



Integrated Resource Plan



2015



**Submitted to the
North Dakota Public Service Commission
July 1, 2015**

Volume IV: Attachments C-F

Montana-Dakota Utilities Co.
2015 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

TABLE OF CONTENTS

OVERVIEW	1
Capacity Needs	1
Load and Capability	1
1. Analysis Method	4
2. Resources	5
2.1. Current Resources	5
2.1.1. Coal	6
2.1.2. Natural Gas and Diesel	7
2.1.3. Renewable	7
2.1.4. Purchased Power	8
2.1.5. Demand Response	8
2.1.6. MISO Energy Market	8
2.2 Future Capacity Resources	9
2.3. Considered Supply-Side Resource Alternatives	10
2.3.1. Simple Cycle Combustion Turbine	11
2.3.2. Simple Cycle Reciprocating Internal Combustion Engine	12
2.3.3. Combined Cycle Combustion Turbine	12
2.3.4. Coal	12
2.3.5. Wind (Self-Built)	13
2.3.6. Solar	13
2.3.7. Landfill Gas	13
2.3.8. Biomass	14
2.3.9. Solid Waste	14
2.3.10. Geothermal	14
2.4 Retirements	16
2.5 Integration of Demand-Side and Supply-Side Resources	16
3. Summaries of Results	16
3.1. Base Case Plan Results	19
3.2. Sensitivity Analysis	19
3.2.1. Carbon Tax	19
3.2.2. High and Low Gas Price	20
3.2.3. Ninety percent coincident factor for MISO Resource Adequacy (RA)	21
3.2.4. Low Growth	21
3.2.5. High Growth	21
3.2.6. High Combustion Turbine and Internal Combustion Engines Costs	22
3.2.7. High and Low Market Prices	22
3.2.8. Diminishing Energy Market	22
4. Conclusions	23

5. Future Resource Plan25
6. References.....26

APPENDIX A – EGEAS INPUT DATA FOR THE BASE CASE

APPENDIX B – EGEAS OUTPUT REPORT FOR THE BASE CASE

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 7.1 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 7.1 percent PRM, the product of which is referred to as the planning reserve margin requirement (PRMR).

Montana-Dakota is required to meet an 80.3 percent coincident factor for the 2015-16 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 80.3 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:

$$\text{UCAP} = \text{ICAP} - (1 - \text{XEFOR}_d).$$

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

Figure 1-1 shows that, under the current system forecast and with the current capacity purchase contracts, Montana-Dakota will be capacity deficit by 22.3 ZRC in 2017. This capacity deficit will increase to 70.1 ZRC in 2020 and grow to 123.3 ZRC in 2025. 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 22.3 ZRC will occur in 2017 and grow to 90.1 ZRC in 2020.

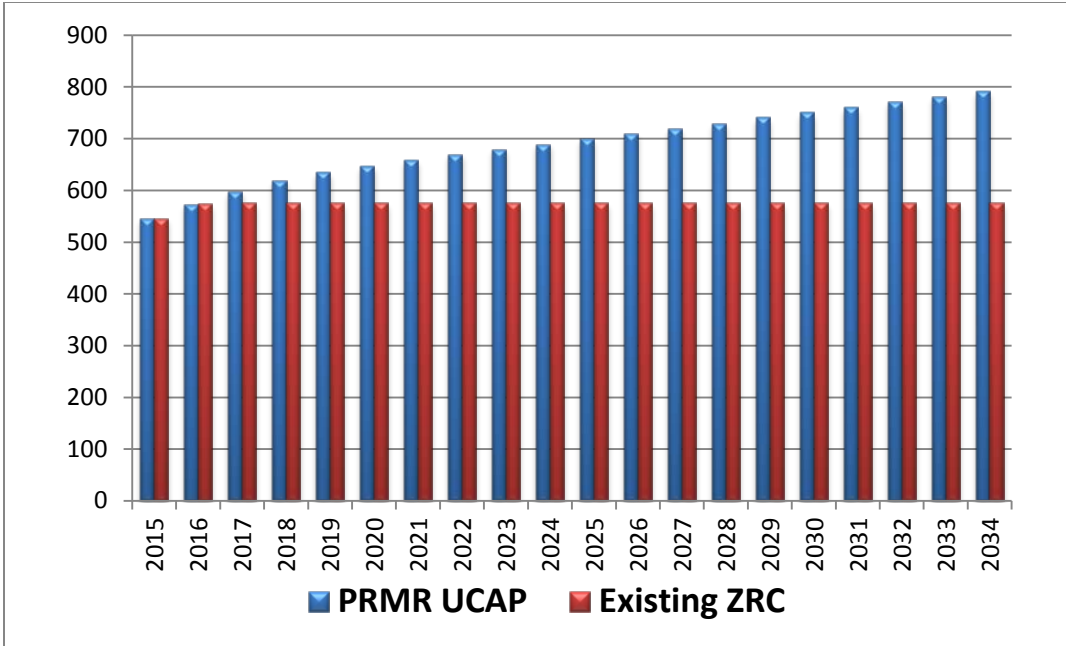


Figure 1-1: Zonal Resource Credit and Planning Reserve Margin Requirement Base Forecast

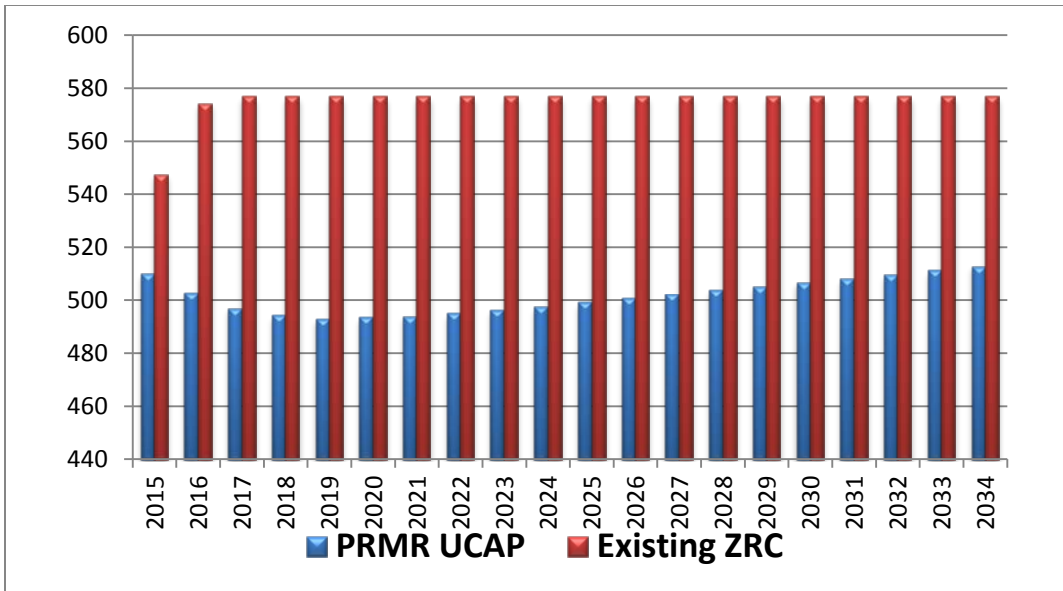


Figure 1-2: Zonal Resource Credit and Planning Reserve Margin Requirement Low Growth Forecast

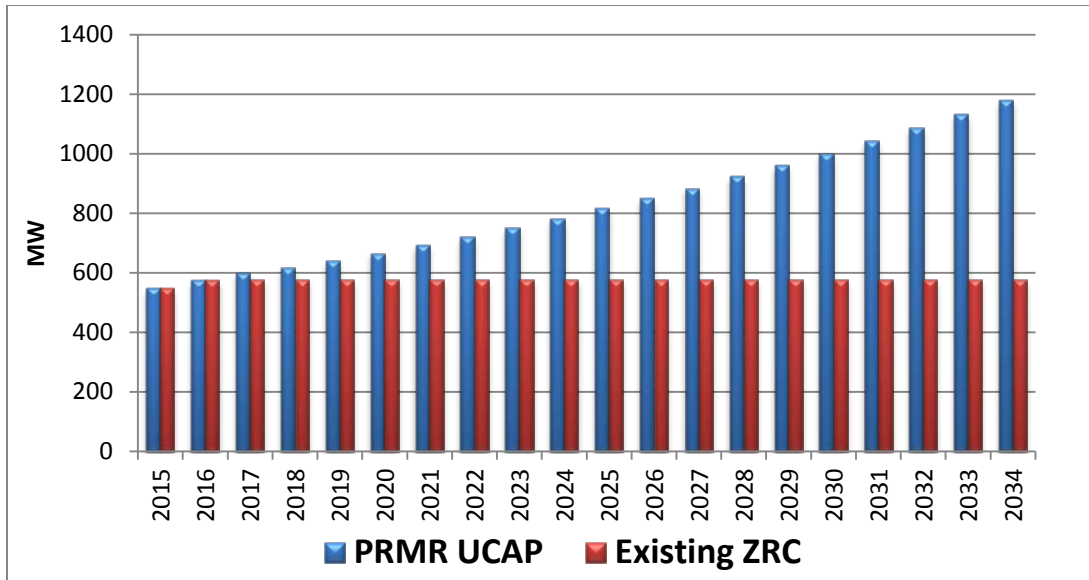


Figure 1-3: Zonal Resource Credit and Planning Reserve Margin Requirement High Growth Forecast

1. Analysis Method

The Electric Generation Expansion Analysis System (EGEAS) version 9.02, 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 2014 with the study period starting in 2015. Costs indicated in this report are in 2014 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2015-2034) 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. The ZRC value for wind resources is based on an effective load carrying capability (ELCC) study performed annually by MISO. This study examines MISO's top eight annual summer peaks for the last five years to determine how much wind is 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 2015-2016 planning year, the ELCC study concluded that 14.7 percent of nameplate wind capacity could be converted into a ZRC value if the wind resource is a network resource up to 20% of nameplate or has a transmission service request (TSR) for the nameplate value. Based upon Montana-Dakota's wind farms' CPNodes, Diamond Willow was determined to contribute up to 18.42 percent of its nameplate capacity to ZRCs, and Cedar Hills was allowed up to 23.16 percent of its nameplate capacity to ZRCs. Ultimately, Diamond Willow, a designated network resource, was accredited with 5.5 ZRCs. Cedar Hills, also a designated network resource, was accredited with 4.5 ZRCs, as Montana-Dakota holds a TSR for Cedar Hills.

2.1. Current Resources

The existing resource portfolio is broken down into five groups: coal, natural gas/oil, renewable, MISO capacity, and DSM. Figure 2-1 shows Montana-Dakota's 2015 current resource mix by zonal resource credits. Sixty percent of Montana-Dakota's

ZRCs comes from coal generation, thirty-one percent from gas-fired generation, three percent from purchased capacity, three percent from DSM and three percent from renewable resources.

2015 Montana-Dakota Zonal Resource Credits

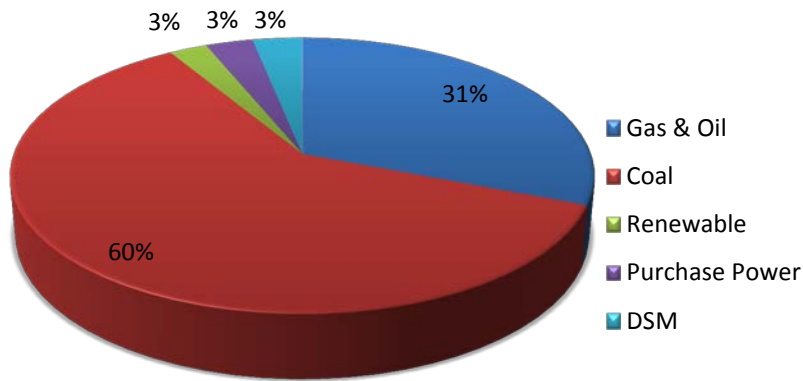


Figure 2-1: Montana-Dakota’s Current Generation Mix by Zonal Resource Credits

2.1.1. Coal

Montana-Dakota currently owns five coal-fired units two of which are jointly owned with other regional utilities. Coal currently accounts for 60 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

<u>Unit</u>	<u>GVTC</u> <u>(MW)</u>	<u>XEFOR_d</u>	<u>Zonal</u> <u>Resource</u> <u>Credit</u> ¹	<u>Fixed O&M</u> <u>(\$/kW-year)</u>	<u>Variable O&M</u> <u>(\$/MWh)</u>	<u>Fuel</u> <u>(\$/MBTU)</u>
Coyote ²	106.8	14.35	92.7	25.60	2.80	1.45
Big Stone ³	107.8	8.01	98.8	24.98	1.65	2.10
Heskett 1	29.2	7.02	20.5	66.14	6.80	1.84
Heskett 2	74.6	8.73	66.7	55.96	6.34	1.84
Lewis & Clark	52.3	0.41	52.1	57.95	4.19	1.77

1. Based on MISO 2015-16 Planning Year ICAP and XEFOR_d
2. Montana-Dakota's 25 percent ownership share
3. Montana-Dakota's 22.7 percent ownership share

2.1.2. Natural Gas and Diesel

Simple-cycle combustion turbines capable of firing natural gas or fuel oil, along with internal combustion engines firing 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

<u>Unit</u>	<u>GVTC</u>	<u>XEFOR_d</u>	<u>Zonal</u> <u>Resource</u> <u>Credit</u> ¹	<u>Fixed O&M</u> <u>(\$/kW-year)</u>	<u>Variable O&M</u> <u>(\$/MWh)</u>	<u>Fuel</u> <u>(\$/MBTU)</u>
Glendive 1	34.78	1.25	33.4	5.32	2.00	2.96
Glendive 2	40.74	0.86	39.8	9.40	2.00	2.96
Miles City	23.15	1.15	21.4	10.46	2.00	2.96
Heskett 3	75.0	5.61	70.8	12.08	2.00	2.96
Diesel 1	2.0	14.00	0	27.58	2.00	25.12
Diesel 2	2.1	14.00	1.8	27.58	2.00	25.12
Diesel 3	2.1	14.00	1.8	27.58	2.00	25.12

1. Based on MISO 2015-16 Planning Year ICAP and XEFOR_d

2.1.3. Renewable

In addition to coal, diesel, and natural gas, Montana-Dakota owns three 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	5.5	22.14	-31.85	-
Cedar Hills ²	4.5	19.79	-31.85	-
Glen Ullin Station 6 ³	3.4	51.95	6.90	-

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 2015-16 Planning Year ICAP and XEFOR_d

2.1.4. Purchased Power

In addition to generation resources that Montana-Dakota owns, the Company purchased capacity from the 2015-16 MISO Planning Year auction as shown in Table 2-4, to meet the 2015-16 planning reserve margin requirements within MISO.

Table 2-4: Montana-Dakota’s Purchase Power

<u>Unit</u>	<u>Zonal Resource Credit</u>	<u>Fixed O&M (\$/kW-year)</u>	<u>Variable O&M (\$/MWh)</u>	<u>Fuel (\$/MBTU)</u>
MISO Capacity Auction	16.6	1.27	0	-

2.1.5. 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 2015.

- Montana-Dakota Interruptible loads – 14.4 MW
- Commercial DSM – 10 MW

2.1.6. 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 50 MW block of energy for off-peak and on-peak periods.

2.2 Future Capacity Resources

Construction is underway on two new natural gas fired simple-cycle reciprocating internal combustion engines (RICE) near the existing Lewis & Clark coal-fired plant in Sidney, MT. The new Lewis & Clark 2 RICE units will be a total of 19 MW and be commercially available by October 31, 2015.

The Big Stone Air Quality Control Systems (AQCS) project at the existing Big Stone plant of which Montana-Dakota is a 22.7 percent owner has become a committed project for Montana-Dakota, and construction began in April 2013. To comply with the regional haze rules, the Big Stone plant is required to install the AQCS using Best Available Retrofit Technology (BART), which was committed in the model in 2016.

Montana-Dakota has entered into a contract to purchase the project or purchase the energy from Thunder Spirit Wind. This is a 107.5 MW wind farm located near Hettinger, ND, which came out of Montana-Dakota's 2013 request for proposal and is considered a least cost resource for the Company through both the 2013 IRP and 2015 IRP. In October 2013, Montana-Dakota entered into a 25 year Power Purchase Agreement (PPA) with Thunder Spirit Wind, LLC (TSW) to purchase the output of a proposed 107.5 MW wind project to be located near Hettinger, ND at an attractive price. The proposed wind project was to be completed by December 31, 2015 and Montana-Dakota's obligations under the PPA were conditioned on TSW obtaining project financing by February 28, 2014 unless the date was extended by Montana-Dakota. Despite extensions to the financing deadline granted by Montana-Dakota and interest by several investors, it became apparent that TSW could not obtain project financing without price increases and other PPA amendments. With the uncertainty of TSW's ability to timely obtain financing even with increased PPA prices, Montana-Dakota determined it was advantageous and in the best interest of its customers to own and operate the TSW Project rather than proceed under the PPA arrangement. In September 2014, Montana-Dakota contacted Allete Clean Energy (ACE), a subsidiary of Allete, Inc., which has developed other wind projects in North Dakota, to determine if ACE would consider acquiring the TSW Project, completing its development, and selling the completed TSW Project to Montana-Dakota. ACE reviewed the TSW Project and determined that it was willing to develop the TSW Project and sell it to Montana-Dakota under an asset purchase agreement (APA) prior to its commercial operations date or under the terms of a PPA if Montana-Dakota was unable to obtain necessary regulatory approvals for the TSW Project ownership. Both

the APA with Thunder Spirit Wind, LLC and ACE Wind, LLC and amended and restated PPA with Thunder Spirit Wind, LLC were signed on November 20, 2014. Under the APA with ACE Wind LLC, Allete will construct the TSW Project and deliver to Montana-Dakota prior to commercial operation of the TSW Project a complete wind project capable of fulfilling the requirements of the Amended and Restated Power Purchase Agreement between the Parties. The amount of energy that Montana-Dakota purchases from the MISO energy market has grown from 10 percent in 2007 to over 20 percent in 2013. This number is forecasted to increase to almost 40 percent by 2016, based upon Plexos generation and market dispatch simulation runs, without the addition of a new energy supply resource like the TSW Project. Even with TSW Project, Montana-Dakota's energy purchases from MISO are still expected to be almost 20 percent of its customers' annual energy requirements in 2016. Ownership of the TSW Project provides Montana-Dakota with control of the project site and equipment along with the ability to capture additional value from the TSW Project after the expiration of a PPA or if the energy from the TSW 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 and ownership of the TSW Project provides Montana-Dakota with the ability to expand the site in the future, if needed, to meet its customers' energy requirements while capturing the economies of scale offered by a larger project site. This TSW Project is scheduled to be online by the end of 2015.

In the 2013 IRP analysis, Montana-Dakota looked at the addition of bag-house to comply with EPA's Mercury Air and Toxic Standard (MATS) at the existing Lewis & Clark Station with an end of year 2015 in-service date. The original cost of the project was modeled at \$27.5 million in the 2013 IRP, but the costs were updated after the 2013 IRP filing and increased to over \$40 million. Montana-Dakota has found a lower cost method to comply with MATS, and these costs have been reflected in the 2015 IRP as this project is committed in the model for the start of 2016.

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,
- Landfill Gas,
- Biomass,
- Solid Waste and,
- Geothermal.

Information regarding the resource alternatives available to Montana-Dakota is summarized in Table 2-5. Unless a specific data source is mentioned, the capital cost, fixed O&M cost, variable O&M cost, fuel cost, and other characteristics estimated for these resource alternatives were developed based on manufacturer's budgetary pricing, consulting engineers, Montana-Dakota's experience and expertise, and other available sources. 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 lowest 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, more susceptible to cold weather reliability problems, and have a maximum of 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 up to 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: a 37.3 MW Aero unit, a 75 MW Frame unit, and an 85.9 MW Aero-hybrid 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. One RICE plant, consisting of three RICE units, was analyzed in the resource expansion analysis: a 28 MW natural gas fired option.

2.3.3. Combined Cycle Combustion Turbine

A conventional combined cycle combustion turbine (CCCT) burns natural gas or fuel oil in a SCCT. The hot exhaust gases from the SCCT pass 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 are higher-cost energy producers compared to coal-fired baseload units. There were six natural gas fired CCCTs analyzed in the resource expansion analysis: a 62.8 MW Aero unit, a 127.6 MW Frame unit (1x1), a 213 MW Frame unit (3x1), a 256.8 MW Frame unit (expansion of Heskett 3), a 294.6 MW Frame unit (1x1) and a 593 MW Frame unit (2x1).

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 significant proposed federal regulations 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 185 MW circulating fluidized bed combustion (CFBC) boiler without CO₂ capture, and a 122 MW 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 four different options: 20 MW and 50 MW North Dakota options, and 20 MW and 50 MW Montana options.

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. Three types of 30 MW solar options were included in the resource expansion analysis: thermal, concentrated, and photovoltaic solar.

2.3.7. Landfill Gas

Methane gas produced from landfill sites can be captured and used as an alternative fuel to produce electricity. Montana-Dakota modeled a 17.3 MW Frame SCCT burning landfill gas in its resource expansion analysis. A project of this size would require a location where there is a substantially sized landfill, which may not be representative of a landfill within Montana-Dakota's service territory.

2.3.8. 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 29.9 MW biomass option was included in the resource expansion analysis.

2.3.9. Solid Waste

Utilizing a boiler similar to what is used in a biomass-fired power plant; a solid waste power plant burns municipal solid waste as its fuel. Included in Montana-Dakota's resource expansion analysis is a 15 MW solid waste boiler.

2.3.10. Geothermal

Using the earth's temperature to heat a working fluid, a geothermal power plant produces power similar to the steam process used in a coal-fired power plant. Once vaporized, the working fluid provides rotational energy to turn a turbine and generator. The geothermal option is considered a renewable resource with high capital and operating and maintenance costs as compared to coal and natural gas fired options. A geothermal plant is dispatchable and would receive ZRCs for resource adequacy purposes similar to a coal or gas-fired facility. A geothermal option was modeled in a 30 MW block in the resource expansion analysis.

Table 2-5

Considered Resource Alternatives Available to Montana-Dakota

EGEAS Model Input Summary, 2015 \$	Plant Size (MW,net)	ZRC	Capital Cost (\$/kW)	Fixed O&M (\$/kW-month)	Variable O&M (\$/MWh)	Major Maintenance (\$/kW-month)	Total Fixed O&M (\$/kW-year)	Full Load Heat Rate (BTU/kWh)	Carbon Intensity (ton/GWh)	Fuel Cost (\$/MBtu)
GE 7EA ^{1,3}	75	70.79	\$815.97	\$0.98	\$2.32	\$0.03	\$17.45	11436	684	\$2.96
GELMS100PB ^{1,3}	85.9	81.08	\$1,056.29	\$1.47	\$4.49	\$0.03	\$22.66	9206	544	\$2.96
GE LM6000PH ^{1,3}	37.3	36.89	\$1,294.83	\$2.12	\$3.95	\$0.03	\$36.52	9960	587.5	\$2.96
GE LM6000PH Sprint (CC) ^{1,3}	62.8	60.34	\$1,462.53	\$1.82	\$4.50	\$0.03	\$28.57	7663	373	\$2.96
GE 7EA (1X1) ^{1,3}	127.6	122.60	\$1,081.45	\$1.04	\$2.99	\$0.03	\$15.97	7608	449.5	\$2.96
GE 7EA (2x1) Addition to existing ^{1,3}	256.8	246.73	\$768.40	\$0.77	\$3.57	\$0.03	\$11.16	7592	448	\$2.96
GE 7FA.05 (1X1) ^{1,3}	294.6	283.05	\$779.50	\$0.69	\$2.88	\$0.03	\$10.00	6672	394	\$2.96
GE 7FA.05 (2X1) ^{1,3}	200	192.16	\$741.76	\$0.63	\$3.46	\$0.03	\$9.92	6631	392	\$2.96
SIEMENS SGT-800 (3x1) ^{1,3}	213.9	205.52	\$1,040.23	\$0.96	\$3.58	\$0.03	\$13.75	7347	433.5	\$2.96
SOLAR TITAN 250 (Landfill gas) ²	17.3	17.11	\$1,341.39	\$2.66	\$2.32	\$0.03	\$32.28	10427	611	\$2.65
WARTSILA 20V34SG ^{1,3}	28	27.69	\$1,550.29	\$0.92	\$9.63	\$0.45	\$30.73	8542	485	\$2.96
BIOMASS	29.9	27.37	\$3,986.40	\$9.73	\$5.82	\$0.03	\$117.12	11056	1218	\$6.75
SOLID WASTE	15	13.73	\$17,475.03	\$9.73	\$5.82	\$0.03	\$117.12	16002	1842.5	\$3.00
PV SOLAR	30	15.00	\$4,036.72	\$1.61	\$0.00	\$0.00	\$19.32	-	-	\$0.00
CONC. SOLAR	30	15.00	\$7,714.65	\$4.55	\$0.00	\$0.00	\$54.60	-	-	\$0.00
THERMAL SOLAR	30	15.00	\$5,282.22	\$6.19	\$0.00	\$0.00	\$74.28	-	-	\$0.00
GEOHERMAL	30	18.90	\$2,723.33	\$10.49	\$0.00	\$0.00	\$125.88	-	-	\$0.00
CFBC WITHOUT CO2 Capture	185	173.18	\$3,882.00	\$18.49	\$12.49	\$0.00	\$221.88	9974	973	\$1.91
CFBC WITH CO2 Capture ⁴	122	114.20	\$7,099.00	\$22.55	\$19.81	\$0.00	\$270.60	13781	124	\$1.91
ND Wind	20	4.16	\$2,031.60	\$2.58	\$0.00	\$0.00	\$30.96	-	-	\$0.00
ND Wind	50	10.40	\$1,878.69	\$2.58	\$0.00	\$0.00	\$30.96	-	-	\$0.00
MT Wind	20	4.16	\$2,069.40	\$2.58	\$0.00	\$0.00	\$30.96	-	-	\$0.00
MT Wind	50	10.40	\$1,916.49	\$2.58	\$0.00	\$0.00	\$30.96	-	-	\$0.00

*No transmission or system upgrades included in any of the cost estimates.

1. No natural gas firming, pipeline, or compressor costs are included.

2. The size of this unit would require a large city, and may not be representative of a unit built in MDU's service area (i.e. it would require detailed site investigation and deliverability studies). In carbon tax sensitivity, this option would be exempted.

3. A \$400,000/yr reservation fee was added to the fixed O&M costs for natural gas-fired units

4. CO₂ Sequestration costs are not included in this cost estimate.

2.4 Retirements

Montana-Dakota is modeling the retirement of Heskett 1 at the end of 2019 and Lewis & Clark at the end of 2025. The retirements are modeled with the assumption that additional EPA rules, including GHG rules, may be finalized in the future that would require the Heskett 1 and Lewis & Clark plants to install new emission controls or shutdown. However, at this time there is no actual plan to retire either of the units.

Additionally, Montana-Dakota’s wind projects Diamond Willow and Cedar Hills are assumed to be retired in the model after a 20 year operating life. 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. As for the Rate 38/39 Interruptible Loads and the Commercial Demand Response programs they are modeled as resources in EGEAS.

As a result of the demand-side analysis in Chapter 3 and Attachment B a new program was found feasible. This “New DSM” is a residential air conditioning cycling program that was modeled in EGEAS as a new supply-side option in a separate resource expansion analysis. The amount of demand reduction and costs associated with the “New DSM” is shown in Table 2-6.

Table 2-6: “New DSM”

<u>Unit</u>	<u>Zonal Resource Credit¹</u>	<u>Fixed O&M (\$/kW- year)</u>
New DSM	10	63.00

1- The program will reach 10 MW by 2021

3. Summaries of Results

Sixteen planning scenarios, which include the base case, base case with “New DSM”, and fifteen 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 and Table 3-2.

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

All Sensitivity Cases run with Base Case													
	Base Case	Base Case w/ New DSM	Low Growth	High Growth	Low Gas Price	High Gas Price	High CT and IC Costs	90% MISO Coincident Factor	Low Market Price	High Market Price	Limiting Energy Purchases (5 years)	Limiting Energy Purchases (10 years)	\$30 Carbon Tax
2015	PP(10)	PP(10)		PP(10)	PP(10)	PP(10)	PP(10)	PP(80)	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)
2016*	TSW	TSW	TSW	TSW	TSW	TSW	TSW	TSW, PP(70)	TSW	TSW	TSW	TSW	TSW
2017	CT(37)	CT(37), New DSM		RICE(28)	RICE(28)	Wind(50), PP(10)	RICE(28)	3-RICE(28), PP(10)	CT(37)	CT(37)	CT(37)	CT(37)	RICE(28)
2018				PP(10)	PP(10)	RICE(28)	PP(10)	CT(37)					PP(10)
2019	Wind(20), PP(10)	PP(10)		Wind(50), PP(10)	CC(127)	Wind(50), PP(10)	Wind(70), PP(10)	PP(10)	Wind(20), PP(10)	Wind(20), PP(10)	CT(75)	CT(75)	Wind(70), PP(10)
2020	CC(200)	CC(200)		CC(200)		CC(200)	CC(200)	CC(200)	CC(200)	CC(200)	CC(200)	CC(200)	CC(200)
2021													
2022						CC-200							
2023													
2024													
2025				CC(200)							CC(127)	CC(127)	
2026					CC(200)								
2027													
2028				CC(200)									
2029								CC(200)					
2030	CC(200)	CC(200)	CC(127)			Wind(50)	CC(200)		CC(200)	CC(200)			CC(200)
2031						Wind(50)							
2032				CC(200)		CC(200)							
2033											CC(200)	CC(200)	
2034						Wind(50)							
NPV ¹	\$4,503.84	\$4,452.60	\$3,163.83	\$5,851.79	\$4,016.03	\$5,757.09	\$4,644.34	\$4,693.38	\$4,424.28	\$4,538.98	\$4,650.15	\$4,636.40	\$5,650.96
Difference	-	-1.1%	-29.8%	29.9%	-10.8%	27.8%	3.1%	-1.8%	0.8%	3.2%	2.9%	4.2%	25.5%

1 - NPV in millions of dollars

*Includes the committed resources; Big Stone AQCS, Lewis & Clark MATS, and Lewis & Clark 2

PP(x) – Purchase Capacity with number representing a MW value

TSW – 107.5 MW Thunder Spirit Wind

CT(37) – 37.3 MW GE LM6000PH Simple Cycle Combustion Turbine

Wind – Self-built wind

CC(200) – 200 MW of a potential partnership of a 593MW GE 7FA.05 (Combined Cycle 2x1)

RICE (28) – 28 MW Wartsila 20V34SG Reciprocating Internal Combustion Engines (contains 3-9.3 MW units)

CT(75) – 75 MW GE 7EA Simple Cycle Combustion Turbine

CC(127) – 127.6 MW Combined Cycle of GE 7EA

New DSM – 10 MW AC Cycling program

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

	Carbon Sensitivities with Base Case				
	Base Case	\$30 Carbon Tax	\$30 Carbon Tax w/\$1.50 gas adder	\$15 Carbon Tax	\$15 Carbon Tax w/\$1.50 gas adder
2015	PP(10)	PP(10)	PP(10)	PP(10)	PP(10)
2016	TSW	TSW	TSW	TSW	TSW
2017	CT(37)	RICE(28)	RICE(28)	CT(37)	CT(37)
2018		PP(10)	PP(10)		
2019	Wind(20), PP(10)	Wind(70), PP(10)	Wind(70), PP(10)	Wind(20), PP(10)	Wind(20), PP(10)
2020	CC(200)	CC(200)	CC(200)	CC(200)	CC(200)
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030	CC(200)	CC(200)	CC(200)	CC(200)	CC(200)
2031					
2032					
2033					
2034					
NPV ¹	\$4,503.84	\$5,650.96	\$6,345.46	\$5,088.83	\$5,779.70
Difference	-	25.5%	40.9%	13.0%	28.3%

1 - NPV in millions of dollars

*Includes the committed resources; Big Stone AQCS, Lewis & Clark MATS, and Lewis & Clark 2

PP(x) – Purchase Capacity with number representing a MW value

TSW – 107.5 MW Thunder Spirit Wind

CT(37) – 37.3 MW GE LM6000PH Simple Cycle Combustion Turbine

Wind – Self-built wind

CC(200) – 200 MW of a potential partnership of a 593MW GE 7FA.05 (Combined Cycle 2x1)

RICE (28) – 28 MW Wartsila 20V34SG Reciprocating Internal Combustion Engines (contains 3-9.3 MW units)

CT(75) – 75 MW GE 7EA Simple Cycle Combustion Turbine

CC(127) – 127.6 MW Combined Cycle of GE 7EA

3.1. Base Case Plan Results

The Base Case least-cost plan consists of the following resource additions for 2015-2020:

- Purchase 10 MW of capacity in 2015;
- Install 107.5 MW of Thunder Spirit Wind in 2015;
- Install 37.3 MW Simple Cycle Combustion Turbine in 2017;
- Continue the commercial demand response program to achieve 15 MW by 2017 and achieve 16 MW from Montana-Dakota's interruptible rate;
- Install 20 MW of self-built wind and purchase 10 MW of capacity in 2019; and
- Assuming the retirement of Heskett 1 at the end of 2019 and Lewis & Clark at the end of 2025 due to environmental rule requirements such as the EPA's GHG rules, be capable of partnering to take 200 MW from a large Combined Cycle unit in 2020.

For the later years an additional 200 MW of large combined cycle unit in 2030. The net present value of the Base Case least-cost plan over the 50-year study period equates to \$4,503.84 million in 2014 dollars, as shown in Attachment C Table 3-1.

When the "New DSM" was added as an additional resource option in the Base Case, it was selected to be implemented in 2017 and take 5 years to reach a max of 10 MW. This addition of the DSM lowers the NPV over the 50 year study period by about 1.1% from the Base Case. The least-cost remained similar except for the 20 MW of self-built wind was not selected in 2019.

3.2. Sensitivity Analysis

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

3.2.1. 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 2020. 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 modeling was done differently in the 2015 IRP as the cost of the carbon tax was included in the dispatch cost of the units instead of in previous IRPs the cost of the carbon tax was added in after the units were dispatched. This new methodology in the model and the low natural gas prices caused the coal fleet to have very low capacity factors compared to the Base Case. So, additional sensitivities were done around the \$30 carbon tax to see what the cost of natural gas would have to increase to with a \$30 carbon tax and what the carbon tax would have to decrease with the base gas prices for the coal fleet to have more normal capacity factors. This caused the natural gas to increase by \$1.50/MBTU with the \$30 carbon tax, and using the base gas prices the carbon tax was reduced to \$15/ton. An additional sensitivity was done combining both of the \$1.50/MBTU gas adder and using the \$15 carbon tax.

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 Optimal Resource case, natural gas was priced for delivery at \$2.96/MBTU for 2015, and increasing to \$3.95/MBTU in 2019. After 2019, 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 2019. The results of the high natural gas price case included an additional 250 MW of self-built wind over the 20 years, and a RICE unit instead of

simple cycle combustion turbine. The NPV of the revenue requirement in this scenario increased 27.8 percent over the Base Case. The results of low natural gas price scenario had a RICE unit in 2017, a 127 MW combined cycle in 2019, and 200 MW combined cycle in 2026 compared to the Base Case. This case decreased the NPV of the revenue requirement by 10.8 percent from the Base Case.

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

The ninety percent coincident factor sensitivity scenario requires 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 80.3 percent coincident factor. The selected least-cost plan for this scenario was different from the base case with additional capacity purchases and RICE units needed to meet the increase of capacity need. The results of this scenario indicate a increase of 4.2 percent in the NPV of the revenue requirement over the Base Case.

3.2.4. 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: Thunder Spirit Wind in 2015 and combined cycle of 127 MW in 2030. This scenario is very unlikely based on forecasted growth levels in the Bakken and surrounding areas.

3.2.5. 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 2015. The basis for 4.4 percent per year assumption came from Montana-Dakota's historical growth rate during 1977-1985. For 2015-2017, the forecasted growth for the 50/50 forecast was used as the growth rate in those three years as it was greater than the 4.4 percent per year. The results of this scenario indicate the need for the following resources over the Base Case: a total of 400 MW of additional combined cycle units over the study period, an additional 30 MW of wind in 2019, and RICE unit in 2017 instead of a combustion turbine.

3.2.6. 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 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. The higher combustion turbine and internal combustion engine cost scenario also accounts for differences in site constructability through Montana-Dakota's service territory, like the Bakken Region, which some areas tends to have higher construction costs due to higher labor, housing, and material costs. These higher cost areas may have additional benefits, like system reliability or access to trapped natural gas, associated with their development which are considered when selecting a new generation site. This scenario selects a RICE unit over the combustion turbine in 2017 and an additional 50 MW of wind in 2019. The results of this sensitivity case indicate an increase of 3.1 percent in the NPV of the revenue requirement over the Base Case.

3.2.7. 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 (\$36.96/MWh) and off-peak (\$26.89/MWh) market prices of the base year. This resulted in the same results, but an increase of 0.8 percent in NPV of the revenue requirement over the Base Case. The lower market price case decreased the base year on- and off-peak prices by \$5/MWh. This resulted in the same results too, but lowered the NPV by 1.8 percent.

3.2.8. 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 it did not pick the 20 MW of wind in 2019, but did select a 75 MW combustion turbine that was later converted into a combined cycle in 2025. These two scenarios of 5 year and 10 year market diminishing saw an increase of the NPV over the Base Case at 3.2 and 2.9 percent, respectively.

4. Conclusions

Based on the current results of the supply-side and integration analysis, the resource plan resulting from the Base Case with “New DSM” is the ultimate modeled 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 2020:

- Install 107.5 MW of Thunder Spirit Wind in 2015;
- Install 37.3 MW Simple Cycle Combustion Turbine in 2017;
- Implement the residential AC Cycling program in 2017 with an initial 2 MW and increasing the program to 10 MW by 2021;
- Continue the commercial demand response program to achieve 15 MW by 2017 and achieve 16 MW from Montana-Dakota’s interruptible rate;
- Install 20 MW of self-built wind and purchase 10 MW of capacity in 2019; and
- Look at options to partner in the construction of a large CCCT in 2020 with an ownership of 200 MW.

Figure 4-1 and 4-2 show a comparison of the resource mix that Montana-Dakota has available to serve its customers’ needs in 2015, as compared to the least cost plan in 2020. Note a Zonal Resource Credit (ZRC) represents one megawatt of accredited generating capacity under the MISO resource adequacy rules.

2015 Montana-Dakota Zonal Resource Credits

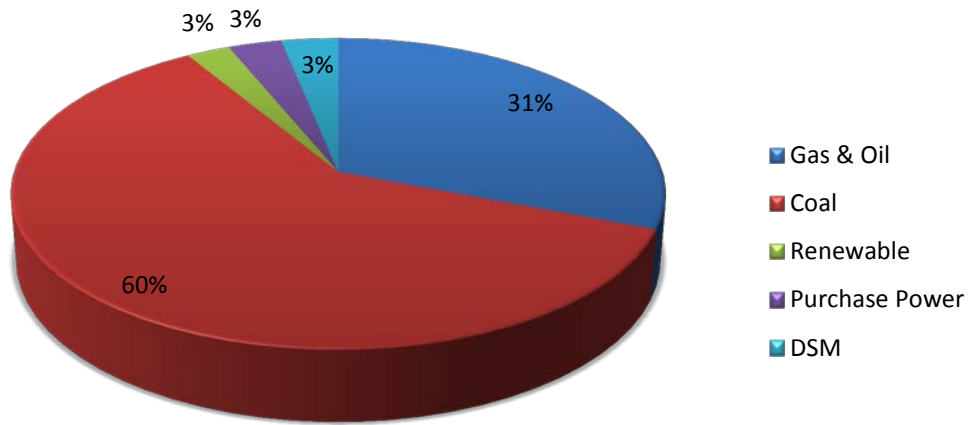


Figure 4-1: 2015 Montana-Dakota Zonal Resource Credits

2020 Montana-Dakota Zonal Resource Credits

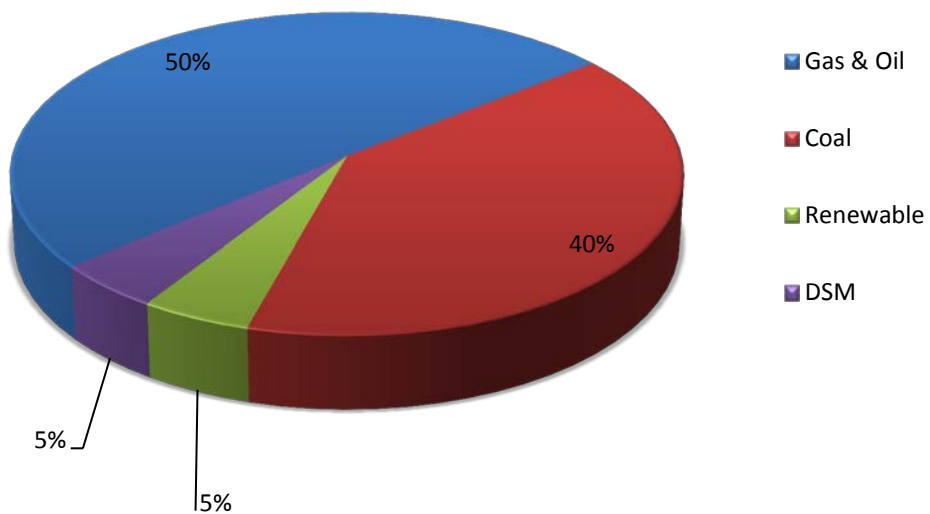


Figure 4-2: 2020 Montana-Dakota Zonal Resource Credits

As shown in Figures 4-1 and 4-2; in 2015 approximately 31 percent of Montana-Dakota's resource capacity comes from natural gas and oil-fired combustion turbines and internal combustion engines while in 2020, based on the base case plan, approximately 50 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, and high natural gas prices. With a \$30 per ton carbon tax, the resource plan remains similar to the Base Case with the exception of a RICE unit in 2017 instead of combustion turbine and an additional 50 MW self-built wind in 2019, but the NPV increased by 25.5 percent.

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 2015-2020 period:

- Continue with the installation of the Big Stone Plant AQCS equipment to be completed in 2015;
- Continue with the construction of Thunder Spirit Wind to be completed by the end of 2015;
- Continue with the installation of the MATS project at Lewis & Clark Station to completed by the end of 2015;
- Continue with the installation of the roughly 19 MW Lewis & Clark 2 simple-cycle reciprocating internal combustion engine project to be completed by the end of 2015;
- Implement the AC Cycling program in 2017 with an initial 2 MW and increasing to 10 MW by 2021;
- Continue the commercial demand response program to achieve 15 MW by 2017 and achieve 16 MW from Montana-Dakota's interruptible rate;
- Short-term capacity deficits will be met via the MISO Capacity Auction or through bi-lateral capacity purchase agreements; and

Begin work on the potential partnership in a large combined cycle resource to be online sometime after 2020. Potential ownership share in this new resource would be 200 MW. Montana-Dakota's recommended resource plan satisfies future customer requirements through a balance of a new peaking capacity resource additions and pollution control investments in the Big Stone and Lewis & Clark low-cost energy resources. In addition, other 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 identified through a generator interconnect study, facility maintenance requirements and ability to perform, best fit with company expertise, and overall operation and maintenance costs.

6. References

MISO Business Practice Manual-11-r14 Resource Adequacy. (September 1, 2014)

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

MISO Planning Year 2015-2016 Loss of load Expectation Study Report. (November 1, 2014)

MISO Planning Year 2015-2016 Wind Capacity Credit. (December 2014)

Appendix A

EGEAS INPUT DATA FOR THE BASE CASE

EGEAS EDIT VERSION 9.02 2015 IRP RELEASE 10/26/00

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EEEEEEEE	GGGGGGG	EEEEEEEE	AA AA	SSSSSSSS
EEEEEEEE	GGGGG	EEEEEEEE	AA AA	SSSSSS

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

Montana-Dakota Utilities Co.
2015 Model
Base Case Run
-- Data updated for the 2015 Model

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3412 HILL VIEW AVENUE
PALO ALTO, CALIFORNIA 94304

EGEAS EDIT VERSION 9.02 CONTROL REPORT PAGE 1

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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SYSTEM A	HOURLOAD	1	0				
HOURLY NDT							
TECHNOLOGY 1	wind40cf	1	0				
TECHNOLOGY 2	wind46cf	1	0				

OUTPUT FILE	NAME	VERSION	UPDATE	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
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	*	Base Case Run									3		
	*	-- Data updated for the 2015 Model									4		
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	*										6		
	*										7		
	*	M	C	---REPORTS---							8		
	*	O	O	C	M	E	F	C				9	
	*	D	S	T	I	R	I	N				10	
	*	E	T	L	R	R	L	T	DESCRIPTIVE INFORMATION			11	
	*	+	-	+	-	+	-	+	-----			12	
CONTROL RECORD	ECC	1	1	1	1	3	0	1	2015 IRP			13	
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	*	NAME	V	U	NAME	V	U				16		
	*	-----++--				-----++--					17		
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SYSTEM DEMAND	ESD	1			436.10003250.6999		1	2				58	
** COMMENT **	*											59	
	*				==	BASIC PLANT TYPE DATA	==					60	
	*											61	
	*											62	
	*						LL SA FL SRVC GEN OWNER UNIT INST LIFE					63	
	*				NAME	TYPECD TV CLS AREA CO PCT. GRP. YEAR OP BK						64	
	*	EBPA			-----	+++++ -+-----	++++	----	+++++	----	++++	-- ++	65
	*				RATED	--CAPACITY MULT.--	EQV. HEAT ENRGY STOR				CAP.MULT.		66
	*				CAP. OPER. EMER. CHRG.	FOR RATE LIMIT EFF.					RESERVE		67
	*	EBPB			-----	+++++	-----	+++++	-----	+++++	-----		68
	*				INSTALL.	INSTALL. LEVEL. FIXED VAR. AFUDC	DEBT M CAP					69	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11		
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890		

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 4

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (1-8), ASSIGNED REC. NO. Includes sections for ** COMMENT ** and BASIC PLANT TYPE with various plant codes like EBPA, EBPB, EBPC, EBPB, EBPE, EBPB, EBPB, EBPB, EBPB.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 5

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO. Includes entries for BASIC PLANT TYPE (EBPG, EBPA, EBPB, EBPC, EBPB, EBPD, EBPF) and comments.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 6

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO. Includes entries for BASIC PLANT TYPE (EBPB, EBPC, EBPB, EBPB, EBPB) and ** COMMENT **.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 7

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (1-8), ASSIGNED REC. NO. Includes entries for BASIC PLANT TYPE (EBPC, EBPB, EBPD, EBPB, EBPB) and ** COMMENT **.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 8

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO. Includes rows for BASIC PLANT TYPE (EBPD, EBPB, EBP, EBPC, EBPD, EBPE, EBP, EBP, EBP) and COMMENT sections.

EGEAS EDIT VERSION 9.02

MIRROR IMAGE REPORT

PAGE 9

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.
--------------------	--------	-----------	----------	-------------	--	--	--	--	--	--	--	-------------------

RECORD COLS	1	2	3	4	5	6	7	8	
-------------	---	---	---	---	---	---	---	---	--

BASIC PLANT TYPE	EBPA	25	SMN	SGT-800	3x1	THRM	P	G	GAS	MDU	NDAK	100.0	1	40	40	251	
	EBPB	25	213.90	85711.0000				0.0392	7347					0.9608		252	
	EBPC	25	1040.230					9.7850	13.7503	5800			1	1		253	
	EBPD	25	30	22	69	0	25	1	0	0	0	23	0	0	0	20	254
	EBPF	25	750.000					30	37	0.0000						255	
	EBPG	25	0.000000000	0.000000000	0.000000000	0.000000000										256	

** COMMENT ** * 257

BASIC PLANT TYPE	EBPA	26	WIND	PPA		NDT	B	G	WIND	MDU	NDAK	100.0	1	20	20	258	
	EBPB	26	107.51	0.0000	0.3810				0.0000					0.2080		259	
	EBPC	26	0.000						0.0000	29.500			1	1		260	
	EBPD	26	42	0	9	0	0	0	0	0	0	2	0	0	21	0	261
	EBPF	26	2400.000					30	38	0.0000						262	
	EBPG	26	0.000000000	0.000000000	0.000000000	0.000000000										263	

** COMMENT ** * 264

BASIC PLANT TYPE	EBPA	27	WIND	50	ND	NDT	B	G	WIND	MDU	NDAK	100.0	1	30	20	265	
	EBPB	27	50.000	1.00000	0.3810				0.0000					0.2080		266	
	EBPC	27	1878.690					11.974	30.9600	0.0000			1	1		267	
	EBPD	27	30	22	0	10	0	0	0	0	0	1	0	0	21	0	268
	EBPF	27	2400.000					30	38	0.0000						269	
	EBPG	27	0.000000000	0.000000000	0.000000000	0.000000000										270	

** COMMENT ** * 271

BASIC PLANT TYPE	EBPA	28	WIND	20	ND	NDT	B	G	WIND	MDU	NDAK	100.0	1	30	20	272	
	EBPB	28	20.000	1.00000	0.3810				0.0000					0.2080		273	
	EBPC	28	2031.600					11.974	30.9600	0.0000			1	1		274	
	EBPD	28	30	22	0	10	0	0	0	0	0	1	0	0	21	0	275
	EBPF	28	2400.000					30	38	0.0000						276	
	EBPG	28	0.000000000	0.000000000	0.000000000	0.000000000										277	

** COMMENT ** * 278

BASIC PLANT TYPE	EBPA	29	GE	7FA.05	2x1	THRM	I	G	GAS	MDU	NDAK	100.0	1	40	40	279	
	EBPB	29	200.00	85711.0000				0.0392	6631					0.9608		280	
	EBPC	29	741.760					9.4950	9.9200	3.4600			1	1		281	
	EBPD	29	30	22	54	0	1	1	0	0	0	8	0	0	20	0	282
	EBPF	29	750.000					30	37	0.0000						283	
	EBPG	29	0.000000000	0.000000000	0.000000000	0.000000000										284	

** COMMENT ** * 285

BASIC PLANT TYPE	EBPA	120	MILES	CITY	C.T.	THRM	P	E	GAS	MDU	MONT	100.0	1	1972	99	30	286
------------------	------	-----	-------	------	------	------	---	---	-----	-----	------	-------	---	------	----	----	-----

RECORD COLS	1	2	3	4	5	6	7	8	
-------------	---	---	---	---	---	---	---	---	--

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 10

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), and ASSIGNED REC. NO. Rows include plant types (BASIC PLANT TYPE) for various units (120, 130, 132, 134, 140, 150, 160) with associated technical data and comments.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 11

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 12

Table with columns: RECORD DESCRIPTION, REC. TYPE, REF. NO., SEQ. NO., DATA FIELDS (8 columns), and ASSIGNED REC. NO. (8 columns). Rows include BASIC PLANT TYPE entries for various equipment (EBPA, EBPB, EBPC, EBPD, EBPB, EBPB, EBPB, EBPB) and ** COMMENT ** entries.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 13

REC. REF SEQ ASSIGNED
RECORD DESCRIPTION C TYPE NO. NO. DATA FIELDS REC. NO.

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

BASIC PLANT TYPE EBPC 370 1294.830 9.785036.5203.9500 1 1 391
EBPD 370 30 22 62 0 28 1 0 0 0 0 0 13 0 0 0 0 0 20 0 392
EBPF 370 850.000 30 37 0.0000 393
EBPG 370 0.0000000000.0000000000.000000000 394

** COMMENT ** * 395

BASIC PLANT TYPE EBPA 390 WIND20 MT NDT B G WIND MDU NDAK 100.0 1 30 20 396
EBPB 390 20.0001.00000.3810 0.0000 0.2080 397
EBPC 390 2069.400 14.86530.9600.0000 1 1 398
EBPD 390 30 22 0 10 0 0 0 0 0 0 1 0 0 0 0 0 21 0 399
EBPF 390 2400.000 30 38 0.0000 400
EBPG 390 0.0000000000.0000000000.000000000 401

** COMMENT ** * 402

BASIC PLANT TYPE EBPA 400 MISO - On peak THRM P E PURC MDU MISO 100.0 1 2014 50 50 403
EBPB 400 50.0001.00001.0000 0.0000 10500 0.0000 404
EBPC 400 0.000036.960 2 0 405
EBPD 400 29 0 0 8 0 0 0 0 0 7 0 0 0 0 0 0 52 406

** COMMENT ** * 407

BASIC PLANT TYPE EBPA 440 COMMERCIAL DSM DTHR1P E PURC MDU MISO 100.0 1 2013 30 30 408
EBPB 440 5.0001.00001.0000 0.0000 1 1.0000 409
EBPC 440 0.000 50.040300.00 2 0 410
EBPD 440 48 49 0 14 8 0 0 0 0 0 0 0 0 0 0 0 4 411
EBPF 440 0.000 0 0.0000 412
EBPG 440 0.0000000000.0000000000.000000000 413

** COMMENT ** * 414
* 415
* == MAINTENANCE CYCLES == 416
* Y YBO ----NUMBER OF WEEKS (W) AND STARTING WEEK (S)---- 417
* I RAP 1 2 3 4 5 6 7 8 9 10 418
* N PST W S W S W S W S W S W S W S W S W S 419
* ++---+ +--- +--- ++--- ++--- ++--- ++--- ++--- ++--- ++--- 420

MAINTENANCE CYCLE EMC 1 1 1 110 2 421

** COMMENT ** * 422

MAINTENANCE CYCLE EMC 2 1 101022 115 715 119 116 216 121 119 117 118 116 423
EMC 2 2 135 142 143 143 141 139 144 143 143 140 424

** COMMENT ** * 425

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

EGEAS EDIT VERSION 9.02

MIRROR IMAGE REPORT

PAGE 14

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.			
				1	2	3	4	5	6	7	8				
RECORD COLS	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890		
MAINTENANCE CYCLE	EMC	3	1	101022	117	114	118	118	117	119	117	116	117	618	426
	EMC	3	2		134	141	141	241	143	138	142	141	141	141	427
** COMMENT **	*														428
MAINTENANCE CYCLE	EMC	4	1	101022	116	115	716	117	118	120	118	118	619	115	429
	EMC	4	2		134	141	142	142	142	138	143	142	142	139	430
** COMMENT **	*														431
MAINTENANCE CYCLE	EMC	5	1	101022	617	116	213	617	118	122	118	116	115	115	432
	EMC	5	2		141	141	141	144	143	141	143	141	537	137	433
** COMMENT **	*														434
MAINTENANCE CYCLE	EMC	6	1	101022	223	212	117	214	214	515	214	217	116	216	435
	EMC	6	2		237	237	239	241	240	242	240	242	242	239	436
** COMMENT **	*														437
MAINTENANCE CYCLE	EMC	7	1	1 110	2										438
** COMMENT **	*														439
MAINTENANCE CYCLE	EMC	8	1	101021	220	1510	221	0	122	536	0	123	122	0	440
** COMMENT **	*														441
MAINTENANCE CYCLE	EMC	9	1	1 110	1										442
** COMMENT **	*														443
MAINTENANCE CYCLE	EMC	10	1	1 110	1										444
** COMMENT **	*														445
MAINTENANCE CYCLE	EMC	12	1	101022	213	319	219	213	614	220	220	219	218	218	446
	EMC	12	2		141	241	240	138	139	237	137	139	243	243	447
** COMMENT **	*														448
MAINTENANCE CYCLE	EMC	13	1	1 110	1										449
** COMMENT **	*														450
MAINTENANCE CYCLE	EMC	14	1	1 100	1										451
RECORD COLS	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	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	12	13	14	15
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890
** COMMENT **	*														452
MAINTENANCE CYCLE	EMC	15	1	101022	116	116	116	116	115	116	116	116	116	114	453
	EMC	15	2		139	139	139	140	139	139	140	0	139	136	454
** COMMENT **	*														455
MAINTENANCE CYCLE	EMC	16	1	1 110	1										456
** COMMENT **	*														457
MAINTENANCE CYCLE	EMC	17	1	1 110	2										458
** COMMENT **	*														459
MAINTENANCE CYCLE	EMC	18	1	101022	213	319	219	213	614	220	220	219	218	218	460
	EMC	18	2		141	241	240	138	139	237	137	139	243	243	461
** COMMENT **	*														462
MAINTENANCE CYCLE	EMC	19	1	1 110	2										463
** COMMENT **	*														464
MAINTENANCE CYCLE	EMC	20	1	101001	1510	221	0	122	536	0	123	122	0	220	465
** COMMENT **	*														466
MAINTENANCE CYCLE	EMC	21	1	1 110	2										467
** COMMENT **	*														468
MAINTENANCE CYCLE	EMC	22	1	101022	122	122	715	124	122	612	123	123	612	121	469
	EMC	22	2		136	137	137	137	136	136	135	137	137	137	470
** COMMENT **	*														471
MAINTENANCE CYCLE	EMC	23	1	1 110	2										472
** COMMENT **	*														473
MAINTENANCE CYCLE	EMC	24	1	1 110	2										474
** COMMENT **	*														475
MAINTENANCE CYCLE	EMC	25	1	1 110	2										476
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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890			
** COMMENT **	*											477			
MAINTENANCE CYCLE	EMC	28	1	1 110	2							478			
** COMMENT **	*											479			
MAINTENANCE CYCLE	EMC	33	1	1 110	3							480			
** COMMENT **	*											481			
	*	---	---	---	-----							482			
	*				== FUEL TYPES ==							483			
	*				MASS	HEAT	AVAILABLE	FUEL	AV	CS	AV	CS	484		
	*				name	UNIT	CONTENT	FUEL	COST	TJ	TJ	SM	SM	NAME	485
	*	EFLA			----	----	-----	-----	-----	-----	-----	-----	-----	486	
	*				MIN.	FUEL	TJ	SM					487		
	*	EFLB			-----	-----	-----	-----	-----	-----	-----	-----	488		
	*	---	---	---	-----							489			
	*												490		
FUEL TYPE	EFLA	1		GAS	DKT	1.0280	-1.000000	5.050000	0	33	0	0	GAS	491	
** COMMENT **	*													492	
FUEL TYPE	EFLA	2		OIL2	GAL	39.1700	-1.000000	25.120000	0	34	0	0	OIL2	493	
** COMMENT **	*													494	
FUEL TYPE	EFLA	3		COAL	TON	14.0700	-1.000000	1.840000	0	35	0	0	COAL	495	
** COMMENT **	*													496	
FUEL TYPE	EFLA	4		COAL	TON	14.0700	-1.000000	1.840000	0	36	0	0	COAL	497	
** COMMENT **	*													498	
FUEL TYPE	EFLA	5		COAL	TON	13.0900	-1.000000	1.770000	0	37	0	0	COAL	499	
** COMMENT **	*													500	
FUEL TYPE	EFLA	6		COAL	TON	16.4300	-1.000000	2.100000	0	38	0	0	COAL	501	
** COMMENT **	*													502	
FUEL TYPE	EFLA	7		COAL	TON	13.8100	-1.000000	1.450000	0	39	0	0	COAL	503	
** COMMENT **	*													504	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	12			
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890			

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.			
RECORD COLS	1	2	3	4	5	6	7	8							
FUEL TYPE	EFLA	8	90	PURC	NONE	0.0100	-1.000000	0.000000	0	0	0	PURC	505		
** COMMENT **	*												506		
FUEL TYPE	EFLA	9	90	LAND	DKT	1.0280	-1.000000	2.650000	0	64	0	0	LANDFILL	507	
** COMMENT **	*												508		
FUEL TYPE	EFLA	10	90	BMP	TON	14.9000	-1.000000	6.750000	0	63	0	0	BMP	509	
** COMMENT **	*												510		
FUEL TYPE	EFLA	11	90	SW	MBTU	1.0000	-1.000000	3.000000	0	67	0	0	SW	511	
** COMMENT **	*												512		
FUEL TYPE	EFLA	12	90	COAL	TON	14.0700	-1.000000	1.910000	0	43	0	0	COAL	513	
** COMMENT **	*												514		
				== PLANNING ALTERNATIVES ==								515			
				1ST	LAST	T	EX	PREREQ	M	M	R		516		
				NAME		BP	YEAR	YEAR	Y	RET	PA	NfR	N	X	Q
				-----	-----	+++	++++	----	+	-----	-----	+++	+		
PLANNING ALTERNATIVE	EPA	1	1	GE	7EA	350	2018	2034	0	0	0	00	0-1	0	520
** COMMENT **	*														521
PLANNING ALTERNATIVE	EPA	2	1	GE	7EA 1x1	340	2018	2034	0	0	1	101	0-1	0	522
** COMMENT **	*														523
PLANNING ALTERNATIVE	EPA	3	1	SOLID	WASTE	11	2018	2034	0	0	0	00	0-1	0	524
** COMMENT **	*														525
PLANNING ALTERNATIVE	EPA	4	1	WIND	20 MT	390	2017	2034	0	0	0	00	0-1	0	526
** COMMENT **	*														527
PLANNING ALTERNATIVE	EPA	5	1	CFBC		360	2020	2034	0	0	0	00	0-1	0	528
** COMMENT **	*														529
PLANNING ALTERNATIVE	EPA	6	1	GE	LM6000PH	370	2017	2034	0	0	0	00	0-1	0	530

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 18

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890	
** COMMENT **	*											531	
PLANNING ALTERNATIVE	EPA	7	1	PURCHASE POWER	310		2015	2034	1	0	0	00 0-1 0	532
** COMMENT **	*											533	
PLANNING ALTERNATIVE	EPA	8	1	GE 7EA 2x1	12		2018	2034	0	5	0	00 0-1 0	534
** COMMENT **	*											535	
PLANNING ALTERNATIVE	EPA	9	1	GE 7FA.05 1x1	18		2020	2034	0	0	0	00 0-1 0	536
** COMMENT **	*											537	
PLANNING ALTERNATIVE	EPA	10	1	BIOMASS	19		2018	2034	0	0	0	00 0-1 0	538
** COMMENT **	*											539	
PLANNING ALTERNATIVE	EPA	11	1	CFBC CO2	24		2020	2034	0	0	0	00 0-1 0	540
** COMMENT **	*											541	
PLANNING ALTERNATIVE	EPA	12	1	CONC SOLAR	22		2018	2034	0	0	0	00 0-1 0	542
** COMMENT **	*											543	
PLANNING ALTERNATIVE	EPA	13	1	GE LM6000PH SPRT	15		2018	2034	0	0	0	00 0-1 0	544
** COMMENT **	*											545	
PLANNING ALTERNATIVE	EPA	14	1	GE LMS100PB	14		2018	2034	0	0	0	00 0-1 0	546
** COMMENT **	*											547	
PLANNING ALTERNATIVE	EPA	15	1	GEO THERMAL	20		2018	2034	0	0	0	00 0-1 0	548
** COMMENT **	*											549	
PLANNING ALTERNATIVE	EPA	16	1	PV SOLAR	21		2018	2034	0	0	0	00 0-1 0	550
** COMMENT **	*											551	
PLANNING ALTERNATIVE	EPA	17	1	SOLAR TITAN	16		2018	2034	0	0	0	00 0-1 0	552
** COMMENT **	*											553	
RECORD COLS	1	2	3	4	5	6	7	8					
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890	

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 19

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				
PLANNING ALTERNATIVE	EPA	18	1	THERMAL SOLAR	23	2018	2034	0	0	0	0	0	0	0	554
** COMMENT **	*														555
PLANNING ALTERNATIVE	EPA	19	1	SMN SGT-800 3x1	25	2020	2034	0	0	0	0	0	0	0	556
** COMMENT **	*														557
PLANNING ALTERNATIVE	EPA	20	1	WIND20 ND	28	2017	2034	0	0	0	0	0	0	0	558
** COMMENT **	*														559
PLANNING ALTERNATIVE	EPA	21	1	TSW	6	2016	2016	0	0	0	0	0	0	0	560
** COMMENT **	*														561
PLANNING ALTERNATIVE	EPA	22	1	WIND50 MT	13	2017	2034	0	0	0	0	0	0	0	562
** COMMENT **	*														563
PLANNING ALTERNATIVE	EPA	23	1	TSW OWN PPA	9	2016	2016	0	0	0	0	0	0	0	564
** COMMENT **	*														565
PLANNING ALTERNATIVE	EPA	24	1	WIND50 ND	27	2017	2034	0	0	0	0	0	0	0	566
** COMMENT **	*														567
PLANNING ALTERNATIVE	EPA	25	1	TSW PPA	26	2016	2016	0	0	0	0	0	0	0	568
** COMMENT **	*														569
PLANNING ALTERNATIVE	EPA	27	1	WRTSLA 20V34SG	17	2017	2034	0	0	0	0	0	0	0	570
** COMMENT **	*														571
PLANNING ALTERNATIVE	EPA	28	1	GE 7FA.05 2x1	29	2020	2034	0	0	0	0	0	0	0	572
** COMMENT **	*														573
				== TRAJECTORIES ==											574
				T B											575
				Y A N YEAR RATE YEAR RATE YEAR RATE YEAR RATE YEAR RATE										576	
				- + -- ++++----- ++++----- ++++----- ++++----- ++++-----											577
				*											578
TRAJECTORY	ETJ	1	1	1 1 21 201417.174	20154.8336	20164.4241	20173.2534	20182.6835							579
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	1	2345	678	90	1234567890123456789012345678901234567890123456789012345678901234567890										

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 20

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.	
				1	2	3	4	5	6	7	8		
TRAJECTORY	ETJ	1	2	20191.8546	20201.8540	20211.7227	20221.4858	20231.4641					580
	ETJ	1	3	20241.4429	20251.4224	20261.4175	20271.3977	20281.3785					581
	ETJ	1	4	20291.3742	20301.3841	20311.3933	20321.3603	20331.3694					582
	ETJ	1	5	20341.3700									583
** COMMENT **	*												584
TRAJECTORY	ETJ	2	1	1 1 21	20149.6286	20156.9085	20166.1655	20174.3389	20183.4594				585
	ETJ	2	2		20192.2582	20202.2508	20212.0545	20221.7127	20231.6796				586
	ETJ	2	3		20241.6560	20251.6311	20261.6310	20271.5752	20281.5780				587
	ETJ	2	4		20291.5822	20301.5859	20311.5890	20321.5623	20331.5688				588
	ETJ	2	5		20341.5600								589
** COMMENT **	*												590
TRAJECTORY	ETJ	3	1	1 1 1	20143.0000								591
** COMMENT **	*												592
TRAJECTORY	ETJ	4	1	1 1 4	2014100.00	201525.000	201620.000	2017.00000					593
** COMMENT **	*												594
TRAJECTORY	ETJ	5	1	1 1 1	20153.0000								595
** COMMENT **	*												596
TRAJECTORY	ETJ	6	1	1 1 1	20153.0000								597
** COMMENT **	*												598
TRAJECTORY	ETJ	7	1	1 1 1	20143.0000								599
** COMMENT **	*												600
TRAJECTORY	ETJ	8	1	1 1 1	20143.0000								601
** COMMENT **	*												602
TRAJECTORY	ETJ	9	1	1 1 1	20143.0000								603
** COMMENT **	*												604
TRAJECTORY	ETJ	10	1	1 1 1	20143.0000								605
** COMMENT **	*												606

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 21

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890
TRAJECTORY	ETJ	11	1	1	1	1	20143.0000					607
** COMMENT **	*											608
TRAJECTORY	ETJ	12	1	1	1	1	20143.0000					609
** COMMENT **	*											610
TRAJECTORY	ETJ	13	1	1	1	1	20143.0000					611
** COMMENT **	*											612
TRAJECTORY	ETJ	14	1	1	1	1	2014.00000					613
** COMMENT **	*											614
TRAJECTORY	ETJ	15	1	1	1	1	20143.0000					615
** COMMENT **	*											616
TRAJECTORY	ETJ	16	1	1	1	3	20145.5555	20155.2631	2016.00000			617
** COMMENT **	*											618
TRAJECTORY	ETJ	17	1	1	1	7	2014-0.188	2015-0.220	2016-0.189	2017-71.50	2018-0.665	619
	ETJ	17	2				2019-126.6	20203.0000				620
** COMMENT **	*											621
TRAJECTORY	ETJ	18	1	1	1	6	20141.5471	20151.5235	20161.5006	20171.4785	20181.4569	622
	ETJ	18	2				20191.5000					623
** COMMENT **	*											624
TRAJECTORY	ETJ	19	1	1	1	7	2014-0.188	2015-0.220	2016-0.189	2017-0.189	2018-0.221	625
	ETJ	19	2				2019-107.5	20203.0000				626
** COMMENT **	*											627
TRAJECTORY	ETJ	20	1	1	1	3	2014141.66	201510.344	2016.00000			628
** COMMENT **	*											629
TRAJECTORY	ETJ	21	1	1	1	1	20143.0000					630
** COMMENT **	*											631
RECORD COLS	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 22

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	22	1	1 1 1	20153.0000						632	
** COMMENT **	*										633	
TRAJECTORY	ETJ	23	1	1 1 1	20153.0000						634	
** COMMENT **	*										635	
TRAJECTORY	ETJ	24	1	1 1 1	20153.0000						636	
** COMMENT **	*										637	
TRAJECTORY	ETJ	25	1	1 1 1	20153.0000						638	
** COMMENT **	*										639	
TRAJECTORY	ETJ	26	1	1 1 1	20153.0000						640	
** COMMENT **	*										641	
TRAJECTORY	ETJ	27	1	1 1 1	2014.00000						642	
** COMMENT **	*										643	
TRAJECTORY	ETJ	28	1	1 1 1	2014.00000						644	
** COMMENT **	*										645	
TRAJECTORY	ETJ	29	1	1 1 12	20145.0054	20154.9987	20165.0061	20175.0011	20184.9855		646	
	ETJ	29	2		20195.0031	20205.0070	20214.9990	20224.9990	20234.9877		647	
	ETJ	29	3		20245.0000	20254.9990					648	
** COMMENT **	*										649	
TRAJECTORY	ETJ	30	1	1 1 1	20153.0000						650	
** COMMENT **	*										651	
TRAJECTORY	ETJ	31	1	1 1 1	20143.0000						652	
** COMMENT **	*										653	
TRAJECTORY	ETJ	32	1	1 1 21	2016-0.623	2017-6.831	2018-0.935	2019-0.981	2020-0.991		654	
	ETJ	32	2		2021-1.040	2022-1.089	2023-1.101	2024-1.154	2025-143.6		655	
	ETJ	32	3		20262.8571	20272.8673	20282.8745	20292.8789	20302.8806		656	
	ETJ	32	4		20312.8000	20322.8793	20332.8744	20342.9411	20353.0000		657	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1 2345 678 90	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 23

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		
TRAJECTORY	ETJ	32	5	20363.0000							658	
** COMMENT **	*										659	
TRAJECTORY	ETJ	33	1	1 1 6	2014-41.38	201511.486	20164.8484	20178.6705	20185.0531		660	
	ETJ	33	2		20193.0000						661	
** COMMENT **	*										662	
TRAJECTORY	ETJ	34	1	1 1 6	2014-2.866	20151.4754	20162.6252	20174.8012	20185.6702		663	
	ETJ	34	2		20193.0000						664	
** COMMENT **	*										665	
TRAJECTORY	ETJ	35	1	1 1 6	20141.0869	201513.978	201611.320	20172.9661	20183.2921		666	
	ETJ	35	2		20193.0000						667	
** COMMENT **	*										668	
TRAJECTORY	ETJ	36	1	1 1 6	20141.0869	201513.978	201611.320	20172.9661	20183.2921		669	
	ETJ	36	2		20193.0000						670	
** COMMENT **	*										671	
TRAJECTORY	ETJ	37	1	1 1 6	20144.5197	20153.7837	20163.6458	20173.5175	20183.8835		672	
	ETJ	37	2		20193.0000						673	
** COMMENT **	*										674	
TRAJECTORY	ETJ	38	1	1 1 6	20146.1904	20153.5874	20165.1948	20172.8806	20183.2000		675	
	ETJ	38	2		20193.0000						676	
** COMMENT **	*										677	
TRAJECTORY	ETJ	39	1	1 1 6	2014.68966	201519.863	20168.5714	2017-0.526	201815.873		678	
	ETJ	39	2		20193.0000						679	
** COMMENT **	*										680	
TRAJECTORY	ETJ	40	1	1 1 17	2014.00000	2015.00000	2016.00000	2017.00000	2018.00000		681	
	ETJ	40	2		2019.00000	2020.00000	2021.00000	2022.00000	2023.00000		682	
	ETJ	40	3		2024.00000	2025.00000	2026.00000	2027.00000	2028-65.00		683	
	ETJ	40	4		2029.00000	2030.00000					684	
** COMMENT **	*										685	
RECORD COLS	1	2	3	4	5	6	7	8	9	10		
1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							

EGEAS EDIT VERSION 9.02

MIRROR IMAGE REPORT

PAGE 24

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	
TRAJECTORY	ETJ	41	1	1 1 20	2016-19.64	2017-19.24	2018-21.82	2019-23.87	2020-22.95		686	
	ETJ	41	2		2021-14.75	2022-12.06	2023-13.43	2024-14.97	2025553.96		687	
	ETJ	41	3		2026-1.395	2027-1.335	2028-1.313	2029-1.330	2030-1.307		688	
	ETJ	41	4		2031-1.240	2032-1.149	2033-1.205	2034-1.111	2035.00000		689	
** COMMENT **	*										690	
TRAJECTORY	ETJ	42	1	1 1 20	2016-1.152	2017-2.503	2018-2.497	2019-2.489	2020-2.515		691	
	ETJ	42	2		2021-2.504	2022-2.491	2023-2.514	2024-2.497	202585.846		692	
	ETJ	42	3		20262.0113	20271.9938	20281.9982	20292.0017	20302.0041		693	
	ETJ	42	4		20311.9852	20322.0068	20332.0066	20341.9865	2035.00000		694	
** COMMENT **	*										695	
TRAJECTORY	ETJ	43	1	1 1 1	20153.0000						696	
** COMMENT **	*										697	
TRAJECTORY	ETJ	44	1	1 1 1	20143.0000						698	
** COMMENT **	*										699	
TRAJECTORY	ETJ	45	1	1 1 5	2016.00000	2017.00000	201841.304	2019.00000	2020.00000		700	
** COMMENT **	*										701	
TRAJECTORY	ETJ	46	1	1 1 12	20144.9832	20154.9946	20164.9932	20175.0128	20184.9877		702	
	ETJ	46	2		20195.0131	20204.9958	20214.9960	20225.0100	20234.9868		703	
	ETJ	46	3		20245.0011	20255.0000					704	
** COMMENT **	*										705	
TRAJECTORY	ETJ	47	1	1 1 3	2016.00000	201714.192	2018.00000				706	
** COMMENT **	*										707	
TRAJECTORY	ETJ	48	1	1 1 1	20143.0000						708	
** COMMENT **	*										709	
TRAJECTORY	ETJ	49	1	1 1 1	2014.00000						710	
** COMMENT **	*										711	
TRAJECTORY	ETJ	50	1	1 1 3	201413.811	20155.6208	20163.0000				712	
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	
1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	12	34567890	

EGEAS EDIT VERSION 9.02

MIRROR IMAGE REPORT

PAGE 25

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890
** COMMENT **	*											713
TRAJECTORY	ETJ	51	1	1 1 3	2014135.75	20153.0000	20163.0000					714
** COMMENT **	*											715
TRAJECTORY	ETJ	52	1	1 1 3	2014.00000	2015.00000	2016.00000					716
** COMMENT **	*											717
TRAJECTORY	ETJ	53	1	1 1 1	2014.00000							718
** COMMENT **	*											719
TRAJECTORY	ETJ	54	1	1 1 1	20153.0000							720
** COMMENT **	*											721
TRAJECTORY	ETJ	55	1	1 1 1	20153.0000							722
** COMMENT **	*											723
TRAJECTORY	ETJ	56	1	1 1 1	20153.0000							724
** COMMENT **	*											725
TRAJECTORY	ETJ	58	1	1 1 1	20153.0000							726
** COMMENT **	*											727
TRAJECTORY	ETJ	59	1	1 1 1	20153.0000							728
** COMMENT **	*											729
TRAJECTORY	ETJ	60	1	1 1 1	20153.0000							730
** COMMENT **	*											731
TRAJECTORY	ETJ	61	1	1 1 1	20153.0000							732
** COMMENT **	*											733
TRAJECTORY	ETJ	62	1	1 1 1	20153.0000							734
** COMMENT **	*											735
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890

EGEAS EDIT VERSION 9.02

MIRROR IMAGE REPORT

PAGE 26

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890	
TRAJECTORY	ETJ	63	1	1 1 1	20143.0000						736		
** COMMENT **	*										737		
TRAJECTORY	ETJ	64	1	1 1 1	20153.0000						738		
** COMMENT **	*										739		
TRAJECTORY	ETJ	66	1	1 1 1	20153.0000						740		
** COMMENT **	*										741		
TRAJECTORY	ETJ	67	1	1 1 1	20153.0000						742		
** COMMENT **	*										743		
TRAJECTORY	ETJ	68	1	1 1 1	20153.0000						744		
** COMMENT **	*										745		
TRAJECTORY	ETJ	69	1	1 1 1	20153.0000						746		
** COMMENT **	*										747		
	*	== LOADING BLOCKS ==									748		
	*	-A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-									749		
	*	N	1	2	3	4	5				750		
	*	- ++++++-----+++++-----+++++									751		
	*										752		
LOADING BLOCK	ELBA	1	3	0.5550390.3488370.096124							753		
	ELBB	1		1.5707530.0001311.333596							754		
	ELBC	1		1.0000000.0000000.0000000							755		
** COMMENT **	*										756		
LOADING BLOCK	ELBA	2	5	0.0970870.2184470.2184470.3155340.150485							757		
	ELBB	2		3.4766010.8593760.6700500.6607520.796610							758		
	ELBC	2		1.0000000.0000000.0000000.0000000.0000000							759		
** COMMENT **	*										760		
LOADING BLOCK	ELBA	3	5	0.3209240.1597550.1508010.2262020.142319							761		
	ELBB	3		1.1399920.9275430.8777890.9097591.038580							762		
	ELBC	3		1.0000000.0000000.0000000.0000000.0000000							763		
** COMMENT **	*										764		
RECORD COLS	1	2	3	4	5	6	7	8					
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890		

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 27

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890
LOADING BLOCK	ELBA	4	5	0.2315790	.2105260	.2105260	.1347370	.212632					765
	ELBB	4	5	1.5180041	.2144031	.0929631	.2074810	.000120					766
	ELBC	4	5	0.7027150	.2810860	.0702710	.0351360	.140543					767
** COMMENT **	*												768
LOADING BLOCK	ELBA	5	5	0.2587690	.1725130	.1725130	.2300170	.166187					769
	ELBB	5	5	1.6222220	.7422220	.7320000	.7942220	.861745					770
	ELBC	5	5	1.0000000	.0000000	.0000000	.0000000	.0000000					771
** COMMENT **	*												772
LOADING BLOCK	ELBA	6	5	0.3632890	.1147230	.1147230	.1720840	.235182					773
	ELBB	6	5	1.1618430	.9304890	.8789340	.8779260	.932287					774
	ELBC	6	5	0.6857320	.1000710	.0984190	.2329840	.443454					775
** COMMENT **	*												776
LOADING BLOCK	ELBA	7	5	0.2000000	.2000000	.2000000	.2000000	.200000					777
	ELBB	7	5	1.0000001	.0000001	.0000001	.0000001	.000000					778
	ELBC	7	5	1.0000000	.0000000	.0000000	.0000000	.000000					779
** COMMENT **	*												780
LOADING BLOCK	ELBA	8	2	0.7000000	.300000								781
	ELBB	8	2	1.4285710	.000012								782
	ELBC	8	2	1.0000000	.000000								783
** COMMENT **	*												784
LOADING BLOCK	ELBA	9	5	0.2325580	.2093020	.1860470	.1860470	.186047					785
	ELBB	9	5	1.8436370	.7766110	.6303580	.7719000	.794509					786
	ELBC	9	5	1.0000000	.0000000	.0000000	.0000000	.000000					787
** COMMENT **	*												788
LOADING BLOCK	ELBA	10	5	0.2325580	.2093020	.1860470	.1860470	.186047					789
	ELBB	10	5	1.8436370	.7766110	.6303580	.7719000	.794509					790
	ELBC	10	5	1.0000000	.0000000	.0000000	.0000000	.000000					791
** COMMENT **	*												792
LOADING BLOCK	ELBA	11	5	0.2325580	.2093020	.1860470	.1860470	.186047					793
	ELBB	11	5	1.8436370	.7766110	.6303580	.7719000	.794509					794
	ELBC	11	5	1.0000000	.0000000	.0000000	.0000000	.000000					795
RECORD COLS	1	2	3	4	5	6	7	8					
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 28

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890
** COMMENT **	*												796
LOADING BLOCK	ELBA	12	5	0.2777780	1.1587300	2.2380950	3.1190480	4.206349					797
	ELBB	12		1.6628350	2.6934860	3.7458490	4.7841630	5.761273					798
	ELBC	12		0.7885320	1.0841890	2.1095830	3.1287550	4.227864					799
** COMMENT **	*												800
LOADING BLOCK	ELBA	13	5	0.2454470	1.2209020	2.1963580	3.1963580	4.140936					801
	ELBB	13		1.8436370	2.7766110	3.6303580	4.7719000	5.713700					802
	ELBC	13		1.0000000	2.0000000	3.0000000	4.0000000	5.0000000					803
** COMMENT **	*												804
LOADING BLOCK	ELBA	14	5	0.2226030	1.1883560	2.2054790	3.2054790	4.178082					805
	ELBB	14		1.1014360	2.6004480	3.5689500	4.9914581	5.803029					806
	ELBC	14		0.5990180	1.0967090	2.3117780	3.2505240	4.258642					807
** COMMENT **	*												808
LOADING BLOCK	ELBA	15	5	0.3927610	1.1970510	2.1340480	3.1340480	4.142091					809
	ELBB	15		1.0653170	2.9015531	3.1667870	4.9644570	5.832163					810
	ELBC	15		0.6892410	1.1361860	2.3041380	3.2250420	4.289710					811
** COMMENT **	*												812
LOADING BLOCK	ELBA	16	5	0.3632890	1.1147230	2.1147230	3.1720840	4.235182					813
	ELBB	16		1.1618430	2.9304890	3.8789340	4.8779260	5.932287					814
	ELBC	16		0.6857320	1.1000710	2.0984190	3.2329840	4.443454					815
** COMMENT **	*												816
LOADING BLOCK	ELBA	17	5	0.3157750	1.1571920	2.1483820	3.2225730	4.156079					817
	ELBB	17		1.1399870	2.9274980	3.8780130	4.9097471	5.034476					818
	ELBC	17		1.0000000	2.0000000	3.0000000	4.0000000	5.0000000					819
** COMMENT **	*												820
LOADING BLOCK	ELBA	18	5	0.4213480	1.1310860	2.1217230	3.1966290	4.129213					821
	ELBB	18		1.1233120	2.8291850	3.7812650	4.7940971	5.290573					822
	ELBC	18		1.0000000	2.0000000	3.0000000	4.0000000	5.0000000					823
** COMMENT **	*												824
LOADING BLOCK	ELBA	19	5	0.2325580	1.2093020	2.1860470	3.1860470	4.186047					825
	ELBB	19		1.8436370	2.7766110	3.6303580	4.7719000	5.794509					826
RECORD COLS	1	2	3	4	5	6	7	8					
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 29

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO. Includes rows for LOADING BLOCK, COMMENT, and CONSTRUCTION EXPEND.

EGEAS EDIT VERSION 9.02 MIRROR IMAGE REPORT PAGE 30

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	NO.	DATA FIELDS								ASSIGNED REC. NO.			
RECORD COLS	1	2	3	4	5	6	7	8	9	10	11	12				
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890			
** COMMENT **	*													861		
CONSTRUCTION EXPEND.	EZCA	37	1	3	69.0027.004.000									862		
** COMMENT **	*													863		
CONSTRUCTION EXPEND.	EZCA	38	1	1	100.0									864		
** COMMENT **	*													865		
	*				== RETURN ON RATE BASE ==									866		
	*				--CAPITAL STRUC--									867		
	*				--RATES OF RETURN--									868		
	*				YEAR COMM PREF DEBT COMM PREF DEBT TAX TAX									869		
	*				-----									870		
RETURN ON RATE BASE	EZR	1	1	1	201550.0000.000050.00010.750					3.4038.0001.1840				870		
** COMMENT **	*													871		
	*				== TAX DEPRECIATION TABLES ==									872		
	*				DEPRECIATION PERCENTAGES FOR YEARS									873		
	*				YR	1	2	3	4	5	6	7	8	9	10	874
	*				--	+++++	-----	+++++	-----	+++++	-----	+++++	-----	+++++	-----	875
	*														876	
TAX DEPRECIATION	EZT	20	1	21	3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464										877	
	EZT	20	2		4.4624.4624.4624.4624.4624.4624.4624.4624.4624.4624.462										878	
	EZT	20	3		2.224										879	
** COMMENT **	*													880		
TAX DEPRECIATION	EZT	21	1	20	3.7507.2196.6776.1775.7135.2854.8884.5224.4624.464										881	
	EZT	21	2		4.4624.4624.4624.4624.4624.4624.4624.4624.4624.4626.686										882	
** COMMENT **	*													883		
	*													884		
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	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.
	2015	1	0	6/18/15	11:13:32	2015 IRP	900

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	2	
NUMBER OF YEARS	21	
FIRST CALENDAR YEAR	2014	
LAST CALENDAR YEAR	2034	
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	2015	1	0	6/18/15	11:13:29	2015 IRP	900
HOURLY LOADS SYSTEM A	HOURLOAD	1	0				
HOURLY NDT TECHNOLOGY 1	wind40cf	1	0				
TECHNOLOGY 2	wind46cf	1	0				

ADDITIONAL HOURLY FILE PARAMETERS

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

GENERAL DATA

BASE YEAR 2014
ALL DATA BASE COSTS
ARE IN 2014 DOLLARS

SYSTEM DISCOUNT RATE (PERCENT) 6.43
CUSTOMER DISCOUNT RATE (PERCENT) 6.43
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 2014
BENCHMARK PEAK 436. MW

SERVICE AREAS AND NAMES IDENTIFYING SYSTEMS

SYSTEM A - SYSA SYSA

GENERATING COMPANIES

Table with 4 columns: SYSTEM, COMPANY, CODE, NAME. Row 1: A, 1, NDAK, NDAK. Row 2: A, 2, MONT, MONT. Row 3: A, 3, SDAK, SDAK. Row 4: A, 4, MISO, MISO.

SYSTEM DEMAND

IN BASE YEAR 2014 -
PEAK LOAD 436.1 MW
ENERGY 3250.7 GWH

YEARLY ESCALATION TRAJECTORIES
PEAK LOAD 1
ENERGY 2

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
1	2014	INITIAL LOAD	436.1	336.6	3250.7	0.85325367	0.77185532	SUNDAY
		LOAD AFTER CONTRACTS	436.1	336.6	3250.7	0.85325367	0.77185532	

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
0.799673985176069	0.623204653542067	0.395174502060133	0.228007158742610	0.115083912542406	0.000909754249350	0.0000000000000000
0.047762098090724	0.020014593485639	0.007505472557117	0.000909754249350	0.0000000000000000	0.0000000000000000	0.0000000000000000

CUMULANTS

0.853253673585332D+00	0.142954068608743D-02	0.234440760977841D-04	0.340878281194063D-09
-0.237100561529616D-07	-0.306492526183317D-08	-0.352710847237434D-09	-0.431043311037337D-11

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
2	2015	INITIAL LOAD	511.0	350.8	3563.7	0.79830271	0.68642376	SUNDAY
		LOAD AFTER CONTRACTS	511.0	350.8	3563.7	0.79830271	0.68642376	

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
0.948942091256374	0.854228091754877	0.768110875760665	0.620827508261009	0.455491217807209	0.000683920747462	0.0000000000000000
0.315857398534480	0.201984594082678	0.123561681707464	0.066796259668428	0.033056169460486	0.0000000000000000	0.0000000000000000
0.019035794137592	0.009004956508204	0.002621696198593	0.000683920747462	0.0000000000000000	0.0000000000000000	0.0000000000000000

CUMULANTS

0.798302714117452D+00	0.270061163770195D-02	0.608739525379339D-04	0.121702758789510D-08
-0.116304383702634D-06	-0.206641484242736D-07	-0.326845264002952D-08	-0.549215796312039D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED	PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
3	2016 INITIAL LOAD	535.7	380.9	3809.9	0.81410287	0.71098806	SUNDAY
	LOAD AFTER CONTRACTS	535.7	380.9	3809.9	0.81410287	0.71098806	

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
0.992005815108618	0.957170781347294	0.852675609458542	0.755608964216531	0.595101251140486	
0.420205081912176	0.281537404881159	0.169444860057561	0.095738617311344	0.047131110538801	
0.022713788211472	0.011697600928910	0.003747775054896	0.000681413646347	0.000000000000000	

CUMULANTS

0.814102866625899D+00	0.229407390444920D-02	0.476594938428783D-04	0.878053414607958D-09
-0.773498452257660D-07	-0.126664124436357D-07	-0.184650036048203D-08	-0.285973957762176D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED	PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
4	2017 INITIAL LOAD	559.4	409.5	4044.8	0.82767903	0.73209474	SUNDAY
	LOAD AFTER CONTRACTS	559.4	409.5	4044.8	0.82767903	0.73209474	

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
0.991270247786885	0.953587420349642	0.841053231313800	0.731281707925785		
0.549147788833035	0.358943172050869	0.224126704015324	0.124830062995878	0.062301549622490	
0.028710914489055	0.013731306929550	0.004652756893486	0.000680891252708	0.000000000000000	

CUMULANTS

0.827679028094547D+00	0.197123451068268D-02	0.379617129311511D-04	0.648458256681516D-09
-0.529403392482041D-07	-0.803613402887424D-08	-0.108592489330660D-08	-0.156107388713462D-10

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
5	2018	INITIAL LOAD	577.6	430.7	4220.3	0.83637976	0.74562166	SUNDAY
		LOAD AFTER CONTRACTS	577.6	430.7	4220.3	0.83637976	0.74562166	

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
0.634405008539291	0.435297198075996	0.272629913543937	0.992329307116181	0.151283989603297	0.907613981856558
0.032100891699122	0.015708947001700	0.005577814515099	0.000682997695729	0.075357412428431	0.796261480267150
				0.0000000000000000	0.0000000000000000

CUMULANTS

0.836379756654961D+00	0.177719924544358D-02	0.324969437650646D-04	0.527042545687342D-09
-0.408584078087068D-07	-0.588897238325442D-08	-0.755624991739650D-09	-0.102778337873746D-10

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
6	2019	INITIAL LOAD	593.1	448.1	4366.3	0.84270005	0.75544773	SUNDAY
		LOAD AFTER CONTRACTS	593.1	448.1	4366.3	0.84270005	0.75544773	

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
0.708559768376141	0.504448327645814	0.314139246991370	0.990320265987895	0.175038252383500	0.960584905889708
0.036390724750717	0.017345111797073	0.006235170907447	0.000793567206405	0.087745859679295	0.833442651738030
				0.0000000000000000	0.0000000000000000

CUMULANTS

0.842700052338787D+00	0.164255216158638D-02	0.288746738122252D-04	0.450394890136695D-09
-0.335535589036731D-07	-0.464931320801734D-08	-0.573505279862900D-09	-0.752691514433736D-11

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
7	2020	INITIAL LOAD	604.1	459.5	4464.9	0.84603881	0.76063847	SUNDAY
		LOAD AFTER CONTRACTS	604.1	459.5	4464.9	0.84603881	0.76063847	

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
0.737860776416769	0.540250859469648	0.334120566433992	0.189372741382251	0.978544480294768	0.858531252355345
0.039188378300397	0.018574838269554	0.006455888910762	0.000792828462728	0.000792828462728	0.0000000000000000

CUMULANTS

0.846038805284729D+00	0.157356456601328D-02	0.270747918422800D-04	0.412974862553432D-09
-0.301406343898094D-07	-0.408774102138828D-08	-0.493551448031212D-09	-0.631891693864607D-11

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
8	2021	INITIAL LOAD	615.3	471.2	4565.4	0.84933553	0.76576382	SUNDAY
		LOAD AFTER CONTRACTS	615.3	471.2	4565.4	0.84933553	0.76576382	

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
0.769439756999716	0.576549246061362	0.359446186516389	0.205349117620967	0.990029927079645	0.889501233137310
0.043524467099521	0.019091672252534	0.006932095282172	0.000909127250124	0.000909127250124	0.0000000000000000

CUMULANTS

0.849335532925733D+00	0.150689743840308D-02	0.253725311493249D-04	0.378721489433158D-09
-0.270489146860372D-07	-0.358989408354086D-08	-0.424148190555916D-09	-0.532618640029406D-11

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: 2022 INITIAL LOAD, 625.9, 482.0, 4659.2, 0.85210630, 0.77007154, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data points for set 9.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for set 9.

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: 2023 INITIAL LOAD, 635.2, 491.0, 4739.0, 0.85401124, 0.77303311, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data points for set 10.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for set 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 11: 2024 INITIAL LOAD, 644.5 MW, 500.0 MW, 4818.6 GWH, 0.85582573, 0.77585405, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data points for set 11.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for set 11.

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: 2025 INITIAL LOAD, 653.8 MW, 509.1 MW, 4898.4 GWH, 0.85762356, 0.77864911, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data points for set 12.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for set 12.

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	2030	INITIAL LOAD	700.8	555.0	5302.9	0.86617714	0.79194728	SUNDAY
		LOAD AFTER CONTRACTS	700.8	555.0	5302.9	0.86617714	0.79194728	

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
0.915964126814286	0.768802369419454	0.548346413661242	0.318193098075798	0.161650721248641	0.0000000000000000	0.0000000000000000
0.068565334012768	0.025428203342486	0.009422057488513	0.001475743943987	0.0000000000000000	0.0000000000000000	0.0000000000000000

CUMULANTS

0.866177141932446D+00	0.118883781568388D-02	0.177796121846045D-04	0.235814976237787D-09
-0.149536733252187D-07	-0.176276940793917D-08	-0.185023532501351D-09	-0.200555434214002D-11

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	2031	INITIAL LOAD	710.5	564.6	5387.0	0.86790116	0.79462757	SUNDAY
		LOAD AFTER CONTRACTS	710.5	564.6	5387.0	0.86790116	0.79462757	

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
0.933126341442867	0.782677466280760	0.573504469079636	0.334015374493612	0.172442513679246	0.0000000000000000	0.0000000000000000
0.073143705736570	0.026155102206113	0.009510946256771	0.001471932158789	0.0000000000000000	0.0000000000000000	0.0000000000000000

CUMULANTS

0.867901157609517D+00	0.115840397682650D-02	0.171012708114097D-04	0.223879292582178D-09
-0.140149406172576D-07	-0.163083430079899D-08	-0.168950284384929D-09	-0.184622074407933D-11

LOAD CURVES - SYSTEM A

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
19	2032	INITIAL LOAD	720.4	574.3	5472.6	0.86957565	0.79723086	SUNDAY
		LOAD AFTER CONTRACTS	720.4	574.3	5472.6	0.86957565	0.79723086	

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
0.950813302100780	0.797835884844098	0.597480167437652	0.349339337336809	0.177728086991394	0.0000000000000000	0.989536872302088
0.077026831838210	0.027525764906892	0.009854903485186	0.001699121290552	0.0000000000000000	0.0000000000000000	0.177728086991394

CUMULANTS

0.869575648878948D+00	0.112922216773760D-02	0.164591521832660D-04	0.212865957898087D-09
-0.131488976455128D-07	-0.151068054113844D-08	-0.154489433916486D-09	-0.170837005676478D-11

DATA SET REF. NO.	FIRST YEAR CURVE USED		PEAK LOAD MW	MINIMUM LOAD MW	ENERGY GWH	LOAD FACTOR	MINIMUM LOAD FRACTION	FIRST DAY OF YEAR
20	2033	INITIAL LOAD	730.2	584.1	5558.1	0.87130840	0.79992481	SUNDAY
		LOAD AFTER CONTRACTS	730.2	584.1	5558.1	0.87130840	0.79992481	

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
0.966168969672910	0.811360589074993	0.623836706258960	0.365769879870870	0.185492722711949	0.0000000000000000	0.990503075063071
0.081634939090835	0.028685610541643	0.010317749246206	0.001700727897729	0.0000000000000000	0.0000000000000000	0.185492722711949

CUMULANTS

0.871308403799395D+00	0.109941695596621D-02	0.158118149334052D-04	0.202052228532783D-09
-0.122982789499735D-07	-0.139419036607771D-08	-0.140692000186370D-09	-0.151612134901905D-11

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	2034	INITIAL LOAD	740.2	594.1	5645.3	0.87302222	0.80258920	SUNDAY
		LOAD AFTER CONTRACTS	740.2	594.1	5645.3	0.87302222	0.80258920	

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
0.972570017391459	0.823485249253891	0.650360035986603	0.380172158093824	0.196971619915002	0.0000000000000000	0.0000000000000000
0.084771167080900	0.030138351012785	0.010610505600009	0.002144676663834	0.0000000000000000	0.0000000000000000	0.0000000000000000

CUMULANTS

0.873022219989885D+00	0.107032946914991D-02	0.151884846677011D-04	0.191299738984189D-09
-0.115009390742952D-07	-0.128642147942893D-08	-0.128101340668182D-09	-0.134451810934763D-11

BASIC PLANT TYPES - 1

DATA SET REF. NO.	1			2			3			4			5		
NAME	BIG STONE AQCS			MISO - Off peak			LEWIS & CLARKMAT			INTERRUPTIBLES			HESKETT #3		
TYPE / LOADING / STATUS /AVD	THRM	B	C	THRM	P	E	THRM	B	C	DTHR	P	E	THRM	P	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	COAL MDU	SDAK		PURC MDU	MISO		COAL MDU	NDAK		PURC MDU	MISO		GAS MDU	NDAK	
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE	1/ 1/2015			1/ 1/2014			1/ 1/2016			1/ 1/2012			1/ 1/2014		
OPERATING/BOOK LIVES, YEARS		40	30		50	50		10	10		30	30		40	25
RATED CAPACITY, MW	105.600			50.000			52.300			14.400			88.000		
- RESERVE	0.9199			0.0000			0.9962			1.0000			0.8045		
CAPACITY - OPERATING	0.9251			1.0000			0.8604			1.0000			0.8371		
MULTIPLIERS - EMERGENCY	1.0000			1.0000			0.9398			1.0000			0.9276		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0801			0.0000			0.0041			0.0000			0.0561		
FULL LOAD HEAT RATE, BTU/KWH	10622.			10500.			12679.			1.			10214.		
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	821.57			0.00			267.69			0.00			875.00		
INSTALLATION COST 2, \$/KW	821.57			0.00			267.69			0.00			875.00		
MULTI-UNIT CAPITAL COST OPT.	1			2			2			1			1		
LEVEL. CARRYING CHARGE, PCT	10.54			0.00			18.32			0.00			9.78		
FIXED O+M COST, \$/KW-YR	24.98			0.00			57.95			50.04			12.08		
VARIABLE O+M COST, \$/MWH	1.65			26.89			4.19			300.00			2.00		
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			0			1			1			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	53	50	51	0	0	46	27	3	11	0	48	49	30	3	15
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE		0	0		0	0		0	0		0	0		0	0
RATED CAPACITY		0			52			0			16			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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	1			2			3			4			5		
MAINTENANCE REQUIREMENTS	20			0			12			14			17		
FUEL 1 / FUEL 2	6	0		8	0		5	0		8	0		1	0	
LOADING BLOCKS / NDT NO.		3	0		7	0		6	0		0	0		2	0
EMISSIONS / SITE / TAX DEPR.	0	0	20	0	0	0	0	0	0	0	0	0	0	0	20
MUST RUN / 1ST YR / LAST YR	M 1980 2080						M 2016 2030								
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			857.00		
CONSTRUCTION COST 2, \$/KW	0.00			0.00			0.00			0.00			857.00		
TRAJECTORY / EXPEND. PATTERN	0	0		0	0		0	0		0	0		30	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.	6			7			8			9			10		
NAME	WIND OWN			DIESEL 2			DIESEL 3			WIND PPA-OWN			LEWIS&CLARK RICE		
TYPE / LOADING / STATUS /AVD	NDT	B	G	THRM	P	E	THRM	P	E	NDT	B	G	THRM	P	C
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	WIND MDU	NDAK		GAS MDU	NDAK		GAS MDU	NDAK		WIND 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/ 1/2016		
OPERATING/BOOK LIVES, YEARS		20	20		99	30		99	30		20	20		40	25
RATED CAPACITY, MW		107.500			2.100			2.100			107.500			19.000	
- RESERVE		0.2080			0.8571			0.8571			0.2080			0.8158	
CAPACITY - OPERATING		1.0000			1.0000			1.0000			1.0000			0.8371	
MULTIPLIERS - EMERGENCY		0.4186			1.0000			1.0000			0.3810			0.9276	
- CHARGING		0.0000			0.0000			0.0000			0.0000			0.0000	
EQUIVALENT FORCED OUTAGE RATE		0.0000			0.1400			0.1400			0.0000			0.0709	
FULL LOAD HEAT RATE, BTU/KWH		0.			11000.			11000.			0.			8368.	
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		2093.00			0.00			0.00			0.00			2180.00	
INSTALLATION COST 2, \$/KW		2093.00			0.00			0.00			0.00			2180.00	
MULTI-UNIT CAPITAL COST OPT.		1			2			2			1			1	
LEVEL. CARRYING CHARGE, PCT		11.97			0.00			0.00			0.00			9.78	
FIXED O+M COST, \$/KW-YR		0.00			27.58			27.58			0.00			29.89	
VARIABLE O+M COST, \$/MWH		-28.87			2.00			2.00			47.39			3.30	
DEFAULT AFUDC, PCT. OF GBV		0.00			0.00			0.00			0.00			0.00	
DEFAULT DEBT, PCT. OF AFUDC		0.00			0.00			0.00			0.00			0.00	
CAPITAL STRUCTURE		1			0			0			1			1	
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	28	0	32	0	3	8	0	3	8	0	0	41	30	22	56
F.O.R./RESERVE CAP/OPER CAP	0	45	0	0	0	0	0	0	0	0	0	0	0	47	0
ENERGY / HEAT RATE		0	0		0	0		0	0		0	0		0	0
RATED CAPACITY		0			0			0			0			0	
SEGMENT MULT. - CAP / ENERGY		0	0		0	0		0	0		0	0		0	0
SUBWEEK ENERGY ALLOCATION		0			0			0			0			0	

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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	6			7			8			9			10		
MAINTENANCE REQUIREMENTS	13			23			23			16			19		
FUEL 1 / FUEL 2	0	0		2	0		2	0		0	0		1	0	
LOADING BLOCKS / NDT NO.	0	0	2	0	0	0	0	0	0	0	0	2	11	0	
EMISSIONS / SITE / TAX DEPR.	0	0	21	0	0	0	0	0	0	0	0	21	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	2400.00			0.00			0.00			2400.00			857.00		
CONSTRUCTION COST 2, \$/KW	2400.00			0.00			0.00			2400.00			857.00		
TRAJECTORY / EXPEND. PATTERN	30	38		0	0		0	0		30	38		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.	11			12			13			14			15		
NAME	SOLID WASTE			GE 7EA 2x1			WIND50 MT			GE LMS100PB			GE LM6000PH SPRT		
TYPE / LOADING / STATUS /AVD	THRM	B	G	THRM	P	G	NDT	B	G	THRM	P	G	THRM	P	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	BMP	MDU	NDAK	GAS	MDU	NDAK	WIND	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	25		40	40		30	20		40	25		40	25
RATED CAPACITY, MW		15.000			256.700			50.000			85.900			62.800	
- RESERVE		0.9154			0.9612			0.2080			0.9439			0.9608	
CAPACITY - OPERATING		0.8371			0.8571			1.0000			0.8371			0.8371	
MULTIPLIERS - EMERGENCY		0.9276			1.0000			0.3810			0.9276			0.9276	
- CHARGING		0.0000			0.0000			0.0000			0.0000			0.0000	
EQUIVALENT FORCED OUTAGE RATE		0.0845			0.0392			0.0000			0.0561			0.0392	
FULL LOAD HEAT RATE, BTU/KWH	16002.			7592.			0.			9206.			7663.		
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		17475.03			768.40			1916.49			1056.29			1462.53	
INSTALLATION COST 2, \$/KW		17475.03			768.40			1916.49			1056.29			1462.53	
MULTI-UNIT CAPITAL COST OPT.		1			1			1			1			1	
LEVEL. CARRYING CHARGE, PCT		9.78			9.78			14.86			9.78			9.78	
FIXED O+M COST, \$/KW-YR		117.12			11.16			30.96			22.66			28.57	
VARIABLE O+M COST, \$/MWH		5.82			3.57			0.00			4.49			4.50	
DEFAULT AFUDC, PCT. OF GBV		0.00			0.00			0.00			0.00			0.00	
DEFAULT DEBT, PCT. OF AFUDC		0.00			0.00			0.00			0.00			0.00	
CAPITAL STRUCTURE		1			1			1			1			1	
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	30	22	66	30	22	68	30	22	0	30	22	24	30	22	26
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE		0	0		0	0		0	0		0	0		0	0
RATED CAPACITY		0			0			0			0			0	
SEGMENT MULT. - CAP / ENERGY		0	0		0	0		0	0		0	0		0	0
SUBWEEK ENERGY ALLOCATION		0			0			0			0			0	

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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	11			12			13			14			15		
MAINTENANCE REQUIREMENTS	7			21			10			28			28		
FUEL 1 / FUEL 2	11	0		1	0		0	0		1	0		1	0	
LOADING BLOCKS / NDT NO.		20	0		21	0		0	1		13	0		4	0
EMISSIONS / SITE / TAX DEPR.	0	0	20	0	0	20	0	0	21	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			750.00			2400.00			857.00			850.00		
CONSTRUCTION COST 2, \$/KW	857.00			750.00			2400.00			857.00			850.00		
TRAJECTORY / EXPEND. PATTERN	30	37		30	37		30	38		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.	16			17			18			19			20		
NAME	SOLAR TITAN			WRTSLA 20V34SG			GE 7FA.05 1x1			BIOMASS			GEO THERMAL		
TYPE / LOADING / STATUS /AVD	THRM	P	G	THRM	P	G	THRM	I	G	THRM	B	G	THRM	B	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	GAS	MDU	NDAK	GAS	MDU	NDAK	GAS	MDU	NDAK	BMP	MDU	NDAK	PURC	MDU	NDAK
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE															
OPERATING/BOOK LIVES, YEARS	40		25	40		25	40		40	40		25	40		25
RATED CAPACITY, MW	17.300			28.000			294.600			29.900			30.000		
- RESERVE	0.9890			0.9889			0.9608			0.9154			0.6300		
CAPACITY - OPERATING	0.8371			0.8371			0.8571			0.8371			0.9000		
MULTIPLIERS - EMERGENCY	0.9276			0.9276			1.0000			0.9276			1.0000		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0109			0.0109			0.0392			0.0845			0.3700		
FULL LOAD HEAT RATE, BTU/KWH	10427.			8542.			6672.			11056.			1.		
HEAT RATE MULT. - 2ND FUEL	0.0000			0.0000			0.0000			0.0000			0.0000		
ANNUAL ENERGY LIMIT, GWH	0.000000			0.000000			0.000000			0.000000			0.000000		
STORAGE EFFICIENCY, PERCENT	0.00			0.00			0.00			0.00			0.00		
INSTALLATION COST 1, \$/KW	1341.39			1550.29			779.50			3986.40			2723.33		
INSTALLATION COST 2, \$/KW	1341.39			1550.29			779.50			3986.40			2723.33		
MULTI-UNIT CAPITAL COST OPT.	1			1			1			1			1		
LEVEL. CARRYING CHARGE, PCT	9.78			9.78			9.49			9.78			9.78		
FIXED O+M COST, \$/KW-YR	32.28			30.73			10.00			117.12			125.88		
VARIABLE O+M COST, \$/MWH	2.32			9.63			2.88			5.82			0.00		
DEFAULT AFUDC, PCT. OF GBV	0.00			0.00			0.00			0.00			0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00			0.00			0.00			0.00			0.00		
CAPITAL STRUCTURE	1			1			1			1			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	30	22	55	30	22	56	30	22	54	30	22	58	30	22	59
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0	0		0	0		0	0		0	0		0	0	
RATED CAPACITY	0			0			0			0			0		
SEGMENT MULT. - CAP / ENERGY	0	0		0	0		0	0		0	0		0	0	
SUBWEEK ENERGY ALLOCATION	0			0			0			0			0		

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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	16			17			18			19			20		
MAINTENANCE REQUIREMENTS	28			28			24			28			28		
FUEL 1 / FUEL 2	9	0		1	0		1	0		10	0		8	0	
LOADING BLOCKS / NDT NO.	9	0		10	0		22	0		19	0		0	0	0
EMISSIONS / SITE / TAX DEPR.	0	0	20	0	0	20	0	0	20	0	0	20	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	857.00			857.00			750.00			857.00			2558.00		
CONSTRUCTION COST 2, \$/KW	857.00			857.00			750.00			857.00			2558.00		
TRAJECTORY / EXPEND. PATTERN	30	37		30	37		30	37		30	37		20	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.	21			22			23			24			25		
NAME	PV SOLAR			CONC SOLAR			THERMAL SOLAR			CFBC CO2			SMN SGT-800 3x1		
TYPE / LOADING / STATUS /AVD	THRM	B	G	THRM	B	G	THRM	B	G	THRM	B	G	THRM	P	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	NDAK	PURC	MDU	NDAK	PURC	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															
OPERATING/BOOK LIVES, YEARS	30		30	30		30	30		30	40		40	40		40
RATED CAPACITY, MW	30.000			30.000			30.000			30.000			213.900		
- RESERVE	0.5000			0.5000			0.5000			0.9367			0.9608		
CAPACITY - OPERATING	0.5000			0.5000			0.5000			0.9500			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	0.0000			0.0000			0.0000			0.0639			0.0392		
FULL LOAD HEAT RATE, BTU/KWH	1.			1.			1.			13781.			7347.		
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	4036.72			7714.65			5282.22			7099.00			1040.23		
INSTALLATION COST 2, \$/KW	4036.72			7714.65			5282.22			7099.00			1040.23		
MULTI-UNIT CAPITAL COST OPT.	1			1			1			1			1		
LEVEL. CARRYING CHARGE, PCT	11.97			11.97			11.97			9.49			9.78		
FIXED O+M COST, \$/KW-YR	19.32			54.60			74.28			270.60			13.75		
VARIABLE O+M COST, \$/MWH	0.00			0.00			0.00			19.81			3.58		
DEFAULT AFUDC, PCT. OF GBV	0.00			0.00			0.00			0.00			0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00			0.00			0.00			0.00			0.00		
CAPITAL STRUCTURE	1			1			1			1			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	30	22	0	30	22	0	30	22	0	30	22	25	30	22	69
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0	0		0	0		0	0		0	0		0	0	
RATED CAPACITY	0			0			0			0			0		
SEGMENT MULT. - CAP / ENERGY	0	0		0	0		0	0		0	0		0	0	
SUBWEEK ENERGY ALLOCATION	0			0			0			0			0		

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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	21			22			23			24			25		
MAINTENANCE REQUIREMENTS	10			10			10			33			25		
FUEL 1 / FUEL 2	8	0		8	0		8	0		12	0		1	0	
LOADING BLOCKS / NDT NO.		0	0		0	0		0	0		0	0		23	0
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	0	0	0	20	0	0	20
MUST RUN / 1ST YR / LAST YR	M	1980	2080	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		2558.00			2558.00			2558.00			3900.00			750.00	
CONSTRUCTION COST 2, \$/KW		2558.00			2558.00			2558.00			3900.00			750.00	
TRAJECTORY / EXPEND. PATTERN		20	0		20	0		20	0		30	31		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.	26			27			28			29			120		
NAME	WIND	PPA		WIND50	ND		WIND20	ND		GE 7FA.05	2x1		MILES	CITY	C.T.
TYPE / LOADING / STATUS /AVD	NDT	B	G	NDT	B	G	NDT	B	G	THRM	I	G	THRM	P	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	WIND	MDU	NDAK	WIND	MDU	NDAK	WIND	MDU	NDAK	GAS	MDU	NDAK	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/ 1/1972
OPERATING/BOOK LIVES, YEARS		20	20		30	20		30	20		40	40		99	30
RATED CAPACITY, MW		107.500			50.000			20.000			200.000			25.200	
- RESERVE		0.2080			0.2080			0.2080			0.9608			0.8492	
CAPACITY - OPERATING		1.0000			1.0000			1.0000			0.8571			0.8299	
MULTIPLIERS - EMERGENCY		0.3810			0.3810			0.3810			1.0000			0.9267	
- CHARGING		0.0000			0.0000			0.0000			0.0000			0.0000	
EQUIVALENT FORCED OUTAGE RATE		0.0000			0.0000			0.0000			0.0392			0.0115	
FULL LOAD HEAT RATE, BTU/KWH		0.			0.			0.		6631.			13050.		
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			1878.69			2031.60			741.76			0.00	
INSTALLATION COST 2, \$/KW		0.00			1878.69			2031.60			741.76			0.00	
MULTI-UNIT CAPITAL COST OPT.		1			1			1			1			2	
LEVEL. CARRYING CHARGE, PCT		0.00			11.97			11.97			9.49			0.00	
FIXED O+M COST, \$/KW-YR		0.00			30.96			30.96			9.92			10.46	
VARIABLE O+M COST, \$/MWH		29.50			0.00			0.00			3.46			2.00	
DEFAULT AFUDC, PCT. OF GBV		0.00			0.00			0.00			0.00			0.00	
DEFAULT DEBT, PCT. OF AFUDC		0.00			0.00			0.00			0.00			0.00	
CAPITAL STRUCTURE		1			1			1			1			0	
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	0	0	42	30	22	0	30	22	0	30	22	54	0	3	5
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE		0	0		0	0		0	0		0	0		0	0
RATED CAPACITY		0			0			0			0			0	
SEGMENT MULT. - CAP / ENERGY		0	0		0	0		0	0		0	0		0	0
SUBWEEK ENERGY ALLOCATION		0			0			0			0			0	

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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	26			27			28			29			120		
MAINTENANCE REQUIREMENTS	9			10			10			1			2		
FUEL 1 / FUEL 2	0	0		0	0		0	0		1	0		1	0	
LOADING BLOCKS / NDT NO.	0	2		0	1		0	1		8	0		12	0	
EMISSIONS / SITE / TAX DEPR.	0	0	21	0	0	21	0	0	21	0	0	20	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	2400.00			2400.00			2400.00			750.00			0.00		
CONSTRUCTION COST 2, \$/KW	2400.00			2400.00			2400.00			750.00			0.00		
TRAJECTORY / EXPEND. PATTERN	30	38		30	38		30	38		30	37		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.	130			132			134			140			150		
NAME	GLENDDIVE CT #1			GLENDDIVE CT #2			DIESEL 1			HESKETT #1			HESKETT #2		
TYPE / LOADING / STATUS /AVD	THRM	P	E	THRM	P	E	THRM	P	E	THRM	B	E	THRM	B	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	GAS MDU MONT			GAS MDU MONT			GAS MDU MONT			COAL MDU NDAK			COAL MDU NDAK		
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE	1/ 1/1979			1/ 1/2003			1/ 1/2005			1/ 1/1954			1/ 1/1963		
OPERATING/BOOK LIVES, YEARS		99	30		99	30		99	30		66	30		99	30
RATED CAPACITY, MW	34.780			40.742			2.000			29.200			74.600		
- RESERVE	0.9603			0.9769			0.0000			0.7021			0.8941		
CAPACITY - OPERATING	0.8061			0.8061			1.0000			0.6849			0.9383		
MULTIPLIERS - EMERGENCY	0.9636			0.9636			1.0000			1.0000			1.0000		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0125			0.0086			0.1400			0.0702			0.0873		
FULL LOAD HEAT RATE, BTU/KWH	11250.			8282.			11000.			18731.			12447.		
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	5.32			9.40			27.58			66.14			55.96		
VARIABLE O+M COST, \$/MWH	2.00			2.00			2.00			6.80			6.34		
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	3	6	0	3	7	0	3	8	0	3	9	0	3	10
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0 0			0 0			0 0			0 0			0 0		
RATED CAPACITY	0			0			0			0			0		
SEGMENT MULT. - CAP / ENERGY	0	0		0	0		0	0		0	0		0	0	
SUBWEEK ENERGY ALLOCATION	0			0			0			0			0		

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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	130			132			134			140			150		
MAINTENANCE REQUIREMENTS	3			4			23			5			6		
FUEL 1 / FUEL 2	1	0		1	0		2	0		3	0		4	0	
LOADING BLOCKS / NDT NO.		5	0		13	0		0	0		14	0		15	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			170			180			220			250		
NAME	LEWIS & CLARK			BIG STONE			COYOTE			WAPA PUR-FT PECK			DIAMOND WILLOW		
TYPE / LOADING / STATUS /AVD	THRM	B	E	THRM	B	E	THRM	B	E	HYDR	B	E	NDT	B	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	COAL MDU	NDAK		COAL MDU	SDAK		COAL MDU	NDAK		HYDR 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/ 1/1975			1/ 1/1981			1/ 1/2001			1/ 1/2008		
OPERATING/BOOK LIVES, YEARS	58		30	40		30	99		30	50		30	22		20
RATED CAPACITY, MW	52.300			107.800			106.800			2.800			30.000		
- RESERVE	0.9962			0.9156			0.8680			0.0000			0.1833		
CAPACITY - OPERATING	0.8604			0.9251			0.9368			0.8929			1.0000		
MULTIPLIERS - EMERGENCY	0.9398			1.0000			1.0000			1.0000			0.3810		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0041			0.0801			0.1435			0.0000			0.0000		
FULL LOAD HEAT RATE, BTU/KWH	12679.			10351.			11921.			0.			0.		
HEAT RATE MULT. - 2ND FUEL	0.0000			0.0000			0.0000			0.0000			0.0000		
ANNUAL ENERGY LIMIT, GWH	0.000000			0.000000			0.000000			14.330000			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	57.95			24.98			25.60			0.00			22.14		
VARIABLE O+M COST, \$/MWH	4.19			1.65			2.80			33.25			-31.85		
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	11	0	3	12	0	3	13	0	0	14	0	3	17
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0 0			0 0			0 0			0 0			0 0		
RATED CAPACITY	0			0			0			0			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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	160			170			180			220			250		
MAINTENANCE REQUIREMENTS	18			8			22			0			10		
FUEL 1 / FUEL 2	5	0		6	0		7	0		0	0		0	0	
LOADING BLOCKS / NDT NO.	16	0		17	0		18	0		0	0	0	0	0	1
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUST RUN / 1ST YR / LAST YR	M	1980	2080	M	1980	2080	M	1980	2080	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.	260			270			310			340			350		
NAME	GLEN ULLIN ORMAT			CEDAR HILLS			PURCHASE POWER			GE 7EA 1x1			GE 7EA		
TYPE / LOADING / STATUS /AVD	THRM	B	E	NDT	B	E	THRM	P	G	THRM	P	G	THRM	P	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	NDAK	WIND	MDU	MONT	PURC	MDU	MISO	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	1/ 1/2009			1/ 1/2010											
OPERATING/BOOK LIVES, YEARS		30	20		20	20		1	1		40	40		40	25
RATED CAPACITY, MW	7.500			19.500			10.000			127.600			75.000		
- RESERVE	0.4533			0.2308			1.0000			0.9489			0.9439		
CAPACITY - OPERATING	0.6667			1.0000			1.0000			0.8571			0.8371		
MULTIPLIERS - EMERGENCY	0.6667			0.3810			1.0000			1.0000			0.9276		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.1058			0.0000			0.0000			0.0392			0.0561		
FULL LOAD HEAT RATE, BTU/KWH	1.			0.			1.			7608.			11436.		
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			601.84			815.97		
INSTALLATION COST 2, \$/KW	0.00			0.00			0.00			601.84			815.97		
MULTI-UNIT CAPITAL COST OPT.	2			2			2			1			1		
LEVEL. CARRYING CHARGE, PCT	0.00			0.00			0.00			9.78			9.78		
FIXED O+M COST, \$/KW-YR	51.95			19.79			34.80			15.97			17.45		
VARIABLE O+M COST, \$/MWH	7.11			-31.85			250.00			2.99			2.32		
DEFAULT AFUDC, PCT. OF GBV	0.00			0.00			0.00			0.00			0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00			0.00			0.00			0.00			0.00		
CAPITAL STRUCTURE	1			1			0			1			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	0	44	18	0	3	19	0	21	21	30	22	23	30	22	60
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0			0			0			0			0		
RATED CAPACITY	0			0			0			0			0		
SEGMENT MULT. - CAP / ENERGY	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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	260			270			310			340			350		
MAINTENANCE REQUIREMENTS	15			10			0			28			28		
FUEL 1 / FUEL 2	8	0		0	0		8	0		1	0		1	0	
LOADING BLOCKS / NDT NO.	0	0	0	0	0	1	0	0	0	1	0	0	2	0	0
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	0	0	0	20	0	0	20
MUST RUN / 1ST YR / LAST YR	M	1980	2080												
SPIN RSV / 1ST YR / LAST YR															
DISPATCH MODIFIER, \$/MWH	0.00			0.00			0.00			0.00			0.00		
TRAJECTORY FOR DISPATCH MODIF	0			0			0			0			0		
CONSTRUCTION COST 1, \$/KW	0.00			0.00			0.00			750.00			857.00		
CONSTRUCTION COST 2, \$/KW	0.00			0.00			0.00			750.00			857.00		
TRAJECTORY / EXPEND. PATTERN	0	0		0	0		0	0		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.	360			370			390			400			440		
NAME	CFBC			GE LM6000PH			WIND20 MT			MISO - On peak			COMMERCIAL DSM		
TYPE / LOADING / STATUS /AVD	THRM	B	G	THRM	P	G	NDT	B	G	THRM	P	E	DTHR	P	E
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	LIGN MDU	NAK		GAS MDU	NAK		WIND MDU	NAK		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/ 1/2013		
OPERATING/BOOK LIVES, YEARS	40		40	40		25	30		20	50		50	30		30
RATED CAPACITY, MW	30.000			37.300			20.000			50.000			5.000		
- RESERVE	0.6934			0.9890			0.2080			0.0000			1.0000		
CAPACITY - OPERATING	0.9500			0.8371			1.0000			1.0000			1.0000		
MULTIPLIERS - EMERGENCY	1.0000			0.9276			0.3810			1.0000			1.0000		
- CHARGING	0.0000			0.0000			0.0000			0.0000			0.0000		
EQUIVALENT FORCED OUTAGE RATE	0.0639			0.0109			0.0000			0.0000			0.0000		
FULL LOAD HEAT RATE, BTU/KWH	9974.			9960.			0.			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			0.000000			0.000000			0.000000		
STORAGE EFFICIENCY, PERCENT	0.00			0.00			0.00			0.00			0.00		
INSTALLATION COST 1, \$/KW	3882.00			1294.83			2069.40			0.00			0.00		
INSTALLATION COST 2, \$/KW	3882.00			1294.83			2069.40			0.00			0.00		
MULTI-UNIT CAPITAL COST OPT.	1			1			1			2			2		
LEVEL. CARRYING CHARGE, PCT	9.49			9.78			14.86			0.00			0.00		
FIXED O+M COST, \$/KW-YR	221.88			36.52			30.96			0.00			50.04		
VARIABLE O+M COST, \$/MWH	12.49			3.95			0.00			36.96			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			1			0			0		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	30	22	61	30	22	62	30	22	0	0	0	29	0	48	49
F.O.R./RESERVE CAP/OPER CAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENERGY / HEAT RATE	0	0		0	0		0	0		0	0		0	0	
RATED CAPACITY	0			0			0			52			4		
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

BASIC PLANT TYPES - 2

DATA SET REF. NO.	360			370			390			400			440		
MAINTENANCE REQUIREMENTS	33			28			10			0			14		
FUEL 1 / FUEL 2	12	0		1	0		0	0		8	0		8	0	
LOADING BLOCKS / NDT NO.		0			13	0		0	1		7	0		0	0
EMISSIONS / SITE / TAX DEPR.	0	0	20	0	0	20	0	0	21	0	0	0	0	0	0
MUST RUN / 1ST YR / LAST YR	M 1980 2080														
SPIN RSV / 1ST YR / LAST YR															
DISPATCH MODIFIER, \$/MWH	0.00			0.00			0.00			0.00			0.00		
TRAJECTORY FOR DISPATCH MODIF	0			0			0			0			0		
CONSTRUCTION COST 1, \$/KW	3900.00			850.00			2400.00			0.00			0.00		
CONSTRUCTION COST 2, \$/KW	3900.00			850.00			2400.00			0.00			0.00		
TRAJECTORY / EXPEND. PATTERN	30	31		30	37		30	38		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	

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION		YEAR	..FIRST PERIOD..		..SECOND PERIOD..	
							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	2	- TWO PERIODS	1	1	15	1	35
						2	7	15	1	42
						3	1	19	1	43
						4	1	16	1	43
						5	2	16	1	41
						6	1	21	1	39
						7	1	19	1	44
						8	1	17	1	43
						9	1	18	1	43
						10	1	16	1	40
3	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	1	17	1	34
						2	1	14	1	41
						3	1	18	1	41
						4	1	18	2	41
						5	1	17	1	43
						6	1	19	1	38
						7	1	17	1	42
						8	1	16	1	41
						9	1	17	1	41
						10	6	18	1	41
4	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	1	16	1	34
						2	1	15	1	41
						3	7	16	1	42
						4	1	17	1	42
						5	1	18	1	42
						6	1	20	1	38
						7	1	18	1	43
						8	1	18	1	42
						9	6	19	1	42
						10	1	15	1	39
5	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	6	17	1	41
						2	1	16	1	41
						3	2	13	1	41
						4	6	17	1	44
						5	1	18	1	43
						6	1	22	1	41
						7	1	18	1	43
						8	1	16	1	41
						9	1	15	5	37
						10	1	15	1	37

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE CYCLES		YEAR	..FIRST PERIOD..		..SECOND PERIOD..	
				MAINTENANCE SPECIFICATION			NO. OF WEEKS	START WEEK	NO. OF WEEKS	START WEEK
6	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	2	23	2	37
						2	2	12	2	37
						3	1	17	2	39
						4	2	14	2	41
						5	2	14	2	40
						6	5	15	2	42
						7	2	14	2	40
						8	2	17	2	42
						9	1	16	2	42
						10	2	16	2	39
7	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	2			
8	10	10	2 - BASE YEAR=1	1	- START WEEKS	1	2	20		
						2	15	10		
						3	2	21		
						4	0	0		
						5	1	22		
						6	5	36		
						7	0	0		
						8	1	23		
						9	1	22		
						10	0	0		
9	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
10	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
12	10	10	2 - BASE YEAR=1	2	- TWO PERIODS	1	2	13	1	41
						2	3	19	2	41
						3	2	19	2	40
						4	2	13	1	38
						5	6	14	1	39
						6	2	20	2	37
						7	2	20	1	37
						8	2	19	1	39
						9	2	18	2	43
						10	2	18	2	43
13	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
14	1	1	0 - INSTALLATION	0	- NO. WEEKS ONLY	1	1			

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD..		..SECOND PERIOD..	
						NO. OF WEEKS	START WEEK	NO. OF WEEKS	START WEEK
15	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	1	16	1	39
					2	1	16	1	39
					3	1	16	1	39
					4	1	16	1	40
					5	1	15	1	39
					6	1	16	1	39
					7	1	16	1	40
					8	1	16	0	0
					9	1	16	1	39
					10	1	14	1	36
16	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	1			
17	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
18	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	2	13	1	41
					2	3	19	2	41
					3	2	19	2	40
					4	2	13	1	38
					5	6	14	1	39
					6	2	20	2	37
					7	2	20	1	37
					8	2	19	1	39
					9	2	18	2	43
					10	2	18	2	43
19	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
20	10	10	0 - INSTALLATION	1 - START WEEKS	1	15	10		
					2	2	21		
					3	0	0		
					4	1	22		
					5	5	36		
					6	0	0		
					7	1	23		
					8	1	22		
					9	0	0		
					10	2	20		
21	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			

MAINTENANCE CYCLES

DATA SET REF. NO.	YEARS INPUT	YEARS IN CYCLE	BASIS FOR YEARS	MAINTENANCE SPECIFICATION	YEAR	..FIRST PERIOD..		..SECOND PERIOD..	
						NO. OF WEEKS	START WEEK	NO. OF WEEKS	START WEEK
22	10	10	2 - BASE YEAR=1	2 - TWO PERIODS	1	1	22	1	36
					2	1	22	1	37
					3	7	15	1	37
					4	1	24	1	37
					5	1	22	1	36
					6	6	12	1	36
					7	1	23	1	35
					8	1	23	1	37
					9	6	12	1	37
					10	1	21	1	37
23	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
24	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
25	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
28	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	2			
33	1	1	1 - BASE YEAR=0	0 - NO. WEEKS ONLY	1	3			

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	1.03	-1.00	0.00	5.050000	0	0	33	0	0	0
2	OIL2	GAL	39.17	-1.00	0.00	25.120001	0	0	34	0	0	0
3	COAL	TON	14.07	-1.00	0.00	1.840000	0	0	35	0	0	0
4	COAL	TON	14.07	-1.00	0.00	1.840000	0	0	36	0	0	0
5	COAL	TON	13.09	-1.00	0.00	1.770000	0	0	37	0	0	0
6	COAL	TON	16.43	-1.00	0.00	2.100000	0	0	38	0	0	0
7	COAL	TON	13.81	-1.00	0.00	1.450000	0	0	39	0	0	0
8	PURC	NONE	0.01	-1.00	0.00	0.000000	0	0	0	0	0	0
9	LANDFILL	DKT	1.03	-1.00	0.00	2.650000	0	0	64	0	0	0
10	BMP	TON	14.90	-1.00	0.00	6.750000	0	0	63	0	0	0
11	SW	MBTU	1.00	-1.00	0.00	3.000000	0	0	67	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-----			LAG MIN	YEAR MAX	REQUIRED OPTION	
				FIRST YEAR	LAST YEAR			PLAN. ALT.	MULTIPLIER NO.	RETIRE. FLAG				RETIRE. OPTION
1	GE 7EA	350	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
2	GE 7EA 1x1	340	0	2018	2034	0	0	1	1	0	1 - YES	0	-1	0
3	SOLID WASTE	11	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
4	WIND20 MT	390	0	2017	2034	0	0	0	0	0	0 - NO	0	-1	0
5	CFBC	360	0	2020	2034	0	0	0	0	0	0 - NO	0	-1	0
6	GE LM6000PH	370	0	2017	2034	0	0	0	0	0	0 - NO	0	-1	0
7	PURCHASE POWER	310	0	2015	2034	1	0	0	0	0	0 - NO	0	-1	0
8	GE 7EA 2x1	12	0	2018	2034	0	5	0	0	0	0 - NO	0	-1	0
9	GE 7FA.05 1x1	18	0	2020	2034	0	0	0	0	0	0 - NO	0	-1	0
10	BIOMASS	19	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
11	CFBC CO2	24	0	2020	2034	0	0	0	0	0	0 - NO	0	-1	0
12	CONC SOLAR	22	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
13	GE LM6000PH SPRT	15	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
14	GE LMS100PB	14	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
15	GEO THERMAL	20	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
16	PV SOLAR	21	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
17	SOLAR TITAN	16	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
18	THERMAL SOLAR	23	0	2018	2034	0	0	0	0	0	0 - NO	0	-1	0
19	SMN SGT-800 3x1	25	0	2020	2034	0	0	0	0	0	0 - NO	0	-1	0
20	WIND20 ND	28	0	2017	2034	0	0	0	0	0	0 - NO	0	-1	0
21	TSW	6	0	2016	2016	0	0	0	0	0	0 - NO	0	-1	0
22	WIND50 MT	13	0	2017	2034	0	0	0	0	0	0 - NO	0	-1	0
23	TSW OWN PPA	9	0	2016	2016	0	0	0	0	0	0 - NO	0	-1	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				
24	WIND50 ND	27	0	2017	2034	0	0	0	0	0	0 - NO	0	-1	0
25	TSW PPA	26	0	2016	2016	0	0	0	0	0	0 - NO	0	-1	0
27	WRTSLA 20V34SG	17	0	2017	2034	0	0	0	0	0	0 - NO	0	-1	0
28	GE 7FA.05 2x1	29	0	2020	2034	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	2014	17.17	2015	4.83	2016	4.42	2017	3.25	2018	2.68
		2019	1.85	2020	1.85	2021	1.72	2022	1.49	2023	1.46
		2024	1.44	2025	1.42	2026	1.42	2027	1.40	2028	1.38
		2029	1.37	2030	1.38	2031	1.39	2032	1.36	2033	1.37
		2034	1.37								
2	1 - RATE	2014	9.63	2015	6.91	2016	6.17	2017	4.34	2018	3.46
		2019	2.26	2020	2.25	2021	2.05	2022	1.71	2023	1.68
		2024	1.66	2025	1.63	2026	1.63	2027	1.58	2028	1.58
		2029	1.58	2030	1.59	2031	1.59	2032	1.56	2033	1.57
		2034	1.56								
3	1 - RATE	2014	3.00								
4	1 - RATE	2014	100.00	2015	25.00	2016	20.00	2017	0.00		
5	1 - RATE	2015	3.00								
6	1 - RATE	2015	3.00								
7	1 - RATE	2014	3.00								
8	1 - RATE	2014	3.00								
9	1 - RATE	2014	3.00								
10	1 - RATE	2014	3.00								
11	1 - RATE	2014	3.00								
12	1 - RATE	2014	3.00								
13	1 - RATE	2014	3.00								
14	1 - RATE	2014	0.00								
15	1 - RATE	2014	3.00								
16	1 - RATE	2014	5.56	2015	5.26	2016	0.00				
17	1 - RATE	2014	-0.19	2015	-0.22	2016	-0.19	2017	-71.50	2018	-0.67
		2019	-126.60	2020	3.00						
18	1 - RATE	2014	1.55	2015	1.52	2016	1.50	2017	1.48	2018	1.46
		2019	1.50								
19	1 - RATE	2014	-0.19	2015	-0.22	2016	-0.19	2017	-0.19	2018	-0.22
		2019	-107.50	2020	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
20	1 - RATE	2014	141.66	2015	10.34	2016	0.00				
21	1 - RATE	2014	3.00								
22	1 - RATE	2015	3.00								
23	1 - RATE	2015	3.00								
24	1 - RATE	2015	3.00								
25	1 - RATE	2015	3.00								
26	1 - RATE	2015	3.00								
27	1 - RATE	2014	0.00								
28	1 - RATE	2014	0.00								
29	1 - RATE	2014	5.01	2015	5.00	2016	5.01	2017	5.00	2018	4.99
		2019	5.00	2020	5.01	2021	5.00	2022	5.00	2023	4.99
		2024	5.00	2025	5.00						
30	1 - RATE	2015	3.00								
31	1 - RATE	2014	3.00								
32	1 - RATE	2016	-0.62	2017	-6.83	2018	-0.94	2019	-0.98	2020	-0.99
		2021	-1.04	2022	-1.09	2023	-1.10	2024	-1.15	2025	-143.60
		2026	2.86	2027	2.87	2028	2.87	2029	2.88	2030	2.88
		2031	2.80	2032	2.88	2033	2.87	2034	2.94	2035	3.00
		2036	3.00								
33	1 - RATE	2014	-41.38	2015	11.49	2016	4.85	2017	8.67	2018	5.05
		2019	3.00								
34	1 - RATE	2014	-2.87	2015	1.48	2016	2.63	2017	4.80	2018	5.67
		2019	3.00								
35	1 - RATE	2014	1.09	2015	13.98	2016	11.32	2017	2.97	2018	3.29
		2019	3.00								
36	1 - RATE	2014	1.09	2015	13.98	2016	11.32	2017	2.97	2018	3.29
		2019	3.00								
37	1 - RATE	2014	4.52	2015	3.78	2016	3.65	2017	3.52	2018	3.88
		2019	3.00								
38	1 - RATE	2014	6.19	2015	3.59	2016	5.19	2017	2.88	2018	3.20
		2019	3.00								

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
39	1 - RATE	2014	0.69	2015	19.86	2016	8.57	2017	-0.53	2018	15.87
		2019	3.00								
40	1 - RATE	2014	0.00	2015	0.00	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	-19.64	2017	-19.24	2018	-21.82	2019	-23.87	2020	-22.95
		2021	-14.75	2022	-12.06	2023	-13.43	2024	-14.97	2025	553.96
		2026	-1.39	2027	-1.34	2028	-1.31	2029	-1.33	2030	-1.31
		2031	-1.24	2032	-1.15	2033	-1.21	2034	-1.11	2035	0.00
42	1 - RATE	2016	-1.15	2017	-2.50	2018	-2.50	2019	-2.49	2020	-2.52
		2021	-2.50	2022	-2.49	2023	-2.51	2024	-2.50	2025	85.85
		2026	2.01	2027	1.99	2028	2.00	2029	2.00	2030	2.00
		2031	1.99	2032	2.01	2033	2.01	2034	1.99	2035	0.00
43	1 - RATE	2015	3.00								
44	1 - RATE	2014	3.00								
45	1 - RATE	2016	0.00	2017	0.00	2018	41.30	2019	0.00	2020	0.00
46	1 - RATE	2014	4.98	2015	4.99	2016	4.99	2017	5.01	2018	4.99
		2019	5.01	2020	5.00	2021	5.00	2022	5.01	2023	4.99
		2024	5.00	2025	5.00						
47	1 - RATE	2016	0.00	2017	14.19	2018	0.00				
48	1 - RATE	2014	3.00								
49	1 - RATE	2014	0.00								
50	1 - RATE	2014	13.81	2015	5.62	2016	3.00				
51	1 - RATE	2014	135.75	2015	3.00	2016	3.00				
52	1 - RATE	2014	0.00	2015	0.00	2016	0.00				
53	1 - RATE	2014	0.00								
54	1 - RATE	2015	3.00								
55	1 - RATE	2015	3.00								
56	1 - RATE	2015	3.00								
58	1 - RATE	2015	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
59	1 - RATE	2015	3.00								
60	1 - RATE	2015	3.00								
61	1 - RATE	2015	3.00								
62	1 - RATE	2015	3.00								
63	1 - RATE	2014	3.00								
64	1 - RATE	2015	3.00								
66	1 - RATE	2015	3.00								
67	1 - RATE	2015	3.00								
68	1 - RATE	2015	3.00								
69	1 - RATE	2015	3.00								

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
1	3	1	0.555039	1.570753	1.000000
		2	0.348837	0.000131	0.000000
		3	0.096124	1.333596	0.000000
2	5	1	0.097087	3.476601	1.000000
		2	0.218447	0.859376	0.000000
		3	0.218447	0.670050	0.000000
		4	0.315534	0.660752	0.000000
		5	0.150485	0.796610	0.000000
3	5	1	0.320924	1.139992	1.000000
		2	0.159755	0.927543	0.000000
		3	0.150801	0.877789	0.000000
		4	0.226202	0.909759	0.000000
		5	0.142319	1.038580	0.000000
4	5	1	0.231579	1.518004	0.702715
		2	0.210526	1.214403	0.281086
		3	0.210526	1.092963	0.070271
		4	0.134737	1.207481	0.035136
		5	0.212632	0.000120	0.140543
5	5	1	0.258769	1.622222	1.000000
		2	0.172513	0.742222	0.000000
		3	0.172513	0.732000	0.000000
		4	0.230017	0.794222	0.000000
		5	0.166187	0.861745	0.000000
6	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
7	5	1	0.200000	1.000000	1.000000
		2	0.200000	1.000000	0.000000
		3	0.200000	1.000000	0.000000
		4	0.200000	1.000000	0.000000
		5	0.200000	1.000000	0.000000
8	2	1	0.700000	1.428571	1.000000
		2	0.300000	0.000012	0.000000
9	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

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
10	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000
11	5	1	0.232558	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
12	5	1	0.277778	1.662835	0.788532
		2	0.158730	0.693486	0.084189
		3	0.238095	0.745849	0.109583
		4	0.119048	0.784163	0.128755
		5	0.206349	0.761273	0.227864
13	5	1	0.245447	1.843637	1.000000
		2	0.220902	0.776611	0.000000
		3	0.196358	0.630358	0.000000
		4	0.196358	0.771900	0.000000
		5	0.140936	0.713700	0.000000
14	5	1	0.222603	1.101436	0.599018
		2	0.188356	0.600448	0.096709
		3	0.205479	0.568950	0.311778
		4	0.205479	0.991458	0.250524
		5	0.178082	1.803029	0.258642
15	5	1	0.392761	1.065317	0.689241
		2	0.197051	0.901553	0.136186
		3	0.134048	1.166787	0.304138
		4	0.134048	0.964457	0.225042
		5	0.142091	0.832163	0.289710
16	5	1	0.363289	1.161843	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	1.139987	1.000000
		2	0.157192	0.927498	0.000000
		3	0.148382	0.878013	0.000000
		4	0.222573	0.909747	0.000000
		5	0.156079	1.034476	0.000000

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
18	5	1	0.421348	1.123312	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
20	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
21	3	1	0.555039	1.570753	1.000000
		2	0.348837	0.000131	0.000000
		3	0.096124	1.333596	0.000000
22	2	1	0.700000	1.428571	1.000000
		2	0.300000	0.000012	0.000000
23	3	1	0.555039	1.570753	1.000000
		2	0.348837	0.000131	0.000000
		3	0.096124	1.333596	0.000000

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

DATA SET REF. NO.	CALENDAR YEAR	COMPOUNDING OPTION	AFUDC RATE
1	2015	1 - COMPOUND	10.50

CONSTRUCTION COST EXPENDITURE PATTERN

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

RETURN ON RATE BASE

DATA SET REFERENCE NUMBER 1 (DEFAULT)

CALENDAR YEAR	-----CAPITAL STRUCTURE-----			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						
2015	50.00	0.00	50.00	10.75	0.00	3.40	38.00	1.18	10.37

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

EGEAS EDIT VERSION 9.02

INDEX OF REPORTS

PAGE 85

CONTROL REPORT PAGE 1

MIRROR IMAGE REPORT PAGE 2

ERROR REPORT PAGE 31

DATA BASE CONTENTS
REPORT PAGE 33

Appendix B

EGEAS OUTPUT REPORT FOR THE BASE CASE

```

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

```

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

REPORT PROGRAM

Montana-Dakota Utilities Co.
2015 Model
Base Case Run
-- Data updated for the 2015 Model

RPI 1529

ELECTRIC POWER RESEARCH INSTITUTE
3412 HILL VIEW AVENUE
PALO ALTO, CALIFORNIA 94304

REPORT FILE OPTION 0 - STANDARD

REPORT OPTIONS

```

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

INPUT FILES	NAME	VERSION	UPDATE	RUN	CREATION DATE	CREATION TIME	DESCRIPTION	EGEAS VERS.
EGEAS DATA BASE	2015	1	0		6/18/15	11:13:32	2015 IRP	900
EXPANSION PLAN	2015	1	0	1	6/18/15	11:13:34	2015 IRP	900
SUBPERIOD REPORT	2015	1	0	1	6/18/15	11:13:34	2015 IRP	900
UNIT REPORT	2015	1	0	1	6/18/15	11:13:34	2015 IRP	900
UNIT CAPITAL COST REPORT	2015	1	0	1	6/18/15	11:13:34	2015 IRP	900

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	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	12	34567890
** COMMENT **	*	Montana-Dakota Utilities Co.									1	
	*	2015 Model									2	
	*	Base Case Run									3	
	*	-- Data updated for the 2015 Model									4	
	*	CONTROL RECORD									5	
	*	SbUnUcc									6	
	*										7	
	*	C M E S F									8	
	*	T I R E I									9	
	*	L R R L L									10	
	*	+ - + - +									11	
	*	DESCRIPTIVE INFORMATION									12	
CONTROL RECORD	RCC	1 1 3 1 0			2015						13	
** COMMENT **	*	--INPUT FILES--									14	
	*	NAME V U RUN									15	
	*	-----+-----									16	
	*										17	
FILE IDENTIFICATION	RFF	2015	1 0	1								18
** COMMENT **	*	== PLAN SELECTION ==									19	
	*	PLANS C O C E M									20	
	*	DR 1 L P M S N O									21	
	*	-----+-----									22	
	*	-----+-----									23	
PLAN SELECTION	RRA	1 1	1 0 1	3 2 0								24
** COMMENT **	*	== TIME PERIODS ==									25	
	*	--YEARS-- -SG- -SW-									26	
	*	1ST LAST 1 L 1 L									27	
	*	---- +---- -+ - +									28	
	*										29	
TIME PERIOD	RRB	2015 2034	113 1 3									30
** COMMENT **	*	== REPORT SELECTION ==									31	
	*	-PROD- MNT -STORAGE-- -FL -EM- -ECON INT- -COST-									32	
	*	S S S UOBRRSU DOSPD -PJ- SU SSU GCF TSTU CUT UCTCA									33	
	*	Y U YAFNRLEEYN EPWRS C 1 L YN YIN E+m RYIN OFF NOOOS									34	
	*	S M SRLTDKLSST TRKDP E 1 L ST STT NRT NSET PCT. TNTVT									35	
	*	- + -+-----+ +--+ -+--									36	
	*	- + -+-----+ +--+ -+--									37	
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	12	34567890	


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

 EGEAS REPORT VERSION 9.02 SELECTED REPORTS PAGE 5

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 = 2015 FIRST SEGMENT = 1 FIRST SUBWEEK = 1
 LAST YEAR = 2034 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 = 1 - ANNUAL
 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	NEW UNITS ADDED														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2015	0.	0.	1+	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2016	0.	0.	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	1+
2017	0	0	0	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	1	0+
2018	0	0	0	0	0	0	0.	0.	0	0	0	0.	0	0	0+
2019	1	0	1+	0	0	0	0.	0.	0	0	0	0.	0	0	0+
2020	0	0	0	0	0	0	0	0	0	0	0	1+	0	0	0+
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0+
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0+
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0+
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0+
2025	0	0	0.	0	0	0	0	0	0	0	0	0	0	0	0+
2026	0	0	0.	0	0	0	0	0	0	0	0	0	0	0	0+
2027	0	0	0.	0	0	0	0	0	0	0	0	0	0	0	0+
2028	0	0	0.	0	0	0	0	0	0	0	0	0	0	0	0+
2029	0	0	0.	0	0	0	0	0	0	0	0	0	0	0	0+
2030	0	0	0.	0	0	0	0	0	0	0	0	1+	0	0	0+
2031	0	0	0.	0	0	0	0	0	0	0	0	0+	0	0	0+
2032	0	0	0.	0	0	0	0	0	0	0	0	0+	0	0	0+
2033	0	0	0.	0	0	0	0	0	0	0	0	0+	0	0	0+
2034	0	0	0.	0	0	0	0	0	0	0	0	0+	0	0	0+

TOTAL COST, M\$
 --W/O EXT 2595.264
 --WITH EXT 4508.418

UNIT TYPES

1 PA 20 WIND20 ND	20.000 MW	2 PA 24 WIND50 ND	50.000 MW	3 PA 7 PURCHASE POWER	10.000 MW
4 PA 10 BIOMASS	29.900 MW	5 PA 16 PV SOLAR	30.000 MW	6 PA 3 SOLID WASTE	15.000 MW
7 PA 5 CFBC	30.000 MW	8 PA 11 CFBC CO2	30.000 MW	9 PA 1 GE 7EA	75.000 MW
10 PA 2 GE 7EA 1x1	127.600 MW	11 PA 8 GE 7EA 2x1	256.700 MW	12 PA 28 GE 7FA.05 2x1	200.000 MW
13 PA 27 WRTSLA 20V34SG	28.000 MW	14 PA 6 GE LM6000PH	37.300 MW	15 PA 23 TSW OWN PPA	107.500 MW

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2014.
 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
2015	0.00 .	0.00 .	1.00 +	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2016	0.00 .	0.00 .	0.00	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
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	1.00	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	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00 .	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	1.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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

UNIT TYPES

1 PA 20	WIND20 ND	20.000 MW	2 PA 24	WIND50 ND	50.000 MW	3 PA 7	PURCHASE POWER	10.000 MW
4 PA 10	BIOMASS	29.900 MW	5 PA 16	PV SOLAR	30.000 MW	6 PA 3	SOLID WASTE	15.000 MW
7 PA 5	CFBC	30.000 MW	8 PA 11	CFBC CO2	30.000 MW	9 PA 1	GE 7EA	75.000 MW
10 PA 2	GE 7EA 1x1	127.600 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12	13	14	15
2015	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .
2016	0.00 .	0.00 .	0.00 .	0.00 .	1.00 +
2017	0.00 .	0.00 .	0.00 .	1.00 .	0.00 +
2018	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2019	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2020	0.00 .	1.00 +	0.00 .	0.00 .	0.00 +
2021	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2022	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2023	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2024	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2025	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2026	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2027	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2028	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2029	0.00 .	0.00 .	0.00 .	0.00 .	0.00 +
2030	0.00 .	1.00 +	0.00 .	0.00 .	0.00 +
2031	0.00 .	0.00 +	0.00 .	0.00 .	0.00 +
2032	0.00 .	0.00 +	0.00 .	0.00 .	0.00 +
2033	0.00 .	0.00 +	0.00 .	0.00 .	0.00 +
2034	0.00 .	0.00 +	0.00 .	0.00 .	0.00 +
TOTAL	0.00	2.00	0.00	1.00	1.00

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

UNIT TYPES

11 PA 8	GE 7EA 2x1	256.700 MW	12 PA 28	GE 7FA.05 2x1	200.000 MW	13 PA 27	WRTSLA 20V34SG	28.000 MW
14 PA 6	GE LM6000PH	37.300 MW	15 PA 23	TSW OWN PPA	107.500 MW			

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2015	0.000	0.000	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
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	20.000	0.000	10.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	20.000	0.000	20.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

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

UNIT TYPES

1 PA 20	WIND20 ND	20.000 MW	2 PA 24	WIND50 ND	50.000 MW	3 PA 7	PURCHASE POWER	10.000 MW
4 PA 10	BIOMASS	29.900 MW	5 PA 16	PV SOLAR	30.000 MW	6 PA 3	SOLID WASTE	15.000 MW
7 PA 5	CFBC	30.000 MW	8 PA 11	CFBC CO2	30.000 MW	9 PA 1	GE 7EA	75.000 MW
10 PA 2	GE 7EA 1x1	127.600 MW						

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12	13	14	15
2015	0.000	0.000	0.000	0.000	0.000
2016	0.000	0.000	0.000	0.000	107.500
2017	0.000	0.000	0.000	37.300	0.000
2018	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000
2020	0.000	200.000	0.000	0.000	0.000
2021	0.000	0.000	0.000	0.000	0.000
2022	0.000	0.000	0.000	0.000	0.000
2023	0.000	0.000	0.000	0.000	0.000
2024	0.000	0.000	0.000	0.000	0.000
2025	0.000	0.000	0.000	0.000	0.000
2026	0.000	0.000	0.000	0.000	0.000
2027	0.000	0.000	0.000	0.000	0.000
2028	0.000	0.000	0.000	0.000	0.000
2029	0.000	0.000	0.000	0.000	0.000
2030	0.000	200.000	0.000	0.000	0.000
2031	0.000	0.000	0.000	0.000	0.000
2032	0.000	0.000	0.000	0.000	0.000
2033	0.000	0.000	0.000	0.000	0.000
2034	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	400.000	0.000	37.300	107.500

UNIT TYPES

11 PA 8	GE 7EA 2x1	256.700 MW	12 PA 28	GE 7FA.05 2x1	200.000 MW	13 PA 27	WRTSLA 20V34SG	28.000 MW
14 PA 6	GE LM6000PH	37.300 MW	15 PA 23	TSW OWN PPA	107.500 MW			

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	436.1	3250.70				744.8	532.5	23.13	1.0000			
2015	511.0	3563.67	115.6	107.8	5.8	758.4	546.7	7.36	99.9999	86.758	0.000	
2016	535.7	3809.87	178.8	62.3	3.3	878.2	577.9	8.32	99.9999	56.663	0.000	
2017	559.4	4044.76	37.3	0.0	2.5	918.0	617.3	10.96	99.9999	51.238	0.000	
2018	577.6	4220.26	0.0	0.0	0.0	918.0	619.5	7.67	99.9999	0.000	0.000	
2019	593.1	4366.26	30.0	0.0	0.0	948.0	633.7	7.22	80.7920	45.732	0.000	
2020	604.1	4464.85	200.0	39.2	0.0	1108.8	795.3	33.37	99.9999	171.981	0.000	
2021	615.3	4565.35	0.0	0.0	0.0	1108.8	795.3	30.81	99.9999	0.000	0.000	
2022	625.9	4659.15	0.0	0.0	0.0	1108.8	795.3	28.48	99.9999	0.000	0.000	
2023	635.2	4738.95	0.0	0.0	0.0	1108.8	795.3	26.50	99.9999	0.000	0.000	
2024	644.5	4818.54	0.0	0.0	0.0	1108.8	795.3	24.58	99.9999	0.000	0.000	
2025	653.8	4898.34	0.0	0.0	0.0	1108.8	795.3	22.72	99.9999	0.000	0.000	
2026	663.1	4978.24	0.0	52.3	0.0	1056.5	743.2	12.67	56.8574	0.000	0.000	
2027	672.5	5059.43	0.0	0.0	0.0	1056.5	743.2	11.02	62.6040	0.000	0.000	
2028	681.9	5139.13	0.0	0.0	0.0	1056.5	743.2	9.42	52.2777	0.000	0.000	
2029	691.3	5220.23	0.0	0.0	-19.5	1037.0	739.6	7.32	33.5086	0.000	0.000	
2030	700.8	5302.82	200.0	30.0	0.0	1207.0	925.4	33.53	99.9999	231.127	0.000	
2031	710.5	5386.92	0.0	0.0	0.0	1207.0	925.4	31.62	99.9999	0.000	0.000	
2032	720.4	5472.51	0.0	0.0	0.0	1207.0	925.4	29.73	99.9999	0.000	0.000	
2033	730.2	5558.01	0.0	0.0	0.0	1207.0	925.4	27.92	99.9999	0.000	0.000	
2034	740.2	5645.20	0.0	0.0	0.0	1207.0	925.4	26.11	99.9999	0.000	0.000	

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

YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2015	110.894	16.676	127.570	127.570	119.863	119.863
2016	132.840	23.415	156.254	283.824	137.944	257.807
2017	143.185	28.428	171.614	455.438	142.351	400.158
2018	155.449	28.428	183.877	639.315	143.308	543.466
2019	167.780	33.904	201.684	840.999	147.690	691.156
2020	160.583	50.234	210.817	1051.816	145.051	836.207
2021	167.130	50.234	217.363	1269.179	140.520	976.727
2022	175.617	50.234	225.851	1495.031	137.186	1113.913
2023	182.683	50.234	232.917	1727.947	132.930	1246.844
2024	191.198	50.234	241.432	1969.379	129.465	1376.309
2025	202.460	50.234	252.694	2222.073	127.318	1503.627
2026	231.292	47.670	278.961	2501.034	132.061	1635.688
2027	239.355	47.670	287.025	2788.059	127.669	1763.358
2028	251.050	47.670	298.720	3086.780	124.844	1888.202
2029	270.636	47.670	318.305	3405.085	124.992	2013.194
2030	263.715	69.615	333.331	3738.416	122.984	2136.178
2031	275.107	69.615	344.722	4083.138	119.503	2255.682
2032	288.038	69.615	357.653	4440.791	116.495	2372.177
2033	299.608	69.615	369.223	4810.014	112.998	2485.176
2034	313.229	69.615	382.845	5192.859	110.088	2595.264
EXT.	1661.837	251.318			1913.155	4508.419

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 2014.
 - 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	
2015	3560.56	0.00	0.00	0.00	0.00	0.00	3.11	3563.67
2016	3807.15	0.00	0.00	0.00	0.00	0.00	2.71	3809.87
2017	4043.37	0.00	0.00	0.00	0.00	0.00	1.40	4044.76
2018	4217.39	0.00	0.00	0.00	0.00	0.00	2.87	4220.26
2019	4361.27	0.00	0.00	0.00	0.00	0.00	4.98	4366.26
2020	4464.44	0.00	0.00	0.00	0.00	0.00	0.41	4464.85
2021	4564.75	0.00	0.00	0.00	0.00	0.00	0.60	4565.35
2022	4658.08	0.00	0.00	0.00	0.00	0.00	1.07	4659.15
2023	4737.83	0.00	0.00	0.00	0.00	0.00	1.11	4738.95
2024	4817.17	0.00	0.00	0.00	0.00	0.00	1.38	4818.54
2025	4894.94	0.00	0.00	0.00	0.00	0.00	3.40	4898.34
2026	4970.87	0.00	0.00	0.00	0.00	0.00	7.37	4978.24
2027	5052.71	0.00	0.00	0.00	0.00	0.00	6.72	5059.43
2028	5130.89	0.00	0.00	0.00	0.00	0.00	8.24	5139.13
2029	5206.43	0.00	0.00	0.00	0.00	0.00	13.80	5220.23
2030	5301.87	0.00	0.00	0.00	0.00	0.00	0.95	5302.82
2031	5385.66	0.00	0.00	0.00	0.00	0.00	1.26	5386.92
2032	5470.62	0.00	0.00	0.00	0.00	0.00	1.89	5472.51
2033	5556.02	0.00	0.00	0.00	0.00	0.00	1.99	5558.01
2034	5642.78	0.00	0.00	0.00	0.00	0.00	2.42	5645.20
EXT.	5642.78	0.00	0.00	0.00	0.00	0.00	2.42	5645.20

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
2015	67.351	22.629	20.497	0.000	0.000	0.000	0.000	0.000	0.417	110.894
2016	70.752	40.132	21.581	0.000	0.000	0.000	0.000	0.000	0.374	132.840
2017	81.622	37.554	23.811	0.000	0.000	0.000	0.000	0.000	0.198	143.185
2018	89.964	40.540	24.525	0.000	0.000	0.000	0.000	0.000	0.421	155.449
2019	98.193	42.474	26.361	0.000	0.000	0.000	0.000	0.000	0.751	167.780
2020	100.646	33.143	26.730	0.000	0.000	0.000	0.000	0.000	0.063	160.583
2021	108.658	30.844	27.532	0.000	0.000	0.000	0.000	0.000	0.096	167.130
2022	113.948	33.135	28.358	0.000	0.000	0.000	0.000	0.000	0.176	175.617
2023	121.567	31.717	29.209	0.000	0.000	0.000	0.000	0.000	0.189	182.683
2024	127.405	33.466	30.085	0.000	0.000	0.000	0.000	0.000	0.241	191.198
2025	134.691	36.170	30.988	0.000	0.000	0.000	0.000	0.000	0.612	202.460
2026	141.825	60.505	27.596	0.000	0.000	0.000	0.000	0.000	1.366	231.292
2027	148.754	60.895	28.424	0.000	0.000	0.000	0.000	0.000	1.282	239.355
2028	156.049	64.104	29.277	0.000	0.000	0.000	0.000	0.000	1.620	251.050
2029	166.289	72.070	29.483	0.000	0.000	0.000	0.000	0.000	2.794	270.636
2030	178.503	52.548	32.466	0.000	0.000	0.000	0.000	0.000	0.199	263.715
2031	189.811	51.586	33.440	0.000	0.000	0.000	0.000	0.000	0.270	275.107
2032	200.388	52.788	34.443	0.000	0.000	0.000	0.000	0.000	0.419	288.038
2033	209.762	53.918	35.476	0.000	0.000	0.000	0.000	0.000	0.453	299.608
2034	220.252	55.868	36.541	0.000	0.000	0.000	0.000	0.000	0.569	313.229
EXT.	1199.470	261.860	197.432	0.000	0.000	0.000	0.000	0.000	3.074	1661.837

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2014.

PLAN 1

YEARTOTAL SYSTEM.....		..FUEL CLASS - COAL..		..FUEL CLASS - PURC..		..FUEL CLASS - GAS ..	
	ENERGY, GWH	COST, M\$	ENERGY, GWH	COST, M\$	ENERGY, GWH	COST, M\$	ENERGY, GWH	COST, M\$
2015	3560.56	110.477	2201.31	72.506	531.21	18.716	644.11	23.088
2016	3807.15	132.465	2192.18	78.282	457.22	15.950	549.41	21.910
2017	4043.37	142.987	2317.62	86.177	461.49	16.429	655.92	27.965
2018	4217.38	155.028	2354.63	89.782	508.08	19.339	746.33	34.234
2019	4361.27	167.028	2233.34	90.989	549.35	24.160	901.72	42.312
2020	4464.44	160.520	2005.72	81.179	285.36	11.768	1496.49	56.952
2021	4564.75	167.034	2040.04	84.951	229.80	10.241	1618.04	62.934
2022	4658.08	175.441	2018.72	87.231	275.15	12.680	1687.35	67.432
2023	4737.83	182.494	2109.81	92.907	220.72	10.966	1730.43	71.062
2024	4817.16	190.957	2114.08	95.980	245.40	12.605	1780.82	75.337
2025	4894.94	201.849	2018.97	95.969	275.42	15.116	1923.68	84.230
2026	4970.87	229.926	1847.96	88.460	361.75	20.913	2084.29	95.639
2027	5052.71	238.073	1950.28	94.845	344.69	20.712	2080.87	97.818
2028	5130.89	249.430	1949.81	97.770	371.87	23.435	2132.35	103.723
2029	5206.43	267.841	1824.07	95.555	464.78	31.321	2307.53	117.530
2030	5301.87	263.517	1709.49	91.414	120.09	8.617	2965.02	141.580
2031	5385.66	274.837	1721.13	94.836	82.76	6.674	3074.51	151.660
2032	5470.62	287.619	1711.84	97.968	77.31	6.700	3174.21	161.504
2033	5556.02	299.156	1782.23	103.873	77.06	6.934	3189.47	167.100
2034	5642.78	312.660	1788.43	107.562	85.59	7.853	3261.50	176.202
EXT.	5642.78	1658.763	1788.43	581.170	62.23	35.148	3284.86	961.911

YEAR	..FUEL CLASS - WIND..		..FUEL CLASS - BMPFUEL CLASS - HYDR..		..FUEL CLASS - LIGN..	
	ENERGY, GWH	COST, M\$	ENERGY, GWH	COST, M\$	ENERGY, GWH	COST, M\$	ENERGY, GWH	COST, M\$
2015	169.61	-4.310	0.00	0.000	14.33	0.476	0.00	0.000
2016	594.01	15.847	0.00	0.000	14.33	0.476	0.00	0.000
2017	594.01	11.940	0.00	0.000	14.33	0.476	0.00	0.000
2018	594.01	11.196	0.00	0.000	14.33	0.476	0.00	0.000
2019	662.54	9.091	0.00	0.000	14.33	0.476	0.00	0.000
2020	662.54	10.144	0.00	0.000	14.33	0.476	0.00	0.000
2021	662.54	8.432	0.00	0.000	14.33	0.476	0.00	0.000
2022	662.54	7.622	0.00	0.000	14.33	0.476	0.00	0.000
2023	662.54	7.083	0.00	0.000	14.33	0.476	0.00	0.000
2024	662.54	6.558	0.00	0.000	14.33	0.476	0.00	0.000
2025	662.54	6.056	0.00	0.000	14.33	0.476	0.00	0.000
2026	662.54	24.438	0.00	0.000	14.33	0.476	0.00	0.000
2027	662.54	24.222	0.00	0.000	14.33	0.476	0.00	0.000
2028	662.54	24.025	0.00	0.000	14.33	0.476	0.00	0.000
2029	595.72	22.959	0.00	0.000	14.33	0.476	0.00	0.000
2030	492.93	21.429	0.00	0.000	14.33	0.476	0.00	0.000
2031	492.93	21.191	0.00	0.000	14.33	0.476	0.00	0.000
2032	492.93	20.970	0.00	0.000	14.33	0.476	0.00	0.000
2033	492.93	20.772	0.00	0.000	14.33	0.476	0.00	0.000
2034	492.93	20.566	0.00	0.000	14.33	0.476	0.00	0.000
EXT.	492.93	78.731	0.00	0.000	14.33	1.802	0.00	0.000

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2014.
 - COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1 YEAR 2015 * 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.	-3268.	684.	-2584.	-25.13
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	-2124.	397.	-1727.	-25.84
MISO - Off peak			50.000	10500.	0.000	98.59	430.63	0.	12157.	0.	12157.	28.23
LEWIS & CLARK	MUST		52.300	12680.	1.850	77.45	353.86	8301.	1527.	3122.	12950.	36.60
COYOTE	MUST		106.800	11921.	1.460	77.15	719.82	12528.	2076.	2816.	17420.	24.20
GLENDIVE CT #2			40.742	8282.	2.960	76.84	273.50	6706.	563.	394.	7663.	28.02
HESKETT #2	MUST		74.600	12515.	1.860	73.31	477.74	11121.	3120.	4300.	18540.	38.81
BIG STONE AQCS	MUST		105.600	10615.	2.230	59.55	549.35	13004.	2137.	3002.	18143.	33.03
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	57.32	37.56	0.	271.	401.	672.	17.91
HESKETT #3			88.000	11418.	2.960	39.56	304.15	10281.	627.	1095.	12002.	39.46
HESKETT #1	MUST		29.200	14755.	1.860	39.41	100.54	2759.	704.	1989.	5453.	54.23
GLENDIVE CT #1			34.780	11648.	2.960	18.93	57.50	1983.	115.	191.	2288.	39.80
MISO - On peak			50.000	10500.	0.000	12.74	55.66	0.	2160.	0.	2160.	38.81
PURCHASE POWER	2015		10.000	1.	0.000	3.68	3.22	0.	829.	358.	1187.	368.86
MILES CITY C.T.			25.200	13618.	2.960	3.46	7.61	307.	15.	271.	593.	77.99
DIESEL 2			2.100	11000.	24.400	2.62	0.48	129.	1.	60.	189.	394.75
DIESEL 3			2.100	11000.	24.400	2.49	0.46	122.	1.	60.	183.	401.31
DIESEL 1			2.000	11000.	24.400	2.36	0.41	111.	1.	57.	168.	408.37
INTERRUPTIBLES	D		15.200	1.	0.000	2.17	2.88	0.	863.	783.	1647.	572.25
COMMERCIAL DSM	D		10.000	1.	0.000	1.44	1.26	0.	377.	515.	893.	709.79

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

PLAN 1 YEAR 2016 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST \$/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL COST 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.	-3261.	705.	-2556.	-24.87
CEDAR HILLS			NDT	19.500	0.	0.000	39.22	66.81	0.	-2119.	409.	-1710.	-25.59
TSW OWN PPA		2016	NDT	107.500	0.	0.000	45.19	424.40	0.	20113.	0.	20113.	47.39
MISO - Off peak				50.000	10500.	0.000	87.40	381.76	0.	11315.	0.	11315.	29.64
BIG STONE AQCS			MUST	105.600	10619.	2.310	81.15	748.62	18363.	2999.	3171.	24533.	32.77
LEWIS & CLARKMAT			MUST	52.300	12682.	1.920	78.98	360.86	8786.	1604.	3215.	13606.	37.70
GLENDIVE CT #2				40.742	8313.	3.300	65.96	234.77	6441.	498.	406.	7345.	31.29
COYOTE			MUST	106.800	11785.	1.750	65.32	609.48	12570.	1810.	2901.	17281.	28.35
HESKETT #2			MUST	74.600	12654.	2.120	60.18	392.20	10521.	2638.	4429.	17588.	44.84
WAPA PUR-FT PECK			MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT			MUST	7.500	1.	0.000	57.32	37.56	0.	275.	413.	689.	18.34
LEWIS&CLARK RICE				19.000	8455.	3.300	46.92	77.88	2173.	265.	585.	3023.	38.81
HESKETT #1			MUST	29.200	15379.	2.120	31.76	81.01	2641.	584.	2049.	5274.	65.11
HESKETT #3				88.000	11480.	3.300	25.05	192.55	7295.	409.	1128.	8832.	45.87
GLENDIVE CT #1				34.780	11657.	3.300	12.33	37.48	1442.	77.	196.	1715.	45.77
MISO - On peak				50.000	10500.	0.000	7.89	34.48	0.	1405.	0.	1405.	40.75
MILES CITY C.T.				25.200	13642.	3.300	2.62	5.77	260.	12.	280.	551.	95.52
DIESEL 2				2.100	11000.	24.760	1.84	0.34	92.	1.	61.	154.	456.99
DIESEL 3				2.100	11000.	24.760	1.76	0.32	88.	1.	61.	150.	465.16
DIESEL 1				2.000	11000.	24.760	1.68	0.29	80.	1.	59.	139.	473.58
INTERRUPTIBLES			D	16.000	1.	0.000	1.59	2.22	0.	667.	849.	1517.	681.91
COMMERCIAL DSM			D	12.500	1.	0.000	1.10	1.20	0.	361.	664.	1024.	852.01

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.	-3254.	726.	-2529.	-24.60
CEDAR HILLS			NDT	19.500	0.	0.000	39.22	66.81	0.	-2115.	422.	-1694.	-25.35
TSW OWN PPA		2016	NDT	107.500	0.	0.000	45.19	424.40	0.	16162.	0.	16162.	38.08
MISO - Off peak				50.000	10500.	0.000	91.66	400.36	0.	12459.	0.	12459.	31.12
BIG STONE AQCS			MUST	105.600	10621.	2.430	84.82	782.44	20193.	3229.	3266.	26688.	34.11
LEWIS & CLARKMAT			MUST	52.300	12680.	1.990	80.74	368.91	9309.	1689.	3312.	14310.	38.79
GLENDIVE CT #2				40.742	8290.	3.460	76.58	272.57	7819.	596.	418.	8833.	32.41
COYOTE			MUST	106.800	11825.	1.900	75.08	700.47	15738.	2143.	2988.	20869.	29.79
HESKETT #2			MUST	74.600	12651.	2.360	60.20	392.32	11713.	2718.	4562.	18993.	48.41
WAPA PUR-FT PECK			MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
LEWIS&CLARK RICE				19.000	8435.	3.460	57.43	95.32	2782.	334.	602.	3718.	39.01
GLEN ULLIN ORMAT			MUST	7.500	1.	0.000	57.32	37.56	0.	279.	426.	705.	18.78
HESKETT #1			MUST	29.200	15341.	2.360	28.80	73.48	2660.	546.	2110.	5317.	72.36
HESKETT #3				88.000	11400.	3.460	27.58	212.03	8364.	463.	1162.	9989.	47.11
GE LM6000PH		2017		37.300	10515.	3.460	14.51	47.29	1721.	198.	1445.	3364.	71.13
GLENDIVE CT #1				34.780	11714.	3.460	8.11	24.64	999.	52.	202.	1253.	50.86
MISO - On peak				50.000	10500.	0.000	4.90	21.39	0.	915.	0.	915.	42.79
MILES CITY C.T.				25.200	13650.	3.460	1.59	3.50	165.	7.	288.	461.	131.59
DIESEL 2				2.100	11000.	25.410	1.08	0.20	56.	0.	63.	119.	600.28
DIESEL 3				2.100	11000.	25.410	1.04	0.19	53.	0.	63.	117.	614.32
DIESEL 1				2.000	11000.	25.410	1.01	0.18	49.	0.	60.	110.	624.81
INTERRUPTIBLES			D	16.000	1.	0.000	0.96	1.34	0.	402.	875.	1277.	953.24
COMMERCIAL DSM			D	15.000	1.	0.000	0.64	0.84	0.	252.	820.	1072.	1275.81

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

PLAN 1 YEAR 2018 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	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.	-928.	748.	-180.	-1.75
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2111.	434.	-1677.	-25.10
TSW OWN PPA		NDT	107.500	0.	0.000	45.19	424.40	0.	13053.	0.	13053.	30.76
MISO - Off peak			50.000	10500.	0.000	98.60	430.66	0.	14074.	0.	14074.	32.68
BIG STONE AQCS		MUST	105.600	10622.	2.500	83.46	769.97	20446.	3273.	3364.	27083.	35.17
COYOTE		MUST	106.800	11921.	1.890	77.15	719.82	16218.	2268.	3077.	21564.	29.96
LEWIS & CLARKMAT		MUST	52.300	12680.	2.060	74.15	338.80	8850.	1598.	3411.	13859.	40.91
GLENDIVE CT #2			40.742	8348.	3.760	71.08	252.98	7941.	569.	431.	8942.	35.34
HESKETT #2		MUST	74.600	12573.	2.430	66.67	434.50	13275.	3100.	4699.	21074.	48.50
LEWIS&CLARK RICE			19.000	8429.	3.760	59.36	98.53	3123.	355.	621.	4099.	41.60
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	284.	439.	722.	19.23
HESKETT #3			88.000	11180.	3.760	36.27	278.81	11721.	628.	1196.	13545.	48.58
HESKETT #1		MUST	29.200	14963.	2.430	35.89	91.54	3329.	701.	2174.	6203.	67.76
GE LM6000PH		2017	37.300	10425.	3.760	21.34	69.53	2726.	300.	1489.	4514.	64.93
GLENDIVE CT #1			34.780	11659.	3.760	12.98	39.45	1730.	86.	208.	2024.	51.31
MISO - On peak			50.000	10500.	0.000	8.22	35.92	0.	1614.	0.	1614.	44.93
MILES CITY C.T.			25.200	13619.	3.760	2.73	6.01	308.	13.	297.	617.	102.80
DIESEL 2			2.100	11000.	26.630	1.96	0.36	105.	1.	65.	171.	476.90
DIESEL 3			2.100	11000.	26.630	1.87	0.34	101.	1.	65.	167.	484.80
DIESEL 1			2.000	11000.	26.630	1.80	0.31	92.	1.	62.	155.	493.00
INTERRUPTIBLES		D	16.000	1.	0.000	1.72	2.41	0.	722.	901.	1623.	674.62
COMMERCIAL DSM		D	15.000	1.	0.000	1.18	1.54	0.	462.	845.	1307.	848.59

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PLAN 1 YEAR 2019 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	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.	-921.	770.	-151.	-1.47
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2107.	447.	-1659.	-24.83
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	697.	697.	10.17
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	10205.	0.	10205.	24.04
MISO - Off peak			50.000	10500.	0.000	99.83	436.04	0.	14960.	0.	14960.	34.31
LEWIS & CLARKMAT		MUST	52.300	12680.	2.140	79.10	361.38	9807.	1755.	3514.	15075.	41.72
BIG STONE AQCS		MUST	105.600	10622.	2.580	76.92	709.58	19446.	3107.	3465.	26017.	36.67
GLENDIVE CT #2			40.742	8320.	3.950	74.59	265.48	8726.	616.	444.	9785.	36.86
COYOTE		MUST	106.800	11841.	2.190	67.86	633.14	16418.	2055.	3170.	21642.	34.18
LEWIS&CLARK RICE			19.000	8406.	3.950	66.32	110.08	3655.	409.	639.	4703.	42.73
HESKETT #2		MUST	74.600	12531.	2.510	66.29	432.04	13588.	3175.	4840.	21603.	50.00
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	288.	452.	739.	19.69
HESKETT #3			88.000	10894.	3.950	45.31	348.29	14989.	808.	1232.	17029.	48.89
HESKETT #1		MUST	29.200	14944.	2.510	38.11	97.20	3646.	766.	2239.	6651.	68.42
GE LM6000PH	2017		37.300	10310.	3.950	31.23	101.77	4145.	452.	1533.	6130.	60.24
GLENDIVE CT #1			34.780	11571.	3.950	20.82	63.26	2892.	142.	214.	3249.	51.35
MISO - On peak			50.000	10500.	0.000	14.88	64.98	0.	3065.	0.	3065.	47.17
MILES CITY C.T.			25.200	13598.	3.950	5.49	12.08	649.	27.	306.	982.	81.27
PURCHASE POWER	2019		10.000	1.	0.000	4.25	3.71	0.	1075.	403.	1479.	398.56
INTERRUPTIBLES		D	16.000	1.	0.000	3.08	4.31	0.	1292.	928.	2220.	515.59
COMMERCIAL DSM		D	15.000	1.	0.000	2.10	2.75	0.	826.	870.	1696.	615.91
DIESEL 2			2.100	11000.	28.140	1.45	0.27	82.	1.	67.	150.	563.91
DIESEL 3			2.100	11000.	28.140	1.39	0.26	79.	1.	67.	147.	575.02
DIESEL 1			2.000	11000.	28.140	1.33	0.23	72.	1.	64.	137.	586.31

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.	245.	793.	1038.	10.10
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	158.	461.	619.	9.26
WIND20 ND	2019 NDT		20.000	0.	0.000	39.22	68.53	0.	0.	718.	718.	10.47
TSW OWN PPA	2016 NDT		107.500	0.	0.000	45.19	424.40	0.	7769.	0.	7769.	18.31
BIG STONE AQCS	MUST		105.600	10603.	2.657	81.27	749.73	21124.	3381.	3569.	28074.	37.45
LEWIS & CLARKMAT	MUST		52.300	12733.	2.204	76.08	347.62	9756.	1739.	3619.	15114.	43.48
GE 7FA.05 2x1	2020		200.000	6917.	4.069	74.77	1306.42	36767.	5240.	2300.	44308.	33.92
COYOTE	MUST		106.800	11492.	2.256	68.65	640.52	16604.	2141.	3265.	22010.	34.36
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	57.32	37.56	0.	292.	465.	757.	20.16
MISO - Off peak			50.000	10500.	0.000	55.67	243.14	0.	8760.	0.	8760.	36.03
HESKETT #2	MUST		74.600	12951.	2.585	41.10	267.85	8969.	2028.	4985.	15981.	59.66
GLENDIVE CT #2			40.742	8586.	4.069	29.12	103.66	3621.	248.	457.	4326.	41.74
LEWIS&CLARK RICE			19.000	8546.	4.069	18.16	30.15	1048.	115.	658.	1822.	60.44
HESKETT #3			88.000	12203.	4.069	5.64	43.35	2153.	104.	1269.	3525.	81.32
GE LM6000PH	2017		37.300	10589.	4.069	2.42	7.89	340.	36.	1579.	1955.	247.81
GLENDIVE CT #1			34.780	11686.	4.069	1.38	4.19	199.	10.	221.	430.	102.58
MISO - On peak			50.000	10500.	0.000	0.91	3.99	0.	198.	0.	198.	49.53
MILES CITY C.T.			25.200	13568.	4.069	0.35	0.77	42.	2.	315.	359.	467.46
INTERRUPTIBLES	D		16.000	1.	0.000	0.29	0.41	0.	122.	956.	1078.	2655.96
COMMERCIAL DSM	D		15.000	1.	0.000	0.20	0.26	0.	79.	896.	975.	3713.09
DIESEL 2			2.100	11000.	28.984	0.13	0.02	8.	0.	69.	77.	3130.68
DIESEL 3			2.100	11000.	28.984	0.13	0.02	7.	0.	69.	77.	3263.07
DIESEL 1			2.000	11000.	28.984	0.12	0.02	7.	0.	66.	73.	3398.77

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
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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.	252.	817.	1069.	10.40
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	163.	475.	637.	9.54
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	739.	739.	10.79
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	5986.	0.	5986.	14.10
BIG STONE AQCS		MUST	105.600	10606.	2.737	80.40	741.68	21532.	3445.	3676.	28653.	38.63
LEWIS & CLARKMAT		MUST	52.300	12722.	2.270	77.02	351.91	10164.	1813.	3727.	15705.	44.63
GE 7FA.05 2x1	2020		200.000	6845.	4.191	76.11	1329.85	38147.	5494.	2369.	46010.	34.60
COYOTE		MUST	106.800	11514.	2.323	69.04	644.14	17232.	2218.	3363.	22812.	35.42
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	302.	479.	782.	20.40
GLENDIVE CT #2			40.742	8478.	4.191	50.80	180.82	6425.	445.	471.	7341.	40.60
HESKETT #2		MUST	74.600	12782.	2.663	46.39	302.31	10289.	2357.	5134.	17781.	58.82
MISO - Off peak			50.000	10500.	0.000	42.48	185.54	0.	7019.	0.	7019.	37.83
LEWIS&CLARK RICE			19.000	8529.	4.191	21.73	36.06	1289.	142.	678.	2109.	58.49
HESKETT #3			88.000	12117.	4.191	7.13	54.82	2784.	135.	1307.	4226.	77.09
GE LM6000PH	2017		37.300	10593.	4.191	3.09	10.08	448.	48.	1627.	2122.	210.46
GLENDIVE CT #1			34.780	11691.	4.191	1.75	5.30	260.	13.	228.	500.	94.30
MISO - On peak			50.000	10500.	0.000	1.16	5.06	0.	263.	0.	263.	52.01
MILES CITY C.T.			25.200	13539.	4.191	0.45	1.00	57.	2.	324.	383.	384.14
INTERRUPTIBLES		D	16.000	1.	0.000	0.39	0.54	0.	162.	985.	1147.	2121.49
COMMERCIAL DSM		D	15.000	1.	0.000	0.27	0.36	0.	107.	923.	1031.	2878.41
DIESEL 2			2.100	11000.	29.854	0.19	0.03	11.	0.	71.	83.	2420.45
DIESEL 3			2.100	11000.	29.854	0.18	0.03	11.	0.	71.	82.	2512.74
DIESEL 1			2.000	11000.	29.854	0.17	0.03	10.	0.	68.	78.	2607.19

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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 COST 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.	260.	841.	1101.	10.71
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	168.	489.	656.	9.83
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	762.	762.	11.11
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	5103.	0.	5103.	12.02
BIG STONE AQCS		MUST	105.600	10611.	2.819	81.21	749.20	22412.	3584.	3786.	29782.	39.75
GE 7FA.05 2x1	2020		200.000	6768.	4.317	77.35	1351.47	39486.	5751.	2440.	47677.	35.28
LEWIS & CLARKMAT		MUST	52.300	12710.	2.338	76.48	349.42	10385.	1855.	3839.	16079.	46.02
COYOTE		MUST	106.800	11561.	2.393	62.90	586.86	16236.	2082.	3463.	21781.	37.12
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	301.	494.	794.	21.15
MISO - Off peak			50.000	10500.	0.000	52.36	228.69	0.	9084.	0.	9084.	39.72
GLENDIVE CT #2			40.742	8423.	4.317	51.14	182.02	6618.	461.	485.	7565.	41.56
HESKETT #2		MUST	74.600	12718.	2.743	51.13	333.23	11624.	2676.	5288.	19588.	58.78
LEWIS&CLARK RICE			19.000	8504.	4.317	28.67	47.58	1747.	193.	698.	2638.	55.45
HESKETT #3			88.000	11950.	4.317	10.58	81.35	4196.	206.	1347.	5749.	70.67
GE LM6000PH	2017		37.300	10597.	4.317	4.72	15.39	704.	75.	1675.	2454.	159.45
GLENDIVE CT #1			34.780	11703.	4.317	2.59	7.88	398.	19.	234.	652.	82.74
MISO - On peak			50.000	10500.	0.000	1.71	7.47	0.	408.	0.	408.	54.61
MILES CITY C.T.			25.200	13503.	4.317	0.68	1.50	88.	4.	334.	425.	283.07
INTERRUPTIBLES		D	16.000	1.	0.000	0.61	0.85	0.	255.	1014.	1269.	1493.99
COMMERCIAL DSM		D	15.000	1.	0.000	0.44	0.58	0.	174.	951.	1125.	1939.62
DIESEL 2			2.100	11000.	30.749	0.31	0.06	19.	0.	73.	93.	1634.05
DIESEL 3			2.100	11000.	30.749	0.30	0.05	18.	0.	73.	92.	1686.06
DIESEL 1			2.000	11000.	30.749	0.29	0.05	17.	0.	70.	87.	1719.03

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.	268.	867.	1134.	11.04
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	173.	504.	676.	10.12
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	784.	784.	11.45
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	4488.	0.	4488.	10.57
BIG STONE AQCS		MUST	105.600	10611.	2.904	82.86	764.41	23553.	3767.	3900.	31220.	40.84
GE 7FA.05 2x1	2020		200.000	6761.	4.446	77.50	1354.00	40700.	5935.	2513.	49148.	36.30
LEWIS & CLARKMAT		MUST	52.300	12708.	2.409	76.64	350.16	10718.	1914.	3954.	16587.	47.37
COYOTE		MUST	106.800	11670.	2.465	71.94	671.18	19307.	2452.	3567.	25326.	37.73
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	305.	508.	814.	21.67
GLENDIVE CT #2			40.742	8428.	4.446	57.27	203.83	7638.	532.	500.	8670.	42.54
HESKETT #2		MUST	74.600	12722.	2.825	49.73	324.06	11647.	2681.	5447.	19774.	61.02
LEWIS&CLARK RICE			19.000	8461.	4.446	43.63	72.43	2725.	303.	719.	3747.	51.73
MISO - Off peak			50.000	10500.	0.000	39.87	174.16	0.	7264.	0.	7264.	41.71
HESKETT #3			88.000	11939.	4.446	9.97	76.61	4067.	200.	1387.	5654.	73.80
GE LM6000PH	2017		37.300	10584.	4.446	4.51	14.69	691.	73.	1726.	2490.	169.54
GLENDIVE CT #1			34.780	11682.	4.446	2.37	7.20	374.	18.	241.	634.	87.99
MISO - On peak			50.000	10500.	0.000	1.73	7.56	0.	434.	0.	434.	57.34
MILES CITY C.T.			25.200	13506.	4.446	0.69	1.52	91.	4.	344.	439.	288.51
INTERRUPTIBLES		D	16.000	1.	0.000	0.61	0.85	0.	256.	1045.	1300.	1526.18
COMMERCIAL DSM		D	15.000	1.	0.000	0.45	0.58	0.	175.	979.	1155.	1976.26
DIESEL 2			2.100	11000.	31.672	0.31	0.06	20.	0.	76.	96.	1676.38
DIESEL 3			2.100	11000.	31.672	0.30	0.05	19.	0.	76.	95.	1729.02
DIESEL 1			2.000	11000.	31.672	0.29	0.05	18.	0.	72.	90.	1781.94

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.	276.	893.	1168.	11.37
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	178.	519.	696.	10.42
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	808.	808.	11.79
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	3885.	0.	3885.	9.15
BIG STONE AQCS		MUST	105.600	10613.	2.991	80.10	738.93	23456.	3750.	4017.	31223.	42.25
LEWIS & CLARKMAT		MUST	52.300	12702.	2.481	78.77	359.91	11341.	2027.	4073.	17441.	48.46
GE 7FA.05 2x1	2020		200.000	6727.	4.580	77.97	1362.33	41968.	6150.	2589.	50706.	37.22
COYOTE		MUST	106.800	11702.	2.539	72.56	676.95	20111.	2547.	3674.	26333.	38.90
GLENDIVE CT #2			40.742	8406.	4.580	60.63	215.80	8308.	580.	515.	9403.	43.57
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	310.	524.	834.	22.19
HESKETT #2		MUST	74.600	12689.	2.910	51.91	338.28	12490.	2882.	5610.	20983.	62.03
LEWIS&CLARK RICE			19.000	8465.	4.580	47.74	79.24	3072.	341.	741.	4154.	52.42
MISO - Off peak			50.000	10500.	0.000	45.15	197.22	0.	8636.	0.	8636.	43.79
HESKETT #3			88.000	11851.	4.580	12.17	93.58	5079.	252.	1429.	6759.	72.22
GE LM6000PH	2017		37.300	10575.	4.580	5.63	18.33	888.	94.	1777.	2760.	150.54
GLENDIVE CT #1			34.780	11703.	4.580	3.14	9.53	511.	25.	249.	784.	82.29
MISO - On peak			50.000	10500.	0.000	2.04	8.91	0.	537.	0.	537.	60.20
MILES CITY C.T.			25.200	13502.	4.580	0.82	1.80	111.	5.	354.	470.	261.23
INTERRUPTIBLES		D	16.000	1.	0.000	0.73	1.01	0.	304.	1076.	1380.	1360.59
COMMERCIAL DSM		D	15.000	1.	0.000	0.53	0.70	0.	210.	1009.	1219.	1740.37
DIESEL 2			2.100	11000.	32.622	0.38	0.07	25.	0.	78.	103.	1492.49
DIESEL 3			2.100	11000.	32.622	0.36	0.07	24.	0.	78.	102.	1535.52
DIESEL 1			2.000	11000.	32.622	0.35	0.06	22.	0.	74.	96.	1579.22

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.	284.	919.	1204.	11.71
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	183.	534.	717.	10.74
WIND20 ND	2019 NDT		20.000	0.	0.000	39.22	68.53	0.	0.	832.	832.	12.14
TSW OWN PPA	2016 NDT		107.500	0.	0.000	45.19	424.40	0.	3303.	0.	3303.	7.78
GE 7FA.05 2x1	2020		200.000	6661.	4.717	78.82	1377.06	43270.	6403.	2666.	52339.	38.01
LEWIS & CLARKMAT	MUST		52.300	12690.	2.555	76.59	349.93	11347.	2030.	4195.	17572.	50.22
COYOTE	MUST		106.800	11778.	2.615	74.10	691.33	21293.	2679.	3785.	27757.	40.15
GLENDIVE CT #2			40.742	8363.	4.717	68.12	242.44	9564.	671.	530.	10765.	44.40
HESKETT #2	MUST		74.600	12577.	2.997	65.35	425.88	16053.	3738.	5779.	25569.	60.04
BIG STONE AQCS	MUST		105.600	10617.	3.081	59.82	551.83	18049.	2885.	4137.	25071.	45.43
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
LEWIS&CLARK RICE			19.000	8425.	4.717	58.24	96.67	3842.	429.	763.	5034.	52.07
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	57.32	37.56	0.	315.	539.	854.	22.74
MISO - Off peak			50.000	10500.	0.000	49.79	217.47	0.	9999.	0.	9999.	45.98
HESKETT #3			88.000	11504.	4.717	19.84	152.49	8275.	422.	1471.	10168.	66.68
GE LM6000PH	2017		37.300	10512.	4.717	10.39	33.84	1678.	180.	1831.	3688.	108.99
GLENDIVE CT #1			34.780	11684.	4.717	5.93	18.02	993.	48.	256.	1298.	72.02
MISO - On peak			50.000	10500.	0.000	3.87	16.90	0.	1068.	0.	1068.	63.21
INTERRUPTIBLES	D		16.000	1.	0.000	1.46	2.04	0.	612.	1108.	1720.	843.28
MILES CITY C.T.			25.200	13446.	4.717	1.24	2.74	174.	7.	365.	546.	199.43
COMMERCIAL DSM	D		15.000	1.	0.000	1.11	1.45	0.	436.	1039.	1475.	1015.15
DIESEL 2			2.100	11000.	33.601	0.80	0.15	54.	0.	80.	135.	921.73
DIESEL 3			2.100	11000.	33.601	0.77	0.14	52.	0.	80.	133.	940.11
DIESEL 1			2.000	11000.	33.601	0.74	0.13	48.	0.	76.	125.	962.10

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

PLAN 1 YEAR 2026 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST \$/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION COST K\$	\$/MWH
DIAMOND WILLOW	NDT		30.000	0.	0.000	39.22	102.79	0.	293.	947.	1240.	12.06
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	189.	550.	739.	11.06
WIND20 ND	2019 NDT		20.000	0.	0.000	39.22	68.53	0.	0.	857.	857.	12.51
TSW OWN PPA	2016 NDT		107.500	0.	0.000	45.19	424.40	0.	21602.	0.	21602.	50.90
BIG STONE AQCS	MUST		105.600	10621.	3.173	81.61	752.90	25374.	4054.	4262.	33689.	44.75
GE 7FA.05 2x1	2020		200.000	6637.	4.858	79.12	1382.30	44571.	6620.	2746.	53938.	39.02
HESKETT #2	MUST		74.600	12525.	3.087	73.01	475.78	18396.	4301.	5952.	28649.	60.21
LEWIS&CLARK RICE			19.000	8398.	4.858	67.35	111.78	4561.	511.	786.	5858.	52.40
MISO - Off peak			50.000	10500.	0.000	66.93	292.37	0.	14115.	0.	14115.	48.28
COYOTE	MUST		106.800	11842.	2.693	66.37	619.28	19752.	2472.	3898.	26122.	42.18
GLENDIVE CT #2			40.742	8324.	4.858	64.59	229.88	9297.	655.	546.	10498.	45.67
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	57.32	37.56	0.	319.	556.	875.	23.29
HESKETT #3			88.000	11174.	4.858	31.64	243.23	13205.	694.	1516.	15414.	63.37
GE LM6000PH	2017		37.300	10398.	4.858	19.06	62.10	3137.	340.	1886.	5362.	86.35
GLENDIVE CT #1			34.780	11615.	4.858	11.85	36.00	2031.	100.	264.	2395.	66.53
MILES CITY C.T.			25.200	13475.	4.858	8.26	18.19	1191.	50.	376.	1617.	88.89
MISO - On peak			50.000	10500.	0.000	5.72	24.97	0.	1657.	0.	1657.	66.37
INTERRUPTIBLES	D		16.000	1.	0.000	2.88	4.03	0.	1208.	1142.	2350.	583.41
COMMERCIAL DSM	D		15.000	1.	0.000	2.15	2.82	0.	846.	1070.	1916.	679.62
DIESEL 2			2.100	11000.	34.609	1.55	0.28	108.	1.	83.	192.	673.76
DIESEL 3			2.100	11000.	34.609	1.50	0.28	105.	1.	83.	188.	683.34
DIESEL 1			2.000	11000.	34.609	1.45	0.25	97.	1.	79.	176.	692.94

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.	301.	975.	1277.	12.42
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	194.	567.	761.	11.39
WIND20 ND	2019 NDT		20.000	0.	0.000	39.22	68.53	0.	0.	883.	883.	12.88
TSW OWN PPA	2016 NDT		107.500	0.	0.000	45.19	424.40	0.	21301.	0.	21301.	50.19
BIG STONE AQCS	MUST		105.600	10621.	3.268	84.95	783.70	27205.	4346.	4389.	35940.	45.86
GE 7FA.05 2x1	2020		200.000	6633.	5.004	79.16	1383.12	45908.	6823.	2829.	55560.	40.17
COYOTE	MUST		106.800	11844.	2.774	75.46	704.08	23134.	2895.	4015.	30044.	42.67
GLENDIVE CT #2			40.742	8320.	5.004	73.93	263.14	10956.	773.	562.	12291.	46.71
HESKETT #2	MUST		74.600	12529.	3.180	70.97	462.50	18424.	4306.	6131.	28861.	62.40
LEWIS&CLARK RICE			19.000	8404.	5.004	66.57	110.50	4647.	520.	810.	5977.	54.09
MISO - Off peak			50.000	10500.	0.000	63.74	278.42	0.	14114.	0.	14114.	50.69
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT	MUST		7.500	1.	0.000	57.32	37.56	0.	324.	572.	896.	23.86
HESKETT #3			88.000	11229.	5.004	28.55	219.50	12334.	645.	1561.	14540.	66.24
GE LM6000PH	2017		37.300	10404.	5.004	16.94	55.21	2874.	311.	1942.	5127.	92.88
GLENDIVE CT #1			34.780	11614.	5.004	10.55	32.05	1863.	91.	272.	2226.	69.45
MILES CITY C.T.			25.200	13482.	5.004	7.55	16.62	1121.	47.	387.	1556.	93.60
MISO - On peak			50.000	10500.	0.000	5.16	22.53	0.	1570.	0.	1570.	69.69
INTERRUPTIBLES	D		16.000	1.	0.000	2.58	3.61	0.	1082.	1176.	2258.	625.99
COMMERCIAL DSM	D		15.000	1.	0.000	1.96	2.57	0.	771.	1102.	1873.	728.84
DIESEL 2			2.100	11000.	35.647	1.38	0.25	99.	1.	85.	185.	731.06
DIESEL 3			2.100	11000.	35.647	1.34	0.25	96.	1.	85.	182.	741.80
DIESEL 1			2.000	11000.	35.647	1.33	0.23	91.	1.	81.	173.	743.19

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.

- EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

PLAN 1 YEAR 2028 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	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.	310.	1005.	1315.	12.79
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	200.	584.	784.	11.73
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	909.	909.	13.27
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	21017.	0.	21017.	49.52
BIG STONE AQCS		MUST	105.600	10622.	3.366	83.42	769.54	27516.	4396.	4521.	36433.	47.34
GE 7FA.05 2x1	2020		200.000	6631.	5.154	79.18	1383.48	47286.	7030.	2914.	57229.	41.37
COYOTE		MUST	106.800	11860.	2.857	75.82	707.44	23976.	2996.	4136.	31107.	43.97
GLENDIVE CT #2			40.742	8313.	5.154	75.05	267.10	11445.	808.	579.	12832.	48.04
HESKETT #2		MUST	74.600	12517.	3.275	72.55	472.82	19382.	4534.	6314.	30230.	63.94
LEWIS&CLARK RICE			19.000	8398.	5.154	68.67	113.98	4934.	552.	834.	6320.	55.45
MISO - Off peak			50.000	10500.	0.000	68.61	299.67	0.	15951.	0.	15951.	53.23
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	329.	589.	918.	24.45
HESKETT #3			88.000	11153.	5.154	31.89	245.13	14092.	742.	1608.	16441.	67.07
GE LM6000PH	2017		37.300	10379.	5.154	19.57	63.77	3411.	370.	2000.	5782.	90.67
GLENDIVE CT #1			34.780	11603.	5.154	12.70	38.58	2307.	113.	280.	2700.	70.00
MILES CITY C.T.			25.200	13460.	5.154	8.82	19.43	1348.	57.	399.	1803.	92.84
MISO - On peak			50.000	10500.	0.000	6.23	27.21	0.	1991.	0.	1991.	73.17
INTERRUPTIBLES		D	16.000	1.	0.000	3.12	4.37	0.	1310.	1211.	2521.	577.33
COMMERCIAL DSM		D	15.000	1.	0.000	2.34	3.06	0.	919.	1135.	2054.	670.58
DIESEL 2			2.100	11000.	36.716	1.67	0.31	124.	1.	88.	212.	693.02
DIESEL 3			2.100	11000.	36.716	1.61	0.30	120.	1.	88.	208.	702.77
DIESEL 1			2.000	11000.	36.716	1.56	0.27	110.	1.	83.	195.	712.15

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

PLAN 1 YEAR 2029 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	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	10.500	0.	0.000	39.22	35.98	0.	112.	362.	474.	13.18
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	206.	601.	807.	12.08
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	937.	937.	13.67
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	20741.	0.	20741.	48.87
MISO - Off peak			50.000	10500.	0.000	84.46	368.94	0.	20619.	0.	20619.	55.89
GE 7FA.05 2x1	2020		200.000	6631.	5.309	79.18	1383.48	48704.	7241.	3001.	58946.	42.61
BIG STONE AQCS		MUST	105.600	10622.	3.467	76.92	709.58	26134.	4175.	4657.	34965.	49.28
GLENDIVE CT #2			40.742	8284.	5.309	76.78	273.29	12019.	852.	597.	13467.	49.28
LEWIS&CLARK RICE			19.000	8378.	5.309	73.60	122.16	5434.	610.	859.	6902.	56.50
HESKETT #2		MUST	74.600	12486.	3.373	72.06	469.64	19780.	4639.	6504.	30923.	65.84
COYOTE		MUST	106.800	11905.	2.943	69.12	644.85	22594.	2813.	4260.	29667.	46.01
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	334.	607.	941.	25.05
HESKETT #3			88.000	10987.	5.309	44.51	342.18	19959.	1066.	1656.	22681.	66.29
GE LM6000PH	2017		37.300	10333.	5.309	28.98	94.44	5181.	564.	2060.	7806.	82.65
GLENDIVE CT #1			34.780	11562.	5.309	19.43	59.04	3624.	179.	288.	4091.	69.29
MILES CITY C.T.			25.200	13420.	5.309	14.28	31.44	2240.	95.	411.	2746.	87.33
MISO - On peak			50.000	10500.	0.000	10.40	45.45	0.	3492.	0.	3492.	76.83
INTERRUPTIBLES		D	16.000	1.	0.000	5.42	7.57	0.	2272.	1247.	3520.	464.68
COMMERCIAL DSM		D	15.000	1.	0.000	4.02	5.27	0.	1580.	1169.	2749.	522.05
DIESEL 2			2.100	11000.	37.818	2.85	0.52	217.	2.	90.	309.	591.97
DIESEL 3			2.100	11000.	37.818	2.75	0.50	210.	2.	90.	302.	598.05
DIESEL 1			2.000	11000.	37.818	2.66	0.46	193.	1.	86.	281.	604.08

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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 COST K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION COST K\$	\$/MWH
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	965.	965.	14.08
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	20465.	0.	20465.	48.22
BIG STONE AQCS		MUST	105.600	10604.	3.571	81.48	751.67	28465.	4555.	4796.	37817.	50.31
GE 7FA.05 2x1	2020		200.000	6631.	5.468	79.18	1383.48	50165.	7458.	3091.	60714.	43.88
GE 7FA.05 2x1	2030		200.000	6918.	5.468	74.90	1308.62	49504.	7054.	3091.	59649.	45.58
COYOTE		MUST	106.800	11558.	3.031	69.83	651.53	22828.	2927.	4387.	30143.	46.26
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	339.	625.	964.	25.67
HESKETT #2		MUST	74.600	12816.	3.474	47.00	306.29	13638.	3116.	6699.	23453.	76.57
GLENDIVE CT #2			40.742	8563.	5.468	45.40	161.59	7566.	519.	615.	8699.	53.83
LEWIS&CLARK RICE			19.000	8529.	5.468	28.66	47.57	2219.	245.	885.	3348.	70.38
MISO - Off peak			50.000	10500.	0.000	17.98	78.53	0.	4608.	0.	4608.	58.68
HESKETT #3			88.000	11767.	5.468	6.36	48.89	3146.	157.	1706.	5009.	102.44
GE LM6000PH	2017		37.300	10712.	5.468	2.69	8.77	514.	54.	2122.	2690.	306.76
GLENDIVE CT #1			34.780	11788.	5.468	1.34	4.08	263.	13.	297.	573.	140.30
MILES CITY C.T.			25.200	13492.	5.468	0.86	1.88	139.	6.	423.	568.	301.39
MISO - On peak			50.000	10500.	0.000	0.68	2.95	0.	238.	0.	238.	80.67
INTERRUPTIBLES		D	16.000	1.	0.000	0.43	0.61	0.	182.	1285.	1466.	2422.97
COMMERCIAL DSM		D	15.000	1.	0.000	0.35	0.45	0.	136.	1204.	1340.	2959.39
DIESEL 2			2.100	11000.	38.952	0.25	0.05	19.	0.	93.	113.	2475.76
DIESEL 3			2.100	11000.	38.952	0.24	0.04	19.	0.	93.	112.	2542.80
DIESEL 1			2.000	11000.	38.952	0.24	0.04	18.	0.	89.	106.	2576.07

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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 COST K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION COST K\$	\$/MWH
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	994.	994.	14.50
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	20197.	0.	20197.	47.59
BIG STONE AQCS		MUST	105.600	10608.	3.678	80.74	744.84	29065.	4649.	4940.	38655.	51.90
GE 7FA.05 2x1	2020		200.000	6631.	5.632	79.18	1383.48	51670.	7681.	3184.	62535.	45.20
GE 7FA.05 2x1	2030		200.000	6846.	5.632	76.13	1330.10	51288.	7385.	3184.	61857.	46.51
COYOTE		MUST	106.800	11583.	3.122	70.29	655.84	23720.	3035.	4519.	31274.	47.69
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	58.47	38.31	0.	351.	644.	995.	25.97
GLENDIVE CT #2			40.742	8531.	5.632	50.67	180.36	8666.	596.	633.	9895.	54.86
HESKETT #2		MUST	74.600	12774.	3.579	49.17	320.45	14649.	3358.	6900.	24907.	77.73
LEWIS&CLARK RICE			19.000	8523.	5.632	33.70	55.94	2686.	296.	911.	3893.	69.59
HESKETT #3			88.000	11419.	5.632	13.74	105.64	6794.	349.	1757.	8901.	84.25
MISO - Off peak			50.000	10500.	0.000	9.10	39.76	0.	2450.	0.	2450.	61.62
GE LM6000PH	2017		37.300	10657.	5.632	3.40	11.09	666.	70.	2186.	2922.	263.51
GLENDIVE CT #1			34.780	11799.	5.632	1.76	5.36	356.	17.	306.	679.	126.77
MILES CITY C.T.			25.200	13557.	5.632	1.08	2.37	181.	8.	436.	625.	263.05
MISO - On peak			50.000	10500.	0.000	0.79	3.45	0.	292.	0.	292.	84.70
INTERRUPTIBLES		D	16.000	1.	0.000	0.50	0.70	0.	211.	1323.	1534.	2185.12
COMMERCIAL DSM		D	15.000	1.	0.000	0.41	0.54	0.	162.	1241.	1403.	2595.43
DIESEL 2			2.100	11000.	40.121	0.31	0.06	25.	0.	96.	121.	2146.05
DIESEL 3			2.100	11000.	40.121	0.30	0.05	24.	0.	96.	120.	2194.54
DIESEL 1			2.000	11000.	40.121	0.28	0.05	22.	0.	91.	113.	2282.91

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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 COST K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION COST K\$	\$/MWH
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	1023.	1023.	14.93
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	19947.	0.	19947.	47.00
BIG STONE AQCS		MUST	105.600	10613.	3.789	81.68	753.49	30298.	4844.	5088.	40231.	53.39
GE 7FA.05 2x1	2020		200.000	6631.	5.801	79.18	1383.48	53220.	7912.	3279.	64412.	46.56
GE 7FA.05 2x1	2030		200.000	6764.	5.801	77.43	1352.82	53082.	7737.	3279.	64097.	47.38
COYOTE		MUST	106.800	11641.	3.216	64.25	599.44	22443.	2857.	4655.	29955.	49.97
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	349.	663.	1012.	26.96
HESKETT #2		MUST	74.600	12700.	3.686	55.07	358.92	16801.	3874.	7107.	27782.	77.41
GLENDIVE CT #2			40.742	8445.	5.801	53.10	189.01	9260.	644.	652.	10555.	55.85
LEWIS&CLARK RICE			19.000	8510.	5.801	42.84	71.11	3510.	388.	939.	4837.	68.02
HESKETT #3			88.000	11514.	5.801	17.06	131.14	8759.	447.	1810.	11016.	84.00
GE LM6000PH	2017		37.300	10330.	5.801	10.70	34.88	2090.	228.	2252.	4570.	131.00
MISO - Off peak			50.000	10500.	0.000	7.73	33.75	0.	2184.	0.	2184.	64.70
GLENDIVE CT #1			34.780	11793.	5.801	2.67	8.10	554.	27.	315.	896.	110.62
MILES CITY C.T.			25.200	13634.	5.801	1.57	3.46	274.	11.	449.	734.	212.13
MISO - On peak			50.000	10500.	0.000	1.02	4.44	0.	395.	0.	395.	88.94
INTERRUPTIBLES		D	16.000	1.	0.000	0.62	0.87	0.	260.	1363.	1623.	1870.00
COMMERCIAL DSM		D	15.000	1.	0.000	0.53	0.69	0.	207.	1278.	1485.	2150.03
DIESEL 2			2.100	11000.	41.325	0.40	0.07	33.	0.	99.	132.	1810.04
DIESEL 3			2.100	11000.	41.325	0.39	0.07	32.	0.	99.	131.	1841.10
DIESEL 1			2.000	11000.	41.325	0.38	0.07	31.	0.	94.	125.	1856.56

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	1054.	1054.	15.38
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	19718.	0.	19718.	46.46
BIG STONE AQCS		MUST	105.600	10613.	3.902	83.25	768.01	31808.	5086.	5241.	42135.	54.86
GE 7FA.05 2x1	2020		200.000	6631.	5.975	79.18	1383.48	54817.	8149.	3378.	66344.	47.95
GE 7FA.05 2x1	2030		200.000	6762.	5.975	77.44	1352.96	54666.	7969.	3378.	66013.	48.79
COYOTE		MUST	106.800	11636.	3.313	71.29	665.11	25637.	3266.	4794.	33697.	50.66
GLENDIVE CT #2			40.742	8458.	5.975	58.60	208.56	10541.	731.	672.	11944.	57.27
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	354.	683.	1038.	27.63
HESKETT #2		MUST	74.600	12705.	3.797	53.57	349.11	16839.	3881.	7320.	28041.	80.32
LEWIS&CLARK RICE			19.000	8502.	5.975	41.08	68.19	3464.	383.	967.	4814.	70.60
HESKETT #3			88.000	11456.	5.975	16.94	130.26	8917.	457.	1864.	11238.	86.27
GE LM6000PH	2017		37.300	10348.	5.975	10.51	34.25	2118.	230.	2319.	4667.	136.27
MISO - Off peak			50.000	10500.	0.000	7.59	33.16	0.	2253.	0.	2253.	67.93
GLENDIVE CT #1			34.780	11743.	5.975	2.58	7.85	551.	27.	324.	902.	114.89
MILES CITY C.T.			25.200	13619.	5.975	1.68	3.71	302.	13.	462.	777.	209.43
MISO - On peak			50.000	10500.	0.000	1.08	4.74	0.	442.	0.	442.	93.38
INTERRUPTIBLES		D	16.000	1.	0.000	0.64	0.90	0.	269.	1404.	1673.	1863.32
COMMERCIAL DSM		D	15.000	1.	0.000	0.54	0.71	0.	212.	1316.	1528.	2165.11
DIESEL 2			2.100	11000.	42.564	0.41	0.08	35.	0.	102.	137.	1823.64
DIESEL 3			2.100	11000.	42.564	0.40	0.07	34.	0.	102.	136.	1867.90
DIESEL 1			2.000	11000.	42.564	0.39	0.07	32.	0.	97.	129.	1884.86

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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
WIND20 ND	2019	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	1086.	1086.	15.84
TSW OWN PPA	2016	NDT	107.500	0.	0.000	45.19	424.40	0.	19480.	0.	19480.	45.90
BIG STONE AQCS		MUST	105.600	10616.	4.020	80.64	743.97	31746.	5075.	5398.	42219.	56.75
GE 7FA.05 2x1	2020		200.000	6631.	6.155	79.18	1383.48	56461.	8394.	3479.	68334.	49.39
GE 7FA.05 2x1	2030		200.000	6716.	6.155	78.14	1365.24	56429.	8283.	3479.	68191.	49.95
COYOTE		MUST	106.800	11679.	3.412	72.11	672.74	26807.	3402.	4938.	35147.	52.24
GLENDIVE CT #2			40.742	8410.	6.155	63.81	227.12	11756.	820.	692.	13268.	58.42
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLEN ULLIN ORMAT		MUST	7.500	1.	0.000	57.32	37.56	0.	360.	704.	1063.	28.31
HESKETT #2		MUST	74.600	12658.	3.910	57.04	371.72	18400.	4256.	7540.	30196.	81.23
LEWIS&CLARK RICE			19.000	8487.	6.155	47.81	79.36	4145.	459.	996.	5600.	70.57
HESKETT #3			88.000	11516.	6.155	19.67	151.21	10718.	546.	1920.	13184.	87.19
GE LM6000PH	2017		37.300	10315.	6.155	12.10	39.43	2503.	273.	2389.	5165.	130.98
MISO - Off peak			50.000	10500.	0.000	9.29	40.60	0.	2896.	0.	2896.	71.33
GLENDIVE CT #1			34.780	11748.	6.155	3.53	10.71	775.	38.	334.	1146.	107.01
MILES CITY C.T.			25.200	13634.	6.155	2.13	4.68	393.	16.	476.	886.	189.06
MISO - On peak			50.000	10500.	0.000	1.29	5.63	0.	552.	0.	552.	98.05
INTERRUPTIBLES		D	16.000	1.	0.000	0.72	1.01	0.	302.	1446.	1748.	1738.38
COMMERCIAL DSM		D	15.000	1.	0.000	0.61	0.79	0.	238.	1356.	1594.	2005.49
DIESEL 2			2.100	11000.	43.841	0.46	0.08	41.	0.	105.	146.	1721.59
DIESEL 3			2.100	11000.	43.841	0.45	0.08	40.	0.	105.	145.	1747.20
DIESEL 1			2.000	11000.	43.841	0.44	0.08	37.	0.	100.	137.	1773.01

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2014.

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.
2015	511.0	3563.67	546.7	7.36	741.8	32.16	0.003681	686.6	3.11	0.09
2016	535.7	3809.87	577.9	8.32	860.2	25.73	0.002945	803.3	2.71	0.07
2017	559.4	4044.76	617.3	10.96	897.3	13.49	0.001544	837.0	1.40	0.03
2018	577.6	4220.26	619.5	7.67	897.3	26.97	0.003087	837.0	2.87	0.07
2019	593.1	4366.26	633.7	7.22	927.3	45.58	0.005218	867.0	4.98	0.11
2020	604.1	4464.85	795.3	33.37	1088.1	4.13	0.000473	1008.4	0.41	0.01
2021	615.3	4565.35	795.3	30.81	1088.1	6.04	0.000691	1008.4	0.60	0.01
2022	625.9	4659.15	795.3	28.48	1088.1	10.62	0.001215	1008.4	1.07	0.02
2023	635.2	4738.95	795.3	26.50	1088.1	11.11	0.001272	1008.4	1.11	0.02
2024	644.5	4818.54	795.3	24.58	1088.1	13.63	0.001560	1008.4	1.38	0.03
2025	653.8	4898.34	795.3	22.72	1088.1	29.92	0.003425	1008.4	3.40	0.07
2026	663.1	4978.24	743.2	12.67	1039.0	64.77	0.007414	963.4	7.37	0.15
2027	672.5	5059.43	743.2	11.02	1039.0	58.83	0.006734	963.4	6.72	0.13
2028	681.9	5139.13	743.2	9.42	1039.0	70.45	0.008064	963.4	8.24	0.16
2029	691.3	5220.23	739.6	7.32	1019.5	109.91	0.012581	943.9	13.80	0.26
2030	700.8	5302.82	925.4	33.53	1189.5	6.94	0.000794	1085.4	0.95	0.02
2031	710.5	5386.92	925.4	31.62	1189.5	9.56	0.001095	1085.4	1.26	0.02
2032	720.4	5472.51	925.4	29.73	1189.5	15.81	0.001810	1085.4	1.89	0.03
2033	730.2	5558.01	925.4	27.92	1189.5	16.50	0.001889	1085.4	1.99	0.04
2034	740.2	5645.20	925.4	26.11	1189.5	20.72	0.002372	1085.4	2.42	0.04
EXT.	740.2	5645.20	925.4	26.11	1189.5	20.72	0.002372	1085.4	2.42	0.04

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	
2015	511.0	0.0	-25.2	485.8	521.5	0.0	0.0	521.5	7.36
2016	535.7	0.0	-28.5	507.2	549.4	0.0	0.0	549.4	8.32
2017	559.4	0.0	-31.0	528.4	586.3	0.0	0.0	586.3	10.96
2018	577.6	0.0	-31.0	546.6	588.5	0.0	0.0	588.5	7.67
2019	593.1	0.0	-31.0	562.1	602.7	0.0	0.0	602.7	7.22
2020	604.1	0.0	-31.0	573.1	764.3	0.0	0.0	764.3	33.37
2021	615.3	0.0	-31.0	584.3	764.3	0.0	0.0	764.3	30.81
2022	625.9	0.0	-31.0	594.9	764.3	0.0	0.0	764.3	28.48
2023	635.2	0.0	-31.0	604.2	764.3	0.0	0.0	764.3	26.50
2024	644.5	0.0	-31.0	613.5	764.3	0.0	0.0	764.3	24.58
2025	653.8	0.0	-31.0	622.8	764.3	0.0	0.0	764.3	22.72
2026	663.1	0.0	-31.0	632.1	712.2	0.0	0.0	712.2	12.67
2027	672.5	0.0	-31.0	641.5	712.2	0.0	0.0	712.2	11.02
2028	681.9	0.0	-31.0	650.9	712.2	0.0	0.0	712.2	9.42
2029	691.3	0.0	-31.0	660.3	708.6	0.0	0.0	708.6	7.32
2030	700.8	0.0	-31.0	669.8	894.4	0.0	0.0	894.4	33.53
2031	710.5	0.0	-31.0	679.5	894.4	0.0	0.0	894.4	31.62
2032	720.4	0.0	-31.0	689.4	894.4	0.0	0.0	894.4	29.73
2033	730.2	0.0	-31.0	699.2	894.4	0.0	0.0	894.4	27.92
2034	740.2	0.0	-31.0	709.2	894.4	0.0	0.0	894.4	26.11
EXT.	740.2	0.0	-31.0	709.2	894.4	0.0	0.0	894.4	26.11

PLAN 1

YEAR	FIXED CHARGES	OPERATING COSTS	TOTAL SYSTEM COST	OTHER ELECTRIC REVENUES	SALES GWH	-----SYSTEM AVERAGE RATE-----	
						\$/MWH	PERCENT INCREASE 1 YEAR
2015	16676.	110894.	127570.	0.	3559.54	35.839	
2016	23415.	132840.	156254.	0.	3806.44	41.050	14.540
2017	28428.	143185.	171614.	0.	4042.58	42.451	3.414
2018	28428.	155449.	183877.	0.	4216.31	43.611	2.731
2019	33904.	167780.	201684.	0.	4359.20	46.266	6.089
2020	50234.	160583.	210817.	0.	4464.18	47.224	2.070
2021	50234.	167130.	217363.	0.	4564.45	47.621	0.840
2022	50234.	175617.	225851.	0.	4657.72	48.490	1.824
2023	50234.	182683.	232917.	0.	4737.51	49.164	1.391
2024	50234.	191198.	241432.	0.	4816.83	50.123	1.949
2025	50234.	202460.	252694.	0.	4894.85	51.625	2.997
2026	47670.	231292.	278961.	0.	4971.39	56.113	8.695
2027	47670.	239355.	287025.	0.	5053.25	56.800	1.224
2028	47670.	251050.	298720.	0.	5131.70	58.211	2.484
2029	47670.	270636.	318305.	0.	5207.39	61.126	5.008
2030	69615.	263715.	333331.	0.	5301.77	62.872	2.856
2031	69615.	275107.	344722.	0.	5385.68	64.007	1.806
2032	69615.	288038.	357653.	0.	5470.96	65.373	2.134
2033	69615.	299608.	369223.	0.	5556.41	66.450	1.647
2034	69615.	313229.	382845.	0.	5643.40	67.839	2.091
TOTAL	971012.	4221848.	5192858.				
PRESENT VALUE REVENUE REQUIREMENTS (THOUSANDS OF 2014 DOLLARS)	481602.	2113663.	2595265.				
LEVELIZED SYSTEM AVERAGE RATE =	49.942	\$/MWH					
						MINIMUM	0.840
						MAXIMUM	14.540
						COMPOUND AVERAGE	3.415

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

EGEAS REPORT VERSION 9.02

INDEX OF REPORTS

PAGE 38

CONTROL REPORT PAGE 1

MIRROR IMAGE REPORT PAGE 2

ERROR REPORT PAGE 4

REPORT SELECTION PAGE 5

		EXPANSION PLAN DIRECTORY	PAGE	6
PLAN	1	EXPANSION PLAN SUMMARY	PAGE	7
PLAN	1	PROD. COST - SYSTEM ANNUAL	PAGE	12
PLAN	1	PROD. COST - FUEL ANNUAL	PAGE	14
PLAN	1	PROD. COST - UNIT ANNUAL	PAGE	15
PLAN	1	RELIABILITY - ANNUAL	PAGE	35
PLAN	1	RESERVE - ANNUAL	PAGE	36
PLAN	1	SYSTEM TOTAL COST	PAGE	37

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

Jay Skabo

Vice President—Electric Supply

Abbie Krebsbach	Director of Environmental
Alan Welte	Director of Generation
Rob Frank	Director of Electric Transmission Engineering
Bob Morman	Director of Gas Supply
Matt Lund	Engineer II – Power Production
Niles Hushka*	KLJ

* *Invited presenter*

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

October 21, 2014 Meeting Agenda

Overview of the IRP Planning Process	Brian Giggee
2013 IRP Action Plans	Brian Giggee Larry Oswald
Heskett 3, Big Stone AQCS, Lewis & Clark Station	Alan Welte
Future Supply Side Resources	Alan Welte
Load Forecast	Kayla Kaul
Environmental Challenges	Jay Skabo
WAPA/Basin SPP Membership	Darcy Neigum
Wrap-up	Group Discussion
Meeting Logistics	
Discussion Topics for Future Meetings	
Meeting Schedule through 2014-15	

December 17, 2014 Meeting Agenda

Gas Supply Update	Bob Morman
Regulatory Topics	Tamie Aberle
MDU Transmission Projects	Rob Frank
MISO Planning Reserve Margin	Brian Giggee

Demand Side Updates	Larry Oswald
Preliminary EGEAS modeling	Brian Giggee
Thunder Spirit Wind Distributed Generation	Darcy Neigum
Wrap-up	
Meeting Logistics	
Discussion Topics for Future Meetings	
Future Meeting Schedule 2015	
February(week of the 9 th or 16 th)	
May (week of the 4 th or 11 th)	

May 20, 2015 Meeting Agenda

MT State Legislative Review	Garrett Martin
ND State Legislative Review	Senator Wardner
SD State Legislative Review	Patrick Steffensen
Environmental Overview	Abbie Krebsbach
Oil Price Impact	Niles Hushka
Load Forecast Overview	Kayla Kaul
Demand Side Overview	Larry Oswald
Generation Updates	Alan Welte
Supply Side Overview	Brian Giggee
Two Year Action Plan	Darcy Neigum
Wrap-up	
IRP Filing Timeline	
Feedback from the PAG members	
Future PAG membership for 2017 IRP	

Attachment E

Supply-Side Resources Study

Montana-Dakota Utilities Co.



Explanation of IRP Supply-Side Resources Cost Analysis

April 3, 2015



Project No. 14-0257

		<u>Page No.</u>
A-9	Renewable Fuel and Coal Boiler EGEAS Model Input Summary, 2015\$	A - 9
A-10	Renewable Non-Fuel EGEAS Model Input Summary, 2015\$	A - 10
A-11	Geothermal and Solar Input Summary, 2015\$	A - 11

LIST OF ABBREVIATIONS

Allowance for Funds Used During Construction (AFUDC)

Best Available Control Technology (BACT)

Bubbling Fluidized Bed (BFB)

Circulating Fluidized Bed Combustion (CFBC)

Combustion Turbine Generator (CTG)

Dry Low NO_x (DLN)

Electric Generation Expansion Analysis System (EGEAS)

Engineering and Supervision and General and Administrative (ES&GA)

Full-Time Equivalent (FTE)

General Electric (GE)

Generator Step-Up (GSU)

Hazardous Air Pollutant (HAP)

Heat Recovery Steam Generator (HRSG)

Integrated Resource Plan (IRP)

Municipal Solid Waste (MSW)

New Source Performance Standards (NSPS)

Operation and Maintenance (O&M)

Original Equipment Manufacturer (OEM)

Photo-Voltaic (PV)

Plant Engineering and Construction Estimator (PEACE)

Reciprocating Internal Combustion Engine (RICE)

Selective Catalytic Reduction (SCR)

Spray Intercooling for Power Augmentation (SPRINT)

Total Capital Investment (TCI)

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

1.1 INTRODUCTION

Montana-Dakota Utilities Co. (Montana-Dakota) requested Segra Inc. (Segra) to conduct a cost analysis of supply-side resources to be included in Montana-Dakota's 2015 Integrated Resource Plan (IRP) model.

This report includes costs for 23 supply-side options. Of these, the overall model costs for the four wind and the two coal alternative resources have been developed by Montana-Dakota and included in this report. These six options are based on Montana-Dakota's knowledge from the construction of three self-built wind farms, as well as "*A Study of Lignite-Based Advanced Generation Technology Systems*" completed by WorleyParson's for the Lignite Energy Council. The information was supplied by Montana-Dakota and is included in the report in order to provide a comprehensive data set for the model.

The results of the current IRP Supply-Side Resource Costs Analysis will be used for Montana-Dakota's 2015 IRP and input into the Electric Generation Expansion Analysis System (EGEAS).

1.2 PERFORMANCE BASIS

The following assumptions (provided by Montana-Dakota) were used in the combustion models. The site-specific inputs were based on Williston, North Dakota, whose geography and weather conditions are close averages to that of most western North Dakota and eastern Montana locations. For the 2x1 7EA Heskett Station Unit 3 (Heskett 3) expansion option, site specific elevation, humidity, and temperature were used, which is detailed in Section 1.5.2.

1. Elevation: 1,950 feet AMSL.

2. Humidity: 36 percent.
3. Temperature: 82.1 degrees F.
4. Generation Power Factor: 0.85.
5. Generator Terminal Voltage: 13.8-kV.
6. Interconnection Voltage: 115-kV.
7. Fuel for Combustion Turbine Generators (CTGs): Natural gas.
8. LHV to HHV Ratio: 1.11.
9. Fuel for Landfill Gas: GT PRO default.
10. Fuel for Biomass: GT PRO default (wood pellets).
11. Fuel for Solid-Waste Burner: GT PRO default.

1.3 SUPPLY-SIDE RESOURCES CONSIDERED

The cost analysis includes the following generating facilities:

1. Simple-Cycle CTGs:
 - a. GE 7EA (frame, natural gas-fired).
 - b. GE LMS100PB (aero-hybrid, natural gas-fired).
 - c. GE LM6000PH (aero derivative, natural gas-fired).
 - d. Solar Titan 250 (frame, landfill gas-fired).
2. Combined-Cycle CTGs:
 - a. 1x1 General Electric (GE) LM6000PH (aero derivative, natural gas-fired).
 - b. 1x1 GE 7EA (frame, natural gas-fired).
 - c. 2x1 GE 7EA (frame, natural gas-fired, add an additional GE 7EA to existing R.M. Heskett 3).
 - d. 1x1 GE 7FA.05 (frame, natural gas-fired).

- e. 2x1 GE 7FA.05 (frame, natural gas-fired).
- f. 3x1 Siemens SGT 800 (frame, natural gas-fired).
- 3. Reciprocating Internal Combustion Engine (30 MW):
 - a. Wartsila 20V34SG (natural gas-fired).
- 4. Fuel Boilers:
 - a. Generic solid-waste burner (15 MW).
 - b. Generic biomass (30 MW).
 - c. Generic coal with CO₂ capture (122 MW).
 - d. Generic coal without CO₂ capture (185 MW).
- 5. Renewable Non-Fuel:
 - a. Generic photovoltaic solar (30 MW).
 - b. Generic concentrated solar (30 MW).
 - c. Generic thermal solar (30 MW).
 - d. Generic geothermal (30 MW).
 - e. Generic wind North Dakota (20 MW).
 - f. Generic wind North Dakota (50 MW).
 - g. Generic wind Montana (20 MW).
 - h. Generic wind Montana (50 MW).

1.4 DELIVERABLES

Sega performed the cost analysis of these supply-side options by developing/updating design-costing models, requesting vendor data, researching cost information sources, and creating an IRP cost analysis spreadsheet. Tables from this spreadsheet are provided in Appendix A. For each option considered, the following deliverables are presented in Table A-1, which is a roll-up summary of the IRP costing spreadsheet for all of the options:

1. Plant Size (MW, net): Based on the data specified in the performance basis.
2. Capital Cost (\$/kW) - Total Capital Investment (TCI) Unloaded, divided by the plant size.
3. Fixed Operation and Maintenance (O&M) (\$/kW-month): Total of the O&M fixed costs including labor, maintenance, and other expenses.
4. Variable O&M (\$/MWh): Total of the O&M variable costs including maintenance, utilities, and chemicals.
5. Major maintenance (\$/kW-month).
6. Full load heat rate (Btu/kWh, net).
7. Carbon intensity (lb/MWh).
8. NO_x (ppmvd at 15-percent O₂).
9. CO (ppmvd at 15-percent O₂).
10. Fuel Cost (\$/MBtu): Landfill gas and municipal solid waste (MSW) cost provided by Sega, all other fuel costs provided by Montana-Dakota.

Each cost includes the applicable emissions equipment, (i.e., water injection, duct burner, SCR, CatOx, etc.) as noted in summary Tables A-1 to A-9.

Capital costs were evaluated on a TCI-unloaded and TCI-loaded basis. The unloaded costs include the generator step-up (GSU) transformer, however, interconnection costs (i.e., transmission, gas, and system upgrades), land, interest during construction, spare parts and materials, financing, and project administration and developer's fees have not been included as listed in *Figure 1*. Sega estimated the TCI-loaded cost by rerunning the unloaded cost analysis with a project administration and developer's fee of 1 percent and a financing cost of 4 percent for CTGs and 1 percent for the boiler options. The TCI-loaded cost was used as a basis to calculate the fixed costs of property tax and insurance for the CTG options.

	Not in TCI-Unloaded
Transmission Interconnect and Upgrades (Except for GSU*)	✓
Interest During Construction	✓
Fuel Supply Pipeline	✓
Land	✓
Spare Parts and Materials	✓
Project Administration and Developer's Fee	✓
Financing	✓
* GSU transformer cost is included in project TCI.	

**Figure 1 - Project-Specific Costs
Not Included in TCI-Unloaded**

1.5 CTG OPTIONS

A capital cost analysis was performed for the CTGs using Thermoflow Inc.'s thermal engineering software GT PRO that includes a Plant Engineering and Construction Estimator (PEACE) module for determining capital costs. Thermoflow uses information from Original Equipment Manufacturers (OEMs), material suppliers, engineering firms, and contractors to determine the cost indices contained in the PEACE module. The cost indices are refreshed on a routine basis (typically, bi-annual) 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. 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.

For the Thermoflow model runs, the natural gas quality specified by Montana-Dakota (see *Figure 2*) was customized as a user-defined fuel in Thermoflow for each of the nine natural gas-fired CTG options. For each of the CTGs, the inlet air filter pressure drop was assumed to be 2”H₂O with a duct and stack draft loss of 5.5”H₂O.

Natural Gas Quality	Volume Percent
CH ₄	90.0
C ₂ H ₆	6.35
C ₃ H ₈	0.55
C ₄ H ₁₀	0.13
C ₅ H ₁₂	0.04
C ₆ H ₁₄₊	0.02
N ₂	1.18
CO ₂	1.11
H ₂	0.07
He	0.55
Total	100
Fuel Gas Temperature	80 °F
Fuel Gas Pressure (Range)	375 - 1,000 psig
Fuel Heating Value (LHV)	20,393 Btu/lb
LHV to HHV Factor	1.11

Figure 2 - Natural Gas Quality Assumed for CTG Analyses

Once these assumptions, along with the site-specific assumptions from Section 1.2, were entered into Thermoflow, the only information that varied between the natural gas-fired CTG cases were the plant cycle set up, the CTG type, and the emission reduction techniques, which included an oxidation catalyst for CO reduction and a SCR system for NO_x control. All plant information, TCI-loaded, TCI-unloaded, NO_x, CO, and CO₂ emissions could be either found directly in or calculated from Thermoflow’s text or PEACE outputs. The plant size, performance, emission controls, operational parameters, emissions, capital costs, fixed costs, variable costs, and summary for all CTG plant options considered are shown in Tables A-2 through A-5.

1.5.1 Simple-Cycle CTGs

Figure 3 summarizes key performance and descriptors for the three natural gas-fired simple-cycle CTGs assessed.

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NO _x (ppmdv)	Pre-SCR NO _x Control	Gas Pressure Needed (psig)	Dual-fuel Capable	Technology Type	Model Maturity
GE 7EA	84.1 10,634	9	Dry	311	Yes	Frame	Mature
GE LMS100PB	99.5 8,540	25	Dry	975	No	Aero-Hybrid	Some actual models operating
GE LM6000PH	51.0 8,912	15	Dry	700	No	Aero	LM6000 mature; PH very new model
* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.							

Figure 3 - Summary of Gas-Fired Simple-Cycle CTGs

The following paragraphs provide a summary of key assumptions in the assessment for each of the CTGs.

The simple-cycle 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). Because of this very low CTG emission level as a starting point the incremental emission reduction cost (\$/ton removed) for adding SCR would be relatively high. Therefore, Sega has assumed the additional emission control equipment of SCR would not be needed for permitting to meet Best Available Control Technology (BACT) requirements. Similarly, Sega assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT. This assumption is also based on the relatively high emission reduction cost effectiveness for adding oxidation catalyst to a simple cycle CTG.

The simple-cycle GE LMS100PB utilizes DLN technology to minimize NO_x emissions. However, even with reduction technologies, the LMS100 has an uncontrolled NO_x emission level of 25 parts per million by dry volume (ppmvd at 15-percent O₂). With the relatively high starting point of 25 ppmvd, Segal concludes that the incremental emission reduction cost (\$/ton removed) will be low enough to require the use of SCR for permitting to meet BACT. The SCR NO_x reduction effectiveness was set to 90 percent (2.5 ppmvd outlet), ammonia slip was set to 5 ppmvw using a 19-percent aqueous ammonia solution; urea usage was not included in the analysis. The SCR auxiliary power and SCR capital investment were determined by the difference of two cases separately run in Thermoflow; one with SCR and one without SCR. Segal assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT. This assumption is based on the relatively high emission reduction cost effectiveness for adding oxidation catalyst to a simple-cycle CTG.

The simple-cycle GE LM6000PH also utilizes DLN, with a NO_x emission level of 15 ppmvd. With the starting point of 15 ppmvd, Segal concludes that the incremental emission reduction cost (\$/ton removed) will be low enough to require the use of SCR for permitting to meet BACT. The SCR NO_x reduction effectiveness was set to 80 percent (3 ppmvd outlet), ammonia slip was set to 5 ppmvw using a 19-percent aqueous ammonia solution. Segal also assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT.

1.5.2 Combined-Cycle CTGs

Figure 4 summarizes key performance and descriptors for the six combined-cycle CTG facilities assessed.

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NO _x (ppmdv)	Pre-SCR NO _x Control	Gas Pressure Needed (psi)	Dual-Fuel Capable	Technology Type	Model Maturity
GE LM6000PH Sprint (1x1)	62.8 7,663	15	Dry	700	No	Aero	LM6000 mature; PH very new model
GE 7EA (1x1)	127.6 7,608	9	Dry	350	Yes	Frame	Mature
GE 7EA (2x1) Heskett 3 Expansion	256.7 7,570	9	Dry	350	Yes	Frame	Mature
GE 7FA.05 (1x1)	294.6 6,672	9	Dry	600	Yes	Frame	Mature
GE 7FA.05 (2x1)	593.0 6,631	9	Dry	600	Yes	Frame	Mature
Siemens SGT 800 (3x1)	213.9 7,347	15	Dry	350	Yes	Frame	Mature
* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.							

Figure 4 - Summary of Combined-Cycle CTGs

The following paragraphs provide a summary of key assumptions in the assessment for each of the facilities.

The combined-cycle with an LM6000PH CTG was set up in a similar way as the simple-cycle CTG except that it includes spray intercooling for power augmentation (SPRINT) and a 1x1 single-pressure combined-cycle plant with an extraction 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. Sega assumes that the cycle cooling system will include a mechanical draft cooling tower. As with the simple-cycle case, an SCR system was included with a NO_x reduction effectiveness of 80 percent (3.0 ppmdv outlet). Sega assumes that an oxidation catalyst would be required

for permitting to meet BACT for CO reduction. This conclusion is based on the relatively low incremental emission reduction cost effectiveness of installing oxidation catalyst in a heat recovery steam generator (HRSG). The catalyst was included at 80-percent CO reduction effectiveness.

The two GE 7EA combined-cycle cases were modeled as a dual-pressure no-reheat 1x1 combined-cycle plant with a mechanical draft cooling tower and a 2x1 dual-pressure no-reheat combined-cycle with a mechanical draft cooling tower. A duct burner was included in each case and the firing temperature was specified at 1,200 degrees F. Segra assumes that an SCR system would be required for permitting to meet BACT for NO_x reduction. This conclusion is based on the relatively low incremental emission reduction cost effectiveness of installing an SCR system in a HRSG, and that the combined-cycle facility would not have any limitations of annual hours of operation. The SCR was included at 80-percent reduction effectiveness resulting in an outlet level of approximately 2.0 ppm_{dv}, which is the lowest consistently achievable level. Segra assumes that an oxidation catalyst would be required for permitting to meet BACT for CO reduction. As with the other combined-cycle options, this conclusion is based on the relatively low incremental emission reduction cost effectiveness of installing oxidation catalyst in a HRSG and that the combined-cycle facility would not have any limitations of annual hours of operation. The catalyst was included at 80-percent CO reduction effectiveness.

The GE 7EA 2x1 combined-cycle is a unique case that incorporates the existing simple-cycle 7EA located at the Heskett 3 into a new 2x1 arrangement. The performance is based on the Thermoflow model for a complete and new plant site including two engines, two HRSGs, a common cooling tower, and a common steam turbine similar to the other combined-cycle options.

The GE 7EA combined-cycle plant output, performance, and all operational parameters for the 1x1 plant were based on the design site average conditions specified by Montana-Dakota (82.1 degrees F, 36-percent relative humidity, and elevation of 1,950 AMSL). The plant output, performance, and all operational parameters for the 2x1 plant were based on the design site average conditions specified by Montana-Dakota for Heskett 3

(83.8 degrees F, 40-percent relative humidity, and elevation of 1,695 ft. AMSL). For both the 1x1 and 2x1 plant, the steam turbine, HRSG, and condenser were sized for a cooler condition of 40 degrees F and 40-percent relative humidity since this equipment must be sized to accommodate higher CTG output at reduced ambient temperatures. However, the cooling tower was still sized for the design site average condition for each plant since it must be sized to accommodate the warmer site design condition. Thus, all plant information (output, performance, operational parameters, etc.) listed in Tables A-2 through A-5 are associated with the design site average conditions for that plant, whereas, all TCI information (except for the cooling tower) are based on the cooler conditions.

The GE 7FA.05 combined-cycle cases were modeled as a triple-pressure reheat 1x1 combined-cycle plant with a mechanical draft cooling tower, and as a triple-pressure reheat 2x1 combined-cycle plant with a mechanical draft cooling tower. For the same reasons described for the GE 7EA combined-cycle options, the NO_x reduction effectiveness of SCR was set to 80 percent (2.0 ppm_{dv} outlet) and an oxidation catalyst was included at 80-percent CO reduction effectiveness. Like the GE 7EA 1x1 plant, all plant information (output, performance, operational parameters, etc.) listed in Tables A-2 through A-5 are associated with the design site average conditions, whereas all TCI information (except for the cooling tower) are based on the cooler condition.

The Siemens SGT 800 combined-cycle case was modeled as a dual-pressure no-reheat 3x1 combined-cycle plant with a mechanical draft cooling tower. Similar to the other CTG combined-cycle options, the NO_x reduction effectiveness of SCR was set to 80 percent (3.0 ppm_{dv} outlet), and an oxidation catalyst was included at 80-percent CO reduction effectiveness. All plant information (output, performance, operational parameters, etc.) listed in Tables A-2 through A-5 are associated with the design site average conditions, whereas, all TCI information (except for the cooling tower) are based on the cooler condition.

1.5.3 Landfill Gas-Fired CTG

A simple-cycle Solar Titan 250 was modeled to develop a cost estimate for a landfill gas-fueled plant. *Figure 5* shows the makeup of the Thermoflow defined landfill gas that was selected for the fuel. Note that the siting of a landfill gas-fired plant of this size would require a location where there is a substantially sized landfill to produce enough gas to support a CTG-based plant. This may significantly limit the possible locations of such a facility in Montana-Dakota's service territory in the eastern interconnection. *Figure 6* summarizes key performance and descriptors for the CTG assessed. The following paragraph provides a summary of key assumptions in the assessment for the CTG.

The simple-cycle Titan 250 CTG utilizes SoLoNO_x technology to minimize NO_x emissions to less than 15 ppmdv. Because of this lower CTG emission level, Sega has assumed the additional emission control equipment of SCR would not be needed for permitting to meet BACT. When firing landfill gas, there is a general industry concern of contaminants in the gas which may poison the catalyst and make NO_x reduction ineffective.

Sega assumes that an oxidation catalyst would be required for permitting to meet BACT for CO reduction. This conclusion is based on the lower incremental emission reduction cost effectiveness resulting from the relatively high CO emissions from the Titan 250 firing landfill gas. The catalyst was included at 80-percent CO reduction effectiveness.

Constituent		
Hydrogen, H ₂	% vol	2.5
Carbon Dioxide, CO ₂	% vol	33.0
Methane, CH ₄	% vol	63.5
Hydrogen Sulfide, H ₂ S	% vol	1.0
Higher Heating Value (at 77°F)	Btu/lb	9,908

Figure 5 - Assumed Landfill Gas Properties

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NO _x (ppmdv)	Pre-SCR NO _x Control	Gas Pressure Needed (psi)	Dual- Fuel Capable	Technology Type	Model Maturity
Solar Titan 250	21.7 9,740	15	Dry	450	Yes	Frame	Mature
* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.							

Figure 6 - Summary of Landfill Gas-Fired CTG

1.5.4 CTG Cost Estimation

The cost basis, capital costs, and annual costs are contained in Tables A-2 through A-5 of the IRP cost analysis spreadsheet in Appendix A. The PEACE economic model was updated with 2014 pricing data. These costs were escalated to 2015 dollars at 3-percent per year. The estimated annual O&M costs for each of the CTGs assessed are contained in these tables as well as the pertinent CTG performance data, identification of additional information specific to the CTGs assessed, TCI, labor costs, and emissions. The performance, capital investment, and emissions were outputs from the Thermoflow model for the specific CTGs assessed. The 2015\$ labor rate was provided by Montana-Dakota.

It should be noted, while the performance design of the 7EA 2x1 is very similar to the other CTG cases, it differs in the fact that the cost estimate is a hybrid approach because the facility includes an existing 7EA unit. The cost estimate for the hybrid system subtracts the cost of a single 7EA from the total cost of the new 2x1 total plant cost. All other methods of analysis for the cost estimate remain the same as the other CTG cases.

The basis for and results of calculating the O&M fixed costs (\$/kW-month, 2015\$) are shown in Table A-3. The basis for the calculations are from Montana-Dakota and discussions with Sega staff. Montana-Dakota provided maintenance rates based on 2010\$, which were escalated to 2015\$ at a 3-percent per year rate. The total fixed annual cost for each CTG assessed is shown at the bottom of the table.

Table A-4 lists the basis for and results of calculating the annual O&M variable costs (\$/MWh, 2015\$). The basis for the calculations were from Montana-Dakota, output from the Thermoflow model, and discussions between Sega and Montana-Dakota staff. Montana-Dakota provided maintenance rates based on 2010\$, which were escalated to 2015\$ at a 3-percent per year rate.

Landfill gas prices were estimated using the median value of prices reported to EPA current as of 2013 and escalated to 2015\$ at 3-percent per year.

1.5.5 CTG Fixed and Variable O&M Annual Cost Estimation

Table A-1 (summary results) includes the rolled-up summary of the capital cost along with the fixed and variable O&M costs for each option. Table A-2 (cost basis) provides a listing of the cost basis and assumptions for the cost calculations (used in Table A-3) including the assumed labor rate and the plant consumption rate of fuel, ammonia, water, and auxiliary power. The plant consumption rates are outputs from the Thermoflow model runs for the specific CTG models. Note that some CTG options have zero consumption rates in some categories, for example, the GE 7EA has no ammonia consumption since it is assumed to not have an SCR, whereas the GE LM6000PH has an ammonia consumption rate since it is assumed to have an SCR. The hourly labor rate of \$59.10 (2015\$), provided by Montana-Dakota, is multiplied by the full-time equivalent (FTE) amount of 2,080 work hours per year to calculate the annual FTE cost of \$122,928 for plant O&M labor costs used in Table A-3.

1.5.5.1 CTG O&M Fixed Costs (Table A-3)

Table A-3 shows the calculated buildup of the total annual fixed O&M costs for the CTG options. 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 separated by: 1) labor costs, 2) maintenance costs, and 3) other expenses. All calculated costs are shown in units of \$ per MW-year, which is

the total annual cost divided by the total MW capacity of the plant. The total fixed O&M cost is summed at the bottom of the table. The following paragraphs explain the process of calculating the three categories of fixed costs noted:

1. Labor Costs:

The annual fixed labor cost is the cost of the number of FTE operating staff required at the plant to perform the duties necessary to run the plant. There are separate categories of labor depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M fixed labor costs, whereas, the GE 7EA does not since this option is assumed to not have SCR. The number of FTE for each category was provided by Montana-Dakota based on actual experience or result of research. The number of FTE shown for a labor category is multiplied by the FTE rate (\$122,928/yr) and then divided by the MW capacity of the plant to calculate the \$/MW-yr values shown in the table for each option.

2. Maintenance 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 operating hours. There are separate categories of maintenance cost depending on the type of CTG and specific equipment at the plant option. The maintenance rate in \$/MW-yr for each category was provided by Montana-Dakota based on actual experience or result of research. The maintenance rate shown for a maintenance category is simply transferred over to the CTG option columns since it is already in the required units of measure.

3. Other Expenses:

The annual fixed cost for other expenses is the cost associated with administration, property tax, and insurance. Administration cost is shown as a fixed rate in \$/MW-yr and was provided by Montana-Dakota based on actual experience. This rate is transferred over to the CTG option columns since it is already in the required units of measure. The property tax and insurance are a function of the TCI shown in Table A-2. The property tax and insurance rate shown is multiplied by the TCI for that option and then divided by the MW capacity of the plant to calculate the \$/MW-yr values shown in the table for each option

1.5.5.2 CTG O&M Variable Costs (Table A-4)

Table A-4 shows the calculated buildup of the total annual variable O&M costs for the CTG options. Variable O&M costs are those which are expected to be a function of how much the CTGs are operated in terms of the number of MWhs generated. These calculations are separated by: 1) maintenance, 2) utilities, and 3) chemicals. All calculated costs are shown in units of \$ per MWh. The total variable O&M cost is summed at the bottom of the table. The following paragraphs explain the process of calculating the three categories of variable costs noted:

1. Maintenance:

The variable-maintenance cost is the cost to perform the particular maintenance activities which are needed after operating for a certain number of MWhs. This cost includes both labor and parts. There are separate categories of maintenance depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M variable-maintenance costs (for catalyst replacement), whereas, the Solar Titan 250 does not since this option is assumed not to have SCR (SCR catalysts must be replaced periodically as a function of operating hours). The variable-cost rate shown in \$/MWh for each category was provided by Montana-Dakota based on actual experience or result of research, or input from and discussions with Sega based on engineering estimates. This rate is transferred over to the CTG option columns since it is already in the required units of measure.

2. Utilities:

The variable-utilities cost is the cost of auxiliary power to operate the plant. There are separate categories of utilities depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M utilities costs (for powering the SCR-related equipment such as pumps, fans, and heaters). For the “all models” category, the rate shown in \$/MWh was provided by Montana-Dakota. This rate is transferred over to the CTG option columns since it is already in the required units of measure. The utilities cost for the other two categories (SCR and Intercooling auxiliary power) are the utility cost rate of 25.16 \$/MWh, provided by Montana-Dakota, times the amount of auxiliary power required by the equipment. The utility rate for a category is multiplied by the auxiliary power required (shown in Table A-2) and then divided by the MW capacity of the plant to calculate the \$/MWh values shown in the table for each option.

3. Chemicals:

The variable-chemicals cost is the cost of chemicals (including water) to operate the plant. There are separate categories of chemicals depending on the type of CTG or specific equipment operated for the particular option. For example, the GE LM6000PH option has SCR O&M chemicals costs (for ammonia), whereas, the Solar Titan 250 does not since this option is assumed not to have SCR. For the “all models” and “intercooling heat rejection equipment” categories, the rate shown in \$/MWh was provided by Montana-Dakota. These rates are transferred over to the CTG option columns since they are already in the required units of measure. The chemicals cost for the other category applicable to simple-cycle CTG options (SCR ammonia) is the ammonia cost rate of 1.4 \$/gal, provided by Segal, as an estimate. The ammonia cost rate is multiplied by the use rate in gal/hr from the Thermoflow model output (shown in Table A-2) and then divided by the MW capacity of the plant to calculate the \$/MWh values shown in the table for each option.

A summary of the cost analysis for all CTG options is presented in Table A-5.

1.6 RECIPROCATING INTERNAL COMBUSTION ENGINE OPTION

A cost analysis was performed for the reciprocating internal combustion engine (RICE) selected for the assessment. The Wartsila 20V34SG is a spark ignition 4-stroke engine. *Figure 7* summarizes key performance and descriptors for the RICE assessed.

RICE Model	ISO Ratings* (MW) Heat Rate (Btu/kWh)	NO _x Emissions (ppm)	Gas Pressure Needed (psi)	Duel-Fuel Capable	Technology Info	Model Maturity
Wartsila 20V34SG	9.3 8,293	5	75	No	4 Stroke Spark Ignition	Growing in Use
* Ratings at ISO conditions, HHV, gross are provided for reference. Site-specific ratings are provided in the IRP Information Spreadsheet.						

Figure 7 - Reciprocating Internal Combustion Engines

The RICE was assumed to meet the federal new source performance standards (NSPS) and 40 CFR 63 hazardous air pollutant (HAP) emission standards and therefore quoted to have both SCR and oxidation catalyst installed as part of the base package. The plant size, performance, emission controls, operational parameters, CO₂ emissions, capital costs, fixed costs, variable costs, and summary for the RICE plant options considered are shown in Table A-6.

1.6.1 RICE Cost Estimation

Sega requested budgetary quotations from Wartsila for capital and operational costs for the Wartsila 20V34SG model. All cost and performance numbers for the engines were provided by Wartsila. Sega adjusted these numbers to account for any information not provided by Wartsila. This information is contained in Table A-6 of the IRP cost analysis spreadsheet. The spreadsheet includes a breakdown of the capital costs by equipment, installation, loaded and unloaded Owner's soft costs, and loaded and unloaded TCI.

1.7 RENEWABLE FUEL BOILER OPTIONS

A capital cost analysis was performed for two renewable fuel-fired boilers using the Thermoflow engineering software with a PEACE module (see Section 1.5 for Thermoflow/PEACE details). The Thermoflow models incorporate a bubbling fluidized bed (BFB) boiler and a mechanical draft cooling tower. Inputs to the model also included Montana-Dakota defined baseline assumptions as well as a user selected fuel. All other inputs besides the baseline assumptions and the fuel were left at default values. The plant size, performance, emission controls, operational parameters, CO₂ emissions, capital costs, fixed costs, variable costs, and summary for both renewable fuel and coal fired boiler options are shown in Tables A-8 and A-9.

1.7.1 Municipal Solid-Waste Fuel

A Thermoflow defined municipal solid-waste fuel was selected for the solid-waste burner; the composition of this fuel can be found in *Figure 8*. Note that the siting of a municipal solid-waste fired plant of this size would require a location where there is a substantially sized population to produce enough fuel to support a solid waste based plant. This may significantly limit the possible locations of such a facility in Montana-Dakota's service territory in the eastern interconnection.

Constituent		
Moisture	% wt	35.70
Ash	% wt	32.00
Carbon	% wt	16.90
Nitrogen	% wt	0.20
Chlorine	% wt	0.35
Sulfur	% wt	0.15
Oxygen	% wt	12.40
Higher Heating Value	Btu/lb	3,001

Figure 8 - Assumed Municipal Solid-Waste Properties

1.7.2 Biomass

Wood pellets, the fuel for the biomass plant, was chosen from Thermoflow’s fuel library and its makeup can be found in *Figure 9*. Note that the siting of a wood pellet fired plant of this size would require close proximity to a location where there is a substantial supply of the fuel from trees and wood-related manufacturing industries. Sega anticipates a woody biomass product to be in short supply in North Dakota and this may significantly limit the possible locations of such a facility in the state.

Constituent		
Moisture	% wt	8.70
Ash	% wt	0.50
Carbon	% wt	45.80
Nitrogen	% wt	0.08
Chlorine	% wt	0.01
Sulfur	% wt	0.01
Oxygen	% wt	39.40
Higher Heating Value	Btu/lb	7,824

Figure 9 - Assumed Biomass - Wood Pellet Properties

1.7.3 Cost Estimation

The capital and annual costs are contained in Tables A-8 and A-9 of the IRP cost analysis spreadsheet. PEACE outputs are current as of 2014 and were escalated to 2015\$ at 3-percent annually. The fixed and variable O&M are from assumptions made in the Department of Energy Annual Energy Outlook from 2013 which were escalated to 2015\$ at 3-percent annually.

1.8 COAL BOILER OPTIONS

For a new coal-fired power plant, Montana-Dakota used the results of a 2012 study completed by WorleyParsons for the Lignite Energy Council, which 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 circulating fluidized bed combustion (CFBC).

The overall assessment evaluated both quantitative and qualitative criteria. The assessed criteria 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 when including, and not including, CO₂ capture. The CFBC technology options were used as inputs to the resource expansion analysis, with the cost estimates escalated to 2015\$. The coal option inputs to the resource expansion analysis are included in *Figure 10* and in Table A-9.

	CFBC with CO ₂ Capture	CFBC without CO ₂ Capture
Plant Size (MW, net)	122	185
Capital Cost (\$/kW)	\$7,099	\$3,882
Fixed O&M (\$/kW-month)	\$22.55	\$18.49
Variable O&M (\$/MWh)	\$19.81	\$12.49
Major Maintenance (\$/kW-month)	\$0.00	\$0.00
Net Full Load Heat Rate (Btu/kWh HHV)	13,781	9,974
Carbon Intensity (lb/MWh)	248	1,945
WorleyParsons. 2012. A Study of Lignite-Based Advanced Generation Technology Systems. Unpublished manuscript.		

Figure 10 - Coal Inputs to the Resource Expansion Analysis

The CO₂ capture option was based on nominally 90-percent CO₂ capture, resulting in a carbon intensity of 248-lb CO₂/MWh, which ensures compliance with the proposed EPA CO₂ regulatory limit of 1,000-lb CO₂/MWh. Sequestration costs associated with CO₂ capture are not included in the cost estimate.

1.9 RENEWABLE NON-FUEL OPTIONS

A cost analysis was performed for the four non-fuel renewable energy options listed in *Figure 11*. These costs are contained in Tables A-10 and A-11 of the IRP cost analysis spreadsheet in Appendix A.

Non-Fuel Option	Size (MW net)
Photo-Voltaic (PV) Solar	30
Concentrated Solar	30
Thermal Solar	30
Geothermal	30
Wind (ND & MT)	20
Wind (ND & MT)	50

Figure 11 - Renewable Non-Fuel Options

1.9.1 Solar and Geothermal

Sega used estimates and updates from the following three documents to develop costs for the solar and geothermal options for the 2015 model:

1. **Black & Veatch. 2012.** *Cost and Performance Data for Power Generation Technologies.* 2012.
2. **Delaquil, Pat, Goldstein, Gary and Wright, Evelyn. 2008.** US Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways. *drdc.org*. [Online] 2008. [Cited: January 14, 2013.] http://docs.nrdc.org/globalwarming/files/glo_08051401A.pdf.
3. **U.S. Energy Information Administration. 2013.** *Assumptions to the Annual Energy Outlook 2013.*

Costs from each report are presented in Tables A-10 and A-11 after applying 3-percent escalation to 2015\$. There was a large variance in the cost for some of the technologies between the different reports. Sega chose DOE/EIA Annual Energy Outlook 2013 as a default where updates were available to the original 2012 report (regardless of whether it was higher). Note that in the case of Concentrated Solar, Sega used “Cost and Performance Data for Power Generation Technologies” since the DOE/EIA document did not provide costs for this option. This particular alternate reference was used because its costs were closest to the DOE/EIA reference costs for the Thermal Solar category. Some of the reports did not separate the cost for Concentrated Solar and Thermal Solar and put both technologies under Thermal Solar. In these cases, the Concentrated Solar costing included thermal storage. Thermal Solar did not include storage.

1.9.2 Wind

The analysis for the wind farms was based on indicative turbine pricing from GE for wind farm sizes of 20 MW and 50 MW. Costs associated with construction and O&M were estimated based on Montana-Dakota's experience constructing the Cedar Hills Wind Farm and the Diamond Willow Wind Farms.

1.9.3 Wind Cost Estimate

An analysis was performed to estimate the cost of a self-built 20 MW or 50 MW wind farm in Montana-Dakota's service territory. GE was contacted by Montana-Dakota to provide indicative pricing for wind turbines that could provide the generation required for these wind farms. The performance and cost estimates in this analysis assumed the GE 2.0-116 Series 2.0 MW wind turbines for both the 20 MW and 50 MW wind farms. Budgetary turbine prices, provided by GE, are provided in *Figure 12*. Sales tax was not included in the estimate, as North Dakota House Bill 1382, relating to sales tax exemption for a wind-powered electrical generating facility, was extended until January 1, 2017, and the state of Montana does not charge sales tax.

	North Dakota Site	Montana Site
20 MW Wind Farm or 10 x 2.0 MW Wind Turbines	\$2.442M per turbine	\$2.505M per turbine
50 MW Wind Farm or 25 x 2.0 MW Wind Turbines	\$2.405M per turbine	\$2.468M per turbine

Figure 12 - GE-Supplied Budgetary Turbine Price

To estimate the capital cost for the new wind farm options, a cost comparison was made to the total construction cost Montana-Dakota incurred during the 2010 Cedar Hills Wind Farm build. Engineering and supervision and general and administrative (ES&GA) and allowance for funds used during construction (AFUDC) were subtracted from the total construction costs to allow the cost basis to be unloaded. Wind turbine costs for Cedar Hills Wind Farm were replaced by the new indicative pricing supplied by GE, and the construction and installation costs for Cedar Hills Wind Farm were escalated at an annual

capital cost increase of 4 percent to bring it to 2015\$. Based on Montana-Dakota's experience with the new Thunder Spirit Wind Farm, an additional 20-percent project development and management fee was added to the total cost.

O&M costs were determined using the costs incurred over the nine cumulative years of data Montana-Dakota has compiled operating and maintaining Diamond Willow 1 Wind Farm, Diamond Willow 2 Wind Farm, and Cedar Hills Wind Farm. The wind option inputs to the resource expansion analysis are shown in *Figure 13*.

	ND - 20 MW	ND - 50 MW	MT - 20 MW	MT- 50 MW
Plant Size (MW, net)	20.0	50.0	20.0	50.0
Capital Cost (\$/kW)	\$2,032	\$1,879	\$2,069	\$1,916
Fixed O&M (\$/kW-month)	\$2.58	\$2.58	\$2.58	\$2.58
Variable O&M (\$/MWh)	\$0.00	\$0.00	\$0.00	\$0.00
Major Maintenance (\$/kW-month)	\$0.00	\$0.00	\$0.00	\$0.00
Net Full Load Heat Rate (Btu/kWh HHV)	-	-	-	-
Carbon Intensity (lb/MWh)	-	-	-	-

Figure 13 - Wind Inputs for the Resource Expansion Analysis

APPENDIX A - COST ANALYSIS TABLES

Table A-1. EGEAS Model Input Summary, 2015 \$ Summary Results for All Supply-Side Options Assessed

CATEGORY	FUEL	MODEL	PLANT SIZE (MW/net plant output)	CAPITAL COST (\$/kW)	FIXED O&M (\$/M-month)	VARIABLE O&M (\$/MWh)	MAJOR MAINTENANCE (\$/M-month)	FULL-LOAD HEAT RATE (BTU/MWh)	CARBON INTENSITY (lb/MWh)	NOx (ppmv @ 15% O ₂)	CO (ppmv @ 15% O ₂)	Fuel Cost (\$/MWh)
GT	NATURAL GAS	7EA	75.0	86	0.08	2.32	0.03	11,436	1,388	2.0	5.0	236
		LMS00PS	85.0	1056	1.47	4.49	0.03	9,206	1,088	2.5	25.0	236
		LM600PH	37.3	1,255	2.12	3.85	0.03	9,960	1,175	3.0	10.00	236
		LM600PH-Sprint [X1]	62.8	1,463	1.82	4.50	0.03	7,663	746	3.0	20.0	236
		7E5-[X1]	17.6	1,081	1.04	2.99	0.03	7,808	889	2.0	5.0	236
		7E4-[X1] Header & Expansion	25.68	788	0.77	3.57	0.03	7,921	886	2.0	5.0	236
		7FA.05 [X1]	294.6	779	0.69	2.88	0.03	6,672	788	2.0	2.0	236
		7FA.05 [X1]	593.0	742	0.63	3.46	0.03	6,631	783	2.0	2.0	236
		5F800 [X1]	213.9	1,040	0.96	3.58	0.03	7,347	887	3.0	2.0	236
		Titan 250	17.3	1,341	2.66	2.32	0.03	10,427	1,221	15.0	5.0	265
		20P466	28.0	1,550	0.92	9.63	0.45	8,842	970	5.0	15.0	236
		BOILER	SOLID WASTE/ASH	SOLID WASTE	15.0	17,475	973	5.82	0.03	16,002	3,685	70.0
BIOWASS	2.99			3,896	973	5.82	0.03	11,056	2,436	70.0	76.0	675
BOILER	COAL/LIGNITE	COAL (lignite) with CO ₂ capture	122.0	7,099	22.25	19.81	0.00	13,781	248	15.0	40.0	191
		COAL (lignite) without CO ₂ capture	185.0	3,882	18.49	12.49	0.00	9,974	1,945	15.0	40.0	191
RENEWABLE	NON-FUEL	PH SOLAR	300	4,037	1.61	0.00	0.00	-	-	-	-	0.00
		CONC SOLAR	300	7,715	4.55	0.00	0.00	-	-	-	-	0.00
		THERMAL SOLAR	300	5,282	6.19	0.00	0.00	-	-	-	-	0.00
		GEO THERMAL	300	2,723	10.49	0.00	0.00	-	-	-	-	0.00
		WIND ND-20MW	200	2,032	2.38	0.00	0.00	-	-	-	-	0.00
		WIND ND-50MW	500	1,879	2.38	0.00	0.00	-	-	-	-	0.00
		WIND MT-20MW	200	2,089	2.38	0.00	0.00	-	-	-	-	0.00
		WIND MT-50MW	500	1,916	2.38	0.00	0.00	-	-	-	-	0.00

APPENDIX A - COST ANALYSIS TABLES

Table A-5. CTG EGES Model Input Summary, 2015 \$

	GE 7E4 ¹ (simple cycle)	GE UMS10DP2 ² (simple cycle)	GE UM60DPH ³ (simple cycle)	GE UMS00DH Spint ⁴ (HX)	GE 7E4 ⁵ (HX)	GE 7E6 ⁶ (HX)	GE 7E66 (HX) Heatex3 Expansion	GE 7FA.05 ⁷ (HX)	GE 7FA.05 ⁸ (HX)	SIEMENS SGT800 ⁹ (HX)	Solar Solar Titan 250 ¹⁰ (simple cycle landfill gas)
Plant Size (MW) net output	75.0	85.9	37.3	62.8	127.6	252.8	294.6	356.0	213.9	17.3	
Capital Cost (\$/kW) ¹¹	\$816	\$1,056	\$1,295	\$1,463	\$1,081	\$788	\$799	\$792	\$1,040	\$1,341	
Fixed O&M (\$/M-month)	\$0.98	\$1.47	\$2.12	\$1.82	\$1.04	\$0.77	\$0.69	\$0.63	\$0.96	\$2.66	
Variable O&M (\$/MWh)	\$2.82	\$4.49	\$3.36	\$4.50	\$2.99	\$3.37	\$2.88	\$3.46	\$3.38	\$2.32	
Major Maintenance (\$/M-month)	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	
Full Load Heat Rate (BTU/MWh)	114.86	92.06	9,990	7,663	7,608	7,592	6,672	6,681	7,347	10,427	
Carbon Intensity (lb/MWh)	1,268	1,088	1,175	746	889	866	788	788	867	1,221	
NOx (ppmvd @ 15% O2) (Controlled)	2.0	2.5	3.0	3.0	2.0	2.0	2.0	2.0	2.0	1.50	
CO (ppmvd @ 15% O2)	5	25	100	20	5	5	2	2	2	5	
Fuel Cost (\$/Mcu) ^{12,13}	\$296	\$296	\$296	\$296	\$296	\$296	\$296	\$296	\$296	\$296	

1. Simple cycle gas turbine, one GE 7FA engine
 2. Simple cycle gas turbine, one GE UMS10DPH engine
 3. Simple cycle gas turbine, one GE UM60DPH engine
 4. Single pressure cc; extraction condensing turbine, water cooling with mechanical draft cooling tower.
 5. Double pressure, no reheat cc
 6. Double pressure, no reheat cc. New CT, HRSG, and ST, sub. cooling tower, added to the existing 7FA
 7. Triple pressure reheat cc; reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions (40 deg F, 40% RH); duct burner
 8. Two triple pressure reheat cc; reheat before IP, water cooling with mechanical draft cooling tower, cooling tower sized for summer conditions (40 deg F, 40% RH); duct burner
 9. Three Siemens engines, joint configuration GT, HRSG, and condensing no reheat ST
 10. Simple cycle gas turbine, one Solar Titan 250 engine
 11. Total Capital Investment - Unloaded, divided by net output
 12. Landfill Gas - Estimated median landfill gas cost based on range of \$1.4/MWh as stated in the EPA document - An overview of landfill gas energy in the United States based on the MOP database and program. File updated in 2013. Escalated to 2015 \$ at 3% a year.
 13. Natural Gas Price per Montana-Dakota
- Note: All based on net output.

APPENDIX A - COST ANALYSIS TABLES

Table A-6. RICE Costs Basis and Capital Costs, 2015 \$

	WARTSILA 20V34SG¹
Plant Information	
Number of Engines	3
Unit Size (MW, net)	9.3
Unit Size (MMBtu/hr HHV)	77
Plant Size (MW, net)	28
Plant Size (MMBtu/hr HHV)	232
Net Heat Rate (Btu/kWh HHV)	8,542
Additional Plant Information	
CatOx	Y
SCR	Y
Cost Information	
Total equipment cost	\$16,222,500
BOP/Engineering	\$24,333,750
Owner Soft Cost (Loaded)	\$3,650,063
Owner Soft Cost (Unloaded)	\$1,622,250
Total Capital Investment (TCI-UL)-Unloaded, 2015 \$ ²	\$42,178,500
Total Capital Investment (TCI)-Loaded, 2015 \$	\$44,206,313
Pollutant Information	
CO2 (lb/MWh, net)	970
NOx (ppmvd @ 15% O2) (Controlled)	5

APPENDIX A - COST ANALYSIS TABLES

Table A-7. RICE EGEAS Model Input Summary, 2015 \$

	WARTSILA 20V34SG ¹
Plant Size (MW, net plant output)	28
Capital Cost (\$/kW) ^{2,3}	\$1,550
Fixed O&M (\$/kW-month)	\$0.92
Variable O&M (\$/MWh)	\$9.63
Major Maintenance (\$/kW-month)	\$0.45
Full Load Heat Rate (Btu/kWh, HHV, net)	8,542
Carbon Intensity (lb/MWh)	970
NOx (ppmvd @15% O ₂)	5
CO (ppmvd @ 15% O ₂)	15
Fuel Cost (\$/MMBtu) ⁴	\$2.96

1. All cost and performance numbers supplied by Wartsila.
2. Without Owner's AFUDC or Administrative Costs.
3. Total Capital Investment - Unloaded, divided by net output
4. Montana-Dakota provided

APPENDIX A - COST ANALYSIS TABLES

Table A-8. Renewable Fuel Boiler Cost Basis and Results

	BOILER¹ SOLID WASTE	BOILER² BIOMASS
Plant Information		
Number of Boilers	1	1
Unit Size (MW, net)	15.0	29.9
Unit Size (MMBtu/hr HHV)	54	359
Plant Size (MW, net)	15.0	29.9
Plant Size (MMBtu/hr HHV)	54	359
Net Heat Rate (Btu/kWh HHV)	16,002	11,056
Water (1,000 lb/hr)	159	218
Water (1000 gallons/hr)	19.2	26.2
Additional Plant Information		
CatOx	N	N
SCR	N	N
Cost Information		
Total Capital Investment (TCI-UL)-Unloaded, 2015 \$ ³	\$261,426,399	\$119,193,386
Total Capital Investment (TCI)-Loaded, 2015 \$	\$161,248,116	\$125,964,969
Labor Rate (\$/hr), 2015 \$	\$59.10	\$59.10
FTE Hours (hr/yr), 2015 \$	\$2,080	\$2,080
FTE Cost (\$/yr), 2015 \$	\$122,928	\$122,928
Pollutant Information		
CO2 (lb/hr, net)	49,353	72,846
CO2 (lb/MWh, net)	3,299	2,436

1. Municipal solid waste (36% moisture, 32% ash, 17% carbon); water cooling with mechanical draft cooling tower; BFB boiler.

2. Wood pellets; water cooling with mechanical draft cooling tower; BFB boiler.

3. Total Capital Investment - Unloaded, divided by net output

APPENDIX A - COST ANALYSIS TABLES

**Table A-9. Renewable Fuel and Coal Boiler
EGEAS Model Input Summary, 2015 \$**

	BOILER¹ SOLID WASTE BURNER	BOILER² BIOMASS	BOILER - CFBC with CO₂ Capture³ COAL (Lignite)	BOILER - CFBC without CO₂ Capture³ COAL (Lignite)
Plant Size (MW, net plant output)	15.0	29.9	122.0	185.0
Capital Cost (\$/kW) ⁴	\$17,475	\$3,986	\$7,099	\$3,882
Fixed O&M (\$/kW-month) ⁵	\$9.73	\$9.73	\$22.55	\$18.49
Variable O&M (\$/MWh) ⁵	\$5.82	\$5.82	\$19.81	\$12.49
Major Maintenance (\$/kW-month)	\$0.03	\$0.03	\$0.00	\$0.00
Full Load Heat Rate (Btu/kWh, HHV, net)	16,002	11,056	13,781	9,974
Carbon Intensity (lb/MWh)	3,685	2,436	248	1,945
NO _x (ppmvd @ 15% O ₂)	70	70	15	15
CO (ppmvd @ 15% O ₂)	76	76	40	40
Fuel Cost (\$/MBtu) ⁶	\$3.00	\$6.75	\$1.91	\$1.91

1. Municipal solid waste (36% moisture, 32% ash, 17% carbon); water cooling with mechanical draft cooling tower, BFB boiler.
2. Wood pellets; water cooling with mechanical draft cooling tower, BFB boiler.
3. Montana-Dakota provided values
4. Without Owner's AFUDC or Administrative Costs. Total Capital Investment - Unloaded, divided by net output
5. Assumptions to the Annual Energy Outlook 2013, EIA/DOE.
6. Solid waste burner fuel costs estimated by Segs Inc. Coal boiler costs provided by Montana-Dakota.

Boiler Input Summary

Therminflow Default Cost	BOILERS (BIOMASS OR SOLID WASTE)	
	Fixed O&M \$/kw/month	Variable O&M \$/MWh
Cost and Performance Data for Power Generation Technologies ¹	\$3.53	\$6.37
Assumptions to the Annual Energy Outlook 2013, EIA/DOE ²	\$9.74	\$18.45
	\$9.73	\$5.82

1. Values adjusted to 2015\$ from the 2013 model 3%/yr escalation
2. Values adjusted to 2015 \$ (based on 2011 \$/MWh reported) 3%/yr escalation

APPENDIX A - COST ANALYSIS TABLES

**Table A-10. Renewable Non-Fuel
EGEAS Model Input Summary, 2015 \$**

	PV SOLAR	CONC. SOLAR	THERMAL SOLAR	GEO THERMAL	WIND ² ND - 20MW	WIND ² ND - 50MW	WIND ² MT - 20MW	WIND ² MT - 50MW
Plant Size (MW, net plant output)	30	30	30	30	20	50	20	50
Capital Cost (\$/kW) ¹	\$4,037	\$7,715	\$5,282	\$2,723	\$2,032	\$1,879	\$2,069	\$1,916
Fixed O&M (\$/kW-month)	\$1.61	\$4.55	\$6.19	\$10.49	\$2.58	\$2.58	\$2.58	\$2.58
Variable O&M (\$/MWh)	\$0	\$0	\$0	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Major Maintenance (\$/kW-month)	\$0	\$0	\$0	\$0	\$0.00	\$0.00	\$0.00	\$0.00
Full Load Heat Rate (BTU/kWh, HHV, net)	-	-	-	-	-	-	-	-
Carbon Intensity (lb/MWh)	-	-	-	-	-	-	-	-
NOx (ppmvd @ 15% O ₂)	-	-	-	-	-	-	-	-
CO (ppmvd @ 15% O ₂)	-	-	-	-	-	-	-	-
Fuel Cost (\$/MBtu)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

1. Assumptions to the Annual Energy Outlook 2013, EIA/DOE.

2. Montana-Dakota provided values

APPENDIX A - COST ANALYSIS TABLES

	PV SOLAR		CONC. SOLAR		THERMAL SOLAR		GEOTHERMAL		
	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Variable O&M*
	\$5,114	\$1.23	\$3,680	\$2.46	\$3,391	\$3.69	\$3,690	\$9.33	\$11.86
\$3,377	\$4.55	\$7,715	\$4.55	\$5,365	\$4.55	\$6,491	\$0.00	\$33.87	
\$4,037	\$1.61	NA	NA	\$5,282	\$6.19	\$2,723	\$10.49	\$0.00	

Table A-11. Geothermal and Solar Input Summary, 2015 \$

US Technology Choices, Cost and Opportunities under the Lieberman-Warner Security Act: Assessing Compliance Pathways¹

Cost and Performance Data for Power Generation Technologies¹
Assumptions to the Annual Energy Outlook 2013²

1. Values adjusted to 2015\$ from the 2013 model 3%/yr escalation

2. Values adjusted to 2015 \$ (based on 2011 \$/MWh reported) 3%/yr escalation

Attachment F

FUTURE TRANSMISSION SERVICE CHARGE IMPACTS

FUTURE TRANSMISSION SERVICE CHARGE IMPACTS

Montana-Dakota's electric service customers in the Interconnected System will continue to be faced with increases in direct and indirect transmission service charges in the future. The increased transmission service charges result from the termination of the Transmission Services Agreement (TSA) with Western Area Power Administration (WAPA) on December 31, 2015 along with WAPA and Basin Electric Power Cooperative (BEPC) intent to join Southwest Power Pool (SPP) as a transmission owning member on October 1, 2015; 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 the allocation of future MISO Multi-Value Projects (MVP). MISO is also developing protocols through its stakeholder process, per FERC Order 1000, for the development and cost allocation of interregional transmission projects.

Transmission Services Agreement with Western Area Power Administration

Montana-Dakota and WAPA have a long history of sharing transmission facilities and providing service across each other's systems using a reciprocal wheeling arrangement. This agreement has worked well in the past for Montana-Dakota's customers. The current TSA with WAPA will expire on December 15, 2015. Montana-Dakota has attempted to enter into negotiations with WAPA to extend the TSA, but WAPA has indicated that it is unable to extend the TSA. WAPA and BEPC have announced their intention to join SPP as a transmission owning member on October 1, 2015 and as such transmission service across their facilities will be covered under the SPP Tariff. With the expiration of the WAPA TSA, Montana-Dakota will be required to take Network Integrated Transmission Service (NITS) under the SPP Tariff for service that it currently receives 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 to the rest of Montana-Dakota's interconnected service territory and the MISO.

Montana-Dakota continues to see greater value in remaining a MISO transmission owning member as compared to the exit MISO and join SPP option. The greater MISO 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 as all customer load does not peak at the same time. Montana-Dakota receives a significant benefit as being the western most transmission owning member in MISO as Montana-Dakota's customer only need to currently

supply 80.3% 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 supply mix.

Based on Montana-Dakota's average customer load in 2014, Montana-Dakota would have been required to secure approximately 325 MW of NITS service from the IS Tariff at \$2.96 per kW-month or approximately \$11,544,000 per year. The UMZ (WAPA/ BEPC load zone) rate under SPP Tariff is still unknown and Montana-Dakota is estimating the rate to be close to \$4.00 per kW-month (\$15,600,000 per year) with the inclusion of SPP's regional highway / byway cost allocation included.¹ Montana-Dakota is working with SPP, WAPA, and BEPC to minimize the increased transmission bill to its customers via the receipt of Section 30.9 Facility Credits under the SPP Tariff. Montana-Dakota is currently in FERC settlement negotiations with SPP, WAPA, and BEPC on the requirements for receipt of SPP Section 30.9 Facility credits which Montana-Dakota expects will offset a significant portion of its SPP transmission bill. Even with the facility credit offsets, Montana-Dakota is still estimating an increased transmission service charge of \$5 million to \$7 million over current WAPA-IS and BEPC charges which is still in the range of what was forecasted in the 2013 IRP of \$6.7 million.

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 Federal Energy Regulatory Commission (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. As previously approved MISO RECB I and II projects are completed, Montana-Dakota and its customers will see an increase in MISO Schedule 26 charges. 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. The Alexandria to Fargo 345kV transmission line is scheduled to be 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

¹ Note, the UMZ SPP transmission zonal rate has not been established and is dependant on the ultimate transmission owners in the UMZ zone and facilities they wish to place under SPP's Tariff and functional control.

all MISO load through a post-stamp rate. Montana-Dakota's allocated investment share of the Alexandria to Fargo 345 kV line is expected to be around \$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 \$3,101,419 million dollars in 2016 which includes the cost of the Mandan 230 kV Junction Substation.² Montana-Dakota also receives RECB I (MISO Schedule 26) revenues from Otter Tail Power for the reliability benefits they are assigned for the Mandan 230kV Junction Substation.

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.

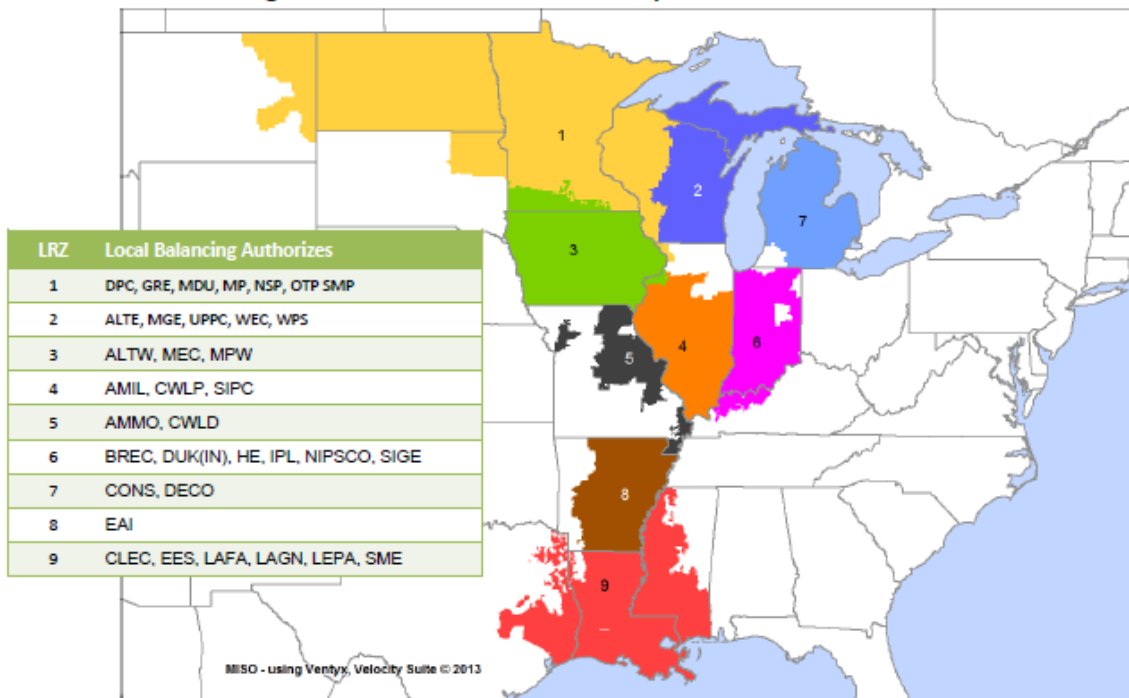
To qualify as a MEP, network transmission upgrades must be shown to have regional economic benefits as demonstrated through multi-future and multi-year planning. MEP's currently involve transmission facilities operating at voltages of 345kV and higher. Project costs must be at least \$5 million or more 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.

² MISO Indicative Annual charges for approved Baseline Reliability Projects (Schedule 26).
<https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx>

Local Resource Zones (LRZ)

2014 Planning Year – MISO LRZ Map



MISO engaged stakeholders in 2013 to review the MEP metrics and qualification criteria including the additional possible MEP metrics and benefit calculations for: (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. Based upon stakeholder comments and concerns MISO tabled further discussion until 2015. Montana-Dakota's position regarding MEP's is that the current cost allocation for MEPs is sufficient and is not in the need of any changes. If changes to voltage threshold or benefit criteria are contemplated for change than MISO must also locate at cost allocation for MEPs which could include the direct assignment of project requirements to direct benefiting loads or the redrawing of zonal boundaries for MISO Local Resource Zones.

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 (excluding PJM). The exclusion of MVP export charges to PJM was remanded by the 7th Circuit Court of Appeals back to FERC and FERC has established a paper hearing to revisit the applicability of MVP export charges for generation exports from MISO to PJM.

MVP Eligibility Criteria

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

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

2011 MVP Portfolio

MTEP 2011 approved \$5.6 billion for 17 Multi-Value Projects that were selected as part of a regional portfolio to improve reliability of the transmission system, meet public policy targets, and distribute economic benefits across the entire MISO footprint.³ The MTEP 2011 Report identified potential benefits of at least 1.6 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.⁴

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

³ MISO Transmission Expansion Plan 2011.

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

⁴ MISO 2014 MVP Triennial Review Report.

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

Company and it is expected to have an in-service date of 2019 with a constructed cost of \$396 million.

The 2019 forecasted MISO Schedule 26-A (MVP Cost Adder) charge is \$1.60 per MWh.⁵ Assuming a 2019 Total Energy Requirements of 4,366,313 MWh, this would result in a total charge of \$6.986,100 to Montana-Dakota's customers.

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

FERC Order 1000 and Intraregional Cost Sharing Principles

FERC Order 1000 requires MISO to develop interregional transmission planning protocols and cost allocation principles for developing regionally beneficial transmission projects, baseline reliability and market efficiency, with its neighbors including SPP and JPM. These planning protocols and cost allocation principles are still under development.

⁵ MISO Indicative Annual charges for approved Multi-Value Projects (Schedule 26-A).
<https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx>