1.3%	\$ 182,966 1.3%
Checksum	\$ 84,006,053	\$ 1,319,261	\$ 1,258,563	\$ 5,221,132	\$ 6,528,523	\$ 5,421,738	\$ 5,646,522	\$ 7,375,787	\$ 2,706,356	\$ 3,311,930	\$ 2,645,659	\$ 2,645,659	\$ 2,645,659	\$ 2,765,659	\$ 2,778,984	\$ 2,778,984	\$ 2,778,984	\$ 1,097,793	\$ 1,097,793	\$ 1,097,793	\$ 1,097,793	\$ 1,097,793	\$ 1,111,119	\$ 2,265,310	\$ 1,111,119
Monthly		1.6%	1.5%	6.2%	7.8%	6.5%	6.7%	8.8%	3.2%	3.9%	3.1%	3.1%	3.1%	3.3%	3.3%	3.3%	3.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	2.7%	1.3%
Cumulative		20.9%	22.4%	28.6%	36.3%	42.8%	49.5%	58.3%	61.5%	65.5%	68.6%	71.8%	74.9%	78.2%	81.5%	84.8%	88.1%	89.4%	90.7%	92.0%	93.4%	94.7%	96.0%	98.7%	100.0%
AFUDC Cash Flow		-	-	28.4%	7.8%	6.5%	6.7%	8.8%	3.2%	3.9%	3.1%	3.1%	3.1%	3.3%	3.3%	3.3%	3.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	2.7%	1.3%

WIND

GE 2.5-116-80m (20 MW)

Wind - GE 2.5-116-80m (20 MW)

Scope	Totals	Month																								
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	
Engineering (Included in Contractor Internal Costs)	\$ - 0%		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Major Equipment (Included in Contractor Internal Costs)	\$ 18,480,000 100%													\$ 3,696,000 20%	\$ 1,478,400 8%	\$ 1,478,400 8%	\$ 1,478,400 8%	\$ 1,478,400 8%	\$ 1,108,800 6%	\$ 1,108,800 6%	\$ 1,108,800 6%	\$ 4,620,000 25%		\$ 924,000 5%		
Fuel Gas Conditioning Skid	\$ - 0%																\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
MISO Queue Fees and Network Upgrades	\$ 1,125,000 100%	\$ 205,000 18%				\$ 20,000 2%				\$ 100,000 9%									\$ 200,000 18%	\$ 200,000 18%	\$ 200,000 18%	\$ 200,000 18%				
Gas Interconnect	\$ - 0%															\$ -	\$ -	\$ -	\$ -							
Water Interconnect	\$ - 0%																\$ -	\$ -	\$ -							
Land	\$ 236,544 100%					\$ 236,544 100%																				
Spare Parts and Mat'ls	\$ 236,544 100%																						\$ 236,544 100%			
Developers Fee	\$ 236,544 100%																\$ 236,544 100%									
Engr Supv G&A	\$ 211,500 100%																		\$ 211,500 100%							
Permits, Licences, Fees	\$ 473,088 100%																		\$ 473,088 100%							
Legal/Financial	\$ 473,088 100%													\$ 236,544 50%	\$ 23,654 5%	\$ 23,654 5%	\$ 23,654 5%	\$ 23,654 5%	\$ 23,654 5%	\$ 23,654 5%	\$ 23,654 5%	\$ 23,654 5%	\$ 18,924 4%	\$ 14,193 3%	\$ 14,193 3%	
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ - 0%													\$ -								\$ -	\$ -	\$ -	\$ -	
Contractor Internal Costs	\$ 5,174,400 100%													\$ 1,034,880 20%	\$ 776,160 15%	\$ 776,160 15%	\$ 517,440 10%	\$ 517,440 10%	\$ 258,720 5%	\$ 258,720 5%	\$ 258,720 5%	\$ 258,720 5%	\$ 258,720 5%	\$ 258,720 5%		
Contingency (15%)	\$ 3,997,006 100%	\$ 30,750 0.8%				\$ 35,482 0.9%	\$ 3,000 0.1%			\$ 15,000 0.4%				\$ 141,926 3.6%	\$ 713,180 17.8%	\$ 341,732 8.5%	\$ 341,732 8.5%	\$ 334,649 8.4%	\$ 332,924 8.3%	\$ 238,676 6.0%	\$ 238,676 6.0%	\$ 238,676 6.0%	\$ 770,128 19.3%	\$ 40,937 1.0%	\$ 179,537 4.5%	
	\$ 30,643,714	\$ 235,750	\$ -	\$ -	\$ -	\$ 272,026	\$ 23,000	\$ -	\$ -	\$ 115,000	\$ -	\$ -	\$ -	\$ 1,088,102	\$ 5,467,715	\$ 2,619,947	\$ 2,619,947	\$ 2,565,644	\$ 2,552,419	\$ 1,829,851	\$ 1,829,851	\$ 1,829,851	\$ 5,904,316	\$ 313,850	\$ 1,376,450	
Monthly		0.8%	0.0%	0.0%	0.0%	0.9%	0.1%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	3.6%	17.8%	8.5%	8.5%	8.4%	8.3%	6.0%	6.0%	6.0%	19.3%	1.0%	4.5%	
Cumulative		0.8%	0.8%	0.8%	0.8%	1.7%	1.7%	1.7%	1.7%	2.1%	2.1%	2.1%	2.1%	5.7%	23.5%	32.1%	40.6%	49.0%	57.3%	63.3%	69.2%	75.2%	94.5%	95.5%	100.0%	
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49.0%	8.3%	6.0%	6.0%	6.0%	19.3%	1.0%	4.5%	

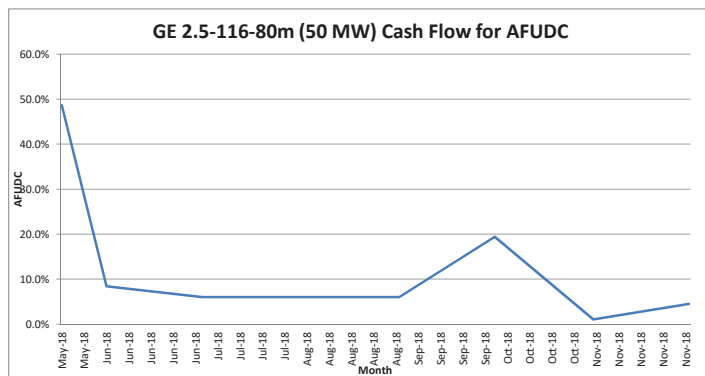


WIND

GE 2.5-116-80m (50 MW)

Wind - GE 2.5-116-80m (50 MW)

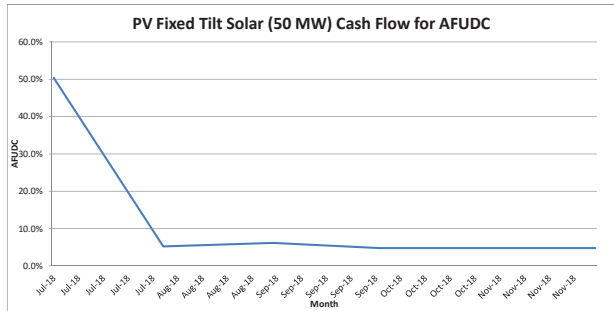
Scope	Totals	Month																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Engineering (Included in Contractor Internal Costs)	\$ - 0%		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Major Equipment (Included in Contractor Internal Costs)	\$ 45,800,000 100%													\$ 9,160,000 20%	\$ 3,664,000 8%	\$ 3,664,000 8%	\$ 3,664,000 8%	\$ 3,664,000 8%	\$ 2,748,000 6%	\$ 2,748,000 6%	\$ 2,748,000 6%	\$ 11,450,000 25%	\$ 2,290,000 5%		
Fuel Gas Conditioning Skid	\$ - 0%																\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
MISO Queue Fees and Network Upgrades	\$ 2,685,000 100%	\$ 385,000 14%				\$ 50,000 2%			\$ 250,000 9%									\$ 500,000 19%	\$ 500,000 19%	\$ 500,000 19%	\$ 500,000 19%				
Gas Interconnect	\$ - 0%															\$ -	\$ -	\$ -	\$ -						
Water Interconnect	\$ - 0%																\$ -	\$ -	\$ -						
Land	\$ 586,240 100%					\$ 586,240 100%																			
Spare Parts and Mat'ls	\$ 586,240 100%																						\$ 586,240 100%		
Developers Fee	\$ 586,240 100%												\$ 586,240 100%												
Engr Supv G&A	\$ 211,500 100%																	\$ 211,500 100%							
Permits, Licences, Fees	\$ 1,172,480 100%												\$ 1,172,480 100%												
Legal/Financial	\$ 1,172,480 100%												\$ 586,240 50%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 58,624 5%	\$ 46,899 4%	\$ 35,174 3%	\$ 35,174 3%
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ - 0%													\$ -								\$ -	\$ -	\$ -	\$ -
Contractor Internal Costs	\$ 12,824,000 100%													\$ 2,564,800 20%	\$ 1,923,600 15%	\$ 1,923,600 15%	\$ 1,282,400 10%	\$ 1,282,400 10%	\$ 641,200 5%	\$ 641,200 5%	\$ 641,200 5%	\$ 641,200 5%	\$ 641,200 5%	\$ 641,200 5%	
Contingency (15%)	\$ 9,843,627 100%	\$ 57,750 0.6%				\$ 87,936 0.9%	\$ 7,500 0.1%			\$ 37,500 0.4%			\$ 351,744 3.6%	\$ 1,767,514 18.0%	\$ 846,934 8.6%	\$ 846,934 8.6%	\$ 782,479 7.9%	\$ 825,754 8.4%	\$ 592,174 6.0%	\$ 592,174 6.0%	\$ 592,174 6.0%	\$ 1,908,651 19.4%	\$ 101,456 1.0%	\$ 444,956 4.5%	
	\$ 75,467,807																								
Checksum	\$ 75,467,807	\$ 442,750	\$ -	\$ -	\$ -	\$ 674,176	\$ 57,500	\$ -	\$ -	\$ 287,500	\$ -	\$ -	\$ -	\$ 2,696,704	\$ 13,550,938	\$ 6,493,158	\$ 6,493,158	\$ 5,999,003	\$ 6,330,778	\$ 4,539,998	\$ 4,539,998	\$ 4,539,998	\$ 14,632,990	\$ 777,831	\$ 3,411,331
Monthly		0.6%	0.0%	0.0%	0.0%	0.9%	0.1%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	3.6%	18.0%	8.6%	8.6%	7.9%	8.4%	6.0%	6.0%	6.0%	19.4%	1.0%	4.5%
Cumulative		0.6%	0.6%	0.6%	0.6%	1.5%	1.6%	1.6%	1.6%	1.9%	1.9%	1.9%	1.9%	5.5%	23.5%	32.1%	40.7%	48.6%	57.0%	63.0%	69.0%	75.1%	94.4%	95.5%	100.0%
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48.6%	8.4%	6.0%	6.0%	6.0%	19.4%	1.0%	4.5%



SOLAR

Photovoltaic Fixed Tilt Solar (50 MW)

PV Fixed Tilt Solar (50 MW)																														
Scope	Totals	Month																												
		1 Jan-17	2 Feb-17	3 Mar-17	4 Apr-17	5 May-17	6 Jun-17	7 Jul-17	8 Aug-17	9 Sep-17	10 Oct-17	11 Nov-17	12 Dec-17	13 Jan-18	14 Feb-18	15 Mar-18	16 Apr-18	17 May-18	18 Jun-18	19 Jul-18	20 Aug-18	21 Sep-18	22 Oct-18	23 Nov-18	24 Dec-18	25 Jan-19	26 Feb-19	27 Mar-19	28 Apr-19	29 May-19
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -				\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Major Equipment (Included in Contractor Internal Costs)	\$ -													\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Fuel Gas Conditioning Skid	\$ -																\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
MISO Queue Fees and Network Upgrades	\$ 2,685,000	\$ 385,000				\$ 50,000				\$ 250,000									\$ 500,000	\$ 500,000	\$ 500,000	\$ 500,000								
Gas Interconnect	\$ -																		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Water Interconnect	\$ -																			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Land (Included in Contractor Internal Costs)	\$ -				\$ -																									
Spare Parts and Mat's	\$ 1,080,707																											\$ 1,080,707	100%	
Developers Fee	\$ 1,080,707													\$ 1,080,707	100%															
Engr Supv G&A	\$ 211,500																			\$ 211,500	100%									
Permits, Licenses, Fees (Included in Contractor Internal Costs)	\$ -													\$ -																
Legal/Financial (Included in Contractor Internal Costs)	\$ -													\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -													\$ -								\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Contractor Internal Costs	\$ 108,070,700													\$ 16,210,605	\$ 10,807,070	\$ 10,807,070	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535	\$ 5,403,535
Contingency (25%)	\$ 28,282,154	\$ 96,250				\$ 12,500				\$ 62,500				\$ 270,177	\$ 4,052,651	\$ 2,701,768	\$ 2,701,768	\$ 1,350,884	\$ 1,475,884	\$ 1,528,759	\$ 1,475,884	\$ 1,746,061	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884
	\$ 141,410,768	\$ 96,250				\$ 62,500				\$ 62,500				\$ 270,177	\$ 4,052,651	\$ 2,701,768	\$ 2,701,768	\$ 1,350,884	\$ 1,475,884	\$ 1,528,759	\$ 1,475,884	\$ 1,746,061	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884	\$ 1,350,884
Checksum	\$ 141,410,768	\$ 481,250	\$ -	\$ -	\$ -	\$ 62,500	\$ -	\$ -	\$ -	\$ 312,500	\$ -	\$ -	\$ -	\$ 1,350,884	\$ 20,263,256	\$ 13,508,838	\$ 13,508,838	\$ 6,754,419	\$ 7,379,419	\$ 7,643,794	\$ 7,379,419	\$ 8,730,303	\$ 6,754,419	\$ 6,754,419	\$ 6,754,419	\$ 6,754,419	\$ 6,754,419	\$ 6,754,419	\$ 6,754,419	\$ 6,754,419
Monthly		0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	1.0%	14.3%	9.6%	9.6%	4.8%	5.2%	5.4%	5.2%	6.2%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	
Cumulative		0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.6%	0.6%	0.6%	0.6%	1.6%	15.9%	25.4%	35.0%	39.8%	45.0%	50.4%	55.6%	61.8%	66.6%	71.3%	76.1%	80.9%	85.7%	90.4%	95.2%	100.0%	
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50.4%	5.2%	6.2%	4.8%	4.8%	4.8%	4.8%	4.8%	4.8%	

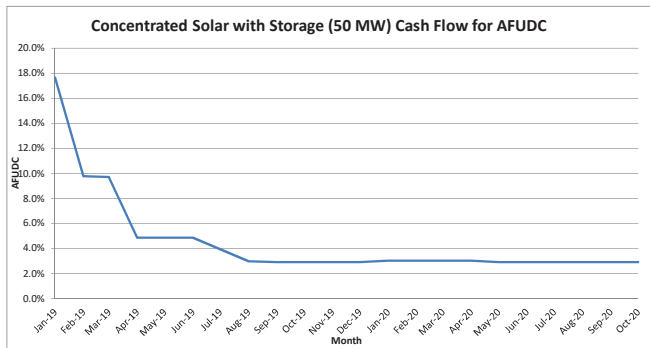


SOLAR

Concentrated Solar with Storage (50 MW)

Concentrated Solar with Storage (50 MW)

Scope	Totals	Month																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Major Equipment (Included in Contractor Internal Costs)	\$ -													\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Fuel Gas Conditioning Skid	\$ -																								
MISO Queue Fees and Network Upgrades	\$ 2,685,000	\$ 385,000				\$ 50,000				\$ 250,000															
Gas Interconnect	\$ -																								\$ -
Water Interconnect	\$ 1,000,000																								
Land (Included in Contractor Internal Costs)	\$ -				\$ -																				
Spare Parts and Mat'ls	\$ 4,384,567																								
Developers Fee	\$ 4,384,567												\$ 4,384,567												
Engr Supv G&A	\$ 211,500																								
Permits, Licences, Fees (Included in Contractor Internal Costs)	\$ -													\$ -											
Legal/Financial (Included in Contractor Internal Costs)	\$ -												\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -													\$ -											
Contractor Internal Costs	\$ 438,456,709													\$ 21,922,835											
Contingency (25%)	\$ 112,780,586	\$ 96,250				\$ 12,500				\$ 62,500			\$ 1,096,142	\$ 5,480,709											
	\$ 563,902,929																								
Checksum	\$ 563,902,929	\$ 481,250	\$ -	\$ -	\$ -	\$ -	\$ 62,500	\$ -	\$ -	\$ 312,500	\$ -	\$ -	\$ -	\$ 5,480,709	\$ 27,403,544	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Monthly		0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	1.0%	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cumulative		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	1.1%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-



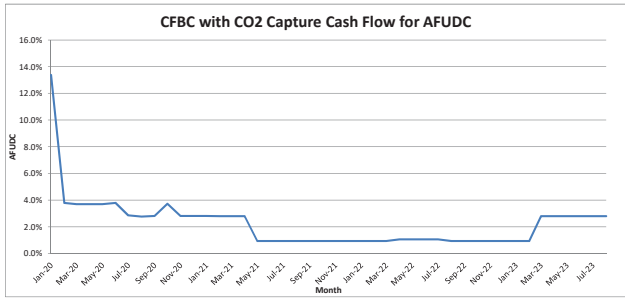
Concentrated Solar with Storage (50 MW)

Scope	Totals	Month																							
		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20		
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Major Equipment (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -													\$ -			
Fuel Gas Conditioning Skid	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -																	
MISO Queue Fees and Network Upgrades	\$ 2,685,000												\$ 500,000	\$ 500,000	\$ 500,000	\$ 500,000									
Gas Interconnect	\$ -	\$ -	\$ -						\$ -																
Water Interconnect	\$ 1,000,000	\$ 250,000	\$ 250,000					\$ 250,000	\$ 250,000																
Land (Included in Contractor Internal Costs)	\$ -																								
Spare Parts and Mat'ls	\$ 4,384,567							\$ 4,384,567																	
Developers Fee	\$ 4,384,567																								
Engr Supv G&A	\$ 211,500	\$ 211,500																							
Permits, Licences, Fees (Included in Contractor Internal Costs)	\$ -																								
Legal/Financial (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Contractor Internal Costs	\$ 438,456,709	\$ 52,614,805	\$ 43,845,671	\$ 43,845,671	\$ 21,922,835	\$ 21,922,835	\$ 21,922,835	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701	\$ 13,153,701			
Contingency (25%)	\$ 112,780,586	\$ 13,269,076	\$ 11,023,918	\$ 10,961,418	\$ 5,480,709	\$ 5,480,709	\$ 5,480,709	\$ 4,447,067	\$ 3,350,925	\$ 3,288,425	\$ 3,288,425	\$ 3,288,425	\$ 3,288,425	\$ 3,413,425	\$ 3,413,425	\$ 3,413,425	\$ 3,413,425	\$ 3,413,425	\$ 3,288,425	\$ 3,288,425	\$ 3,288,425	\$ 3,288,425	\$ 3,288,425		
Checksum	\$ 563,902,929	\$ 66,345,381	\$ 55,119,589	\$ 54,807,089	\$ 27,403,544	\$ 27,403,544	\$ 27,403,544	\$ 22,235,335	\$ 16,754,627	\$ 16,442,127	\$ 16,442,127	\$ 16,442,127	\$ 16,442,127	\$ 17,067,127	\$ 17,067,127	\$ 17,067,127	\$ 17,067,127	\$ 17,067,127	\$ 16,442,127	\$ 16,442,127	\$ 16,442,127	\$ 16,442,127	\$ 16,442,127		
Monthly		11.8%	9.8%	9.7%	4.9%	4.9%	4.9%	3.9%	3.0%	2.9%	2.9%	2.9%	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%	2.9%	2.9%	2.9%	2.9%	2.9%		
Cumulative		17.7%	27.5%	37.2%	42.1%	47.0%	51.8%	55.8%	58.7%	61.7%	64.6%	67.5%	70.4%	73.4%	76.5%	79.5%	82.5%	85.4%	88.3%	91.3%	94.2%	97.1%	100.0%		
AFUDC Cash Flow		17.7%	9.8%	9.7%	4.9%	4.9%	4.9%	3.9%	3.0%	2.9%	2.9%	2.9%	2.9%	3.0%	3.0%	3.0%	3.0%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%		

COAL

Circulating Fluidized Bed Combustion with Carbon Capture

CFBC with CO2 Capture		Month																														
Scope	Totals	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	
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -															\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
	0%																															
Major Equipment (Included in Contractor Internal Costs)	\$ -																							\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
	0%																															
Fuel Gas Conditioning Skid	\$ -																															
	0%																															
MISO Queue Fees and Network Upgrades	\$ 6,375,000																							\$ 763,000						\$ 122,000		
	100%																							12%						2%		
Gas Interconnect	\$ -																															
	0%																															
Water Interconnect	\$ 3,658,705																															
	100%																															
Land	\$ 9,367,106					\$ 9,367,106																										
	100%					100%																										
Spare Parts and Mat'ls	\$ 9,367,106																															
	100%																															
Developers Fee	\$ 9,367,106																							\$ 9,367,106								
	100%																							100%								
Engr Supv G&A	\$ 211,500																															
	100%																															
Permits, Licences, Fees	\$ 18,734,212																								\$ 18,734,212							
	100%																							100%								
Legal/Financial	\$ 18,734,212																							\$ 9,367,106	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	
	100%																							50%	1%	1%	1%	1%	1%	1%	1%	1%
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -																								\$ -							
	0%																															
Contractor Internal Costs	\$ 936,710,608																								\$ 28,101,318							
	100%																								3%							
Contingency (20%)	\$ 202,505,111					\$ 1,873,421																		\$ 7,493,685	\$ 5,810,332	\$ 37,468	\$ 37,468	\$ 37,468	\$ 37,468	\$ 61,868	\$ 37,468	
	100%					0.9%																		3.7%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	\$ 1,215,030,666	\$ -	\$ -	\$ -	\$ -	\$ 11,240,527	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Checksum	\$ 1,215,030,666	\$ -	\$ -	\$ -	\$ -	\$ 11,240,527	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Monthly		0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		
Cumulative		0.0%	0.0%	0.0%	0.0%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%		
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		



CFBC with CO2 Capture		Month																											
		Month																											
		31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58
Scope	Totals	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Major Equipment (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Fuel Gas Conditioning Skid	\$ -						\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
MISO Queue Fees and Network Upgrades	\$ 6,375,000	\$ 610,000																											
Gas Interconnect	\$ -					\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Water Interconnect	\$ 3,658,705						\$ 914,676	\$ 914,676					\$ 914,676	\$ 914,676															
Land	\$ 9,367,106																												
Spare Parts and Mat'ls	\$ 9,367,106																			\$ 9,367,106									
Developers Fee	\$ 9,367,106																												
Engr Supv G&A	\$ 211,500						\$ 211,500																						
Permits, Licences, Fees	\$ 18,734,212																												
Legal/Financial	\$ 18,734,212	\$ 187,342	\$ 187,342	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 374,684	\$ 374,684	\$ 374,684	\$ 374,684	\$ 374,684	\$ 374,684	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -						\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Contractor Internal Costs	\$ 936,710,608						\$ 65,569,743	\$ 37,468,424	\$ 37,468,424	\$ 37,468,424	\$ 37,468,424	\$ 37,468,424	\$ 37,468,424	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 28,101,318	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106
Contingency (20%)	\$ 202,505,111	\$ 159,468	\$ 37,468				\$ 13,339,184	\$ 7,676,620	\$ 7,493,685	\$ 7,493,685	\$ 7,493,685	\$ 7,493,685	\$ 7,676,620	\$ 5,803,199	\$ 5,620,264	\$ 5,695,200	\$ 7,568,622	\$ 5,695,200	\$ 5,695,200	\$ 5,695,200	\$ 5,695,200	\$ 5,657,732	\$ 5,657,732	\$ 5,657,732	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890
	\$ 1,215,030,666	\$ 956,811	\$ 224,811	\$ -	\$ -	\$ -	\$ 80,035,103	\$ 46,059,721	\$ 44,962,109	\$ 44,962,109	\$ 44,962,109	\$ 44,962,109	\$ 46,059,721	\$ 34,819,193	\$ 33,721,582	\$ 34,171,203	\$ 45,411,730	\$ 34,171,203	\$ 34,171,203	\$ 34,171,203	\$ 34,171,203	\$ 33,946,392	\$ 33,946,392	\$ 33,946,392	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338
Monthly		0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	3.8%	3.7%	3.7%	3.7%	3.8%	2.9%	2.8%	2.8%	3.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	0.9%	0.9%	0.9%	0.9%	0.9%
Cumulative		7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	14.3%	18.1%	21.8%	25.5%	29.2%	33.0%	35.9%	38.6%	41.4%	45.2%	48.0%	50.8%	53.6%	56.4%	59.2%	62.0%	62.9%	63.9%	64.8%	65.8%	66.7%	67.7%
AFUDC Cash Flow		-	-	-	-	-	-	13.4%	3.8%	3.7%	3.7%	3.7%	3.8%	2.9%	2.8%	2.8%	3.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	0.9%	0.9%	0.9%	0.9%	0.9%

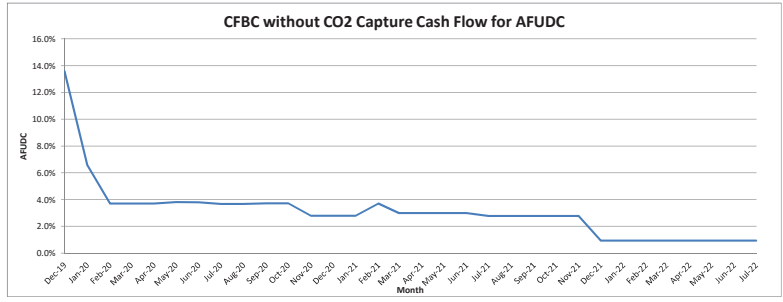
CFBC with CO2 Capture																							
Scope	Totals	Month																					
		59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Major Equipment (Included in Contractor Internal Costs)	\$ -																					\$ -	
Fuel Gas Conditioning Skid	\$ -																						
MISO Queue Fees and Network Upgrades	\$ 6,375,000						\$ 1,220,000	\$ 1,220,000	\$ 1,220,000	\$ 1,220,000													
Gas Interconnect	\$ -																						
Water Interconnect	\$ 3,658,705																						
Land	\$ 9,367,106																						
Spare Parts and Mat'ls	\$ 9,367,106																						
Developers Fee	\$ 9,367,106																						
Engr Supv G&A	\$ 211,500																						
Permits, Licences, Fees	\$ 18,734,212																						
Legal/Financial	\$ 18,734,212	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342	\$ 187,342
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Contractor Internal Costs	\$ 936,710,608	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106	\$ 9,367,106
Contingency (20%)	\$ 202,505,111	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890	\$ 1,910,890
	\$ 1,215,030,666																						
Checksum	\$ 1,215,030,666	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 12,929,338	\$ 12,929,338	\$ 12,929,338	\$ 12,929,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 11,465,338	\$ 33,946,392	\$ 33,946,392	\$ 33,946,392	\$ 33,946,392	\$ 33,946,392	\$ 33,946,392
Monthly		0.9%	0.9%	0.9%	0.9%	0.9%	1.1%	1.1%	1.1%	1.1%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
Cumulative		68.6%	69.5%	70.5%	71.4%	72.4%	73.4%	74.5%	75.6%	76.6%	77.6%	78.5%	79.5%	80.4%	81.3%	82.3%	83.2%	86.0%	88.8%	91.6%	94.4%	97.2%	100.0%
AFUDC Cash Flow		0.9%	0.9%	0.9%	0.9%	0.9%	1.1%	1.1%	1.1%	1.1%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%

COAL

Circulating Fluidized Bed Combustion without Carbon Capture

CFBC without CO2 Capture

Scope	Totals	Month																								
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -															\$ -	\$ -	\$ -	\$ -	
	0%																									
Major Equipment (Included in Contractor Internal Costs)	\$ -																								\$ -	
	0%																									
Fuel Gas Conditioning Skid	\$ -																									
	0%																									
MISO Queue Fees and Network Upgrades	\$ 8,675,000																		\$ 947,000					\$ 168,000		
	100%																		11%					2%		
Gas Interconnect	\$ -																									
	0%																									
Water Interconnect	\$ 3,658,705																									
	100%																									
Land	\$ 7,053,192					\$ 7,053,192																				
	100%					100%																				
Spare Parts and Mat'ls	\$ 7,053,192																									
	100%																									
Developers Fee	\$ 7,053,192																							\$ 7,053,192		
	100%																							100%		
Engr Supv G&A	\$ 211,500																									
	100%																									
Permits, Licenses, Fees	\$ 14,106,384																							\$ 14,106,384		
	100%																							100%		
Legal/Financial	\$ 14,106,384																							\$ 7,053,192	\$ 282,128	
	100%																							50%	2%	
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -																								\$ -	
	0%																									
Contractor Internal Costs	\$ 705,319,189																								\$ 21,159,576	
	100%																								3%	
Contingency (20%)	\$ 153,447,348					\$ 1,410,638.40													\$ 189,400					\$ 5,676,154	\$ 4,288,341	
	100%					0.9%													0.1%					3.7%	2.8%	
	\$ 920,684,086																									
Checksum	\$ 920,684,086	\$ -	\$ -	\$ -	\$ -	\$ 8,463,830	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,136,400	\$ -	\$ -	\$ -	\$ -	\$ 34,056,922	\$ 25,730,044	
Monthly		0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	3.7%	2.8%
Cumulative		0.0%	0.0%	0.0%	0.0%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	4.7%	7.5%
AFUDC Cash Flow		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	



CFBC without CO2 Capture

Scope	Totals	Month																							
		25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Major Equipment (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Fuel Gas Conditioning Skid	\$ -											\$ -	\$ -	\$ -	\$ -										
MISO Queue Fees and Network Upgrades	\$ 8,675,000	\$ 840,000																							
Gas Interconnect	\$ -											\$ -	\$ -	\$ -					\$ -						
Water Interconnect	\$ 3,658,705											\$ 914,676	\$ 914,676					\$ 914,676	\$ 914,676						
Land	\$ 7,053,192																								
Spare Parts and Mat'ls	\$ 7,053,192																								
Developers Fee	\$ 7,053,192																								
Engr Supv G&A	\$ 211,500											\$ 211,500													
Permits, Licences, Fees	\$ 14,106,384																								
Legal/Financial	\$ 14,106,384	\$ 282,128	\$ 282,128	\$ 282,128	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ -	\$ -	\$ -	\$ 282,128	\$ 282,128	\$ 282,128	\$ 282,128
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -											\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Contractor Internal Costs	\$ 705,319,189											\$ 49,372,343	\$ 49,372,343	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 28,212,768	\$ 21,159,576	\$ 21,159,576
Contingency (20%)	\$ 153,447,348	\$ 224,426	\$ 56,426	\$ 56,426	\$ 28,213	\$ 28,213	\$ 28,213	\$ 28,213	\$ 28,213	\$ 28,213	\$ 28,213	\$ 10,127,917	\$ 10,085,617	\$ 5,670,766	\$ 5,670,766	\$ 5,670,766	\$ 5,670,766	\$ 5,853,702	\$ 5,825,489	\$ 5,642,554	\$ 5,642,554	\$ 5,698,979	\$ 5,698,979	\$ 4,288,341	\$ 4,288,341
	\$ 920,684,086																								
Checksum	\$ 920,684,086	\$ 1,346,553	\$ 338,553	\$ 338,553	\$ 169,277	\$ 169,277	\$ 169,277	\$ 169,277	\$ 169,277	\$ 169,277	\$ 169,277	\$ 60,767,500	\$ 60,513,700	\$ 34,024,598	\$ 34,024,598	\$ 34,024,598	\$ 35,122,209	\$ 34,952,933	\$ 33,855,321	\$ 33,855,321	\$ 34,193,874	\$ 34,193,874	\$ 25,730,044	\$ 25,730,044	
Monthly		0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	6.6%	3.7%	3.7%	3.7%	3.7%	3.8%	3.8%	3.7%	3.7%	3.7%	3.7%	2.8%	2.8%
Cumulative		7.7%	7.7%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.9%	7.9%	7.9%	14.5%	21.1%	24.8%	28.5%	32.2%	36.0%	39.8%	43.5%	47.1%	50.8%	54.6%	57.4%
AFUDC Cash Flow														13.6%	6.6%	3.7%	3.7%	3.7%	3.8%	3.8%	3.7%	3.7%	3.7%	2.8%	2.8%

CFBC without CO2 Capture																					
Scope	Totals	Month																			
		49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	
		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	
Engineering (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Major Equipment (Included in Contractor Internal Costs)	\$ -																		\$ -	\$ -	
Fuel Gas Conditioning Skid	\$ -																				
MISO Queue Fees and Network Upgrades	\$ 8,675,000			\$ 1,680,000	\$ 1,680,000	\$ 1,680,000	\$ 1,680,000														
Gas Interconnect	\$ -																				
Water Interconnect	\$ 3,658,705																				
Land	\$ 7,053,192																				
Spare Parts and Mat'ls	\$ 7,053,192		\$ 7,053,192																		
Developers Fee	\$ 7,053,192																				
Engr Supv G&A	\$ 211,500																				
Permits, Licences, Fees	\$ 14,106,384																				
Legal/Financial	\$ 14,106,384	\$ 282,128	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	\$ 141,064	
Contractor's Soft Costs (Included in Contractor Internal Costs)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Contractor Internal Costs	\$ 705,319,189	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 21,159,576	\$ 7,053,192	\$ 7,053,192	\$ 7,053,192	\$ 7,053,192	\$ 7,053,192	\$ 7,053,192	\$ 7,053,192	
Contingency (20%)	\$ 153,447,348	\$ 4,288,341	\$ 5,670,766	\$ 4,596,128	\$ 4,596,128	\$ 4,596,128	\$ 4,596,128	\$ 4,260,128	\$ 4,260,128	\$ 4,260,128	\$ 4,260,128	\$ 4,260,128	\$ 1,438,851	\$ 1,438,851	\$ 1,438,851	\$ 1,438,851	\$ 1,438,851	\$ 1,438,851	\$ 1,438,851	\$ 1,438,851	
	\$ 920,684,086																				
Checksum	\$ 920,684,086	\$ 25,730,044	\$ 34,024,598	\$ 27,576,767	\$ 27,576,767	\$ 27,576,767	\$ 27,576,767	\$ 25,560,767	\$ 25,560,767	\$ 25,560,767	\$ 25,560,767	\$ 25,560,767	\$ 8,633,107	\$ 8,633,107	\$ 8,633,107	\$ 8,633,107	\$ 8,633,107	\$ 8,633,107	\$ 8,633,107	\$ 8,633,107	
Monthly		2.8%	3.7%	3.0%	3.0%	3.0%	3.0%	2.8%	2.8%	2.8%	2.8%	2.8%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	
Cumulative		62.9%	66.6%	69.6%	72.6%	75.6%	78.6%	81.4%	84.2%	86.9%	89.7%	92.5%	93.4%	94.4%	95.3%	96.2%	97.2%	98.1%	99.1%	100.0%	
AFUDC Cash Flow		2.8%	3.7%	3.0%	3.0%	3.0%	3.0%	2.8%	2.8%	2.8%	2.8%	2.8%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	

APPENDIX D

BIOMASS RESEARCH INFORMATION

Biomass Fuel Assumptions				Source
	Value	Unit	Comment	
Total Planted Wheat	111,838.92	ac	Grain and Forage (50 mi radius around Bismarck, ND)	https://www.fsa.usda.gov/news-room/eoia/electronic-reading-room/frequently-requested-information/crop-acreage-data/index
Wheat Yield	46.7	bu/ac		https://www.nass.usda.gov/Quick_Stats/Ag_Overview/stateOverview.php?state=north%20dakota
Wheat_Spring_ Excl Durum Yield	48	bu/ac		https://www.nass.usda.gov/Quick_Stats/Ag_Overview/stateOverview.php?state=north%20dakota
Wheat_Spring_ Durum Yield	39.5	bu/ac		https://www.nass.usda.gov/Quick_Stats/Ag_Overview/stateOverview.php?state=north%20dakota
Wheat_Winter Yield	44	bu/ac		https://www.nass.usda.gov/Quick_Stats/Ag_Overview/stateOverview.php?state=north%20dakota
Average Wheat Yield	44.55	bu/ac	Average of all types of wheat	
Wheat Legal Weight in North Dakota	60	lb/bu		http://chestofbooks.com/gardening-horticulture/farming/Farm-And-Garden-Rule-Book/Legal-Weights-of-the-Bushel.html
Straw-to-Spring Wheat Ratio	1.3:1.0			http://bioweb.sungrant.org/Technical/Biomass+Resources/Agricultural+Resources/Crop+Residues/Wheat+Straw/Default.htm
Straw-to-Winter Wheat Ratio	1.7:1.0			http://bioweb.sungrant.org/Technical/Biomass+Resources/Agricultural+Resources/Crop+Residues/Wheat+Straw/Default.htm
Straw-to-Average Wheat Ratio	1.5:1.0		Average of the two ratios	
Percent Wheat Straw Removed	40	%	Assumed based on amount of corn stover removed from field	http://www.agweb.com/article/corn-stover-baling-logistics-naa-university-news-release/
Gross Heating Value of Wheat Straw (HHV)	7,309	Btu/lb		Thermoflow (Great Plains Institute Feasibility of Biomass Co-Firing report and slide show for comparison)
Net Heating Value of Wheat Straw (LLV)	6,706	Btu/lb		Thermoflow (Great Plains Institute Feasibility of Biomass Co-Firing report and slide show for comparison)
Moisture Content of Wheat Straw	10.3	%		Thermoflow (Great Plains Institute Feasibility of Biomass Co-Firing report and slide show for comparison)

Wheat Straw and Boiler Size Calculations			
	Value	Unit	Source
Bushels of Wheat	4,982,423.89	bu	Calculated
Weight of Wheat	298,945,433.16	lb	Calculated
Weight of Total Wheat Straw	448,418,149.74	lb	Calculated
Weight of Usable Wheat Straw	179,367,259.90	lb	Calculated
Wheat Straw Fuel Consumption	1,310,941,492.401.90	Btu/yr	Calculated using HHV
Hours of Operation	8,760	hr/yr	Assumed
Wheat Straw Fuel Consumption	149,650,855	Btu/hr	Calculated
Conversion Factor	14,273	Btu/kW-hr	Thermoflow
Possible Size for Wheat Straw Boiler	10,485	kW	Calculated
Possible Size for Wheat Straw Boiler	10	MW	Calculated

Feasible Boiler Size Calculations			
	Value	Unit	Source
Possible Size for Wheat Straw Boiler	10	MW	Assumed
Possible Size for Wheat Straw Boiler	10,000	kW	Calculated
Conversion Factor	14,273	Btu/kW-hr	Thermoflow
Wheat Straw Fuel Consumption	142,730,000	Btu/hr	Calculated
Hours of Operation	8,760	hr/yr	Assumed
Wheat Straw Fuel Consumption	1,250,314,800,000	Btu/yr	Calculated
Weight of Usable Wheat Straw	171,072,120	lb/yr	Calculated using HHV
Weight of Wheat Straw Transported	468,691	lb/d	Calculated
Largest Truck Capacity	4050	ft ³	http://yrc.com/trailer-dimensions/
Large/Mid-Sized Square Bale Density (low end of density range)	13	lb/ft ³	http://www.omafra.gov.on.ca/english/engineer/facts/11-035.htm
Large/Mid-Sized Square Bale Density (high end of density range)	16	lb/ft ³	http://www.omafra.gov.on.ca/english/engineer/facts/11-035.htm
Trucks per Day (low end of density range)	8.9	trucks/d	Calculated
Trucks per Day (high end of density range)	7.2	trucks/d	Calculated

Fuel Cost Calculations			
	Value	Unit	Source
Harvesting Cost	16.00	2008\$/ton	GPI Feasibility of Biomass
Commodity Cost	16.00	2008\$/ton	GPI Feasibility of Biomass
Transportation Cost	14.00	2008\$/ton	GPI Feasibility of Biomass
Total Biomass Fuel Cost	46.00	2008\$/ton	Calculated
Cost Reference Year	2008		GPI Feasibility of Biomass
Cost Input Year	2017		
Total Years of Escalation	9		
Escalation Rate	3	%	Assumed
Total Biomass Fuel Cost	60.02	2017\$/ton	Calculated
Total Biomass Fuel Cost	0.03	2017\$/lb	Calculated
Total Biomass Fuel Cost	4.11	2017\$/MMBtu	Calculated using HHV

APPENDIX E

SOLAR RESEARCH INFORMATION

PV (Fixed Tilt) Solar Data*			
	Value	Unit	Comment
Plant Size	50	MW	
Area Required			3-5 acres per 1 MWp
Topography			Flat or slightly south facing slope
Shading	0	%	
Module Type			72 cell Multi-Crystalline
Power Output Range	300 - 315	W	
Maximum Efficiency	16	%	
Quantity of Modules	161,290		
Quantity of Inverters w/ Transformers	300		

*Information based off of project that took place in Missouri. Site has similar annual average solar resource data as Bismarck, ND.

Concentrated Solar Data			
	Value	Unit	Comment
Central Tower			
Plant Size	50	MW	Gross, 1 unit
Collector Area Required	264	acres	
Storage Capacity	2	hours	
Parabolic Trough			
Plant Size	50	MW	Gross, 1 unit
Collector Area Required	275	acres	
Storage Capacity	6	hours	
Parabolic Trough w/ Storage			
Plant Size	50	MW	Gross, 1 unit
Collector Area Required	275	acres	
Storage Capacity	6	hours	

Solar Resources for Bismarck, ND			
	Value	Unit	Source
Concentrating Solar Collectors - Direct Normal Irradiance (DNI)	4.265	kWh/m sq.	NREL
Horizontal Flat Plate Collectors - Global Horizontal Irradiance (GHI)	3.787	kWh/m sq.	NREL
Tilted Flat Plate Collectors - Latitude Tilt Irradiance (TILT)	4.27	kWh/m sq.	NREL
Air Temperature at 10m Above Ground	4.6	degrees C	NREL
Earth Skin Temperature	5.89	degrees C	NREL
Cooling Days above 10 deg C	1,079	degree days	NREL
Heating Days below 18 deg C	5,128	degree days	NREL
Atmospheric Pressure	94.7	kPa	NREL
Relative Humidity	68.01	%	NREL

Climate - Bismarck Yearly Averages (per U.S. Climate Data)		
	Value	Unit
Temperatures	42.8	degrees F
Snowfall	50	inches
Precipitation	17.82	inches
Wind Max	Unknown	

Assumptions from NREL Annual Technology Baseline Spreadsheet 2016 Final			
	Value	Unit	Comment
Plant Size	100	MW	Representative size in spreadsheet
Basis Year	2014		Basis year dollars were escalated to 2017 dollars using escalation rate determined by Segal and MDU
Average Capacity Factor for PV	20	%	
Concentrated Solar Plant Technology			Based on molten salt power towers w/ a steam Rankine cycle before 2020
Hours of Storage for Concentrated Solar	10	hrs	
Radiation Level Class	Class 1		Fair Resource

Unloaded Capital Cost Calculations for Concentrated (Thermal) Unit with Storage	
<p>*Includes CSP Generation Plant (which includes installed solar collectors, solar receiver, piping and heat-transfer fluid system, power block-heat exchangers, power turbine, generator, cooling system, thermal energy storage system, and installation), balance of system (which includes land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance, electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center, generator voltage is 13.8 kV, step-up transformer will be 13.8/230 kV, the transmission tie line will 230 kV, project indirect costs including engineering distributable labor and materials, construction management startup and commissioning, and contractor overhead costs, and fees and profit), and financial costs (which includes owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, onsite electrical equipment, nominal-distance spur line, and necessary upgrades at a transmission substation. Represents total expenditure required to achieve commercial operation in a given year. Does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines cost. (Capital cost referred to as CAPEX in Annual Technology Baseline spreadsheet/report from NREL)</p>	

Unloaded Capital Cost Calculations for Photovoltaic Unit (Fixed Tilt)	
<p>*Includes modules (which includes module supply, power electronics, racking, foundation, AC&DC materials and installation), balance of system (which includes land acquisition, site preparation, installation of underground utilities, access roads, fencing, buildings for operations and maintenance, electrical infrastructure such as transformers, switchgear and electrical system connecting modules to each other and to control center, project indirect costs including engineering, distributable labor and materials, construction management start up and commissioning, and contractor overhead costs, fees and profit), and financial costs (owner's costs such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, onsite electrical equipment, nominal-distance spur line, and necessary upgrades at a transmission substation. Represents total expenditure required to achieve commercial operation in a given year. Does not explicitly represent regional variants associated with labor rates, material costs, etc. or geographically determined spur lines cost. (Capital cost referred to as CAPEX in Annual Technology Baseline spreadsheet/report from NREL)</p>	

Attachment F

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

2016 RFP for Capacity and Energy

Overview

Montana-Dakota issued a Request for Proposal (RFP) on August 1, 2016 for capacity and energy totaling at least 10 MW and no more than 100 MW during the period of June 1, 2019 to May 31, 2024 (First Period); and for the long term totaling at least 10 MW and no more than 200 MW for a period to begin June 1, 2024 (Second Period).

Process

Once the RFP was issued, companies had until August 15, 2016 to submit a Notice of Intent to Bid (NOIB), which there were twenty three companies that submitted a NOIB. The companies then had until September 15, 2016 to submit their final proposals to Montana-Dakota. This resulted in sixteen companies submitting final bids with several companies submitting multiple proposals.

The original date for a shortlist was to be October 14, 2016, but with the amount of bids that were received this was delayed by a couple weeks. The final shortlist left seven projects to be further analyzed and had a final selection date of December 1, 2016. The final selection was completed before the final selection date, and one project was selected for further consideration from the process.

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

Summary of bids

As noted above there were a lot of proposals and the list below shows the types of responses that were received:

- Wind – 16
- Solar – 3
- Combined Cycle Combustion Turbine – 2
- Coal – 1
- Hydro – 1
- Battery Storage – 1
- Solar and Battery Storage – 1
- Capacity Contract – 1
- Reciprocating Internal Combustion Engines – 1

The above list was then reduced to a shortlist that includes the following proposals:

- Five wind proposals (48 MW to 200 MW)
- One Combined Cycle Combustion Turbine proposal (95 MW)
- One solar proposal (5 MW)

Results analysis

The initial modeling of the shortlist proposals selected multiple wind projects as part of the least cost plan, but the results produced a significant amount of dump energy or energy ultimately sold back into the energy market above our retail customer load. A few changes to the modeling were applied to eliminate some or all of the dump energy from the results. One of the changes to the model was to allow for a multiplier to be added to the dump energy that increased the cost of this dump energy or in sense a penalty factor was applied. This helped reduced the level of multiple wind proposals from being selected as part of the least cost plan. The next change was looking at the MISO market prices. The original MISO market prices, which can be seen in Table-1 are based on a 5 year historical average which; was higher than most of the wind proposal prices. This was one of the main reasons that multiple wind proposals were being selected. The ‘low prices’ scenario in Table-1, which were based on a 1 year historical average, were more comparable or lower than the wind proposal prices which also led to less wind be selected. The last adjustment done was to increase the amount of MISO market energy purchases the model could select at any one time, since the initial results were showing the model was selecting as much energy as it could from wind and the market. With the above changes, the Base modeling results selected 148 MW of new wind as compared to 498 MW of new wind in the initial screening models.

Table-1: MISO Market Prices for RFP analysis

MISO Market Prices (\$/MWh)			
2017\$	Original prices ¹	mid-prices ²	low prices ²
on-peak	\$27.15	\$24.29	\$21.43
off-peak	\$21.45	\$19.89	\$18.31
1 - Escalated at 3%			
2 - Escalated at 2%			

The combined cycle proposal was initially selected during the screening analysis in several scenarios as part of the least cost plan, which can be seen in Table-2. This proposal was not ultimately selected as a viable resource option due to fact of its location in Wisconsin was not within Montana-Dakota’s service territory, short timeframe needed to commit to the project, and the project could end up being stranded in MISO if Montana-Dakota were to join SPP at some point in the future.

Table-2: Combined Cycle options selected

Combined Cycle Option Selected				
	original MISO prices at 200 MW	original MISO prices at 300 MW	mid MISO prices at 300 MW	Low MISO prices at 300 MW
Base*	CC(95 MW)	CC(95 MW)	CC(95 MW)	CC(95 MW)
TSW only	CC(188 MW)	CC(95 MW)	CC(95 MW)	CC(95 MW)
no wind	CC(95 MW) CC(188 MW)	CC(95 MW)	CC(95 MW)	CC(95 MW)
*Left the Market option at 200 MW for all base case scenarios CC(95 MW) – RFP proposal CC(188 MW) – Build out of Heskett 3 into Combined Cycle				

The model selected the 5 MW solar proposal in many of the modeling scenarios that were done, because of its small project size and its high MISO capacity accreditation factor. This proposal was tabled to be re-evaluated in more depth at a later date.

In the end the only proposal selected from the RFP process for inclusion in the IRP analysis was the 48 MW Thunder Spirit Wind expansion project. The other wind proposals either came in at a higher cost, were withdrawn by the bidder from the RFP process, and/or were still in the MISO Interconnection queue with risks for unknown costs adjustments associated with required network transmission upgrades to interconnect to the transmission system. The Thunder Spirit Wind expansion project has its final interconnection agreement, is fully permitted, and controls the necessary wind leases for the project and based on Table-3 the Thunder Spirit Wind expansion project comes in at a lower NPV versus adding more wind or adding no additional wind in a majority of the scenarios.

Table-3: The modeling results based on the Net Present Value (NPV)

50 Year NPV (M\$)				
	original MISO prices at 200 MW	original MISO prices at 300 MW	mid MISO prices at 300 MW	low MISO prices at 300 MW
Base*	\$2,690.00	\$2,690.00	\$2,489.00	\$2,427.00
TSW only	\$2,788.00	\$2,685.00	\$2,389.00	\$2,298.00
no wind	\$2,850.00	\$2,743.00	\$2,441.00	\$2,346.00
*Left the Market option at 200 MW for all base case scenarios				

Appendix A

2016 Request for Proposal for Capacity and Energy

Montana-Dakota Utilities Co.

**Request for Proposal for
Capacity and Energy Supply**

August 1, 2016

Montana-Dakota Utilities Co.
Request for Proposal - Capacity and Energy Supply

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Exhibit B – Form of Notice of Intent to Bid

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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 totaling at least 10 megawatts (MW) and no more than 100 MW during the period of June 1, 2019 to May 31, 2024 (First Period); and for long-term Proposals for capacity and energy totaling at least 10 MW and no more than 200 MW for a period to begin June 1, 2024 (Second Period). Persons or entities responding to this RFP are referred to as “Respondents.”

1.2. Product Description and Requirements

Montana-Dakota is seeking Proposals involving the purchase of capacity and energy resources for a term of at least five years, with five year extension options available, with deliveries to begin June 1, 2019 (First Period) and Proposals involving long-term purchases of capacity and energy resources with deliveries to begin June 1, 2024 (Second Period). Delivery dates after June 1, 2019 (First Period) and June 1, 2024 (Second Period) will be considered but preference will be given to resources available for delivery no later than June 1, 2019 (First Period) and June 1, 2024 (Second Period).

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. Proposals must be for generating capacity of at least 10 MW and no more than 100 MW during the First Period; and for generating capacity of at least 10 MW and no more than 200 MW during the Second Period.

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.

Power Purchase Agreements (PPA) of a term shorter or longer than five years during the First Period and of a term shorter than twenty years during the Second Period will be considered in this RFP. Preference will be given to Proposals with an initial term of five years or longer during the First Period and with a term of twenty years or longer during the Second Period.

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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 in order to fully evaluate the costs and impacts 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.

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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, 2016
Bidder's Conference	None
Notice of Intent to Bid Due	August 15, 2016
RFP Responses Due	September 15, 2016
Shortlist Notification	October 14, 2016
Selection Process Complete	December 1, 2016

* 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 (NOIB)

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 NOIB on or before 5:00 P.M. CDT on August 15, 2016. 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-

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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 15, 2016 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. **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 2016 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 1, 2016. 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 14, 2016 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

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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 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.

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- 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 1, 2016.
- 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).

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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.

2.9.11.5.7 The Respondent may provide proposals for seasonal capacity and energy. Seasonal capacity and energy must be available for the entire period of June 1 to September 30 or October 1 to May 31 for each MISO Planning Year.¹

2.9.11.6 Information on the makeup of the Respondent Company and its parent organization, if any, shall be provided along with the more recent financial report, the current audited annual financial report, and 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.

¹ MISO Planning Years run from June 1st to May 31st.

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- 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) 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.
- 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. Montana-Dakota will also accept Proposals that provide seasonal capacity and energy. Seasonal capacity and energy must be available for the entire period of June 1 to September 30 or October 1 to May 31 for each MISO Planning Year.
- 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).

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- 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.

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- 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 the system impacts from new-build alternatives and/or market purchases in determining the appropriate purchases and/or acquisitions for Montana-Dakota's future capacity and energy needs.
- 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 compete 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

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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. Montana-Dakota will include in each Proposal evaluation the cost of any credit requirements from Montana-Dakota.

- 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 and the highest level of reliability.
- 3.1.11 Montana-Dakota will entertain proposals which contain provisions for an asset sale or option for an asset sale from the Respondent to Montana-Dakota as part of the Respondent's bid.

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 must be available for delivery no later than June 1, 2019 (First Period) and June 1, 2024 (Second Period). Delivery dates after June 1, 2019 (First Period) and June 1, 2014 (Second Period) will be considered but preference will be given to resources available for delivery no later than June 1, 2019 (First Period) and June 1, 2014 (Second Period)
- e. The capacity and energy is available and deliverable to Montana-Dakota's system.

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- g. The capacity is at least 10 MW and no more than 100 MW during the First Period, and at least 10 MW and no more than 200 MW during the Second Period.
- h. During the First Period, PPA's of a term shorter or longer than five years will be considered in this RFP. Preference will be given to Proposals with an initial term of five years or longer.
- i. During the Second Period, PPA's of a term shorter than twenty years will be considered in this RFP. Preference will be given to Proposals with an initial term of twenty years or longer.

3.2.2. Operating Performance Thresholds

- a. The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit.
- b. The Respondent must certify that any identified generating unit is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.
- c. 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 agreement must accompany the Respondent's Proposal.

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- 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 14, 2016, 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 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.

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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, submit, and negotiate its Proposal, subsequent contract, and any related activity including 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) 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.

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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:

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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

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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 its 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:

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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: _____

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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, 2016. 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

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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

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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 _____, 2016.

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 Basin 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 the 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 Basin 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 all MISO customer load does not peak at the same time. Montana-Dakota receives a significant benefit being the western most transmission owning member in MISO and Montana-Dakota's customer currently only need to supply 80.7% of their full capacity requirements. If Montana-Dakota were to join SPP, Montana-Dakota would have to add 130 MW of additional capacity resources to its generation portfolio.

Montana-Dakota is planning to annually calculate the cost impact of taking both SPP and MISO NITS service versus a withdrawn from MISO membership scenario to ensure that the current netting arrangement is in the best interest of serving its customer obligations for a safe, reliable, and economic system.

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 post-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 \$3.1 million dollars in 2017, which includes the cost of the Mandan 230 kV Junction Substation.¹ 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

¹ MISO Indicative Annual charges for approved Baseline Reliability Projects (Schedule 26).
<https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx>

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.

MISO Allocation of Cost Sharing under RECB II Criteria

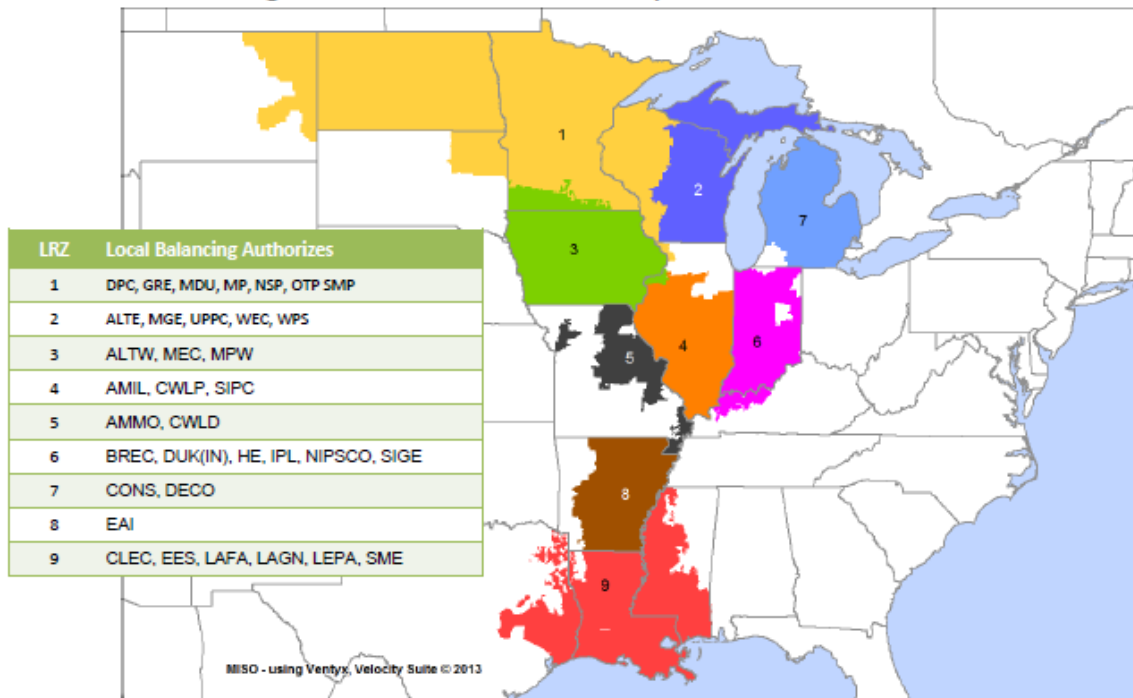
The MISO RECB II cost allocation allows for the cost sharing of approved market efficiency projects (MEPs) with the benefiting transmission owners or with the entire MISO footprint.

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 wind postage stamp.

Local Resource Zones (LRZ)

2014 Planning Year – MISO LRZ Map



MISO is currently engaging stakeholders through the RECB Task Force to review the MEP metrics and voltage qualification criteria including the additional possible MEP metrics and 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’s believes current cost allocation for MEPs is sufficient and no changes are needed. If changes to voltage threshold or additional benefit criteria are implemented than 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 the 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.² The MTEP 2011 Report identified potential benefits of at least 1.6 to 2.8 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.³

One of the 2011 MVP Portfolio projects is a 345 kV transmission line from Big Stone, SD to Ellendale, ND. Montana-Dakota is developing this project in partnership with Otter Tail Power Company and it is expected to have an in-service date of 2019 with a constructed cost of \$396 million.

² MISO Transmission Expansion Plan 2011.

<https://www.midwestiso.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf>

³ MISO 2014 MVP Triennial Review Report.

<https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MTEP14%20MVP%20Triennial%20Review%20Report.pdf>

The 2019 forecasted MISO Schedule 26-A (MVP Cost Adder) charge is \$1.84 per MWh.⁴ Assuming a 2019 Total Energy Requirements of 3,458,081 MWh, this would result in a total charge of \$6,365,971 to Montana-Dakota's customers.

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

⁴ MISO Indicative Annual charges for approved Multi-Value Projects (Schedule 26-A).
<https://www.misoenergy.org/layouts/MISO/ECM/Redirect.aspx?ID=230305>

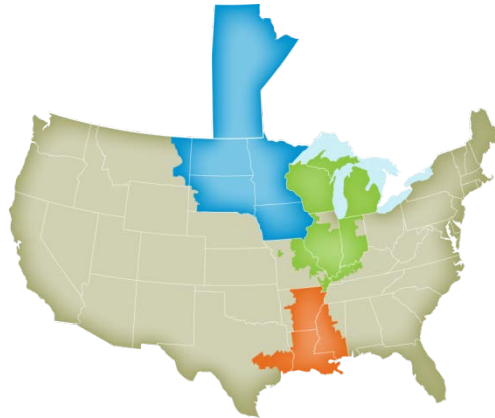
Attachment H

**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 Operations¹

1. Generation Capacity
 - 174,874 MW (market)
 - 190,539 MW (reliability)
2. Generation Fuel Mix
 - 43% Gas
 - 35% Coal
 - 14% Renewable (16,017 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 2017

<https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf>

- 65,800 miles
- 6. Balancing Authorities
 - 36 Local Balancing Authorities in MISO
- 7. Network Model
 - 291,539 SCADA data points
 - 6,541 generating units

MISO has four main areas of services that it provides to its members²

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 249,000 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 Day. Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic

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

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 (LSE) and other Market Participants (MP) against congestion charges in MISO's Day-Ahead Market. An ARR is a MP's entitlement to a share of revenue generated in annual FTR auctions. A MP's firm historical usage of MISO's transmission system determines its share, and depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge. MISO facilitates annual and monthly FTR Auctions.

4. Transmission and Resource Planning

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

The projects listed in Appendix A of the MTEP Report constitute the essential transmission projects recommended to the MISO Board of Directors bi-annually basis 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

Value Proposition

As a means of providing a measurement of value related services to its members, MISO annually updates its value proposition. Areas included in the MISO Value Proposition for 2016³ were:

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

³ MISO Website. Value Proposition for 2016.

<https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2017/Value%20Proposition/2016%20Value%20Proposition%20Presentation.pdf>

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 20.98% to 15.2%. This decrease delays the need to construct new capacity.

H. GENERATOR AVAILABILITY IMPROVEMENT

MISO’s wholesale power market improved power plant availability by 1.18%, 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 2016 Value Proposition study indicates that MISO provides between \$2.6 and \$3.3 billion in annual economic benefits to its members and the surrounding region.

