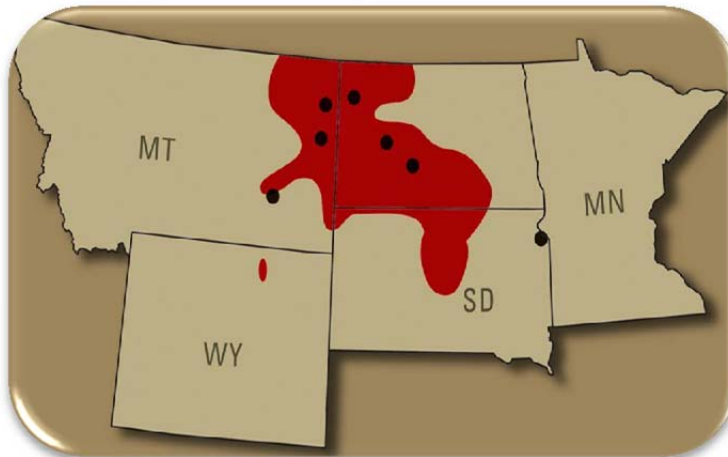




Integrated Resource Plan



2013



Submitted to the
North Dakota Public Service Commission
July 1, 2013

Volume IV: Attachments C-H

Montana-Dakota Utilities Co.
2013 Integrated Resource Plan

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**MONTANA-DAKOTA
UTILITIES CO.**

A Division of MDU Resources Group, Inc.

Attachment C

SUPPLY-SIDE AND INTEGRATION ANALYSIS DOCUMENTATION

Supply Side and Integration Analysis

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APPENDIX A – EGEAS INPUT DATA FOR THE OPTIMAL RESOURCE CASE

APPENDIX B – EGEAS OUTPUT REPORT FOR THE OPTIMAL RESOURCE CASE

Supply-Side

OVERVIEW

The supply-side analysis was conducted to identify the feasible supply-side resources to be added to Montana-Dakota's generating system to determine the most cost-effective plan. 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 as 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 6.2 percent on an unforced capacity (UCAP) basis for the summer peak. The PRM is adjusted annually through the 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 1.83 percent adder for MISO losses, plus 6.2 percent PRM, the product of which is referred to as the planning reserve margin requirement (PRMR).

Montana-Dakota is required to meet an 80.6 percent coincident factor for the 2013-14 planning year in MISO based on the fact Montana-Dakota does not peak at the time of the MISO system-wide peak. However, for planning purposes Montana-Dakota will use a 90 percent coincident factor to plan for a potential increase in the coincident factor as the coincidence factor is subject to adjustment annually.

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 a 90 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 for every month. 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 PRC 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 52.3 ZRC in 2015. This capacity deficit will increase to 102.3 ZRC in 2020 and grow to 149.4 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 54.3 ZRC will occur in 2015 and grow to 190.0 ZRC in 2020.

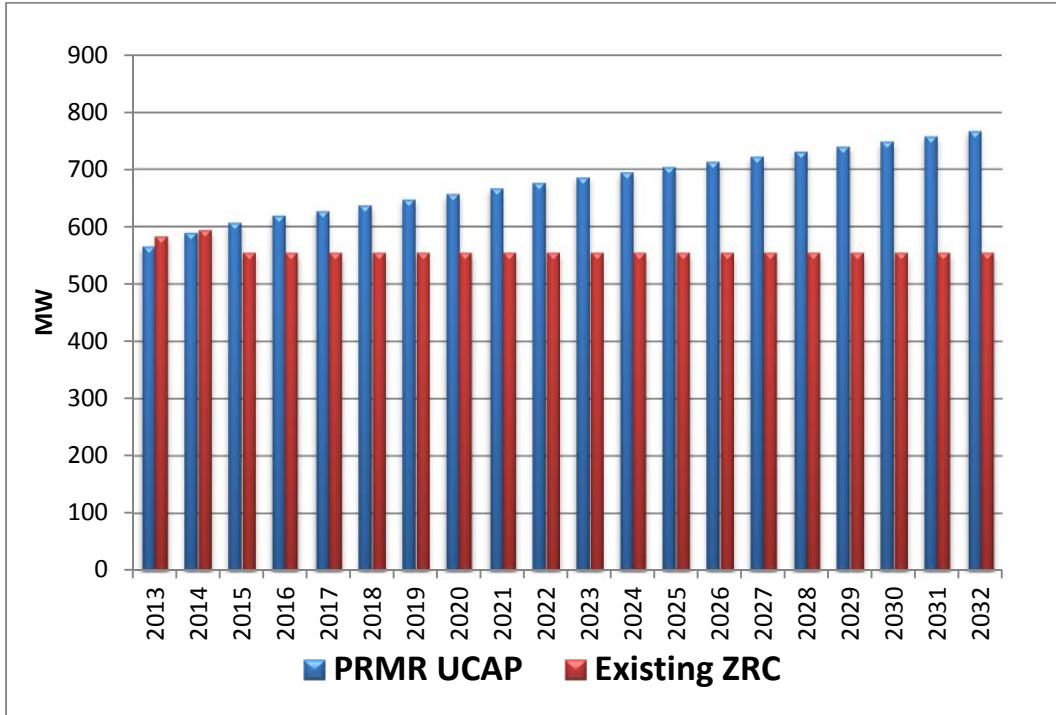


Figure 1-1: Zonal Resource Credit and Planning Reserve Margin Requirement Base Forecast

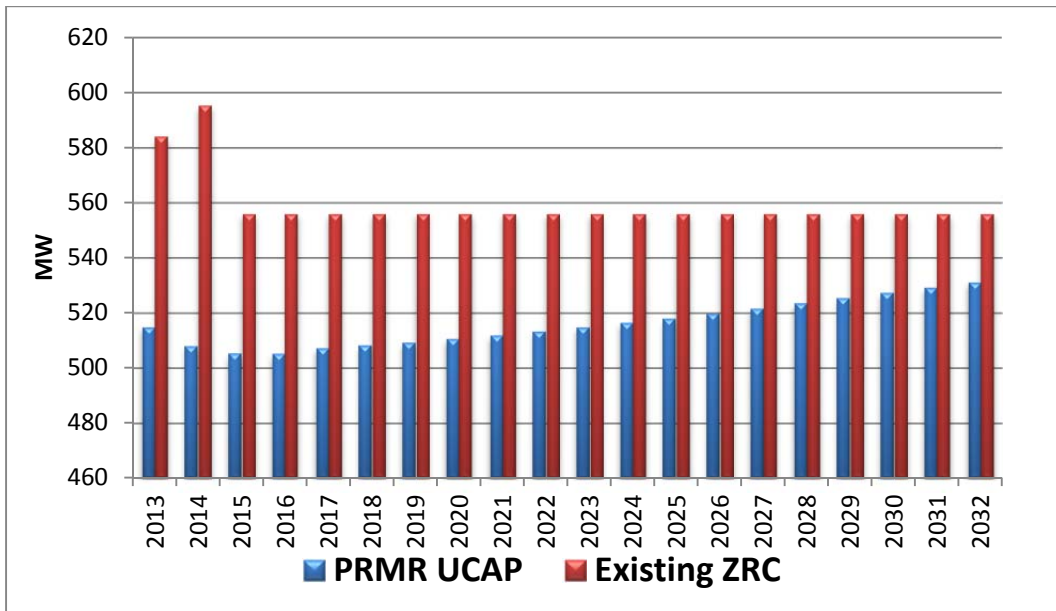


Figure 1-2: Zonal Resource Credit and Planning Reserve Margin Requirement Low Growth Forecast

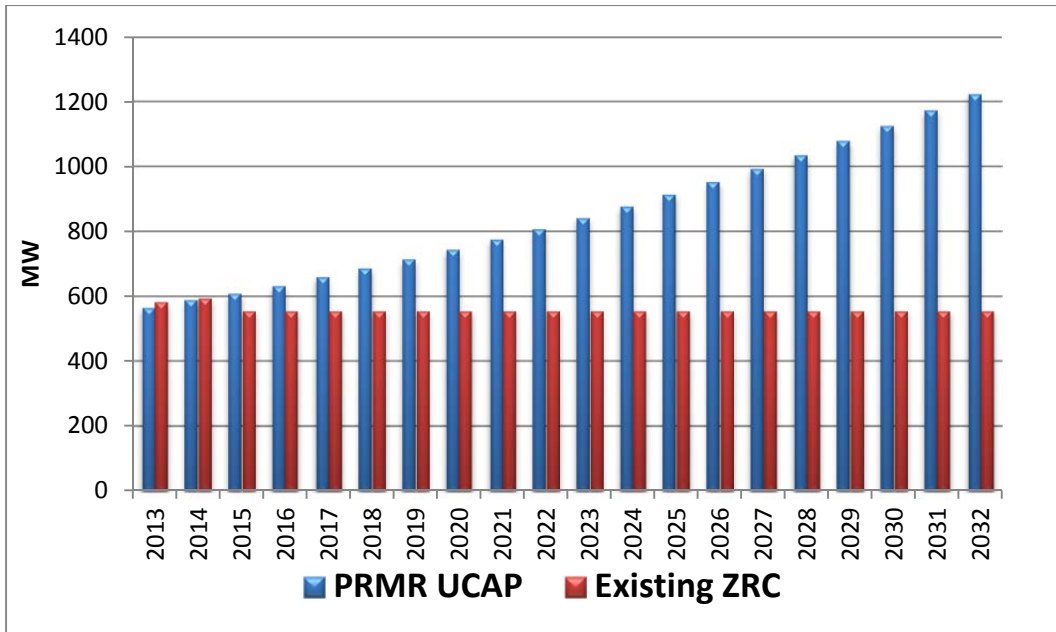


Figure 1-3: Zonal Resource Credit and Planning Reserve Margin Requirement High Growth Forecast

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 2012 with the study period starting in 2013. Costs indicated in this report are in 2012 dollars, unless otherwise specified. The study for each scenario was conducted over a 20-year period (2013-2032) 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, along with a capacity purchase contract – the WE Energies contract for the 2012-2015 timeframe. 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 zonal resource credit (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, the 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 a transmission service request. The ZRC value for wind resources is based on an effective load carrying capability (ELCC) study performed annually by the MISO. This study examined 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 2013-2014 planning year, the ELCC study concluded that 13.3 percent of nameplate wind capacity could be converted into a ZRC value if the wind resource is a network resource or has a transmission service request (TSR). Based upon Montana-Dakota's wind farms' CPNodes, Diamond Willow was determined to contribute up to 17.47 percent of its nameplate capacity to ZRCs, and Cedar Hills was allowed up to 23.06 percent of its nameplate capacity to ZRCs. Ultimately, Diamond Willow, a designated network resource, was accredited with 5.2 ZRCs as Montana-Dakota holds a TSR for Diamond Willow. Cedar Hills, also a designated network resource with a TSR, was accredited with 4.5 ZRCs.

2.1. Current Resources

The existing generation portfolio is broken down into four groups: coal, natural gas/oil, renewable, and purchase power. Figure 2-1 shows Montana-Dakota's 2013 current generation mix by zonal resource credits. Fifty-eight percent of Montana-Dakota's ZRCs comes from coal generation, 17 percent from gas-fired generation, 20 percent from purchased capacity, three percent from DSM and two percent from renewable resources.

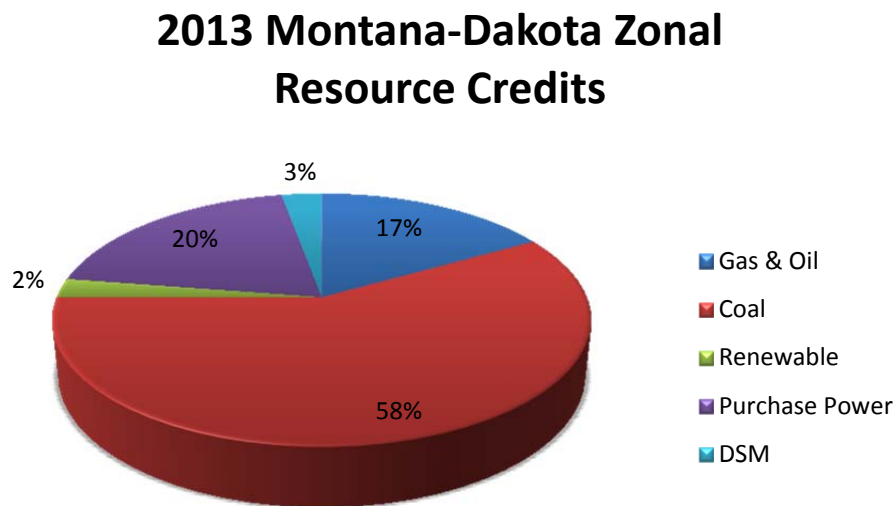


Figure 2-1: Montana-Dakota's Current Generation Mix by Zonal Resource Credits

2.1.1. Coal

Montana-Dakota currently owns five coal-fired units two of which are jointly owned with other regional utilities. Coal currently accounts for 58 percent of the zonal resource credits on Montana-Dakota's system. Table 2-1 shows the capacity in MW established by the MISO Generator Verification Test Capability (GVTC) process, equivalent forced outage rate (XEFOR_d), number of zonal resource credits, and various costs for each coal-fired plant serving Montana-Dakota's customers.

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

<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	107.0	4.74	101.7	23.86	2.47	1.45
Big Stone ³	107.7	6.32	101.3	23.19	1.63	2.20
Heskett 1	28.2	5.37	20.8	57.55	7.36	1.81
Heskett 2	74.2	11.60	64.6	53.78	7.71	1.80
Lewis & Clark	52.3	0.47	52.1	52.01	3.02	1.44

1. Based on MISO 2013-14 Planning Year ICAP and XEFOR_d
2. Montana-Dakota’s 22.7 percent ownership share
3. Montana-Dakota’s 25 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 17 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 Generator

<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	34.7	7.43	33.8	5.57	2.00	3.70
Glendive 2	40.3	4.20	38.6	5.81	2.00	3.70
Miles City	23.0	9.63	20.8	10.13	2.00	3.70
Diesel 1	2.0	9.75	1.8	3.69	2.00	28.16
Diesel 2	2.1	9.75	1.8	3.69	2.00	28.16
Diesel 3	2.1	9.75	1.9	3.69	2.00	28.16

1. Based on MISO 2013-14 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 two 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 ¹	5.2	23.22	-31.85	-
Cedar Hills ¹	4.5	23.22	-31.85	-
Glen Ullin Station 6 ²	4.3	50.10	6.90	-

1. ZRC is based on MISO ELCC study. Variable O&M cost includes the Production Tax Credit, which is represented by a negative \$/MWh cost value.
2. Based on MISO 2013-14 Planning Year ICAP and XEFOR_d

2.1.4. Purchased Power

In addition to generation resources that Montana-Dakota owns, the Company has entered into a purchased power contract, shown in Table 2-4, to meet the planning reserve margin requirements within the MISO.

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

<u>Unit</u>	<u>Zonal Resource Credit¹</u>	<u>Fixed O&M (\$/kW/year)</u>	<u>Variable O&M (\$/MWh)</u>	<u>Fuel (\$/MBTU)</u>
WE Energies Contract ¹	115-120	34.80	111.50	-

1. Expires after May 31, 2015

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 2014.

- Montana-Dakota Interruptible loads – 13 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 30 MW block of energy for off-peak and on-peak periods.

2.2 Future Capacity Resources

Construction is underway on a new natural gas fired combustion turbine near the existing Heskett coal-fired plants in Mandan, ND. The new Heskett 3 combustion turbine will be an 88 MW unit commercially available by July 2014.

The cost of 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 2015. The analysis assumed the retirement of the Big Stone plant (with 101.3 ZRCs) in 2015 with a new resource option available to the EGEAS model in 2015 that includes the AQCS retrofit project and associated future operating costs for the Big Stone plant. The new resource option was assumed to be accredited with a lower ZRC value (99.7 ZRCs), as the AQCS would slightly reduce the capacity output of the Big Stone plant.

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 Internal Combustion Engines,
- Combined cycle Combustion Turbine,
- Coal,
- Wind (self-built),
- Solar,
- Wind (purchased energy),
- Landfill Gas,
- Biomass,
- Solid Waste,

- Geothermal and,
- Lewis & Clark Options.

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 F.

2.3.1. Simple Cycle Combustion Turbine

Simple-cycle combustion turbines (SCCT) are primarily built to serve peaking capacity needs and are usually used to supply a limited amount of energy because SCCTs are fueled by natural gas or fuel oil, which results in higher fuel cost than coal. The SCCT units are, however, lower in capital costs 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). Aero SCCT's are adapted from jet and turboshaft jet engines, and are usually lighter, smaller, and more thermally efficient than similar sized Frame units. However, they generally have a higher capital cost, more expensive maintenance costs, are more susceptible to reliability problems in cold weather operation, 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 four Frame units, and one Aero unit. Three options for the SCCT were analyzed in the resource expansion analysis: a 37.4 MW Aero unit, a 71.6 MW Frame unit, and an 87.4 MW Aero unit.

2.3.2. Simple Cycle Internal Combustion Engine

Simple-cycle internal combustion engines (ICE) are primarily built to serve peaking capacity needs and are usually used to supply a limited amount of

energy because ICEs are fueled by natural gas or fuel oil, which results in higher fuel cost than coal. These units require a relatively short lead time (two to three years) and are normally more thermally efficient, lower in capital cost, and require lower fuel pressure compared to other SCCT's of similar power output. Two ICE plants, utilizing two ICE's per plant, were analyzed in the resource expansion analysis: a 36.6 MW natural gas fired option, and a 33.3 MW dual fuel option that is designed to burn natural gas or fuel oil.

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 that produces steam for a steam turbine. CCCT's have one of the highest efficiencies of any new power plant, at more than 60 percent , and are usually used as a baseload unit. However, because they are fueled by natural gas or fuel oil, the units are higher-cost energy producers compared to coal-fired baseload units, which could limit their hours of operation. There were three natural gas fired CCCTs analyzed in the resource expansion analysis: a 47.5 MW Aero unit, a 129 MW Frame unit, and a 560 MW Frame unit.

2.3.4. Coal

Coal-fired power plants are primarily built to serve baseload power requirements. This type of generation is characterized as having a high capital cost with low operating and fuel costs, while providing a stable capacity and energy source. However, as significant new federal regulations are being proposed to reduce air emissions, including greenhouse gases, coal-fired baseload generation is unlikely to be available as a new resource option for the foreseeable future. Two lignite coal-fired power plants, modeled in blocks of 30 MW, were included in the resource expansion analysis: a 168 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 units and combustion turbines, 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. A \$23/MWh (after tax) Production Tax Credit (PTC), which was modeled as a negative variable O&M cost, was assumed to be in effect for new wind generation installed before the end of 2014 as long as construction started at the end of 2013. Once the wind generation was selected (as part of the least-cost plan), the tax credit would continue for ten years from its date of commercial operation. Table 2-5 shows four different options: 20 MW and 50 MW North Dakota options, and 20 MW and 50 MW Montana options. Wind resources installed before the end of 2014 includes the PTC, while wind resource options after 2014 do not include the tax credit.

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. Wind (Purchased Energy)

The wind energy purchase option was modeled in two blocks of 25 MW that provide energy only with no eligible ZRCs. They were included as a 2015 option in the model and scheduled to last for 30 years.

2.3.8. Landfill Gas

Methane gas produced from landfill sites can be captured and used as an alternative fuel to produce electricity. Montana-Dakota modeled a 31.8 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.

2.3.9. 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 37.1 MW biomass option was included in the resource expansion analysis.

2.3.10. 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. A performance and cost analysis was completed for this unit for inclusion into the resource expansion model. However, after a considerable amount of research, an accurate estimate for fuel costs could not be obtained. Therefore, the solid waste option was not included as an alternative for the supply-side resource options.

2.3.11. 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.

2.3.12. Lewis & Clark Options

Additional alternatives were included in the analysis in order to model the cost effectiveness of a baghouse being added to the Lewis & Clark plant or converting the plant to run only on natural gas. To comply with the Mercury and Air Toxics Standards (MATS), the Lewis & Clark plant will be required to install a baghouse for particulate control or convert to natural gas-fired generation only. The baghouse project and natural gas options were studied to compare the required retrofits against other alternatives to determine if it would be more effective to retire the Lewis & Clark plant, convert the plant to natural gas-fired generation only, or install the baghouse required to allow continued operation of the plant. The analysis assumed the retirement of the Lewis & Clark plant at the end of 2014 with the new resource options available to the EGEAS model in 2015. The model assumed if the baghouse option was chosen the life of the plant would be five additional years from the time the baghouse was installed. The five year life is a conservative modeling approach and is used to show the value of continuing to run Lewis & Clark Station on coal even under a limited remaining life scenario. The natural gas-fired options for Lewis & Clark Station were considered to have a twenty year life. The Lewis & Clark Station is located within the Bakken Oil Field development area and is an important generation resource within the Bakken area that serves load and provides voltage support to the region. With the rapid growth of activity in the Bakken area, the Lewis & Clark Station is needed to maintain reliability in the area under both peak system conditions and various transmission outage conditions. For reliability purposes, Lewis & Clark Station natural gas-fired options in the EGEAS model were required to operate at their minimum generation level for four months, equal to a minimum ten percent capacity factor, every year through 2019 to support the Bakken area load.

Table 2-5

Considered Resource Alternatives Available to Montana-Dakota

EGEAS Model Input Summary, 2013 \$	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	71.6	67.4	\$759.13	\$0.96	\$2.70	\$0.03	\$17.47	11955	699	\$3.70
GELMS100PB ¹	87.4	82.2	\$976.15	\$1.42	\$4.45	\$0.03	\$21.98	9049	529	\$3.70
GE LM6000PH ¹	37.4	34.8	\$1,232.02	\$2.06	\$4.24	\$0.03	\$35.78	9943	584	\$3.70
GE LM6000PH Sprint (CC 1X1) ¹	47.7	44.3	\$1,479.03	\$2.10	\$4.65	\$0.03	\$33.95	8295	491	\$3.70
GE 7EA (CC 1X1) ¹	129	122.4	\$1,069.36	\$1.05	\$3.37	\$0.03	\$16.06	7611	447	\$3.70
GE7FA.05 (CC 2X1) ¹	200	189.8	\$827.57	\$0.72	\$3.81	\$0.03	\$11.00	6719	396	\$3.70
SIEMENS SGT-900 LANDFILL GAS ²	31.8	29.6	\$1,165.81	\$1.73	\$2.70	\$0.03	\$21.12	13634	1178.5	\$4.44
WARTSILA 18V50SG	36.6	34.0	\$954.68	\$0.71	\$3.30	\$0.87	\$29.89	8368	461	\$3.70
WARTSILA 18V50DF	33.3	30.9	\$1,053.92	\$0.71	\$3.30	\$0.92	\$31.57	8467	465.5	\$3.70
BIOMASS ⁴	37.1	30.8	\$3,212.76	\$9.16	\$5.46	\$0.03	\$110.28	11218	1196.5	\$6.75
PV SOLAR	30	7.5	\$5,196.00	\$1.52	\$0.00	\$0.00	\$18.24	-	-	\$0.00
CONC. SOLAR	30	9.0	\$7,271.80	\$4.29	\$0.00	\$0.00	\$51.48	-	-	\$0.00
THERMAL SOLAR	30	6.0	\$5,126.00	\$5.83	\$0.00	\$0.00	\$69.96	-	-	\$0.00
GEOTHERMAL	30	18.9	\$2,746.00	\$9.89	\$10.53	\$0.00	\$118.68	-	-	\$0.00
CFBC WITHOUT CO2 Capture	168	155.7	\$3,520.07	\$17.43	\$11.78	\$0.00	\$209.16	9974	973	\$1.45
CFBC WITH CO2 Capture ⁶	122	113.1	\$6,437.54	\$23.92	\$18.67	\$0.00	\$287.04	13781	124	\$1.45
ND Wind ³	20.4	4.0	\$1,897.63	\$3.27	\$0.00	\$0.00	\$39.24	-	-	\$0.00
ND Wind ³	49.3	10.0	\$1,885.16	\$3.27	\$0.00	\$0.00	\$39.24	-	-	\$0.00
MT Wind ³	20.4	4.0	\$1,853.75	\$3.27	\$0.00	\$0.00	\$39.24	-	-	\$0.00
MT Wind ³	49.3	10.0	\$1,836.10	\$3.27	\$0.00	\$0.00	\$39.24	-	-	\$0.00
Wind Energy ⁵	25	-	-	\$0.00	\$28.00	\$0.00	\$0.00	-	-	\$0.00
Lewis & Clark Bag House ^{4,5}	52	51.8	\$527.29	\$5.02	\$3.89	\$0.00	\$60.29	12700	1529	\$1.44
Lewis & Clark Gas Option 1	52.3	52.1	\$196.45	\$3.88	\$1.45	\$0.00	\$46.51	12412	1000	\$3.70
Lewis & Clark Gas Option 2	52.3	52.1	\$22.49	\$5.99	\$1.45	\$0.00	\$71.88	12412	1000	\$3.70
Lewis & Clark Gas Option 3	52.3	52.1	\$298.28	\$3.88	\$1.45	\$0.00	\$46.51	12412	1000	\$3.70

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

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

2. Fuel costs will be set at a 20% premium over natural gas prices. 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. Included an option with a negative variable O&M to represent production tax credits (PTC) for wind through 2014.

4. The capital cost includes AFUDC.

5. The O&M costs are in 2015 dollars.

6. 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. The retirement is modeled with the assumption that additional EPA rules may be developed around 2020 that would require the Heskett 1 plant to install new emission controls or shutdown. However, at this time there is no actual plan to retire Heskett 1.

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.

3. Summaries of Results

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

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

	Lewis & Clark Resource Options					All Sensitivity Cases run with Optimal Resource Case							
	Base Case: Lewis & Clark retire 2014	Lewis & Clark Gas Option 1	Lewis & Clark Gas Option2	Lewis & Clark Gas Option3	Optimal Resource Case	Low Gas price	High Gas Price	Low Growth	High Growth	\$30 Carbon Tax	\$50 Carbon Tax	High CT and IC Costs	Current MISO RA
2013							WIND50			WIND20	WIND50		
2014													
2015	4-WSCT, 2-WIND_PPA	LCNG1, 2- WIND_PPA, 2- WSCT	LCNG2, 2- WIND_PPA, 2-WSCT	LCNG3, 2- WIND_PPA, 2-WSCT	LCBH,2- WIND_PPA, 2-WSCT	LCBH,2- WIND_PPA,2- WSCT	LCBH,2- WIND_PPA,2- WSCT	2- WIND_PPA	LCBH,2- WIND_PPA,2- WSCT	LCBH,2- WIND_PPA, 2-WSCT	LCBH,2- WIND_PPA, 2-WSCT	LCBH, 2- WIND_PPA, 2-WSCT	LCBH,2- WIND_PPA
2016							WSCT		WSCT				
2017		CT72	CT72	CT72	WSCT	WSCT		WSCT	CT72			WSCT	WSCT
2018							WIND20			WSCT	WSCT		
2019	CT72						WIND50						
2020					CC-200	CC-200	CC-200		CC-200	CC-200	CC-200	CC-200	CC-200
2021													
2022		CC-129	CC-129	CC-129									
2023													
2024	CC-129								CC-129				
2025									CT72				
2026								WSCT					
2027									CC-129				
2028		WSCT	WSCT	WSCT					CT72				
2029	WSCT												
2030									CC-129				
2031		WSCT	WSCT	WSCT			WIND20		CT72				
2032	WIND20				WIND20	WIND20	WIND50		WSCT			WIND20	
NPV ¹	\$3,639.70	\$3,643.13	\$3,648.09	\$3,656.01	\$3,525.11	\$3,263.55	\$4,144.76	\$2,417.28	\$5,229.43	\$4,457.98	\$5,061.77	\$3,599.27	\$3,412.59

1 - NPV in millions of dollars

LCBH - Lewis & Clark Bag House(~\$27.4 million)

WSCT - 36.6MW (2 Wartsila18V50SG) Internal Combustion Engine(~\$955/kW or \$33.2 million)

LCNG1 - Lewis & Clark fueled by natural gas(~\$10.3 million)Option1-Bear Paw plant

LCNG2 - Lewis & Clark fueled by natural gas(~\$1.2 million capital and \$1.3 million annual reservation)Option2-Modify WBI Charbonneau station

LCNG3 - Lewis & Clark fueled by natural gas(~\$15.6 million)Option3-Direct build to Northern Border

WIND_PPA - 25MW blocks

CC-200 - 200MW of a potential partnership of a 560MW GE7FA.05(Combined Cycle 2x1) (\$828/kW or \$165.5 million)

CT72 - 71.6MW GE 7EA Combustion Turbine (~759/kW or \$54.4 million)

CC-129 - 129MW Combined Cycle of GE 7EA(incremental increase of~\$648/kW or ~\$83.6 million)

WIND50 - 50 MW of self-built wind

WIND20 - 20 MW of self-built wind

3.1. Optimal Resource Plan Results

The Optimal Resource least-cost plan consists of the following resource additions for 2015-2020:

- Install the Lewis & Clark baghouse in 2015;
- Install 73 MW of Internal Combustion Engines in 2015;
- Contract for 50 to 100 MW of wind energy in 2015;
- Continue the commercial demand response program to achieve 10 MW by 2015 and achieve a total of 13 MW from Montana-Dakota’s interruptible rate;
- Install an additional Internal Combustion Engine (36.6 MW) in 2017; and
- Assuming the retirement of Heskett 1 and Lewis & Clark at the end of 2019, be capable of partnering to take 200 MW from a large Combined Cycle unit (560MW) in 2020.

For the later years, a 20 MW self-built wind farm was selected to be installed in 2032. The NPV of the optimal resource case over the 50-year study period equates to \$3,525.11 million in 2012 dollars, as shown in Attachment C Table 3-1.

The “Base Case: Lewis & Clark retire 2014” assumes nothing is done to meet the EPA Mercury and Air Toxics Standards (MATS) for the Lewis & Clark station and the plant is then retired at the end of 2014 and must be replaced with new resources in 2015. This case raises the NPV over the 50 year study period by 3.15 percent as compared to the Optimal Resource case. The corresponding Base Case least-cost plan consists of the following resource additions for the 2015-2020 timeframe:

- Install 146 MW of Internal Combustion Engines in 2015;
- Contract for 50 to 100 MW of wind energy in 2015;
- Continue the commercial demand response program to achieve 10 MW by 2015 and achieve 13 MW from Montana-Dakota’s interruptible rate; and
- Install a 71.6 MW Combustion Turbine in 2019.

For the later years, the 71.6 MW combustion turbine would be converted to a 129 MW combined cycle in 2024, an additional 36.6 MW of Internal Combustion Engines would be installed in 2029 and a 20 MW self-built wind resource installed in 2032.

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, current MISO Resource Adequacy, higher capital costs for combustion turbines, and Lewis & Clark gas options.

3.2.1. Carbon Tax

With the potential of a future carbon penalty applied to fossil fuel units and MISO energy purchases, an assumed carbon tax was applied to every ton of CO₂ emitted 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 Optimal Resource case consistent with N.D.C.C. §49-02-23, Montana-Dakota modeled a carbon tax of \$30 and \$50 per ton for sensitivity analysis. For both the \$30 and \$50 per ton scenarios, the resource plans selected remained similar to the Optimal Resource case with the only difference being the selection of self-built wind in 2013 of 20 MW in the \$30 per ton and 50 MW in the \$50 per ton scenario. At \$30 per ton the NPV increased by 26.5 percent above the Optimal Resource case, and at \$50 per ton the NPV increased by 43.6 percent over the Optimal Resource case. Montana-Dakota recognizes the amount and applicability of any carbon allowance price or tax have not been established, but this analysis was conducted to provide information regarding possible impacts to customers and to identify potential changes in the Company's future generation resource mix as part of the least-cost plan in the event a carbon tax was implemented.

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 \$3.51/MBTU for 2013, and increasing to \$4.33/MBTU in 2017. After 2017, 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 Optimal Resource case. Therefore, high and low gas price scenarios were also developed, whereby the gas price used in the Optimal Resource case was increased by \$3/MBTU and decreased by \$1/MBTU from the Optimal Resource case, respectively. The high and low gas

price cases were escalated by three percent annually after 2017. The results of the high natural gas price case were similar to the Optimal Resource case with the exceptions of the addition of more self-built wind totaling 190 MW over the 20 years. The NPV of the revenue requirement in this scenario increased 17.58 percent over the optimal resource case. The results of low natural gas price scenario were the same as the optimal resource case. This case decreased the NPV of the revenue requirement by 7.42 percent from the Optimal Resource case.

3.2.3. Current MISO Resource Adequacy (RA)

This sensitivity scenario considered the continuation of current 80.6 percent coincident factor that Montana-Dakota has within MISO's resource adequacy for the 2013-14 planning year. The sensitivity scenario requires a lower capacity need, however the energy needs do not change. The selected least-cost plan for this scenario was different from the optimal resource case with two less combustion turbines needed and no self-built wind in 2032. The results of this scenario indicate a decrease of 3.19 percent in the NPV of the revenue requirement over the Optimal Resource 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: no Lewis & Clark bag house in 2015, two internal combustion engines (2017 and 2026), and the 50 MW of wind energy in 2015. 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 2013-2014, the forecasted growth for the 50/50 forecast was used as the growth rate in those two 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 Optimal Resource case:

a total of 36.6 MW of internal combustion engines over the study period and four SCCT (71.6 MW) of which three would be converted to CCCT (129 MW).

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 Optimal Resource 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 optimal resource case to increases in combustion turbine and internal combustion engine costs. The Optimal Resource case stays the same and the results of this sensitivity case indicate an increase of 2.1 percent in the NPV of the revenue requirement over the optimal resource case.

3.2.7. Lewis & Clark natural gas options

In all three Lewis & Clark natural gas options, the Lewis & Clark unit had to be forced into the model as none of the Lewis & Clark natural gas options were least-cost as compared to the Lewis & Clark baghouse option. The least-cost of the three gas options was option 1, which included the construction of a natural gas pipeline to the nearby ONEOK natural gas processing plant. This resulted in an increase of 3.4 percent in NPV of the revenue requirement over the Optimal Resource case. All three options had the same resource plan which differed from the Optimal Resource plan. They consisted of 36.6 MW more of internal combustion engines over the study period, no self-built wind added in 2032, and a 129 MW CCCT in 2022.

4. Conclusions

Based on the current results of the supply-side and integration analysis, the resource plan resulting from the Optimal Resource case 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 110 MW of internal combustion engines (73 MW in 2015 and 37 MW in 2017);
- Contract for the 50 to 100 MW of wind energy in 2015;

- Install the Lewis & Clark baghouse project in 2015;
- Continue the commercial demand response program to achieve 10 MW by 2015 and achieve 13 MW from Montana-Dakota’s interruptible rate; and
- Look at options to partner in the construction of a large CCCT in 2020 with an ownership of 200 MW.

Figure 4-1, 4-2, and 4-3 show a comparison of the resource mix that Montana-Dakota has available to serve its customers’ needs in 2013, as compared to the Optimal Resource case plan in 2015 and 2020. Note a Zonal Resource Credit (ZRC) represents one megawatt of accredited generating capacity under the MISO resource adequacy rules.

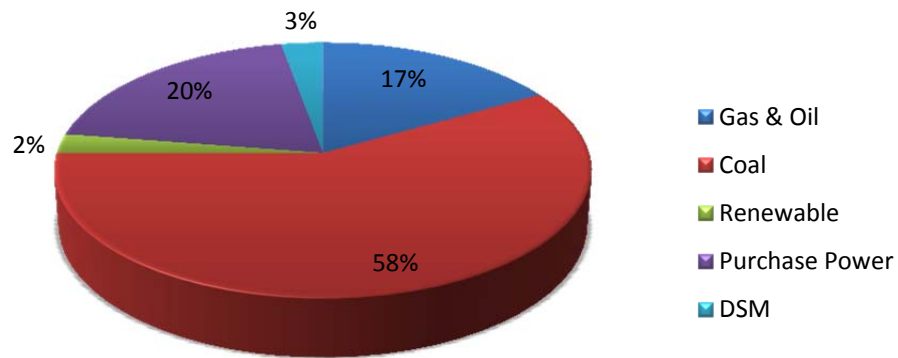


Figure 4-1: 2013 Montana-Dakota Zonal Resource Credits

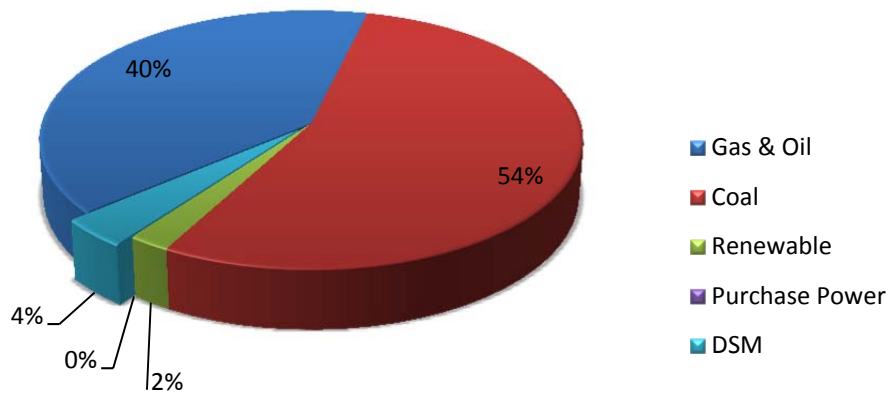


Figure 4-2: 2015 Montana-Dakota Zonal Resource Credits

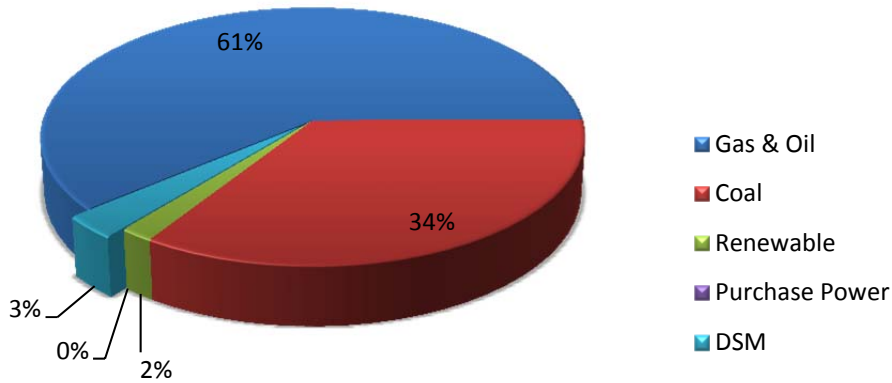


Figure 4-3: 2020 Montana-Dakota Zonal Resource Credits

As shown in Figures 4-1, 4-2 and 4-3; in 2013 approximately 17 percent of Montana-Dakota’s resource capacity comes from natural gas and oil-fired combustion turbines and internal combustion engines while in 2015 and 2020, based on the optimal resource plan, approximately 40 percent and 61 percent respectively 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 replace the current purchased capacity agreements and 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 and high load growth scenarios. With a \$30 per ton carbon tax, the resource plan remains similar to the optimal resource case with the exception of 20 MW self-built wind in 2013, but the NPV increased by 26.5 percent. The same can be seen with \$50 per ton carbon tax – the NPV increases, but the resource plan remains the same except for a 50 MW self-built wind in 2013.

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 2013-2017 period:

- Proceed with the installation of the baghouse at Lewis & Clark Station; Continue with the installation of the Big Stone Plant AQCS equipment to be completed in 2016; and
- Continue with construction of the Heskett 3 simple-cycle combustion turbine (SCCT) to be operational by July 2014.
- Pursue the potential purchase of 50 to 100 MW of wind energy purchase if available at the terms and pricing modeled in the EGEAS analysis.
- Continue the commercial demand response program to achieve 10 MW by 2015 and achieve 13 MW from Montana-Dakota's interruptible rate
- Consider a potential location for the identified Internal Combustion Engine resource to be online in 2015 identified in the Optimal Resource Case.
- 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.

The recommended resource plan does not completely satisfy all customer requirements by 2017. Montana-Dakota issued a request for proposal for capacity and energy resources on March 25, 2013 to potentially acquire additional resources to meet its customers' capacity and energy requirements in 2015 and beyond. In addition, Montana-Dakota will continue to monitor MISO capacity auction or bilateral agreements as ways to meet capacity requirements.

6. References

MISO Business Practice Manual-11-r11 Resource Adequacy. (October 1, 2012)

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

Midwest ISO Planning Year 2013 LOLE Study Report. (November 1, 2012)

Appendix A

EGEAS INPUT DATA FOR THE OPTIMAL RESOURCE CASE

EGEAS EDIT VERSION 9.02 2013 IRP RELEASE 10/26/00

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ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

EDIT PROGRAM

Montana-Dakota Utilities Co.
2013 Model
Base Case Run
-- Data updated for the 2013 Model

RPI 1529

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

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

REPORT OPTIONS

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

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HOURLY NDT TECHNOLOGY 1	wind40cf	1	0				

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	*											5		
	*	Control record.										6		
	*											7		
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	*	D	S	T	I	R	I					N	10	
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	*	+	-	+	-	+	-	+	-----				12	
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* EBPD 75
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		EBPE	6		M		0.0000 0 0					1980 2080	116
** COMMENT **		*											117
BASIC PLANT TYPE		EBPA	7		DIESEL 2		THRM P E GAS MDU NDAK 100.0			1		2012 99 30	118
		EBPB	7		2.1001.00001.0000			0.0975 11000				0.9048	119
		EBPC	7					3.68702.0000			2 0		120
		EBPD	7		3 8 0 23 2 0 0			0 0 0 0 0 0 0 0			0 0 0 0	121	
** COMMENT **		*											122
BASIC PLANT TYPE		EBPA	8		DIESEL 3		THRM P E GAS MDU NDAK 100.0			1		2012 99 30	123
		EBPB	8		2.1001.00001.0000			0.0975 11000				0.9048	124
		EBPC	8					3.68702.0000			2 0		125
		EBPD	8		3 8 0 23 2 0 0			0 0 0 0 0 0 0 0			0 0 0 0	126	
** COMMENT **		*											127
BASIC PLANT TYPE		EBPA	9		LEWIS&CLARK GS 3 THRM B G GAS MDU NDAK 100.0					1		20 20	128
		EBPB	9		52.3000.86040.9398			0.0047 12412				0.9962	129
		EBPC	9		298.280			15.28146.5121.4500			1 1		130
		EBPD	9		30 32 47 0 18 1 0 0			0 0 0 11 0 0 0 0			0 0 0 0	131	
		EBPE	9		M		0.0000 0 0					1980 2019	132
** COMMENT **		*											133
BASIC PLANT TYPE		EBPA	10		USED COAL		THRM B G COAL MDU NDAK 100.0			1		99 20	134
		EBPB	10		50.0000.93681.0000			0.0474 11250				0.9526	135
		EBPC	10		1900.000			12.79823.8602.4700			1 1		136
		EBPD	10		30 3 13 0 22 7 0 0			0 0 0 7 0 0 0 0			0 0 0 0	137	
		EBPE	10		M		0.0000 0 0					1980 2080	138
** COMMENT **		*											139
BASIC PLANT TYPE		EBPA	11		WIND20 MT - 2014 NDT B G WIND MDU NDAK 100.0					1		30 20	140
		EBPB	11		20.0001.00000.3810			0.0000				0.2000	141
		EBPC	11		1853.750			15.28139.190-33.85			1 1		142
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012								34567890

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 rows for BASIC PLANT TYPE (EBPD, EBPF, EBPG, EBPA, EBPB, EBPC) and COMMENT rows.

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							
BASIC PLANT TYPE		EBPF	16		857.000		30 37	0.0000					179
		EBPG	16		0.0000000000.0000000000.0000000000								180
** COMMENT **		*											181
BASIC PLANT TYPE		EBPA	17		WRTSLA 18V50SG	THRM P G GAS	MDU NDAK	100.0	1		40 25		182
		EBPB	17		36.6000.83710.9276		0.0709 8368				0.9292		183
		EBPC	17		954.680		12.26429.8903.3000			1 1			184
		EBPD	17		30 22 56 0 28 1 0 0		0 0 0 10 0 0 0 0 0 0 0 20 0						185
		EBPF	17		857.000		30 37 0.0000						186
		EBPG	17		0.0000000000.0000000000.0000000000								187
** COMMENT **		*											188
BASIC PLANT TYPE		EBPA	18		WRTSLA 18V50DF	THRM P G GAS	MDU NDAK	100.0	1		40 25		189
		EBPB	18		33.3000.83710.9276		0.0709 8467				0.9291		190
		EBPC	18		1053.920		12.26431.5703.3000			1 1			191
		EBPD	18		30 22 57 0 28 1 0 0		0 0 0 10 0 0 0 0 0 0 0 20 0					192	
		EBPF	18		857.000		30 37 0.0000						193
		EBPG	18		0.0000000000.0000000000.0000000000								194
** COMMENT **		*											195
BASIC PLANT TYPE		EBPA	19		BIOMASS	THRM B G BMP	MDU NDAK	100.0	1		40 25		196
		EBPB	19		37.1000.83710.9276		0.0000 11218				0.8299		197
		EBPC	19		3212.760		12.264110.285.4600			1 1			198
		EBPD	19		30 22 58 0 28 10 0 0		0 0 0 19 0 0 0 0 0 0 0 20 0					199	
		EBPF	19		857.000		30 37 0.0000						200
		EBPG	19		0.0000000000.0000000000.0000000000								201
** COMMENT **		*											202
BASIC PLANT TYPE		EBPA	20		GEOHERMAL	THRM B G PURC	MDU NDAK	100.0	1		40 25		203
		EBPB	20		30.0000.90001.0000		0.0000 1				0.9000		204
		EBPC	20		2746.000		12.264118.6810.530			1 1			205
		EBPD	20		30 22 59 0 28 8 0 0		0 0 0 0 0 0 0 0 0 0 0 0 0						206
		EBPF	20		2558.000		20 0 0.0000						207
		EBPG	20		0.0000000000.0000000000.0000000000								208
** COMMENT **		*											209
BASIC PLANT TYPE		EBPA	21		PV SOLAR	THRM B G PURC	MDU NDAK	100.0	1		30 30		210
		EBPB	21		30.0000.50001.0000		0.0000 1				0.3000		211
		EBPC	21		5196.000		11.62018.2400.0000			1 1			212
		EBPD	21		30 22 0 10 8 0 0		0 0 0 0 0 0 0 0 0 0 0 0 0						213
		EBPE	21		M		0.0000 0 0 1980 2080						214
RECORD COLS				1	2	3	4	5	6	7	8		
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890		
BASIC PLANT TYPE	EBPF	21	2558.000	20	0	0.0000				215		
	EBPG	21	0.000000000	0.000000000	0.000000000					216		
** COMMENT **	*									217		
BASIC PLANT TYPE	EBPA	22	CONC SOLAR	THRM B G PURC MDU	NDAK	100.0	1	30	30	218		
	EBPB	22	30.0000.50001.0000	0.0000	1			0.3000		219		
	EBPC	22	7271.800	11.62051.4800.0000			1	1		220		
	EBPD	22	30 22 0 10 8 0 0	0 0 0 0 0 0 0 0 0 0 0 0						221		
	EBPE	22	M	0.0000 0 0	1980 2080					222		
	EBPF	22	2558.000	20 0	0.0000					223		
	EBPG	22	0.000000000	0.000000000	0.000000000					224		
** COMMENT **	*									225		
BASIC PLANT TYPE	EBPA	23	THERMAL SOLAR	THRM B G PURC MDU	NDAK	100.0	1	30	30	226		
	EBPB	23	30.0000.50001.0000	0.0000	1			0.3000		227		
	EBPC	23	5126.000	11.62069.9600.0000			1	1		228		
	EBPD	23	30 22 0 10 8 0 0	0 0 0 0 0 0 0 0 0 0 0 0						229		
	EBPE	23	M	0.0000 0 0	1980 2080					230		
	EBPF	23	2558.000	20 0	0.0000					231		
	EBPG	23	0.000000000	0.000000000	0.000000000					232		
** COMMENT **	*									233		
BASIC PLANT TYPE	EBPA	24	CFBC CO2	THRM B G COAL MDU	NDAK	100.0	1	40	40	234		
	EBPB	24	30.0000.95001.0000	0.0732 13781				0.9267		235		
	EBPC	24	6437.540	10.939287.0418.670			1	1		236		
	EBPD	24	30 22 25 0 33 7 0 0	0 0 0 0 0 0 0 0 0 0 0 0						237		
	EBPE	24	M	0.0000 0 0	1980 2080					238		
	EBPF	24	3900.000	30 31	0.0000					239		
	EBPG	24	0.000000000	0.000000000	0.000000000					240		
** COMMENT **	*									241		
BASIC PLANT TYPE	EBPA	25	WIND20 ND - 2014 NDT	B G WIND MDU	NDAK	100.0	1	30	20	242		
	EBPB	25	20.0001.00000.3810	0.0000				0.2000		243		
	EBPC	25	1897.630	12.79839.240-33.85			1	1		244		
	EBPD	25	30 22 28 0 10	0 0 0 0 0 0 1 0 0 0 0 0 21 0						245		
	EBPF	25	2400.000	30 38	0.0000					246		
	EBPG	25	0.000000000	0.000000000	0.000000000					247		
** COMMENT **	*									248		
BASIC PLANT TYPE	EBPA	26	WIND50 ND - 2014 NDT	B G WIND MDU	NDAK	100.0	1	30	20	249		
	EBPB	26	50.0001.00000.3810	0.0000				0.2000		250		
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	34567890			

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 12345678901234567890123456789012345678901234567890123456789012 34567890

BASIC PLANT TYPE EBPD 31 30 32 47 0 9 1 0 0 0 0 0 0 11 0 0 0 0 0 0 0 0 287
EBPE 31 M 0.0000 0 0 1980 2019 288

** COMMENT ** * 289

BASIC PLANT TYPE EBPA 32 LEWIS&CLARK GS 1 THRM B G GAS MDU NDAK 100.0 1 20 20 290
EBPB 32 52.3000.86040.9398 0.0047 12412 0.9962 291
EBPC 32 196.450 15.28146.5121.4500 1 1 292
EBPD 32 30 32 47 0 12 1 0 0 0 0 0 0 11 0 0 0 0 0 0 0 0 293
EBPE 32 M 0.0000 0 0 1980 2019 294

** COMMENT ** * 295

BASIC PLANT TYPE EBPA 120 MILES CITY C.T. THRM P E GAS MDU MONT 100.0 1 1972 99 30 296
EBPB 120 25.2000.82990.9267 0.0963 13050 0.7738 297
EBPC 120 10.1322.0000 2 0 298
EBPD 120 3 5 0 2 1 0 0 0 0 0 0 12 0 0 0 0 0 0 0 0 299

** COMMENT ** * 300

BASIC PLANT TYPE EBPA 130 GLENDIVE CT #1 THRM P E GAS MDU MONT 100.0 1 1979 99 30 301
EBPB 130 35.5000.80610.9636 0.0743 11250 0.9521 302
EBPC 130 5.57002.0000 2 0 303
EBPD 130 3 6 0 3 1 0 0 0 0 0 0 2 0 0 0 0 0 0 0 0 304

** COMMENT ** * 305

BASIC PLANT TYPE EBPA 132 GLENDIVE CT #2 THRM P E GAS MDU MONT 100.0 1 2003 99 30 306
EBPB 132 43.0000.80610.9636 0.0420 8282 0.9093 307
EBPC 132 5.81002.0000 2 0 308
EBPD 132 3 7 0 4 1 0 0 0 0 0 0 13 0 0 0 0 0 0 0 0 309

** COMMENT ** * 310

BASIC PLANT TYPE EBPA 134 DIESEL 1 THRM P E GAS MDU MONT 100.0 1 2005 99 30 311
EBPB 134 2.0001.00001.0000 0.0975 11000 0.9000 312
EBPC 134 3.68702.0000 2 0 313
EBPD 134 3 8 0 23 2 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 314

** COMMENT ** * 315

BASIC PLANT TYPE EBPA 140 HESKETT #1 THRM B E COAL MDU NDAK 100.0 1 1954 66 30 316
EBPB 140 29.2000.67911.0000 0.0537 18731 0.7123 317
EBPC 140 57.5507.3600 2 0 318
EBPD 140 3 9 0 5 3 0 0 0 0 0 0 14 0 0 0 0 0 0 0 0 319

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

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

RECORD COLS 1 2 3 4 5 6 7 8

** COMMENT ** * 320

BASIC PLANT TYPE EBPA 150 HESKETT #2 THRM B E COAL MDU NDAK 100.0 1 1963 99 30 321
EBPB 150 74.6000.93831.0000 0.1160 12447 0.8660 322
EBPC 150 53.7807.7100 2 0 323
EBPD 150 3 10 0 6 4 0 0 0 0 0 15 0 0 0 0 0 0 324
EBPE 150 M 0.0000 0 0 1980 2080 325

** COMMENT ** * 326

BASIC PLANT TYPE EBPA 160 LEWIS & CLARK THRM B E COAL MDU NDAK 100.0 1 1958 57 30 327
EBPB 160 52.3000.86040.9398 0.0047 12679 0.9962 328
EBPC 160 52.0103.0200 2 0 329
EBPD 160 3 11 0 18 5 0 0 0 0 0 16 0 0 0 0 0 0 330
EBPE 160 M 0.0000 0 0 1980 2080 331

** COMMENT ** * 332

BASIC PLANT TYPE EBPA 170 BIG STONE THRM B E COAL MDU SDAK 100.0 1 1975 40 30 333
EBPB 170 107.80.92511.0000 0.0632 10350 0.9397 334
EBPC 170 23.1901.6300 2 0 335
EBPD 170 3 12 0 8 6 0 0 0 0 0 17 0 0 0 0 0 0 336
EBPE 170 M 0.0000 0 0 1980 2080 337

** COMMENT ** * 338

BASIC PLANT TYPE EBPA 180 COYOTE THRM B E COAL MDU NDAK 100.0 1 1981 99 30 339
EBPB 180 106.80.93681.0000 0.0474 11250 0.9522 340
EBPC 180 23.8602.4700 2 0 341
EBPD 180 3 13 0 22 7 0 0 0 0 0 18 0 0 0 0 0 0 342
EBPE 180 M 0.0000 0 0 1980 2080 343

** COMMENT ** * 344

BASIC PLANT TYPE EBPA 220 WAPA PUR-FT PECK HYDR B E HYDR MDU NDAK 100.0 1 2001 35 30 345
EBPB 220 2.8000.89291.0000 0.0000 14.33 0.0000 346
EBPC 220 0.000 0.000033.250 2 0 347
EBPD 220 14 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 348
EBPE 220 M 0.0000 0 0 1980 2080 349
EBPF 220 0.000 0 0.0000 350
EBPG 220 0.000000000.000000000.00000000 351

** COMMENT ** * 352

BASIC PLANT TYPE EBPA 250 DIAMOND WILLOW NDT B E WIND MDU MONT 100.0 1 2008 22 20 353
EBPB 250 30.0001.00000.3810 0.0000 0.1733 354

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

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO. Includes rows for BASIC PLANT TYPE (EBPC, EBPD, EBPA, EBPB, EBPC, EBPB, EBPD, EBPE) and various energy sources (GLEN ULLIN, CEDAR HILLS, WE ENERGIES, PURCHASE POWER, GE 7EA).

RECORD DESCRIPTION	REC. C	REF. TYPE	SEQ. NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							
BASIC PLANT TYPE	EBPC	440		0.000	50.040300.00	2	0					426
	EBPD	440		48 49 0 14 8 0 0	0 0 0 0 0 0 0 0 0 0 0 0 0 4							427
	EBPF	440		0.000	0	0.0000						428
	EBPG	440		0.0000000000.0000000000.0000000000								429
** COMMENT **	*											430
	*			== MAINTENANCE CYCLES ==								431
	*			Y YBO ---NUMBER OF WEEKS (W) AND STARTING WEEK (S)---								432
	*			I RAP 1 2 3 4 5 6 7 8 9 10								433
	*			N PST W S W S W S W S W S W S W S W S W S								434
	*			+-+-+ -+-+- -+-+- -+-+- -+-+- -+-+- -+-+- -+-+- -+-+- -+-+- -+-+-								435
	*											436
MAINTENANCE CYCLE	EMC	1	1	1 110 2								437
** COMMENT **	*											438
MAINTENANCE CYCLE	EMC	2	1	101012 416 119 116 119 116 216 121 119 117 118								439
	EMC	2	2	142 139 142 143 143 141 139 144 143 143								440
** COMMENT **	*											441
MAINTENANCE CYCLE	EMC	3	1	101012 121 117 117 118 118 117 119 117 116 117								442
	EMC	3	2	141 137 141 141 241 148 138 142 141 141								443
** COMMENT **	*											444
MAINTENANCE CYCLE	EMC	4	1	101012 123 116 118 816 117 118 120 118 118 619								445
	EMC	4	2	140 138 140 142 142 142 138 143 142 142								446
** COMMENT **	*											447
MAINTENANCE CYCLE	EMC	5	1	101012 216 117 115 213 617 120 122 118 116 116								448
	EMC	5	2	137 535 141 141 144 148 140 143 141 537								449
** COMMENT **	*											450
MAINTENANCE CYCLE	EMC	6	1	101012 613 211 212 117 212 211 514 214 218 117								451
	EMC	6	2	238 543 237 239 241 240 242 240 242 242								452
** COMMENT **	*											453
MAINTENANCE CYCLE	EMC	7	1	1 110 1								454
** COMMENT **	*											455
RECORD COLS	1	2	3	4	5	6	7	8				
1 2345 678 90	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	C	REC. REF SEQ		DATA FIELDS												ASSIGNED REC. NO.							
		TYPE	NO.	NO.																			
RECORD COLS			1	2	3	4	5	6	7	8													
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890																	
MAINTENANCE CYCLE		EMC	8	1	101011	220	122	15	9	121	123	122	220	637	123	122	456						
** COMMENT **		*															457						
MAINTENANCE CYCLE		EMC	9	1	101002	218	219	214	713	219	219	219	219	218	215		458						
		EMC	9	2		140	240	137	139	237	136	140	243	140	539		459						
** COMMENT **		*															460						
MAINTENANCE CYCLE		EMC	10	1	1	110	1											461					
** COMMENT **		*																462					
MAINTENANCE CYCLE		EMC	11	1	4	101	22	1	0	0	3022						463						
** COMMENT **		*															464						
MAINTENANCE CYCLE		EMC	12	1	101002	218	219	214	713	219	219	219	219	218	215		465						
		EMC	12	2		140	240	137	139	237	136	140	243	140	539		466						
** COMMENT **		*															467						
MAINTENANCE CYCLE		EMC	14	1	1	100	1											468					
** COMMENT **		*																469					
MAINTENANCE CYCLE		EMC	15	1	101012	116	116	116	116	116	116	116	116	116	116		470						
		EMC	15	2		139	139	139	139	140	139	139	140	139	139		471						
** COMMENT **		*															472						
MAINTENANCE CYCLE		EMC	17	1	1	110	2											473					
** COMMENT **		*																474					
MAINTENANCE CYCLE		EMC	18	1	101012	218	219	214	713	219	219	219	219	218	215		475						
		EMC	18	2		140	240	137	139	237	136	140	243	140	539		476						
** COMMENT **		*															477						
MAINTENANCE CYCLE		EMC	20	1	101001	15	9	121	123	122	220	637	123	122	220	122	478						
** COMMENT **		*															479						
MAINTENANCE CYCLE		EMC	22	1	101012	122	122	123	715	111	122	122	611	123	123		480						
		EMC	22	2		137	149	151	137	150	149	149	149	150	149		481						
RECORD COLS				1	2	3	4	5	6	7	8												
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890																	

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
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RECORD COLS	1	2	3	4	5	6	7	8	
1 2345 678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							

FUEL TYPE	EFLA	7	COAL TON	14.0700	-1.000000	1.450000	0 39	0 0	COAL	510
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** COMMENT **	*									511
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FUEL TYPE	EFLA	8	PURC NONE	0.0100	-1.000000	0.000000	0	0 0	PURC	512
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** COMMENT **	*									513
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FUEL TYPE	EFLA	9	LAND DKT	1.0280	-1.000000	4.630000	0 64	0 0	LANDFILL	514
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** COMMENT **	*									515
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FUEL TYPE	EFLA	10	BMP TON	14.9000	-1.000000	6.560000	0 63	0 0	BMP	516
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** COMMENT **	*									517
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	*	== PLANNING ALTERNATIVES ==								518
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	*			1ST	LAST	T	EX	PREREQ	M	M	R	519
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	*	NAME	BP	YEAR	YEAR	Y	RET	PA	Nfr	N	X	Q	520
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	*	-----+++		++++	----	+	-----+--	+	---	+			521
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	*												522
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PLANNING ALTERNATIVE	EPA	1	1	GE 7EA	350	2017	2032	0	0	0	00	0-1	0	523
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** COMMENT **	*													524
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PLANNING ALTERNATIVE	EPA	2	1	GE 7EA 1x1	340	2017	2032	0	0	1	101	0-1	0	525
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** COMMENT **	*													526
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PLANNING ALTERNATIVE	EPA	3	1	USED COAL	10	2015	2015	0	0	0	00	0-1	0	527
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** COMMENT **	*													528
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PLANNING ALTERNATIVE	EPA	4	1	WIND20 MT	390	2015	2032	0	0	0	00	0-1	0	529
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** COMMENT **	*													530
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PLANNING ALTERNATIVE	EPA	5	1	CFBC	360	2018	2032	0	0	0	00	0-1	0	531
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** COMMENT **	*													532
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PLANNING ALTERNATIVE	EPA	6	1	GE LM6000PH	370	2015	2032	0	0	0	00	0-1	0	533
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** COMMENT **	*													534
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PLANNING ALTERNATIVE	EPA	7	1	PURCHASE POWER	310	2010	2014	1	0	0	00	0-1	0	535
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** COMMENT **	*													534
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PLANNING ALTERNATIVE	EPA	7	1	PURCHASE POWER	310	2010	2014	1	0	0	00	0-1	0	535
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RECORD COLS	1	2	3	4	5	6	7	8	
1 2345 678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), ASSIGNED REC. NO. Rows include planning alternatives like LEWIS & CLARK BH, LEWIS&CLARK GS, BIOMASS, CFBC CO2, CONC SOLAR, GE LM6000PH SPRT, GE LMS100PB, GEOTHERMAL, PV SOLAR, SIEMNS SGT-900LG, THERMAL SOLAR, and comment rows.

Table with columns: RECORD DESCRIPTION, REC. C, REF. TYPE, SEQ. NO., DATA FIELDS (8 columns), and ASSIGNED REC. NO. Rows include planning alternatives for WIND20 MT, WIND20 ND, WIND50 MT, WIND50 ND, WRTSLA 18V50DF, WRTSLA 18V50SG, GE7FA.05 CC, and LEWIS&CLARK GS 2.

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							
** COMMENT **	*												582
PLANNING ALTERNATIVE	EPA	31	1	1	LEWIS&CLARK GS 1 32	2015	2015	0	0	0	0	0	583
** COMMENT **	*												584
					== TRAJECTORIES ==								585
					T B								586
					Y A N YEAR RATE YEAR RATE YEAR RATE YEAR RATE YEAR RATE								587
					- + -- ++++----- +++++----- +++++----- +++++----- +++++-----								588
													589
TRAJECTORY	ETJ	1	1	1	1 21 20121.5217	20134.2345	20142.9840	20152.0247	20161.2489				590
	ETJ	1	2		20171.6052	20181.5799	20191.5062	20201.4838	20211.4303				591
	ETJ	1	3		20221.3788	20231.3292	20241.3270	20251.2946	20261.2483				592
	ETJ	1	4		20271.2182	20281.1890	20291.2037	20301.2036	20311.1893				593
	ETJ	1	5		2032.00000								594
** COMMENT **	*												595
TRAJECTORY	ETJ	2	1	1	1 21 201210.603	20136.1621	20144.0427	20152.5707	20161.3420				596
	ETJ	2	2		20171.9148	20181.8815	20191.7455	20201.7512	20211.6534				597
	ETJ	2	3		20221.5944	20231.5013	20241.5198	20251.4428	20261.4200				598
	ETJ	2	4		20271.3359	20281.3387	20291.3388	20301.3410	20311.3428				599
	ETJ	2	5		2032.00000								600
** COMMENT **	*												601
TRAJECTORY	ETJ	3	1	1	1 1 1 20123.0000								602
** COMMENT **	*												603
TRAJECTORY	ETJ	4	1	1	1 1 3 2013100.00	2014.00000	2015.00000						604
** COMMENT **	*												605
TRAJECTORY	ETJ	5	1	1	1 1 1 20123.0000								606
** COMMENT **	*												607
TRAJECTORY	ETJ	6	1	1	1 1 1 20123.0000								608
** COMMENT **	*												609
TRAJECTORY	ETJ	7	1	1	1 1 1 20123.0000								610
** COMMENT **	*												611
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	C	REC. REF SEQ		DATA FIELDS								ASSIGNED REC. NO.
		TYPE	NO.	NO.	1	2	3	4	5	6	7	
RECORD COLS												
	1	2345	678	90	1	2	3	4	5	6	7	8
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						
TRAJECTORY		ETJ	8	1	1	1	1	20123.0000				612
** COMMENT **		*										613
TRAJECTORY		ETJ	9	1	1	1	1	20123.0000				614
** COMMENT **		*										615
TRAJECTORY		ETJ	10	1	1	1	4	20123.0000	20133.0000	201416.510	20153.0000	616
** COMMENT **		*										617
TRAJECTORY		ETJ	11	1	1	1	1	20123.0000				618
** COMMENT **		*										619
TRAJECTORY		ETJ	12	1	1	1	1	20123.0000				620
** COMMENT **		*										621
TRAJECTORY		ETJ	13	1	1	1	1	20123.0000				622
** COMMENT **		*										623
TRAJECTORY		ETJ	14	1	1	1	1	2012.00000				624
** COMMENT **		*										625
TRAJECTORY		ETJ	15	1	1	1	1	20123.0000				626
** COMMENT **		*										627
TRAJECTORY		ETJ	17	1	1	1	9	2012-0.188	2013-0.220	2014-0.189	2015-0.189	2016-0.221
		ETJ	17	2				2017-0.222	2018-0.222	2019-108.0	20203.0000	629
** COMMENT **		*										630
TRAJECTORY		ETJ	18	1	1	1	6	20121.4492	20131.5714	20141.5471	20151.5235	20161.5000
		ETJ	18	2				20171.5000				632
** COMMENT **		*										633
TRAJECTORY		ETJ	19	1	1	1	9	2012-0.188	2013-0.220	2014-0.189	2015-0.189	2016-0.221
		ETJ	19	2				2017-0.222	2018-0.222	2019-108.0	20203.0000	634
** COMMENT **		*										635
RECORD COLS												
	1	2345	678	90	1	2	3	4	5	6	7	8
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.	
					1	2	3	4	5	6	7	8		
RECORD COLS	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890								
TRAJECTORY		ETJ	20	1	1	1	3	201296.666	201310.169	2014.00000				637
** COMMENT **		*												638
TRAJECTORY		ETJ	21	1	1	1	1	20123.0000						639
** COMMENT **		*												640
TRAJECTORY		ETJ	22	1	1	1	1	20133.0000						641
** COMMENT **		*												642
TRAJECTORY		ETJ	23	1	1	1	1	20133.0000						643
** COMMENT **		*												644
TRAJECTORY		ETJ	24	1	1	1	1	20133.0000						645
** COMMENT **		*												646
TRAJECTORY		ETJ	25	1	1	1	1	20133.0000						647
** COMMENT **		*												648
TRAJECTORY		ETJ	26	1	1	1	1	20133.0000						649
** COMMENT **		*												650
TRAJECTORY		ETJ	27	1	1	1	4	20123.0000	20133.0000	20149.2657	20153.0000			651
** COMMENT **		*												652
TRAJECTORY		ETJ	28	1	1	13		2012.00000	2013.00000	2014.00000	2015.00000	2016.00000		653
		ETJ	28	2				2017.00000	2018.00000	2019.00000	2020.00000	2021.00000		654
		ETJ	28	3				2022.00000	2023-100.0	2024.00000				655
** COMMENT **		*												656
TRAJECTORY		ETJ	29	1	1	11		201213.863	20134.9885	20145.0015	20155.0014	20164.9900		657
		ETJ	29	2				20174.9959	20185.0154	20194.9963	20204.9918	20214.9988		658
		ETJ	29	3				20225.0000						659
** COMMENT **		*												660
TRAJECTORY		ETJ	30	1	1	1	1	20133.0000						661
RECORD COLS	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890								

RECORD DESCRIPTION	C	REC. REF SEQ		DATA FIELDS								ASSIGNED	
		TYPE	NO.	NO.									REC. NO.
RECORD COLS		1	2	3	4	5	6	7	8				
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012						34567890		
** COMMENT **	*										662		
TRAJECTORY		ETJ	31	1	1	1	1	20123.0000			663		
** COMMENT **	*										664		
TRAJECTORY		ETJ	32	1	1	1	1	20123.0000			665		
** COMMENT **	*										666		
TRAJECTORY		ETJ	33	1	1	1	6	2012-5.135	20139.1168	20144.6997	20153.7406	20164.0865	667
		ETJ	33	2				20173.0000					668
** COMMENT **	*										669		
TRAJECTORY		ETJ	34	1	1	1	6	20121.7755	20134.8150	20147.4234	20154.4933	20165.3380	670
		ETJ	34	2				20173.0000					671
** COMMENT **	*										672		
TRAJECTORY		ETJ	35	1	1	1	6	2012-0.552	20134.4444	20144.2553	20155.6122	20163.8647	673
		ETJ	35	2				20173.0000					674
** COMMENT **	*										675		
TRAJECTORY		ETJ	36	1	1	1	6	2012-0.555	20134.4692	20144.2780	20155.6410	20163.8835	676
		ETJ	36	2				20173.0000					677
** COMMENT **	*										678		
TRAJECTORY		ETJ	37	1	1	1	6	201226.388	2013-0.549	2014-0.552	2015-1.666	2016.00000	679
		ETJ	37	2				20173.0000					680
** COMMENT **	*										681		
TRAJECTORY		ETJ	38	1	1	1	6	2012-3.181	20135.1643	20146.2500	20152.1008	20161.6460	682
		ETJ	38	2				20173.0000					683
** COMMENT **	*										684		
TRAJECTORY		ETJ	39	1	1	1	6	2012.00000	20131.3793	20146.1224	20152.5641	20162.5000	685
		ETJ	39	2				20173.0000					686
** COMMENT **	*										687		
TRAJECTORY		ETJ	40	1	1	1	18	2012.00000	2013.00000	2014.00000	2015.00000	2016.00000	688
RECORD COLS			1										
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012							34567890	

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
					1	2	3	4	5	6	7	8	
RECORD COLS	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							
TRAJECTORY		ETJ	40	2		2017.00000	2018.00000	2019.00000	2020.00000	2021.00000			689
		ETJ	40	3		2022.00000	2023.00000	2024.00000	2025.00000	2026.00000			690
		ETJ	40	4		2027.00000	2028-65.00	2029.00000					691
** COMMENT **		*											692
TRAJECTORY		ETJ	41	1	1 1 4	20124.5454	20134.3478	2014.00000	2015.00000				693
** COMMENT **		*											694
TRAJECTORY		ETJ	42	1	1 1 1	2012.00000							695
** COMMENT **		*											696
TRAJECTORY		ETJ	43	1	1 1 4	20122.3035	20137.8122	20143.4290	20153.0000				697
** COMMENT **		*											698
TRAJECTORY		ETJ	44	1	1 1 1	20123.0000							699
** COMMENT **		*											700
TRAJECTORY		ETJ	45	1	1 1 4	20123.0000	20133.0000	201421.413	20153.0000				701
** COMMENT **		*											702
TRAJECTORY		ETJ	46	1	1 1 11	20129.5117	20135.0162	20144.9977	20155.0126	20164.9739			703
		ETJ	46	2		20175.0057	20184.9854	20195.0259	20204.9835	20214.9984			704
		ETJ	46	3		20225.0000							705
** COMMENT **		*											706
TRAJECTORY		ETJ	47	1	1 1 1	20123.0000							707
** COMMENT **		*											708
TRAJECTORY		ETJ	48	1	1 1 1	20123.0000							709
** COMMENT **		*											710
TRAJECTORY		ETJ	49	1	1 1 1	2012.00000							711
** COMMENT **		*											712
TRAJECTORY		ETJ	50	1	1 1 4	20123.0000	20133.0000	201416.707	20153.0000				713
RECORD COLS	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	12	34567890
** COMMENT **	*												714
TRAJECTORY		ETJ	51	1	1	1	4	20123.0000	20133.0000	2014125.87	20153.0000		715
** COMMENT **	*												716
TRAJECTORY		ETJ	52	1	1	1	1	2012.00000					717
** COMMENT **	*												718
TRAJECTORY		ETJ	53	1	1	1	1	2012.00000					719
** COMMENT **	*												720
TRAJECTORY		ETJ	54	1	1	1	1	20133.0000					721
** COMMENT **	*												722
TRAJECTORY		ETJ	55	1	1	1	1	20133.0000					723
** COMMENT **	*												724
TRAJECTORY		ETJ	56	1	1	1	1	20133.0000					725
** COMMENT **	*												726
TRAJECTORY		ETJ	57	1	1	1	1	20133.0000					727
** COMMENT **	*												728
TRAJECTORY		ETJ	58	1	1	1	1	20133.0000					729
** COMMENT **	*												730
TRAJECTORY		ETJ	59	1	1	1	1	20133.0000					731
** COMMENT **	*												732
TRAJECTORY		ETJ	60	1	1	1	1	20133.0000					733
** COMMENT **	*												734
TRAJECTORY		ETJ	61	1	1	1	1	20133.0000					735
** COMMENT **	*												736
RECORD COLS					1	2	3	4	5	6	7	8	
	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	12	34567890

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS	1	2	3	4	5	6	7	8				
	1	2345	678	90	12345678901234567890123456789012345678901234567890123456789012	34567890						
TRAJECTORY	ETJ	62	1	1	1	1	20133.0000					737
** COMMENT **	*											738
TRAJECTORY	ETJ	63	1	1	1	1	20123.0000					739
** COMMENT **	*											740
TRAJECTORY	ETJ	64	1	1	1	6	2012-5.183	20139.1116	20144.5929	20153.7924	20164.0384	741
	ETJ	64	2				20173.0000					742
** COMMENT **	*											743
TRAJECTORY	ETJ	65	1	1	1	30	2015-1.500	2016-1.500	2017-1.500	2018-1.500	2019-1.500	744
	ETJ	65	2				2020-1.500	2021-1.500	2022-1.500	2023-1.500	202459.621	745
	ETJ	65	3				20252.0000	20262.0000	20272.0000	20282.0000	20292.0000	746
	ETJ	65	4				20302.0000	20312.0000	20322.0000	20332.0000	2034-10.74	747
	ETJ	65	5				20352.0000	20362.0000	20372.0000	20382.0000	20392.0000	748
	ETJ	65	6				20402.0000	20412.0000	20422.0000	20432.0000	20442.0000	749
** COMMENT **	*											750
	*						== LOADING BLOCKS ==					751
	*						-A:CAPACITY, B:HEAT RATE, C:FORCED OUTAGE-					752
	*						N 1 2 3 4 5					753
	*						- ++++++-----+++++-----+++++					754
	*											755
LOADING BLOCK	ELBA	1	3	0.5550390.3488370.096124								756
	ELBB	1	1.5707530.0001311.333596									757
	ELBC	1	1.0000000.0000000.000000									758
** COMMENT **	*											759
LOADING BLOCK	ELBA	2	5	0.2535210.1690140.1690140.2253520.183099								760
	ELBB	2	1.6222220.7422220.7320000.7942220.877060									761
	ELBC	2	1.0000000.0000000.0000000.0000000.000000									762
** COMMENT **	*											763
LOADING BLOCK	ELBA	3	2	0.4439410.556059								764
	ELBB	3	1.1172100.906424									765
	ELBC	3	1.0000000.000000									766
** COMMENT **	*											767
LOADING BLOCK	ELBA	4	5	0.2315790.2105260.2105260.1347370.212632								768
RECORD COLS	1	2	3	4	5	6	7	8				
	1	2345	678	90	1234567890123456789012345678901234567890123456789012	34567890						

RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
RECORD COLS				1	2	3	4	5	6	7	8	
	1	2345	678 90	12345678901234567890123456789012345678901234567890123456789012	34567890							
LOADING BLOCK		ELBB	4	1.5180041	.2144031	.0929631	.2074810	.000120				769
		ELBC	4	0.7027150	.2810860	.0702710	.0351360	.140543				770
** COMMENT **		*										771
LOADING BLOCK		ELBA	5	5 0.3653850	.1153850	.1153850	.1730770	.230769				772
		ELBB	5	1.1599210	.9289500	.8774800	.8764740	.936220				773
		ELBC	5	0.6879580	.1003950	.0987380	.2337400	.444893				774
** COMMENT **		*										775
LOADING BLOCK		ELBA	7	2 0.4213330	.578667							776
		ELBB	7	1.2133330	.844670							777
		ELBC	7	1.0000000	.000000							778
** COMMENT **		*										779
LOADING BLOCK		ELBA	8	2 0.7000000	.300000							780
		ELBB	8	1.4285710	.000012							781
		ELBC	8	1.0000000	.000000							782
** COMMENT **		*										783
LOADING BLOCK		ELBA	9	5 0.2325580	.2093020	.1860470	.1860470	.186047				784
		ELBB	9	1.8436370	.7766110	.6303580	.7719000	.794509				785
		ELBC	9	1.0000000	.0000000	.0000000	.0000000	.000000				786
** COMMENT **		*										787
LOADING BLOCK		ELBA	10	5 0.2325580	.2093020	.1860470	.1860470	.186047				788
		ELBB	10	1.8436370	.7766110	.6303580	.7719000	.794509				789
		ELBC	10	1.0000000	.0000000	.0000000	.0000000	.000000				790
** COMMENT **		*										791
LOADING BLOCK		ELBA	11	5 0.1013380	.1912050	.1912050	.1912050	.325048				792
		ELBB	11	1.2830411	.0275540	.9706220	.9695080	.930658				793
		ELBC	11	0.6179370	.0901780	.0886890	.2099500	.399612				794
** COMMENT **		*										795
LOADING BLOCK		ELBA	12	5 0.2777780	.1587300	.2380950	.1190480	.206349				796
		ELBB	12	1.6628350	.6934860	.7458490	.7841640	.761273				797
		ELBC	12	0.7885320	.0841890	.1095830	.1287550	.227864				798
** COMMENT **		*										799
RECORD COLS	1	2345	678 90	1234567890123456789012345678901234567890123456789012	34567890							

RECORD DESCRIPTION	C	REC. TYPE	REF NO.	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.		
RECORD COLS					1	2	3	4	5	6	7	8			
1	2345	678	90		12345678901234567890123456789012345678901234567890123456789012								34567890		
** COMMENT **	*												832		
	*	---	---	---									833		
	*				== EXPENDITURE PATTERNS - CONSTRUCTION COST AND CAPITAL EXPENS ES ==								834		
	*				COST PERCENTAGES FOR YEARS BEFORE ON-LINE								835		
	*	YR			1	2	3	4	5	6	7	8	9	10	836
	*	EZCA			----	-----	-----	-----	-----	-----	-----	-----	-----	-----	837
	*				ANNUAL EXPENDITURES FOR YEARS OF OPERATING LIFE								838		
	*	YR F TJ			1	2	3	4	5						839
	*	EZCB			----	-----	-----	-----	-----	-----	-----	-----	-----	-----	840
	*				-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	841
	*				-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	842
CONSTRUCTION EXPEND.	EZCA	31	1	4	13.7035	1.1034	8.8016	5.50						843	
** COMMENT **	*													844	
CONSTRUCTION EXPEND.	EZCA	37	1	3	69.0027	2.004	0.000							845	
** COMMENT **	*													846	
CONSTRUCTION EXPEND.	EZCA	38	1	1	100.0									847	
** COMMENT **	*													848	
	*				== RETURN ON RATE BASE ==								849		
	*				--CAPITAL STRUC-- -RATES OF RETURN- INCOME PROP								850		
	*	YEAR COMM PREF DEBT COMM PREF DEBT TAX TAX												851	
	*				-----	-----	-----	-----	-----	-----	-----	-----	-----	852	
RETURN ON RATE BASE	EZR	1	1	201350.0000	0.000050	0.00010	7.750	5.0038	1.1001	1.1840				853	
** COMMENT **	*													854	
	*				== TAX DEPRECIATION TABLES ==								855		
	*				DEPRECIATION PERCENTAGES FOR YEARS								856		
	*	YR			1	2	3	4	5	6	7	8	9	10	857
	*				----	-----	-----	-----	-----	-----	-----	-----	-----	-----	858
	*				-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	859
TAX DEPRECIATION	EZT	20	1	21	3.7507	2.2196	6.6776	1.1775	7.7135	2.2854	8.8884	5.5224	4.4624	4.464	860
	EZT	20	2		4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.462	861
	EZT	20	3		2.224										862
** COMMENT **	*													863	
TAX DEPRECIATION	EZT	21	1	20	3.7507	2.2196	6.6776	1.1775	7.7135	2.2854	8.8884	5.5224	4.4624	4.464	864
	EZT	21	2		4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.4624	4.4626	6.686	865
RECORD COLS					1	2	3	4	5	6	7	8			
1	2345	678	90		12345678901234567890123456789012345678901234567890123456789012									34567890	

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RECORD DESCRIPTION	REC. C	REF TYPE	SEQ NO.	DATA FIELDS								ASSIGNED REC. NO.
				1	2	3	4	5	6	7	8	
RECORD COLS				1	2	3	4	5	6	7	8	
	1	2345	678 90	1	2	3	4	5	6	7	8	34567890
** COMMENT **			*									866 867
RECORD COLS				1	2	3	4	5	6	7	8	
	1	2345	678 90	1	2	3	4	5	6	7	8	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          **  
**                                     **  
**                                     **  
*****  
*****
```


GENERAL DATA

BASE YEAR	2012	SYSTEM DISCOUNT RATE (PERCENT)	6.92
ALL DATA BASE COSTS ARE IN 2012 DOLLARS		CUSTOMER DISCOUNT RATE (PERCENT)	6.92
		INFLATION RATE (PERCENT)	3.00
NUMBER OF DAYS PER YEAR	364	NUMBER OF CUMULANTS	8
NUMBER OF HOURS PER YEAR	8736	USED IN REPRESENTING PLANT OUTAGES AND LOAD CURVES	
STORAGE GENERATION SUBWEEK	1		
UNSERVED ENERGY COST	130.00 \$/MWH	BENCHMARK YEAR	2012
YEARLY ESCALATION TRAJECTORY	31	BENCHMARK PEAK	526. MW
CAPITAL STRUCTURE FOR NON-EGEAS ASSETS	1		

SERVICE AREAS AND NAMES IDENTIFYING SYSTEMS

SYSTEM A - SYSA SYSA

GENERATING COMPANIES

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

SYSTEM DEMAND

IN BASE YEAR 2012 -

PEAK LOAD	525.7 MW
ENERGY	2919.8 GWH

YEARLY ESCALATION TRAJECTORIES

PEAK LOAD	1
ENERGY	2

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 1: 1, 2012, INITIAL LOAD, 525.7, 228.0, 2919.8, 0.63577361, 0.43372780, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data points for set 1.

CUMULANTS

Table with 4 columns of cumulative values for set 1.

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 2: 2, 2013, INITIAL LOAD, 533.7, 279.1, 3229.4, 0.69264705, 0.52303268, MONDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data points for set 2.

CUMULANTS

Table with 4 columns of cumulative values for set 2.

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 3: 2014 INITIAL LOAD, 556.3 MW, 301.9 MW, 3428.4 GWH, 0.70545578, 0.54272017, TUESDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for set 3.

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for set 3.

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 4: 2015 INITIAL LOAD, 572.9 MW, 318.4 MW, 3567.0 GWH, 0.71270802, 0.55570925, THURSDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical values representing load duration curve data for set 4.

CUMULANTS

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

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 5: 2016 INITIAL LOAD 584.5, LOAD AFTER CONTRACTS 584.5, 327.5, 327.5, 3658.7, 3658.7, 0.71652220, 0.56027955, FRIDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 6: 2017 INITIAL LOAD 591.8, LOAD AFTER CONTRACTS 591.8, 331.6, 331.6, 3707.8, 3707.8, 0.71718092, 0.56027480, SATURDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 7: 2018 INITIAL LOAD, 601.3 MW, 339.0 MW, 3778.8 GWH, 0.71936631, 0.56381336, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 8: 2019 INITIAL LOAD, 610.8 MW, 345.6 MW, 3849.9 GWH, 0.72150242, 0.56583078, TUESDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 9: 2020 INITIAL LOAD, 620.0 MW, 352.3 MW, 3917.1 GWH, 0.72320323, 0.56816770, WEDNESDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 10: 2021 INITIAL LOAD, 629.2 MW, 362.8 MW, 3985.7 GWH, 0.72510893, 0.57656948, THURSDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 11 shows data for 2022 with initial and load after contracts values.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 12 shows data for 2023.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 13: 2024 INITIAL LOAD, 655.6 MW, 379.9 MW, 4178.0 GWH, 0.72948587, 0.57947218, MONDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 14: 2025 INITIAL LOAD, 664.3 MW, 387.0 MW, 4241.5 GWH, 0.73087415, 0.58255742, TUESDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

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

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 15: 2026 INITIAL LOAD, 672.9 MW, 391.3 MW, 4302.7 GWH, 0.73194410, 0.58149109, WEDNESDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for load curve 15.

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 16: 2027 INITIAL LOAD, 681.3 MW, 400.7 MW, 4363.8 GWH, 0.73318541, 0.58812767, FRIDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for load curve 16.

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 17: 2028 INITIAL LOAD, 689.6 MW, 406.0 MW, 4422.1 GWH, 0.73403827, 0.58877885, SATURDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for load curve 17.

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 18: 2029 INITIAL LOAD, 697.8 MW, 412.3 MW, 4481.3 GWH, 0.73512369, 0.59087175, SUNDAY.

LOAD DURATION CURVE (50 POINTS)

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

CUMULANTS

Table with 4 columns of numerical values representing cumulative data for load curve 18.

LOAD CURVES - SYSTEM A

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 19: 2030 INITIAL LOAD, 706.2 MW, 418.2 MW, 4541.3 GWH, 0.73610510, 0.59216490, MONDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical data representing load duration curve points for data set 19.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for data set 19.

Table with 8 columns: DATA SET REF. NO., FIRST YEAR CURVE USED, PEAK LOAD MW, MINIMUM LOAD MW, ENERGY GWH, LOAD FACTOR, MINIMUM LOAD FRACTION, FIRST DAY OF YEAR. Row 20: 2031 INITIAL LOAD, 714.7 MW, 423.3 MW, 4602.2 GWH, 0.73710455, 0.59233995, WEDNESDAY.

LOAD DURATION CURVE (50 POINTS)

Table with 5 columns of numerical data representing load duration curve points for data set 20.

CUMULANTS

Table with 4 columns of numerical values representing cumulative load data for data set 20.

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	2032	INITIAL LOAD	723.2	429.9	4664.0	0.73822286	0.59447245	THURSDAY
		LOAD AFTER CONTRACTS	723.2	429.9	4664.0	0.73822286	0.59447245	

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
0.980988690031690	0.941355243738315	0.872561423639065	0.777175343938756	0.697808030117986	0.6259806456134211	0.559582348715127
0.593285285257470	0.489053202041559	0.380006894758692	0.259806456134211	0.159582348715127	0.0997056876014069	0.06665967748507
0.096342991642038	0.062668604752938	0.037897954058245	0.024884801158728	0.016665967748507	0.00997056876014069	0.006665967748507
0.011186745475026	0.007077328769916	0.004223567169145	0.001598106496435	0.000997056876014069	0.0006665967748507	0.0004444444444444444

CUMULANTS

0.738222863744349D+00	0.444310100619491D-02	0.119632935533316D-03	0.479253366446267D-05
0.119494480506025D-05	0.439857394522826D-07	-0.637638413172860D-07	-0.174632572029237D-07

BASIC PLANT TYPES - 1

Table with columns: DATA SET REF. NO., 1, 2, 4, 5, 6. Rows include: NAME, TYPE / LOADING / STATUS /AVD, CLASS / AREA / GENERATING CO., OWNERSHIP PCT. / NO. UNITS, RATED CAPACITY, CAPACITY, EQUIVALENT FORCED OUTAGE RATE, INSTALLATION COST, FIXED O+M COST, YEARLY TRAJECTORIES, and NOTE.

BASIC PLANT TYPES - 2

DATA SET REF. NO.	1			2			4			5			6		
	-----			-----			-----			-----			-----		
MAINTENANCE REQUIREMENTS	20			0			14			17			18		
FUEL 1 / FUEL 2	6	0		8	0		8	0		1	0		5	0	
LOADING BLOCKS / NDT NO.		3	0		0	0		0	0		2	0		5	0
EMISSIONS / SITE / TAX DEPR.	0	0	20	0	0	0	0	0	0	0	0	20	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			857.00			0.00		
CONSTRUCTION COST 2, \$/KW	0.00			0.00			0.00			857.00			0.00		
TRAJECTORY / EXPEND. PATTERN	0	0		0	0	0	0	0	0	30	37		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

Table with columns for Data Set Ref. No. (7, 8, 9, 10, 11) and rows for various plant parameters including Name, Type, Capacity, Heat Rate, and Costs. Includes a note at the bottom defining abbreviations like THRM, HYDR, and NDT.

BASIC PLANT TYPES - 2

Table with columns for Data Set Ref. No. (7-11) and rows for Maintenance Requirements, Construction Cost, Starting Value of CWIP, DSM Customer Cost, and Percentage for 2nd Fuel.

BASIC PLANT TYPES - 1

Table with columns for Data Set Ref. No. (12, 13, 14, 15, 16) and rows for various plant parameters including Name, Capacity, Costs, and Trajectories. Includes a note at the bottom defining abbreviations like THRM, HYDR, and STORAGE.

BASIC PLANT TYPES - 2

Table with columns for Data Set Ref. No. (12, 13, 14, 15, 16) and rows for Maintenance Requirements, Construction Costs, Starting Value of CWIP, DSM Customer Cost, and Percentage for 2nd Fuel.

BASIC PLANT TYPES - 1

Table with columns for Data Set Ref. No. (17, 18, 19, 20, 21) and rows for various plant parameters including Name, Type, Capacity, Costs, and Trajectories. Includes a note at the bottom defining abbreviations like THRM, HYDR, and STORAGE.

BASIC PLANT TYPES - 2

Table with columns for Data Set Ref. No. (17-21) and rows for various plant parameters including Maintenance Requirements, Construction Costs, Starting Value of CWIP, and Percentage for 2nd Fuel.

BASIC PLANT TYPES - 1

Table with columns for Data Set Ref. No. (22, 23, 24, 25, 26) and rows for various plant parameters including Name, Type, Capacity, Costs, and Trajectories. Includes a note at the bottom defining abbreviations like THRM, HYDR, and NDT.

BASIC PLANT TYPES - 2

DATA SET REF. NO.	22			23			24			25			26		
MAINTENANCE REQUIREMENTS	10			10			33			10			10		
FUEL 1 / FUEL 2	8	0		8	0		7	0		0	0		0	0	
LOADING BLOCKS / NDT NO.		0	0		0	0		0	0		1			0	1
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	20	0	0	21	0	0	21
MUST RUN / 1ST YR / LAST YR	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			3900.00			2400.00			2400.00	
CONSTRUCTION COST 2, \$/KW		2558.00			2558.00			3900.00			2400.00			2400.00	
TRAJECTORY / EXPEND. PATTERN		20	0		20	0		30	31		30	38		30	38
PERCENT CWIP IN RATE BASE		0.00			0.00			0.00			0.00			0.00	
STARTING VALUE OF CWIP, \$/KW		0.00			0.00			0.00			0.00			0.00	
EQUITY AFUDC, \$/KW		0.00			0.00			0.00			0.00			0.00	
DEBT AFUDC, \$/KW		0.00			0.00			0.00			0.00			0.00	
DSM CUSTOMER COST / OPT / TJ	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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
MAXIMUM / TRAJ / SEG MULT		100.00	0	0	100.00	0	0	100.00	0	0	100.00	0	0	100.00	0
TARGET / TRAJ / SEG MULT		0.00	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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
NDT REVENUES / TRAJ		0.00	0		0.00	0		0.00	0		0.00	0		0.00	0

BASIC PLANT TYPES - 1

Table with columns for Data Set Ref. No. (27, 28, 29, 30, 31) and rows for various plant parameters including Name, Capacity, Costs, and Trajectories. Includes a note at the bottom defining abbreviations like THRM, HYDR, and STORAGE.

BASIC PLANT TYPES - 2

DATA SET REF. NO.	27			28			29			30			31		
MAINTENANCE REQUIREMENTS	10			10			1			7			9		
FUEL 1 / FUEL 2	0	0		0	0		1	0		0	0		1	0	
LOADING BLOCKS / NDT NO.		0	1		0	1		8	0		0	1		11	0
EMISSIONS / SITE / TAX DEPR.	0	0	21	0	0	21	0	0	20	0	0	21	0	0	0
MUST RUN / 1ST YR / LAST YR													M 1980 2019		
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			750.00			2400.00			0.00		
CONSTRUCTION COST 2, \$/KW	2400.00			2400.00			750.00			2400.00			0.00		
TRAJECTORY / EXPEND. PATTERN		30	38		30	38		30	37		30	38		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

Table with columns for Data Set Ref. No. (32, 120, 130, 132, 134) and rows for Name, Type, Capacity, Heat Rate, etc. Includes a note at the bottom defining abbreviations like THRM, HYDR, NDT, etc.

BASIC PLANT TYPES - 2

DATA SET REF. NO.	32			120			130			132			134		
MAINTENANCE REQUIREMENTS	12			2			3			4			23		
FUEL 1 / FUEL 2	1	0		1	0		1	0		1	0		2	0	
LOADING BLOCKS / NDT NO.	11	0		12	0		2	0		13	0		0	0	0
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUST RUN / 1ST YR / LAST YR	M 1980 2019														
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	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

Table with columns for Data Set Ref. No. (140, 150, 160, 170, 180) and rows for various plant parameters including Name, Type, Capacity, Heat Rate, and Costs. Includes a note at the bottom defining abbreviations like THRM, HYDR, and NDT.

BASIC PLANT TYPES - 2

Table with columns for Data Set Ref. No. (140, 150, 160, 170, 180) and rows for various plant parameters such as Maintenance Requirements, Fuel, Loading Blocks, Emissions, Construction Cost, and Starting Value of CWIP.

BASIC PLANT TYPES - 1

Table with columns for Data Set Ref. No. (220, 250, 260, 270, 280) and rows for various plant parameters including Name, Capacity, Costs, and Trajectories. Includes a note at the bottom defining abbreviations like THRM, HYDR, and NDT.

BASIC PLANT TYPES - 2

DATA SET REF. NO.	220			250			260			270			280		
MAINTENANCE REQUIREMENTS	0	0		10			15			10			11		
FUEL 1 / FUEL 2	0	0		0	0		8	0		0	0		8	0	
LOADING BLOCKS / NDT NO.	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MUST RUN / 1ST YR / LAST YR	M	1980	2080				M	1980	2080						
SPIN RSV / 1ST YR / LAST YR															
DISPATCH MODIFIER, \$/MWH	0.00			0.00			0.00			0.00			0.00		
TRAJECTORY FOR DISPATCH MODIF	0			0			0			0			0		
CONSTRUCTION COST 1, \$/KW	0.00			0.00			0.00			0.00			0.00		
CONSTRUCTION COST 2, \$/KW	0.00			0.00			0.00			0.00			0.00		
TRAJECTORY / EXPEND. PATTERN	0	0		0	0		0	0		0	0		0	0	
PERCENT CWIP IN RATE BASE	0.00			0.00			0.00			0.00			0.00		
STARTING VALUE OF CWIP, \$/KW	0.00			0.00			0.00			0.00			0.00		
EQUITY AFUDC, \$/KW	0.00			0.00			0.00			0.00			0.00		
DEBT AFUDC, \$/KW	0.00			0.00			0.00			0.00			0.00		
DSM CUSTOMER COST / OPT / TJ	0.00	0	0	0.00	0	0	0.00	0	0	0.00	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.	310			340			350			360			370		
-----	-----			-----			-----			-----			-----		
NAME	PURCHASE POWER			GE 7EA 1x1			GE 7EA			CFBC			GE LM6000PH		
TYPE / LOADING / STATUS /AVD	THRM	P	G	THRM	P	G	THRM	P	G	THRM	B	G	THRM	P	G
LOAD COMPONENT FOR DSM															
CLASS / AREA / GENERATING CO.	PURC	MDU	MISO	GAS	MDU	NDAK	GAS	MDU	NDAK	LIGN	MDU	NDAK	GAS	MDU	NDAK
OWNERSHIP PCT. / NO. UNITS	100.0		1	100.0		1	100.0		1	100.0		1	100.0		1
INSTALLATION DATE															
OPERATING/BOOK LIVES, YEARS		1	1		40	40		40	25		40	40		40	25
RATED CAPACITY, MW	10.000			129.000			71.600			30.000			37.400		
CAPACITY		1.0000			0.9489			0.9406			0.9267			0.9291	
- RESERVE		1.0000			0.8571			0.8371			0.9500			0.8371	
- OPERATING		1.0000			1.0000			0.9276			1.0000			0.9276	
- EMERGENCY		0.0000			0.0000			0.0000			0.0000			0.0000	
- CHARGING															
EQUIVALENT FORCED OUTAGE RATE	0.0000			0.0511			0.0593			0.0732			0.0709		
FULL LOAD HEAT RATE, BTU/KWH	1.			7611.			11955.			9974.			9943.		
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			648.01			759.13			3520.07			1232.02		
INSTALLATION COST 2, \$/KW	0.00			648.01			759.13			3520.07			1232.02		
MULTI-UNIT CAPITAL COST OPT.	2			1			1			1			1		
LEVEL. CARRYING CHARGE, PCT	0.00			12.26			12.26			10.97			12.26		
FIXED O+M COST, \$/KW-YR	34.80			16.06			17.47			209.16			35.78		
VARIABLE O+M COST, \$/MWH	110.00			3.37			2.70			11.78			4.24		
DEFAULT AFUDC, PCT. OF GBV	0.00			0.00			0.00			0.00			0.00		
DEFAULT DEBT, PCT. OF AFUDC	0.00			0.00			0.00			0.00			0.00		
CAPITAL STRUCTURE	0			1			1			1			1		
YEARLY TRAJECTORIES															
COSTS-CAPITAL/FIX OM/VAR OM	0	21	21	30	22	23	30	22	60	30	22	61	30	22	62
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.	310			340			350			360			370		
MAINTENANCE REQUIREMENTS	0			28			28			33			28		
FUEL 1 / FUEL 2	8	0		1	0		1	0		7	0		1	0	
LOADING BLOCKS / NDT NO.		0	0		1	0		2	0		0	0		13	0
EMISSIONS / SITE / TAX DEPR.	0	0	0	0	0	20	0	0	20	0	0	20	0	0	20
MUST RUN / 1ST YR / LAST YR													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			750.00			857.00			3900.00			850.00		
CONSTRUCTION COST 2, \$/KW	0.00			750.00			857.00			3900.00			850.00		
TRAJECTORY / EXPEND. PATTERN	0	0		30	37		30	37		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

Table with columns for Data Set Ref. No. (390, 400, 440) and rows for Name, Type/Loading/Status, Capacity, Equivalent Forced Outage Rate, Installation Cost, Fixed O+M Cost, etc.

BASIC PLANT TYPES - 2

DATA SET REF. NO.	390	400	440
MAINTENANCE REQUIREMENTS	10	0	14
FUEL 1 / FUEL 2	0 0	8 0	8 0
LOADING BLOCKS / NDT NO.	0 1	0 0	0 0
EMISSIONS / SITE / TAX DEPR.	0 0 21	0 0 0	0 0 0
MUST RUN / 1ST YR / LAST YR			
SPIN RSV / 1ST YR / LAST YR			
DISPATCH MODIFIER, \$/MWH	0.00	0.00	0.00
TRAJECTORY FOR DISPATCH MODIF	0	0	0
CONSTRUCTION COST 1, \$/KW	2400.00	0.00	0.00
CONSTRUCTION COST 2, \$/KW	2400.00	0.00	0.00
TRAJECTORY / EXPEND. PATTERN	30 38	0 0	0 0
PERCENT CWIP IN RATE BASE	0.00	0.00	0.00
STARTING VALUE OF CWIP, \$/KW	0.00	0.00	0.00
EQUITY AFUDC, \$/KW	0.00	0.00	0.00
DEBT AFUDC, \$/KW	0.00	0.00	0.00
DSM CUSTOMER COST / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
REBOUND BENEFITS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
CUSTOMER BENEFITS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
TRANS/DISTR COSTS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
OTHER COSTS / OPT / TJ	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
LEV.CARRYING CHARGE, PCT	0.00	0.00	0.00
EXPENDITURE PATTERN	0	0	0
PERCENTAGE FOR 2ND FUEL			
MINIMUM / TRAJ / SEG MULT	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
TARGET / TRAJ / SEG MULT	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
NDT REVENUES / TRAJ	0.00 0	0.00 0	0.00 0

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
1	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	2			
2	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	4	16	1	42
						2	1	19	1	39
						3	1	16	1	42
						4	1	19	1	43
						5	1	16	1	43
						6	2	16	1	41
						7	1	21	1	39
						8	1	19	1	44
						9	1	17	1	43
						10	1	18	1	43
3	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	1	21	1	41
						2	1	17	1	37
						3	1	17	1	41
						4	1	18	1	41
						5	1	18	2	41
						6	1	17	1	48
						7	1	19	1	38
						8	1	17	1	42
						9	1	16	1	41
						10	1	17	1	41
4	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	1	23	1	40
						2	1	16	1	38
						3	1	18	1	40
						4	8	16	1	42
						5	1	17	1	42
						6	1	18	1	42
						7	1	20	1	38
						8	1	18	1	43
						9	1	18	1	42
						10	6	19	1	42
5	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	2	16	1	37
						2	1	17	5	35
						3	1	15	1	41
						4	2	13	1	41
						5	6	17	1	44
						6	1	20	1	48
						7	1	22	1	40
						8	1	18	1	43
						9	1	16	1	41
						10	1	16	5	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	1 - BASE YEAR=0	2	- TWO PERIODS	1	6	13	2	38
						2	2	11	5	43
						3	2	12	2	37
						4	1	17	2	39
						5	2	12	2	41
						6	2	11	2	40
						7	5	14	2	42
						8	2	14	2	40
						9	2	18	2	42
						10	1	17	2	42
7	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
8	10	10	1 - BASE YEAR=0	1	- START WEEKS	1	2	20		
						2	1	22		
						3	15	9		
						4	1	21		
						5	1	23		
						6	1	22		
						7	2	20		
						8	6	37		
						9	1	23		
						10	1	22		
9	10	10	0 - INSTALLATION	2	- TWO PERIODS	1	2	18	1	40
						2	2	19	2	40
						3	2	14	1	37
						4	7	13	1	39
						5	2	19	2	37
						6	2	19	1	36
						7	2	19	1	40
						8	2	19	2	43
						9	2	18	1	40
						10	2	15	5	39
10	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	1			
11	4	1	0 - INSTALLATION	1	- START WEEKS	1	22	1		
						2	0	0		
						3	0	0		
						4	30	22		

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
12	10	10	0 - INSTALLATION	2	- TWO PERIODS	1	2	18	1	40
						2	2	19	2	40
						3	2	14	1	37
						4	7	13	1	39
						5	2	19	2	37
						6	2	19	1	36
						7	2	19	1	40
						8	2	19	2	43
						9	2	18	1	40
						10	2	15	5	39
14	1	1	0 - INSTALLATION	0	- NO. WEEKS ONLY	1	1			
15	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	1	16	1	39
						2	1	16	1	39
						3	1	16	1	39
						4	1	16	1	39
						5	1	16	1	40
						6	1	16	1	39
						7	1	16	1	39
						8	1	16	1	40
						9	1	16	1	39
						10	1	16	1	39
17	1	1	1 - BASE YEAR=0	0	- NO. WEEKS ONLY	1	2			
18	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	2	18	1	40
						2	2	19	2	40
						3	2	14	1	37
						4	7	13	1	39
						5	2	19	2	37
						6	2	19	1	36
						7	2	19	1	40
						8	2	19	2	43
						9	2	18	1	40
						10	2	15	5	39
20	10	10	0 - INSTALLATION	1	- START WEEKS	1	15	9		
						2	1	21		
						3	1	23		
						4	1	22		
						5	2	20		
						6	6	37		
						7	1	23		
						8	1	22		
						9	2	20		
						10	1	22		

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
22	10	10	1 - BASE YEAR=0	2	- TWO PERIODS	1	1	22	1	37
						2	1	22	1	49
						3	1	23	1	51
						4	7	15	1	37
						5	1	11	1	50
						6	1	22	1	49
						7	1	22	1	49
						8	6	11	1	49
						9	1	23	1	50
						10	1	23	1	49
23	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	3.700000	0	0	33	0	0	0
2	OIL2	GAL	0.14	-1.00	0.00	28.160000	0	0	34	0	0	0
3	COAL	TON	14.18	-1.00	0.00	1.810000	0	0	35	0	0	0
4	COAL	TON	14.26	-1.00	0.00	1.800000	0	0	36	0	0	0
5	COAL	TON	13.49	-1.00	0.00	1.440000	0	0	37	0	0	0
6	COAL	TON	16.44	-1.00	0.00	2.200000	0	0	38	0	0	0
7	COAL	TON	14.07	-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	4.630000	0	0	64	0	0	0
10	BMP	TON	14.90	-1.00	0.00	6.560000	0	0	63	0	0	0

CAPACITY PLANNING ALTERNATIVES

DATA SET REF. NO.	NAME	BASIC PLANT INSTALLED	GENERIC SITE	-AVAILABLE-		TYPE	BASIC PLANT RETIRED	-----PREREQUISITE PLANNING ALTERNATIVE----- DEPENDENCY			LAG YEAR MIN MAX	REQUIRED OPTION	
				FIRST YEAR	LAST YEAR			PLAN. ALT.	MULTIPLIER NO.	RETIRE. OPTION FLAG			
1	GE 7EA	350	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
2	GE 7EA 1x1	340	0	2017	2032	0	0	1	1	0	1 - YES	0 -1	0
3	USED COAL	10	0	2015	2015	0	0	0	0	0	0 - NO	0 -1	0
4	WIND20 MT	390	0	2015	2032	0	0	0	0	0	0 - NO	0 -1	0
5	CFBC	360	0	2018	2032	0	0	0	0	0	0 - NO	0 -1	0
6	GE LM6000PH	370	0	2015	2032	0	0	0	0	0	0 - NO	0 -1	0
7	PURCHASE POWER	310	0	2010	2014	1	0	0	0	0	0 - NO	0 -1	0
8	LEWIS & CLARK BH	6	0	2015	2015	0	0	0	0	0	0 - NO	0 -1	0
9	LEWIS&CLARK GS 3	9	0	2015	2015	0	0	0	0	0	0 - NO	0 -1	0
10	BIOMASS	19	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
11	CFBC CO2	24	0	2018	2032	0	0	0	0	0	0 - NO	0 -1	0
12	CONC SOLAR	22	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
13	GE LM6000PH SPRT	15	0	2015	2032	0	0	0	0	0	0 - NO	0 -1	0
14	GE LMS100PB	14	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
15	GEO THERMAL	20	0	2016	2032	0	0	0	0	0	0 - NO	0 -1	0
16	PV SOLAR	21	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
17	SIEMNS SGT-900LG	16	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
18	THERMAL SOLAR	23	0	2017	2032	0	0	0	0	0	0 - NO	0 -1	0
19	WIND20 MT - 2014	11	0	2013	2014	0	0	0	0	0	0 - NO	0 -1	0
20	WIND20 ND	28	0	2015	2032	0	0	0	0	0	0 - NO	0 -1	0
21	WIND20 ND - 2014	25	0	2013	2014	0	0	0	0	0	0 - NO	0 -1	0
22	WIND50 MT	13	0	2015	2032	0	0	0	0	0	0 - NO	0 -1	0
23	WIND50 MT - 2014	12	0	2013	2014	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						
				FIRST YEAR	LAST YEAR			PLAN. ALT.	MULTIPLIER NO.	FLAG	RETIRE. OPTION	LAG MIN	YEAR MAX	REQUIRED OPTION
24	WIND50 ND	27	0	2015	2032	0	0	0	0	0	0 - NO	0	-1	0
25	WIND50 ND - 2014	26	0	2013	2014	0	0	0	0	0	0 - NO	0	-1	0
26	WRTSLA 18V50DF	18	0	2015	2032	0	0	0	0	0	0 - NO	0	-1	0
27	WRTSLA 18V50SG	17	0	2015	2032	0	0	0	0	0	0 - NO	0	-1	0
28	GE7FA.05 CC	29	0	2017	2032	0	0	0	0	0	0 - NO	0	-1	0
29	WIND PPA	30	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
30	LEWIS&CLARK GS 2	31	0	2015	2015	0	0	0	0	0	0 - NO	0	-1	0
31	LEWIS&CLARK GS 1	32	0	2015	2015	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	2012	1.52	2013	4.23	2014	2.98	2015	2.02	2016	1.25
		2017	1.61	2018	1.58	2019	1.51	2020	1.48	2021	1.43
		2022	1.38	2023	1.33	2024	1.33	2025	1.29	2026	1.25
		2027	1.22	2028	1.19	2029	1.20	2030	1.20	2031	1.19
		2032	0.00								
2	1 - RATE	2012	10.60	2013	6.16	2014	4.04	2015	2.57	2016	1.34
		2017	1.91	2018	1.88	2019	1.75	2020	1.75	2021	1.65
		2022	1.59	2023	1.50	2024	1.52	2025	1.44	2026	1.42
		2027	1.34	2028	1.34	2029	1.34	2030	1.34	2031	1.34
		2032	0.00								
3	1 - RATE	2012	3.00								
4	1 - RATE	2013	100.00	2014	0.00	2015	0.00				
5	1 - RATE	2012	3.00								
6	1 - RATE	2012	3.00								
7	1 - RATE	2012	3.00								
8	1 - RATE	2012	3.00								
9	1 - RATE	2012	3.00								
10	1 - RATE	2012	3.00	2013	3.00	2014	16.51	2015	3.00		
11	1 - RATE	2012	3.00								
12	1 - RATE	2012	3.00								
13	1 - RATE	2012	3.00								
14	1 - RATE	2012	0.00								
15	1 - RATE	2012	3.00								
17	1 - RATE	2012	-0.19	2013	-0.22	2014	-0.19	2015	-0.19	2016	-0.22
		2017	-0.22	2018	-0.22	2019	-108.00	2020	3.00		
18	1 - RATE	2012	1.45	2013	1.57	2014	1.55	2015	1.52	2016	1.50
		2017	1.50								
19	1 - RATE	2012	-0.19	2013	-0.22	2014	-0.19	2015	-0.19	2016	-0.22
		2017	-0.22	2018	-0.22	2019	-108.00	2020	3.00		
20	1 - RATE	2012	96.67	2013	10.17	2014	0.00				

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
21	1 - RATE	2012	3.00								
22	1 - RATE	2013	3.00								
23	1 - RATE	2013	3.00								
24	1 - RATE	2013	3.00								
25	1 - RATE	2013	3.00								
26	1 - RATE	2013	3.00								
27	1 - RATE	2012	3.00	2013	3.00	2014	9.27	2015	3.00		
28	1 - RATE	2012	0.00	2013	0.00	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	-100.00	2024	0.00				
29	1 - RATE	2012	13.86	2013	4.99	2014	5.00	2015	5.00	2016	4.99
		2017	5.00	2018	5.02	2019	5.00	2020	4.99	2021	5.00
		2022	5.00								
30	1 - RATE	2013	3.00								
31	1 - RATE	2012	3.00								
32	1 - RATE	2012	3.00								
33	1 - RATE	2012	-5.14	2013	9.12	2014	4.70	2015	3.74	2016	4.09
		2017	3.00								
34	1 - RATE	2012	1.78	2013	4.82	2014	7.42	2015	4.49	2016	5.34
		2017	3.00								
35	1 - RATE	2012	-0.55	2013	4.44	2014	4.26	2015	5.61	2016	3.86
		2017	3.00								
36	1 - RATE	2012	-0.56	2013	4.47	2014	4.28	2015	5.64	2016	3.88
		2017	3.00								
37	1 - RATE	2012	26.39	2013	-0.55	2014	-0.55	2015	-1.67	2016	0.00
		2017	3.00								
38	1 - RATE	2012	-3.18	2013	5.16	2014	6.25	2015	2.10	2016	1.65
		2017	3.00								
39	1 - RATE	2012	0.00	2013	1.38	2014	6.12	2015	2.56	2016	2.50
		2017	3.00								

TRAJECTORIES

DATA SET REF. NO.	TRAJECTORY TYPE	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER	FIRST YEAR	RATE OR MULTIPLIER
40	1 - RATE	2012	0.00	2013	0.00	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				
41	1 - RATE	2012	4.55	2013	4.35	2014	0.00	2015	0.00		
42	1 - RATE	2012	0.00								
43	1 - RATE	2012	2.30	2013	7.81	2014	3.43	2015	3.00		
44	1 - RATE	2012	3.00								
45	1 - RATE	2012	3.00	2013	3.00	2014	21.41	2015	3.00		
46	1 - RATE	2012	9.51	2013	5.02	2014	5.00	2015	5.01	2016	4.97
		2017	5.01	2018	4.99	2019	5.03	2020	4.98	2021	5.00
		2022	5.00								
47	1 - RATE	2012	3.00								
48	1 - RATE	2012	3.00								
49	1 - RATE	2012	0.00								
50	1 - RATE	2012	3.00	2013	3.00	2014	16.71	2015	3.00		
51	1 - RATE	2012	3.00	2013	3.00	2014	125.87	2015	3.00		
52	1 - RATE	2012	0.00								
53	1 - RATE	2012	0.00								
54	1 - RATE	2013	3.00								
55	1 - RATE	2013	3.00								
56	1 - RATE	2013	3.00								
57	1 - RATE	2013	3.00								
58	1 - RATE	2013	3.00								
59	1 - RATE	2013	3.00								
60	1 - RATE	2013	3.00								
61	1 - RATE	2013	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
62	1 - RATE	2013	3.00								
63	1 - RATE	2012	3.00								
64	1 - RATE	2012	-5.18	2013	9.11	2014	4.59	2015	3.79	2016	4.04
		2017	3.00								
65	1 - RATE	2015	-1.50	2016	-1.50	2017	-1.50	2018	-1.50	2019	-1.50
		2020	-1.50	2021	-1.50	2022	-1.50	2023	-1.50	2024	59.62
		2025	2.00	2026	2.00	2027	2.00	2028	2.00	2029	2.00
		2030	2.00	2031	2.00	2032	2.00	2033	2.00	2034	-10.74
		2035	2.00	2036	2.00	2037	2.00	2038	2.00	2039	2.00
		2040	2.00	2041	2.00	2042	2.00	2043	2.00	2044	2.00

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	0.253521	1.622222	1.000000
		2	0.169014	0.742222	0.000000
		3	0.169014	0.732000	0.000000
		4	0.225352	0.794222	0.000000
		5	0.183099	0.877060	0.000000
3	2	1	0.443941	1.117210	1.000000
		2	0.556059	0.906424	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	0.365385	1.159921	0.687958
		2	0.115385	0.928950	0.100395
		3	0.115385	0.877480	0.098738
		4	0.173077	0.876474	0.233740
		5	0.230769	0.936220	0.444893
7	2	1	0.421333	1.213333	1.000000
		2	0.578667	0.844670	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
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	0.101338	1.283041	0.617937
		2	0.191205	1.027554	0.090178
		3	0.191205	0.970622	0.088689
		4	0.191205	0.969508	0.209950
		5	0.325048	0.930658	0.399612

LOADING BLOCKS

DATA SET REF. NO.	NUMBER OF BLOCKS	BLOCK NUMBER	CAPACITY MULTIPLIER	HEAT RATE MULTIPLIER	FORCED OUTAGE RATE MULTIPLIER
-----	-----	-----	-----	-----	-----
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	0.784164	0.128755
		5	0.206349	0.761273	0.227864
13	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
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	0.832164	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	2	1	0.435993	1.146570	1.000000
		2	0.564007	0.886698	0.000000
18	2	1	0.421348	1.213333	1.000000
		2	0.578652	0.844660	0.000000
19	5	1	0.232558	1.843637	1.000000
		2	0.209302	0.776611	0.000000
		3	0.186047	0.630358	0.000000
		4	0.186047	0.771900	0.000000
		5	0.186047	0.794509	0.000000

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

DATA SET REF. NO.	CALENDAR YEAR	COMPOUNDING OPTION	AFUDC RATE
-----	-----	-----	-----
1	2013	1 - COMPOUND	10.50

CONSTRUCTION COST EXPENDITURE PATTERN

DATA SET REF. NO.	NUMBER OF YEARS	YEAR		YEAR		YEAR		YEAR		YEAR	
		BEFORE ON-LINE	PERCENT OF COST	BEFORE ON-LINE	PERCENT OF COST	BEFORE ON-LINE	PERCENT OF COST	BEFORE ON-LINE	PERCENT OF COST	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						
2013	50.00	0.00	50.00	10.75	0.00	5.00	38.10	1.18	11.18

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

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MIRROR IMAGE REPORT	PAGE	2
ERROR REPORT	PAGE	31
DATA BASE CONTENTS REPORT	PAGE	32

Appendix B

EGEAS OUTPUT REPORT FOR THE OPTIMAL RESOURCE CASE

EGEAS REPORT VERSION 9.02 2013 RELEASE 10/26/00

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

ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM

REPORT PROGRAM

Montana-Dakota Utilities Co.
2013 Model
Optimal Resource Case Run
-- Data updated for the 2013 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	2013	1	0		5/ 6/13	14:34:10	2013 IRP	900
EXPANSION PLAN	2013	1	0	1	5/ 6/13	14:34:11	2013 IRP	900
SUBPERIOD REPORT	2013	1	0	1	5/ 6/13	14:34:11	2013 IRP	900
UNIT REPORT	2013	1	0	1	5/ 6/13	14:34:11	2013 IRP	900
UNIT CAPITAL COST REPORT	2013	1	0	1	5/ 6/13	14:34:11	2013 IRP	900

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

RECORD COLS 1 2 3 4 5 6 7 8

** COMMENT ** Montana-Dakota Utilities Co. 2013 Model Optimal Resource Case Run -- Data updated for the 2013 Model CONTROL RECORD SbUnUcc C M E S F T I R E I L R R L L DESCRIPTIVE INFORMATION

CONTROL RECORD RCC 1 1 3 1 0 2013

** COMMENT ** --INPUT FILES-- NAME V U RUN

FILE IDENTIFICATION RFF 2013 1 0 1

** COMMENT ** == PLAN SELECTION == PLANS C O C E M DR 1 L P M S N O --AREAS TO INCLUDE--

PLAN SELECTION RRA 1 1 1 0 1 3 2 0

** COMMENT ** == TIME PERIODS == --YEARS-- -SG- -SW- 1ST LAST 1 L 1 L

TIME PERIOD RRB 2013 2032 113 1 3

** COMMENT ** == REPORT SELECTION == -PROD- MNT -STORAGE-- -FL -EM- -ECON INT- -COST- S S S UOBRRSU DOSPD -PJ- SU SSU Gcf TSTU CUT UCTCA Y U YAFNRLEEYN EPWRS C 1 L YN YIN E+m RYIN OFF NOOOS S M SRLTDKLSST TRKDP E 1 L ST STT NRT NSET PCT. TNTVT

RECORD COLS 1 2 3 4 5 6 7 8

 EGEAS REPORT VERSION 9.02 MIRROR IMAGE REPORT PAGE 3

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	
REPORT SELECTION	RRC	1	2	1011101100	00000	0	00	000	001	00000	0000	00100	38
** COMMENT **	*												39
													40
RECORD COLS	1	2	3	4	5	6	7	8					
1 2345 678 90	1	2345	678	90	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	1234567890	

```
*****  
*****  
**                                     **  
**                                     **  
**          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
 LAST EXPANSION PLAN = 1
 COST SCALING OPTION = 3 - 0.001 M\$
 ENERGY SCALING OPTION = 2 - 0.010 GWH
 MONTHLY OUTPUT OPTION = 0 - NO
 CAPACITY OPTION = 0 - RATED
 FIXED O+M OPTION = 1 - SEPARATE ITEM IN PRODUCTION COST

RRB FIRST YEAR = 2013 FIRST SEGMENT = 1 FIRST SUBWEEK = 1
 LAST YEAR = 2032 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
2013	0.	0.	0.	0.	0.	0.	0.	0.	0.	0	0.	0
2014	0.	0.	0.	0.	1+	0	2	2+	0	0	0	0
2015	0.	0.	0.	0.	0+	0	0	0+	0	0	0	0
2016	0.	0.	0.	0.	0	0	0	1	0+	0	0	0
2017	0	0	0	0	0+	0	0	0+	0	0	0	0
2018	0	0	0	0	0+	0	0	0+	0	0	0	0
2019	0	0	0	0	0+	0	0	0+	0	0	0	0
2020	0	0	0	1+	0+	0	0	0+	0	0	0	0
2021	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
2023	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
2025	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
2027	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
2029	0	0	0	0+	0+	0	0	0+	0	0	0	0
2030	0	0	0	0+	0+	0	0	0+	0	0	0	0
2031	0	0	0	0+	0+	0	0	0+	0	0	0	0
2032	0	0	0	0+	0+	0	0	0+	1	0	0	0

 TOTAL COST, M\$
 --W/O EXT 2092.106
 --WITH EXT 3525.107

UNIT TYPES

1 PA 5	CFBC	30.000 MW	2 PA 1	GE 7EA	71.600 MW	3 PA 2	GE 7EA 1x1	129.000 MW
4 PA 28	GE7FA.05 CC	200.000 MW	5 PA 8	LEWIS & CLARK BH	52.000 MW	6 PA 26	WRTSLA 18V50DF	33.300 MW
7 PA 27	WRTSLA 18V50SG	36.600 MW	8 PA 29	WIND PPA	25.000 MW	9 PA 20	WIND20 ND	20.000 MW
10 PA 21	WIND20 ND - 2014	20.000 MW	11 PA 24	WIND50 ND	50.000 MW	12 PA 25	WIND50 ND - 2014	50.000 MW

NOTES: ALL COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2012.
 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
2013	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00
2014	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00 .	0.00
2015	0.00 .	0.00 .	0.00 .	0.00 .	1.00 +	0.00	2.00	2.00 +	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	1.00	0.00 +	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00 +	0.00	0.00	0.00 +	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00 +	0.00	0.00	0.00 +	0.00	0.00
2020	0.00	0.00	0.00	1.00 +	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 +	1.00	0.00
TOTAL	0.00	0.00	0.00	1.00	1.00	0.00	3.00	2.00	1.00	0.00

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

UNIT TYPES

1 PA 5	CFBC	30.000 MW	2 PA 1	GE 7EA	71.600 MW	3 PA 2	GE 7EA 1x1	129.000 MW
4 PA 28	GE7FA.05 CC	200.000 MW	5 PA 8	LEWIS & CLARK BH	52.000 MW	6 PA 26	WRTSLA 18V50DF	33.300 MW
7 PA 27	WRTSLA 18V50SG	36.600 MW	8 PA 29	WIND PPA	25.000 MW	9 PA 20	WIND20 ND	20.000 MW
10 PA 21	WIND20 ND - 2014	20.000 MW						

PLAN 1

NUMBER OF NEW UNITS ADDED

YEAR	11	12
2013	0.00	0.00
2014	0.00	0.00
2015	0.00	0.00
2016	0.00	0.00
2017	0.00	0.00
2018	0.00	0.00
2019	0.00	0.00
2020	0.00	0.00
2021	0.00	0.00
2022	0.00	0.00
2023	0.00	0.00
2024	0.00	0.00
2025	0.00	0.00
2026	0.00	0.00
2027	0.00	0.00
2028	0.00	0.00
2029	0.00	0.00
2030	0.00	0.00
2031	0.00	0.00
2032	0.00	0.00
TOTAL	0.00	0.00

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

 11 PA 24 WIND50 ND 50.000 MW 12 PA 25 WIND50 ND - 2014 50.000 MW

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	1	2	3	4	5	6	7	8	9	10
2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2015	0.000	0.000	0.000	0.000	52.000	0.000	73.200	50.000	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	36.600	0.000	0.000	0.000
2018	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.000	0.000	0.000	200.000	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	20.000	0.000
TOTAL	0.000	0.000	0.000	200.000	52.000	0.000	109.800	50.000	20.000	0.000

NOTE: . MEANS LOWER AND UPPER BOUNDS ARE EQUAL

UNIT TYPES

1 PA 5	CFBC	30.000 MW	2 PA 1	GE 7EA	71.600 MW	3 PA 2	GE 7EA 1x1	129.000 MW
4 PA 28	GE7FA.05 CC	200.000 MW	5 PA 8	LEWIS & CLARK BH	52.000 MW	6 PA 26	WRTSLA 18V50DF	33.300 MW
7 PA 27	WRTSLA 18V50SG	36.600 MW	8 PA 29	WIND PPA	25.000 MW	9 PA 20	WIND20 ND	20.000 MW
10 PA 21	WIND20 ND - 2014	20.000 MW						

PLAN 1

NEW CAPACITY ADDED, MW

YEAR	11	12
2013	0.000	0.000
2014	0.000	0.000
2015	0.000	0.000
2016	0.000	0.000
2017	0.000	0.000
2018	0.000	0.000
2019	0.000	0.000
2020	0.000	0.000
2021	0.000	0.000
2022	0.000	0.000
2023	0.000	0.000
2024	0.000	0.000
2025	0.000	0.000
2026	0.000	0.000
2027	0.000	0.000
2028	0.000	0.000
2029	0.000	0.000
2030	0.000	0.000
2031	0.000	0.000
2032	0.000	0.000
TOTAL	0.000	0.000

UNIT TYPES

11 PA 24 WIND50 ND 50.000 MW 12 PA 25 WIND50 ND - 2014 50.000 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	525.7	2919.80				715.6	568.5	8.24	1.0000		
2013	533.7	3229.40	5.0	0.0	10.8	731.4	584.3	9.79	99.9999	0.000	0.000
2014	556.3	3428.39	0.0	0.0	11.2	742.6	595.5	7.35	75.5651	0.000	0.000
2015	572.9	3566.99	369.3	280.1	0.0	831.8	624.1	9.31	60.3403	273.633	0.000
2016	584.5	3658.69	0.0	0.0	0.0	831.8	624.1	7.05	40.5311	0.000	0.000
2017	591.8	3707.79	36.6	0.0	0.0	868.4	658.1	11.65	99.9999	39.327	0.000
2018	601.3	3778.79	0.0	0.0	0.0	868.4	658.1	9.82	75.4943	0.000	0.000
2019	610.8	3849.89	0.0	0.0	0.0	868.4	658.1	8.04	56.5963	0.000	0.000
2020	620.0	3917.09	200.0	81.2	0.0	987.2	775.3	26.01	99.9999	203.561	0.000
2021	629.2	3985.68	0.0	0.0	0.0	987.2	775.3	24.10	73.5803	0.000	0.000
2022	638.2	4051.58	0.0	0.0	0.0	987.2	775.3	22.29	53.7683	0.000	0.000
2023	647.0	4116.17	0.0	0.0	0.0	987.2	775.3	20.56	44.4455	0.000	0.000
2024	655.6	4177.97	0.0	0.0	0.0	987.2	775.3	18.92	35.1776	0.000	0.000
2025	664.3	4241.47	0.0	0.0	0.0	987.2	775.3	17.31	29.1812	0.000	0.000
2026	672.9	4302.67	0.0	0.0	0.0	987.2	775.3	15.76	23.8268	0.000	0.000
2027	681.3	4363.77	0.0	0.0	0.0	987.2	775.3	14.28	18.2472	0.000	0.000
2028	689.6	4422.07	0.0	0.0	0.0	987.2	775.3	12.86	16.0166	0.000	0.000
2029	697.8	4481.26	0.0	0.0	-19.5	967.7	771.9	10.98	12.0481	0.000	0.000
2030	706.2	4541.26	0.0	30.0	0.0	937.7	765.6	8.70	8.3519	0.000	0.000
2031	714.7	4602.16	0.0	0.0	0.0	937.7	765.6	7.36	7.4136	0.000	0.000
2032	723.2	4663.96	20.0	0.0	0.0	957.7	769.6	6.63	7.2855	66.550	0.000

.....COST SUMMARY.....						
YEAR	PRODUCTION COST	CAPITAL FIXED CHARGES	ANNUAL	CUMULATIVE ANNUAL	PRESENT WORTH	CUMULATIVE PRES WORTH
2013	92.603	0.000	92.603	92.603	86.609	86.609
2014	103.969	0.000	103.969	196.571	90.946	177.555
2015	114.424	35.341	149.765	346.336	122.527	300.083
2016	122.527	35.341	157.868	504.204	120.797	420.880
2017	125.547	40.164	165.711	669.915	118.593	539.473
2018	132.165	40.164	172.329	842.244	115.346	654.819
2019	139.734	40.164	179.898	1022.142	112.620	767.439
2020	148.780	59.025	207.805	1229.947	121.670	889.109
2021	154.161	59.025	213.186	1443.133	116.742	1005.851
2022	161.645	59.025	220.670	1663.802	113.019	1118.870
2023	169.480	59.025	228.505	1892.307	109.458	1228.328
2024	177.334	59.025	236.359	2128.665	105.892	1334.220
2025	190.611	59.025	249.636	2378.302	104.602	1438.823
2026	199.556	59.025	258.580	2636.882	101.337	1540.160
2027	206.643	59.025	265.668	2902.550	97.377	1637.537
2028	216.183	59.025	275.208	3177.757	94.345	1731.881
2029	229.328	59.025	288.353	3466.110	92.453	1824.335
2030	248.556	59.025	307.580	3773.691	92.235	1916.570
2031	255.752	59.025	314.776	4088.467	88.284	2004.854
2032	265.083	67.542	332.625	4421.092	87.252	2092.106
EXT.	1234.122	198.879			1433.001	3525.107

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 2012.
 - CAPACITY TOTALS INCLUDE BOTH SUPPLY-SIDE AND DEMAND-SIDE RESOURCES. SEE RESERVE REPORT FOR DETAILS.

PLAN 1

	ENERGY, GWH.....							
	GENERATION	DUMP	CHARGING	CONTRACT PURCHASE	CONTRACT SALE	ECONOMY INTERCH	UNMET	TOTAL
2013	3242.96	-14.03	0.00	0.00	0.00	0.00	0.47	3229.40
2014	3434.50	-6.68	0.00	0.00	0.00	0.00	0.58	3428.39
2015	3572.54	-7.29	0.00	0.00	0.00	0.00	1.74	3566.99
2016	3662.86	-7.21	0.00	0.00	0.00	0.00	3.04	3658.69
2017	3716.79	-9.72	0.00	0.00	0.00	0.00	0.71	3707.79
2018	3783.54	-5.60	0.00	0.00	0.00	0.00	0.85	3778.79
2019	3851.66	-3.01	0.00	0.00	0.00	0.00	1.24	3849.89
2020	3916.19	0.00	0.00	0.00	0.00	0.00	0.89	3917.09
2021	3984.93	0.00	0.00	0.00	0.00	0.00	0.76	3985.68
2022	4050.57	0.00	0.00	0.00	0.00	0.00	1.01	4051.58
2023	4114.78	0.00	0.00	0.00	0.00	0.00	1.40	4116.17
2024	4176.39	0.00	0.00	0.00	0.00	0.00	1.58	4177.97
2025	4238.65	0.00	0.00	0.00	0.00	0.00	2.82	4241.47
2026	4299.77	0.00	0.00	0.00	0.00	0.00	2.90	4302.67
2027	4361.07	0.00	0.00	0.00	0.00	0.00	2.70	4363.77
2028	4419.02	0.00	0.00	0.00	0.00	0.00	3.04	4422.07
2029	4477.09	0.00	0.00	0.00	0.00	0.00	4.17	4481.26
2030	4534.01	0.00	0.00	0.00	0.00	0.00	7.25	4541.26
2031	4596.25	0.00	0.00	0.00	0.00	0.00	5.91	4602.16
2032	4657.42	0.00	0.00	0.00	0.00	0.00	6.53	4663.96
EXT.	4657.43	0.00	0.00	0.00	0.00	0.00	6.53	4663.96

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
	----	----	----	----	----	----	----	----	----	----
2013	55.639	15.892	21.010	0.000	0.000	0.000	0.000	0.000	0.062	92.603
2014	61.441	20.425	22.023	0.000	0.000	0.000	0.000	0.000	0.080	103.969
2015	65.891	25.942	22.343	0.000	0.000	0.000	0.000	0.000	0.248	114.424
2016	71.475	27.595	23.013	0.000	0.000	0.000	0.000	0.000	0.445	122.527
2017	72.807	27.699	24.935	0.000	0.000	0.000	0.000	0.000	0.107	125.547
2018	76.821	29.530	25.683	0.000	0.000	0.000	0.000	0.000	0.131	132.165
2019	83.117	29.967	26.453	0.000	0.000	0.000	0.000	0.000	0.198	139.734
2020	91.555	32.889	24.189	0.000	0.000	0.000	0.000	0.000	0.147	148.780
2021	96.784	32.334	24.915	0.000	0.000	0.000	0.000	0.000	0.128	154.161
2022	102.008	33.799	25.662	0.000	0.000	0.000	0.000	0.000	0.176	161.645
2023	107.884	34.912	26.432	0.000	0.000	0.000	0.000	0.000	0.251	169.480
2024	113.400	36.416	27.225	0.000	0.000	0.000	0.000	0.000	0.293	177.334
2025	120.815	41.215	28.042	0.000	0.000	0.000	0.000	0.000	0.539	190.611
2026	126.828	43.274	28.883	0.000	0.000	0.000	0.000	0.000	0.570	199.556
2027	131.753	44.594	29.750	0.000	0.000	0.000	0.000	0.000	0.546	206.643
2028	138.291	46.614	30.642	0.000	0.000	0.000	0.000	0.000	0.635	216.183
2029	148.661	48.959	30.813	0.000	0.000	0.000	0.000	0.000	0.896	229.328
2030	163.773	52.626	30.551	0.000	0.000	0.000	0.000	0.000	1.605	248.556
2031	171.536	51.400	31.468	0.000	0.000	0.000	0.000	0.000	1.347	255.752
2032	176.570	53.191	33.788	0.000	0.000	0.000	0.000	0.000	1.533	265.083
EXT.	864.318	205.741	156.940	0.000	0.000	0.000	0.000	0.000	7.123	1234.122

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1

Table with 9 columns: YEAR, TOTAL SYSTEM ENERGY, COST, FUEL CLASS ENERGY, COST (COAL), FUEL CLASS ENERGY, COST (PURC), FUEL CLASS ENERGY, COST (GAS). Rows for years 2013-2032 and EXT.

Table with 7 columns: YEAR, FUEL CLASS ENERGY, COST (WIND), FUEL CLASS ENERGY, COST (HYDR), FUEL CLASS ENERGY, COST (LIGN). Rows for years 2013-2032 and EXT.

NOTES - ANNUAL COSTS ARE IN MILLIONS OF CURRENT DOLLARS. - EXTENSION PERIOD COSTS ARE IN MILLIONS OF DOLLARS DISCOUNTED TO THE BEGINNING OF 2012. - COSTS INCLUDE FUEL, VARIABLE O+M, AND FIXED O+M.

PLAN 1 YEAR 2013 * 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.	717.	-2550.	-24.81
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	-2124.	466.	-1658.	-24.81
COYOTE	MUST		106.800	11250.	1.450	85.81	800.59	13060.	2037.	2625.	17721.	22.14
MISO - Off peak			30.000	10500.	0.000	84.00	220.14	0.	4740.	0.	4740.	21.53
BIG STONE	MUST		107.800	10350.	2.130	83.33	784.75	17300.	1318.	2575.	21193.	27.01
LEWIS & CLARK	MUST		52.300	12679.	1.820	80.70	368.69	8508.	1147.	2802.	12456.	33.79
HESKETT #2	MUST		74.600	12447.	1.790	70.18	457.40	10191.	3632.	4132.	17956.	39.26
HESKETT #2	DUMP						-14.03					
GLEN ULLIN ORMAT	MUST		6.700	1.	0.000	64.17	37.56	0.	263.	346.	609.	16.21
MISO - On peak			30.000	10500.	0.000	62.23	163.08	0.	4969.	0.	4969.	30.47
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	3.510	28.13	105.66	3071.	218.	257.	3546.	33.57
HESKETT #1			29.200	18731.	1.800	14.68	37.46	1263.	284.	1731.	3278.	87.51
GLENDIVE CT #1			35.500	11250.	3.510	12.03	37.31	1473.	77.	204.	1754.	47.01
MILES CITY C.T.			25.200	13050.	3.510	7.33	16.13	739.	33.	263.	1035.	64.17
WE ENERGIES			115.000	1.	0.000	2.96	29.70	0.	1952.	4002.	5954.	200.47
INTERRUPTIBLES	D		11.800	1.	0.000	0.33	0.34	0.	103.	608.	712.	2063.27
COMMERCIAL DSM	D		5.000	1.	0.000	0.26	0.11	0.	34.	258.	292.	2555.86
DIESEL 2			2.100	11000.	28.660	0.21	0.04	12.	0.	8.	20.	523.59
DIESEL 3			2.100	11000.	28.660	0.20	0.04	12.	0.	8.	20.	535.84
DIESEL 1			2.000	11000.	28.660	0.19	0.03	10.	0.	8.	18.	548.74

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2014 * 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.	-3261.	739.	-2522.	-24.53
CEDAR HILLS	NDT		19.500	0.	0.000	39.22	66.81	0.	-2119.	480.	-1639.	-24.53
MISO - Off peak			30.000	10500.	0.000	91.81	240.63	0.	5441.	0.	5441.	22.61
COYOTE	MUST		106.800	11250.	1.470	85.81	800.59	13240.	2098.	2703.	18041.	22.53
BIG STONE	MUST		107.800	10350.	2.240	85.00	800.45	18558.	1384.	2652.	22594.	28.23
LEWIS & CLARK	MUST		52.300	12679.	1.810	79.05	361.17	8288.	1157.	2886.	12331.	34.14
MISO - On peak			30.000	10500.	0.000	78.22	204.99	0.	6558.	0.	6558.	31.99
HESKETT #2	MUST		74.600	12447.	1.870	71.78	467.79	10888.	3826.	4256.	18971.	40.55
HESKETT #2	DUMP						-6.68					
GLEN ULLIN ORMAT	MUST		6.700	1.	0.000	64.17	37.56	0.	267.	356.	623.	16.59
WAPA PUR-FT PECK	MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	3.830	41.03	154.13	4889.	327.	265.	5481.	35.56
HESKETT #1			29.200	18731.	1.880	20.80	53.06	1868.	414.	1783.	4065.	76.62
GLENDIVE CT #1			35.500	11250.	3.830	17.64	54.70	2357.	116.	210.	2683.	49.04
MILES CITY C.T.			25.200	13050.	3.830	11.89	26.17	1308.	56.	271.	1634.	62.45
WE ENERGIES			120.000	1.	0.000	4.61	48.33	0.	3425.	4176.	7601.	157.26
INTERRUPTIBLES	D		13.000	1.	0.000	0.49	0.55	0.	166.	690.	856.	1547.20
COMMERCIAL DSM	D		10.000	1.	0.000	0.35	0.31	0.	93.	531.	624.	2013.71
DIESEL 2			2.100	11000.	30.040	0.26	0.05	16.	0.	8.	24.	502.06
DIESEL 3			2.100	11000.	30.040	0.25	0.05	15.	0.	8.	23.	512.31
DIESEL 1			2.000	11000.	30.040	0.24	0.04	14.	0.	8.	21.	522.90

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1		YEAR 2015		* 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.	-3254.	761.	-2493.	-24.25	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2115.	495.	-1621.	-24.25	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2398.	0.	2398.	28.00	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2398.	0.	2398.	28.00	
MISO - Off peak			30.000	10500.	0.000	92.74	243.06	0.	5770.	0.	5770.	23.74	
COYOTE		MUST	106.800	11250.	1.560	85.81	800.59	14050.	2161.	2785.	18996.	23.73	
MISO - On peak			30.000	10500.	0.000	82.88	217.21	0.	7296.	0.	7296.	33.59	
LEWIS & CLARK BH		2015 MUST	52.000	12700.	1.800	80.70	366.58	8380.	1426.	3135.	12941.	35.30	
HESKETT #2		MUST	74.600	12447.	1.950	76.56	498.97	12111.	4755.	4384.	21250.	42.59	
HESKETT #2		DUMP					-7.29						
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	271.	367.	638.	16.99	
BIG STONE AQCS		MUST	106.100	10622.	2.380	61.66	571.55	14449.	2232.	3046.	19728.	34.52	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	4.010	49.17	184.71	6135.	404.	273.	6811.	36.87	
WRTSLA 18V50SG		2015	36.600	8368.	4.010	35.70	114.14	3830.	400.	1161.	5390.	47.23	
WRTSLA 18V50SG		2015	36.600	8368.	4.010	24.73	79.08	2654.	277.	1161.	4091.	51.73	
HESKETT #1			29.200	18731.	1.960	13.71	34.98	1284.	281.	1836.	3402.	97.25	
HESKETT #3			88.000	10655.	4.010	7.37	56.67	2421.	124.	1162.	3707.	65.41	
GLENDIVE CT #1			35.500	11250.	4.010	2.26	7.01	316.	15.	216.	548.	78.11	
MILES CITY C.T.			25.200	13050.	4.010	1.27	2.80	146.	6.	279.	431.	154.27	
INTERRUPTIBLES		D	13.000	1.	0.000	1.17	1.33	0.	398.	711.	1109.	835.32	
COMMERCIAL DSM		D	10.000	1.	0.000	0.84	0.74	0.	221.	547.	768.	1042.17	
DIESEL 2			2.100	11000.	32.270	0.63	0.12	41.	0.	8.	50.	430.52	
DIESEL 3			2.100	11000.	32.270	0.60	0.11	39.	0.	8.	47.	434.58	
DIESEL 1			2.000	11000.	32.270	0.57	0.10	35.	0.	8.	43.	438.60	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2016 * 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.	-3248.	784.	-2464.	-23.97
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2111.	510.	-1602.	-23.97
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2362.	0.	2362.	27.58
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2362.	0.	2362.	27.58
MISO - Off peak			30.000	10500.	0.000	92.31	241.92	0.	6031.	0.	6031.	24.93
BIG STONE AQCS		MUST	106.100	10622.	2.430	85.00	787.83	20335.	3169.	3138.	26642.	33.82
MISO - On peak			30.000	10500.	0.000	82.03	214.99	0.	7583.	0.	7583.	35.27
HESKETT #2		MUST	74.600	12447.	2.060	78.16	509.38	13061.	5000.	4516.	22576.	44.32
HESKETT #2		DUMP					-7.21					
COYOTE		MUST	106.800	11250.	1.600	75.51	704.52	12681.	1959.	2868.	17508.	24.85
LEWIS & CLARK BH	2015	MUST	52.000	12700.	1.770	72.46	329.17	7399.	1319.	3229.	11947.	36.30
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	275.	378.	653.	17.39
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	4.160	39.06	146.72	5055.	330.	281.	5666.	38.62
WRTSLA 18V50SG	2015		36.600	8368.	4.160	37.56	120.11	4181.	433.	1195.	5810.	48.37
WRTSLA 18V50SG	2015		36.600	8368.	4.160	26.92	86.07	2996.	310.	1195.	4502.	52.31
HESKETT #3			88.000	10655.	4.160	13.02	100.06	4435.	225.	1196.	5857.	58.53
HESKETT #1			29.200	18731.	2.070	4.45	11.34	440.	94.	1891.	2425.	213.78
GLENDIVE CT #1			35.500	11250.	4.160	3.19	9.90	463.	22.	223.	708.	71.53
MILES CITY C.T.			25.200	13050.	4.160	1.91	4.21	228.	9.	287.	525.	124.86
INTERRUPTIBLES		D	13.000	1.	0.000	1.86	2.11	0.	632.	732.	1364.	647.43
COMMERCIAL DSM		D	10.000	1.	0.000	1.37	1.20	0.	359.	563.	922.	770.57
DIESEL 2			2.100	11000.	33.720	1.04	0.19	71.	0.	9.	80.	418.89
DIESEL 3			2.100	11000.	33.720	0.99	0.18	67.	0.	9.	76.	421.19
DIESEL 1			2.000	11000.	33.720	0.94	0.16	61.	0.	8.	70.	423.67

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2017 * 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 K\$	COST \$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	-3241.	808.	-2434.	-23.67
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2107.	525.	-1582.	-23.67
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2327.	0.	2327.	27.17
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2327.	0.	2327.	27.17
MISO - Off peak			30.000	10500.	0.000	90.97	238.43	0.	6240.	0.	6240.	26.17
COYOTE		MUST	106.800	11250.	1.640	85.81	800.59	14771.	2292.	2954.	20017.	25.00
BIG STONE AQCS		MUST	106.100	10622.	2.470	85.00	787.83	20670.	3265.	3232.	27166.	34.48
MISO - On peak			30.000	10500.	0.000	79.68	208.82	0.	7732.	0.	7732.	37.03
LEWIS & CLARK BH		MUST	52.000	12700.	1.770	79.05	359.09	8072.	1482.	3326.	12880.	35.87
HESKETT #2		MUST	74.600	12447.	2.140	76.57	498.98	13291.	5045.	4651.	22987.	46.07
HESKETT #2		DUMP					-9.72					
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	279.	389.	669.	17.80
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	4.330	45.82	172.12	6172.	399.	290.	6861.	39.86
WRTSLA 18V50SG		2015	36.600	8368.	4.330	31.91	102.03	3697.	379.	1231.	5307.	52.02
WRTSLA 18V50SG		2015	36.600	8368.	4.330	21.04	67.28	2438.	250.	1231.	3919.	58.25
WRTSLA 18V50SG		2017	36.600	8368.	4.330	12.87	41.16	1491.	153.	1231.	2876.	69.86
HESKETT #3			88.000	10655.	4.330	5.02	38.56	1779.	89.	1232.	3101.	80.41
HESKETT #1			29.200	18731.	2.150	1.46	3.73	150.	32.	1948.	2130.	570.90
GLENDIVE CT #1			35.500	11250.	4.330	1.00	3.10	151.	7.	229.	387.	125.04
MILES CITY C.T.			25.200	13050.	4.330	0.56	1.24	70.	3.	296.	369.	297.24
INTERRUPTIBLES		D	13.000	1.	0.000	0.51	0.57	0.	172.	754.	927.	1611.65
COMMERCIAL DSM		D	10.000	1.	0.000	0.37	0.32	0.	96.	580.	676.	2115.62
DIESEL 2			2.100	11000.	35.520	0.27	0.05	19.	0.	9.	28.	573.98
DIESEL 3			2.100	11000.	35.520	0.26	0.05	18.	0.	9.	27.	583.85
DIESEL 1			2.000	11000.	35.520	0.24	0.04	17.	0.	9.	25.	594.11

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

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 K\$	COST \$/MWH	
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	-3234.	832.	-2402.	-23.37	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2102.	541.	-1561.	-23.37	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2292.	0.	2292.	26.76	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2292.	0.	2292.	26.76	
MISO - Off peak			30.000	10500.	0.000	93.41	244.81	0.	6727.	0.	6727.	27.48	
COYOTE		MUST	106.800	11250.	1.689	85.81	800.59	15214.	2361.	3043.	20618.	25.75	
BIG STONE AQCS		MUST	106.100	10622.	2.544	85.00	787.83	21290.	3363.	3329.	27981.	35.52	
MISO - On peak			30.000	10500.	0.000	83.63	219.17	0.	8521.	0.	8521.	38.88	
LEWIS & CLARK BH		MUST	52.000	12700.	1.823	80.70	366.58	8488.	1558.	3426.	13472.	36.75	
HESKETT #2		MUST	74.600	12447.	2.204	76.57	498.98	13690.	5196.	4791.	23677.	47.45	
HESKETT #2		DUMP					-5.60						
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	284.	401.	684.	18.22	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	4.460	49.26	185.06	6835.	442.	298.	7576.	40.94	
WRTSLA 18V50SG		2015	36.600	8368.	4.460	35.00	111.90	4176.	428.	1268.	5872.	52.48	
WRTSLA 18V50SG		2015	36.600	8368.	4.460	23.33	74.58	2784.	285.	1268.	4337.	58.15	
WRTSLA 18V50SG		2017	36.600	8368.	4.460	14.46	46.25	1726.	177.	1268.	3171.	68.57	
HESKETT #3			88.000	10655.	4.460	5.78	44.45	2112.	106.	1269.	3488.	78.46	
HESKETT #1			29.200	18731.	2.215	1.76	4.49	186.	39.	2007.	2232.	497.63	
GLENDIVE CT #1			35.500	11250.	4.460	1.13	3.50	176.	8.	236.	420.	119.94	
MILES CITY C.T.			25.200	13050.	4.460	0.62	1.36	79.	3.	305.	387.	284.28	
INTERRUPTIBLES		D	13.000	1.	0.000	0.57	0.65	0.	195.	777.	972.	1492.95	
COMMERCIAL DSM		D	10.000	1.	0.000	0.42	0.37	0.	110.	598.	707.	1935.35	
DIESEL 2			2.100	11000.	36.585	0.31	0.06	23.	0.	9.	32.	566.21	
DIESEL 3			2.100	11000.	36.585	0.30	0.05	22.	0.	9.	31.	574.92	
DIESEL 1			2.000	11000.	36.585	0.28	0.05	20.	0.	9.	29.	583.79	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

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 K\$	COST \$/MWH	
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	-3227.	857.	-2370.	-23.06	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	-2097.	557.	-1540.	-23.06	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2258.	0.	2258.	26.36	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2258.	0.	2258.	26.36	
MISO - Off peak			30.000	10500.	0.000	95.69	250.79	0.	7235.	0.	7235.	28.85	
COYOTE		MUST	106.800	11250.	1.740	85.81	800.59	15670.	2432.	3134.	21236.	26.53	
BIG STONE AQCS		MUST	106.100	10622.	2.620	83.33	772.38	21499.	3395.	3429.	28323.	36.67	
LEWIS & CLARK BH		MUST	52.000	12700.	1.878	80.70	366.58	8742.	1605.	3529.	13876.	37.85	
MISO - On peak			30.000	10500.	0.000	74.22	194.52	0.	7942.	0.	7942.	40.83	
HESKETT #2		MUST	74.600	12447.	2.270	71.78	467.79	13219.	5018.	4934.	23171.	49.53	
HESKETT #2		DUMP					-3.01						
GLENDIVE CT #2			43.000	8282.	4.594	65.20	244.92	9318.	602.	307.	10228.	41.76	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	288.	413.	701.	18.66	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
WRTSLA 18V50SG		2015	36.600	8368.	4.594	42.22	135.00	5190.	532.	1306.	7028.	52.06	
WRTSLA 18V50SG		2015	36.600	8368.	4.594	29.23	93.46	3593.	368.	1306.	5267.	56.36	
WRTSLA 18V50SG		2017	36.600	8368.	4.594	18.58	59.41	2284.	234.	1306.	3824.	64.37	
HESKETT #3			88.000	10655.	4.594	7.66	58.89	2882.	145.	1307.	4335.	73.61	
HESKETT #1			29.200	18731.	2.281	2.40	6.11	261.	55.	2067.	2383.	389.94	
GLENDIVE CT #1			35.500	11250.	4.594	1.56	4.83	250.	12.	243.	505.	104.46	
MILES CITY C.T.			25.200	13050.	4.594	0.87	1.91	115.	5.	314.	433.	226.43	
INTERRUPTIBLES		D	13.000	1.	0.000	0.81	0.92	0.	276.	800.	1076.	1170.35	
COMMERCIAL DSM		D	10.000	1.	0.000	0.59	0.51	0.	154.	615.	770.	1498.25	
DIESEL 2			2.100	11000.	37.683	0.44	0.08	33.	0.	10.	43.	534.81	
DIESEL 3			2.100	11000.	37.683	0.42	0.08	32.	0.	10.	42.	541.08	
DIESEL 1			2.000	11000.	37.683	0.40	0.07	29.	0.	9.	38.	547.53	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2020 * 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.	258.	882.	1141.	11.10
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	168.	574.	741.	11.10
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2224.	0.	2224.	25.96
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2224.	0.	2224.	25.96
MISO - Off peak			30.000	10500.	0.000	99.96	261.97	0.	7938.	0.	7938.	30.30
COYOTE		MUST	106.800	11250.	1.792	77.23	720.53	14526.	2254.	3228.	20009.	27.77
BIG STONE AQCS		MUST	106.100	10622.	2.699	76.66	710.59	20372.	3218.	3532.	27121.	38.17
HESKETT #2		MUST	74.600	12447.	2.338	76.57	498.98	14524.	5513.	5082.	25119.	50.34
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	292.	425.	717.	19.10
GE7FA.05 CC	2020		200.000	6719.	4.732	62.85	1098.17	34912.	5146.	2706.	42764.	38.94
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	4.732	24.84	93.31	3656.	236.	316.	4209.	45.11
MISO - On peak			30.000	10500.	0.000	21.10	55.30	0.	2371.	0.	2371.	42.87
WRTSLA 18V50SG	2015		36.600	8368.	4.732	10.13	32.40	1283.	132.	1345.	2760.	85.17
WRTSLA 18V50SG	2015		36.600	8368.	4.732	6.72	21.50	851.	87.	1345.	2284.	106.24
WRTSLA 18V50SG	2017		36.600	8368.	4.732	4.19	13.39	530.	54.	1345.	1930.	144.14
HESKETT #3			88.000	10655.	4.732	1.71	13.12	662.	33.	1347.	2041.	155.57
GLENDIVE CT #1			35.500	11250.	4.732	0.68	2.10	112.	5.	250.	368.	174.89
INTERRUPTIBLES		D	13.000	1.	0.000	0.47	0.53	0.	160.	824.	984.	1847.63
MILES CITY C.T.			25.200	13050.	4.732	0.46	1.01	62.	3.	323.	388.	384.29
COMMERCIAL DSM		D	10.000	1.	0.000	0.37	0.32	0.	97.	634.	731.	2257.13
DIESEL 2			2.100	11000.	38.814	0.29	0.05	23.	0.	10.	33.	614.12
DIESEL 3			2.100	11000.	38.814	0.27	0.05	21.	0.	10.	31.	624.86
DIESEL 1			2.000	11000.	38.814	0.27	0.05	20.	0.	9.	29.	629.92

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1		YEAR 2021		* 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.	266.	909.	1175.	11.43	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	173.	591.	764.	11.43	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2191.	0.	2191.	25.57	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2191.	0.	2191.	25.57	
MISO - Off peak			30.000	10500.	0.000	99.90	261.83	0.	8329.	0.	8329.	31.81	
COYOTE		MUST	106.800	11250.	1.846	85.81	800.59	16625.	2580.	3325.	22530.	28.14	
BIG STONE AQCS		MUST	106.100	10622.	2.780	85.00	787.83	23264.	3674.	3638.	30576.	38.81	
HESKETT #2		MUST	74.600	12447.	2.409	76.57	498.98	14959.	5678.	5235.	25872.	51.85	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	297.	438.	735.	19.56	
GE7FA.05 CC		2020	200.000	6719.	4.873	59.56	1040.58	34073.	5022.	2787.	41883.	40.25	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	4.873	21.38	80.33	3242.	210.	326.	3778.	47.03	
WRTSLA 18V50SG		2015	36.600	8368.	4.873	13.79	44.09	1798.	184.	1386.	3368.	76.39	
WRTSLA 18V50SG		2015	36.600	8368.	4.873	9.38	29.99	1223.	125.	1386.	2734.	91.17	
WRTSLA 18V50SG		2017	36.600	8368.	4.873	6.23	19.91	812.	83.	1386.	2281.	114.58	
MISO - On peak			30.000	10500.	0.000	5.09	13.35	0.	601.	0.	601.	45.01	
HESKETT #3			88.000	10655.	4.873	1.45	11.15	579.	29.	1387.	1995.	178.90	
GLENDIVE CT #1			35.500	11250.	4.873	0.58	1.78	98.	5.	258.	360.	202.09	
INTERRUPTIBLES		D	13.000	1.	0.000	0.40	0.45	0.	136.	849.	985.	2173.54	
MILES CITY C.T.			25.200	13050.	4.873	0.39	0.86	55.	2.	333.	390.	454.23	
COMMERCIAL DSM		D	10.000	1.	0.000	0.31	0.27	0.	82.	653.	735.	2675.75	
DIESEL 2			2.100	11000.	39.978	0.24	0.04	20.	0.	10.	30.	669.69	
DIESEL 3			2.100	11000.	39.978	0.24	0.04	19.	0.	10.	29.	676.47	
DIESEL 1			2.000	11000.	39.978	0.22	0.04	17.	0.	10.	27.	689.42	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN	1	YEAR	2022	* 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 K\$	COST \$/MWH	
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	274.	936.	1210.	11.77	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	178.	609.	787.	11.77	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2158.	0.	2158.	25.19	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2158.	0.	2158.	25.19	
MISO - Off peak			30.000	10500.	0.000	99.93	261.90	0.	8747.	0.	8747.	33.40	
COYOTE		MUST	106.800	11250.	1.901	85.81	800.59	17123.	2658.	3425.	23206.	28.99	
BIG STONE AQCS		MUST	106.100	10622.	2.863	85.00	787.83	23962.	3785.	3747.	31493.	39.97	
HESKETT #2		MUST	74.600	12447.	2.481	78.16	509.38	15729.	5970.	5392.	27091.	53.18	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	301.	451.	752.	20.03	
GE7FA.05 CC		2020	200.000	6719.	5.020	61.28	1070.71	36112.	5323.	2871.	44305.	41.38	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	5.020	22.19	83.37	3466.	224.	336.	4026.	48.29	
WRTSLA 18V50SG		2015	36.600	8368.	5.020	16.11	51.50	2163.	222.	1427.	3812.	74.03	
WRTSLA 18V50SG		2015	36.600	8368.	5.020	10.91	34.88	1465.	150.	1427.	3043.	87.23	
WRTSLA 18V50SG		2017	36.600	8368.	5.020	7.31	23.38	982.	101.	1427.	2510.	107.37	
MISO - On peak			30.000	10500.	0.000	6.14	16.08	0.	760.	0.	760.	47.26	
HESKETT #3			88.000	10655.	5.020	1.81	13.88	743.	37.	1429.	2209.	159.07	
GLENDIVE CT #1			35.500	11250.	5.020	0.70	2.17	122.	6.	266.	394.	181.79	
INTERRUPTIBLES		D	13.000	1.	0.000	0.49	0.56	0.	167.	874.	1041.	1874.68	
MILES CITY C.T.			25.200	13050.	5.020	0.47	1.04	68.	3.	343.	414.	397.88	
COMMERCIAL DSM		D	10.000	1.	0.000	0.39	0.34	0.	102.	672.	775.	2273.27	
DIESEL 2			2.100	11000.	41.177	0.30	0.06	25.	0.	10.	36.	642.58	
DIESEL 3			2.100	11000.	41.177	0.29	0.05	24.	0.	10.	35.	650.08	
DIESEL 1			2.000	11000.	41.177	0.28	0.05	22.	0.	10.	32.	655.83	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

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.	282.	964.	1246.	12.12
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	183.	627.	810.	12.12
WIND PPA	2015	NDT	25.000	0.	0.000	39.22	85.66	0.	2125.	0.	2125.	24.81
WIND PPA	2015	NDT	25.000	0.	0.000	39.22	85.66	0.	2125.	0.	2125.	24.81
MISO - Off peak			30.000	10500.	0.000	100.00	262.08	0.	9191.	0.	9191.	35.07
COYOTE		MUST	106.800	11250.	1.958	85.81	800.59	17637.	2737.	3527.	23902.	29.86
BIG STONE AQCS		MUST	106.100	10622.	2.949	83.33	772.38	24197.	3822.	3859.	31878.	41.27
HESKETT #2		MUST	74.600	12447.	2.555	70.18	457.40	14548.	5522.	5554.	25623.	56.02
GE7FA.05 CC	2020		200.000	6719.	5.170	65.47	1143.87	39737.	5857.	2957.	48550.	42.44
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	306.	465.	770.	20.51
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	5.170	29.34	110.23	4720.	305.	346.	5371.	48.73
WRTSLA 18V50SG	2015		36.600	8368.	5.170	19.27	61.63	2666.	273.	1470.	4410.	71.56
WRTSLA 18V50SG	2015		36.600	8368.	5.170	13.12	41.95	1815.	186.	1470.	3471.	82.74
WRTSLA 18V50SG	2017		36.600	8368.	5.170	8.97	28.69	1241.	127.	1470.	2839.	98.95
MISO - On peak			30.000	10500.	0.000	7.62	19.96	0.	990.	0.	990.	49.62
HESKETT #3			88.000	10655.	5.170	2.33	17.95	989.	50.	1471.	2510.	139.84
GLENDIVE CT #1			35.500	11250.	5.170	0.87	2.69	156.	7.	274.	437.	162.82
INTERRUPTIBLES		D	13.000	1.	0.000	0.62	0.70	0.	211.	900.	1112.	1579.09
MILES CITY C.T.			25.200	13050.	5.170	0.55	1.22	82.	3.	353.	439.	360.03
COMMERCIAL DSM		D	10.000	1.	0.000	0.50	0.44	0.	131.	693.	824.	1885.14
DIESEL 2			2.100	11000.	42.413	0.39	0.07	34.	0.	11.	45.	617.64
DIESEL 3			2.100	11000.	42.413	0.38	0.07	32.	0.	11.	43.	623.18
DIESEL 1			2.000	11000.	42.413	0.37	0.06	30.	0.	10.	40.	628.83

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1		YEAR 2024		* 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.	291.	993.	1284.	12.49	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	189.	646.	834.	12.49	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2093.	0.	2093.	24.44	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	2093.	0.	2093.	24.44	
MISO - Off peak			30.000	10500.	0.000	99.99	262.06	0.	9650.	0.	9650.	36.82	
COYOTE		MUST	106.800	11250.	2.017	85.81	800.59	18166.	2819.	3633.	24619.	30.75	
BIG STONE AQCS		MUST	106.100	10622.	3.038	85.00	787.83	25421.	4015.	3975.	33411.	42.41	
HESKETT #2		MUST	74.600	12447.	2.632	71.78	467.79	15325.	5817.	5720.	26862.	57.42	
GE7FA.05 CC			200.000	6719.	5.325	66.21	1156.83	41393.	6101.	3045.	50539.	43.69	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	310.	479.	789.	21.00	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	5.325	31.83	119.58	5274.	341.	356.	5971.	49.93	
WRTSLA 18V50SG			36.600	8368.	5.325	20.80	66.51	2964.	304.	1514.	4782.	71.90	
WRTSLA 18V50SG			36.600	8368.	5.325	14.10	45.08	2009.	206.	1514.	3729.	82.72	
WRTSLA 18V50SG			36.600	8368.	5.325	9.40	30.06	1340.	137.	1514.	2991.	99.50	
MISO - On peak			30.000	10500.	0.000	8.24	21.61	0.	1126.	0.	1126.	52.10	
HESKETT #3			88.000	10655.	5.325	2.55	19.64	1114.	56.	1516.	2686.	136.76	
GLENDIVE CT #1			35.500	11250.	5.325	0.99	3.07	184.	9.	282.	475.	154.59	
INTERRUPTIBLES		D	13.000	1.	0.000	0.68	0.78	0.	233.	927.	1161.	1492.93	
MILES CITY C.T.			25.200	13050.	5.325	0.66	1.45	101.	4.	364.	469.	323.21	
COMMERCIAL DSM		D	10.000	1.	0.000	0.55	0.48	0.	144.	713.	858.	1783.83	
DIESEL 2			2.100	11000.	43.685	0.44	0.08	38.	0.	11.	50.	621.32	
DIESEL 3			2.100	11000.	43.685	0.42	0.08	37.	0.	11.	48.	626.40	
DIESEL 1			2.000	11000.	43.685	0.41	0.07	34.	0.	11.	45.	631.59	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1		YEAR 2025		* 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.	299.	1023.	1322.	12.86	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	195.	665.	859.	12.86	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3342.	0.	3342.	39.01	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3342.	0.	3342.	39.01	
MISO - Off peak			30.000	10500.	0.000	100.00	262.08	0.	10133.	0.	10133.	38.66	
COYOTE		MUST	106.800	11250.	2.078	85.81	800.59	18711.	2904.	3742.	25357.	31.67	
HESKETT #2		MUST	74.600	12447.	2.711	76.57	498.98	16837.	6391.	5892.	29119.	58.36	
GE7FA.05 CC			200.000	6719.	5.485	72.08	1259.45	46416.	6842.	3137.	56395.	44.78	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	315.	493.	808.	21.51	
BIG STONE AQCS		MUST	106.100	10622.	3.129	61.66	571.56	18996.	3000.	4094.	26091.	45.65	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	5.485	44.36	166.65	7570.	489.	367.	8427.	50.57	
WRTSLA 18V50SG			36.600	8368.	5.485	31.15	99.59	4571.	469.	1560.	6600.	66.27	
WRTSLA 18V50SG			36.600	8368.	5.485	21.07	67.38	3093.	317.	1560.	4970.	73.75	
WRTSLA 18V50SG			36.600	8368.	5.485	14.08	45.01	2066.	212.	1560.	3838.	85.26	
MISO - On peak			30.000	10500.	0.000	12.36	32.38	0.	1772.	0.	1772.	54.71	
HESKETT #3			88.000	10655.	5.485	4.20	32.32	1889.	95.	1561.	3545.	109.69	
GLENDIVE CT #1			35.500	11250.	5.485	1.65	5.13	317.	15.	290.	622.	121.26	
INTERRUPTIBLES		D	13.000	1.	0.000	1.09	1.24	0.	371.	955.	1326.	1072.88	
MILES CITY C.T.			25.200	13050.	5.485	1.06	2.34	168.	7.	375.	550.	234.54	
COMMERCIAL DSM		D	10.000	1.	0.000	0.88	0.77	0.	230.	735.	965.	1259.09	
DIESEL 2			2.100	11000.	44.996	0.70	0.13	64.	0.	11.	76.	585.99	
DIESEL 3			2.100	11000.	44.996	0.67	0.12	61.	0.	11.	72.	590.80	
DIESEL 1			2.000	11000.	44.996	0.66	0.11	57.	0.	11.	68.	592.12	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2026 * 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 K\$	COST \$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	308.	1054.	1362.	13.25
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	200.	685.	885.	13.25
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3408.	0.	3408.	39.79
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3408.	0.	3408.	39.79
MISO - Off peak			30.000	10500.	0.000	100.00	262.08	0.	10640.	0.	10640.	40.60
BIG STONE AQCS		MUST	106.100	10622.	3.223	85.00	787.83	26969.	4260.	4217.	35446.	44.99
HESKETT #2		MUST	74.600	12447.	2.792	78.16	509.38	17703.	6720.	6068.	30491.	59.86
COYOTE		MUST	106.800	11250.	2.140	75.51	704.52	16960.	2632.	3854.	23446.	33.28
GE7FA.05 CC			200.000	6719.	5.650	70.86	1237.99	46994.	6927.	3231.	57152.	46.16
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	319.	508.	827.	22.03
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	5.650	33.08	124.25	5814.	376.	378.	6567.	52.86
WRTSLA 18V50SG			36.600	8368.	5.650	29.84	95.41	4511.	462.	1607.	6580.	68.96
WRTSLA 18V50SG			36.600	8368.	5.650	20.64	65.99	3120.	320.	1607.	5046.	76.47
WRTSLA 18V50SG			36.600	8368.	5.650	13.95	44.60	2109.	216.	1607.	3931.	88.14
MISO - On peak			30.000	10500.	0.000	12.39	32.46	0.	1865.	0.	1865.	57.44
HESKETT #3			88.000	10655.	5.650	4.24	32.57	1961.	99.	1608.	3667.	112.59
GLENDIVE CT #1			35.500	11250.	5.650	1.65	5.10	324.	15.	299.	639.	125.19
INTERRUPTIBLES		D	13.000	1.	0.000	1.12	1.27	0.	380.	984.	1364.	1076.27
MILES CITY C.T.			25.200	13050.	5.650	1.07	2.36	174.	7.	386.	568.	240.16
COMMERCIAL DSM		D	10.000	1.	0.000	0.89	0.78	0.	234.	757.	991.	1271.64
DIESEL 2			2.100	11000.	46.345	0.71	0.13	66.	0.	12.	79.	602.67
DIESEL 3			2.100	11000.	46.345	0.69	0.13	64.	0.	12.	76.	605.89
DIESEL 1			2.000	11000.	46.345	0.66	0.11	59.	0.	11.	70.	609.83

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

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 K\$	COST \$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	317.	1085.	1403.	13.65
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	206.	705.	912.	13.65
WIND PPA	2015	NDT	25.000	0.	0.000	39.22	85.66	0.	3477.	0.	3477.	40.59
WIND PPA	2015	NDT	25.000	0.	0.000	39.22	85.66	0.	3477.	0.	3477.	40.59
MISO - Off peak			30.000	10500.	0.000	100.00	262.08	0.	11172.	0.	11172.	42.63
COYOTE		MUST	106.800	11250.	2.204	85.81	800.59	19851.	3081.	3970.	26902.	33.60
BIG STONE AQCS		MUST	106.100	10622.	3.319	85.00	787.83	27778.	4387.	4343.	36509.	46.34
HESKETT #2		MUST	74.600	12447.	2.876	76.57	498.98	17862.	6780.	6251.	30893.	61.91
GE7FA.05 CC	2020		200.000	6719.	5.819	69.36	1211.84	47382.	6984.	3328.	57693.	47.61
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	324.	523.	847.	22.56
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	5.819	39.37	147.91	7128.	461.	389.	7978.	53.94
WRTSLA 18V50SG	2015		36.600	8368.	5.819	27.64	88.38	4304.	441.	1655.	6400.	72.41
WRTSLA 18V50SG	2015		36.600	8368.	5.819	19.13	61.17	2979.	305.	1655.	4939.	80.74
WRTSLA 18V50SG	2017		36.600	8368.	5.819	12.80	40.93	1993.	204.	1655.	3852.	94.11
MISO - On peak			30.000	10500.	0.000	11.47	30.06	0.	1813.	0.	1813.	60.32
HESKETT #3			88.000	10655.	5.819	3.80	29.24	1813.	91.	1656.	3560.	121.77
GLENDIVE CT #1			35.500	11250.	5.819	1.53	4.75	311.	15.	308.	634.	133.44
INTERRUPTIBLES		D	13.000	1.	0.000	1.04	1.18	0.	354.	1013.	1368.	1157.99
MILES CITY C.T.			25.200	13050.	5.819	1.02	2.25	171.	7.	398.	575.	256.02
COMMERCIAL DSM		D	10.000	1.	0.000	0.84	0.73	0.	220.	780.	999.	1364.88
DIESEL 2			2.100	11000.	47.736	0.66	0.12	64.	0.	12.	76.	627.66
DIESEL 3			2.100	11000.	47.736	0.64	0.12	62.	0.	12.	74.	631.16
DIESEL 1			2.000	11000.	47.736	0.62	0.11	57.	0.	11.	68.	634.67

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

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 K\$	COST \$/MWH
DIAMOND WILLOW		NDT	30.000	0.	0.000	39.22	102.79	0.	327.	1118.	1445.	14.06
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	213.	727.	939.	14.06
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3546.	0.	3546.	41.40
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3546.	0.	3546.	41.40
MISO - Off peak			30.000	10500.	0.000	100.00	262.08	0.	11730.	0.	11730.	44.76
COYOTE		MUST	106.800	11250.	2.270	85.81	800.59	20446.	3173.	4089.	27709.	34.61
BIG STONE AQCS		MUST	106.100	10622.	3.419	85.00	787.83	28612.	4519.	4474.	37605.	47.73
HESKETT #2		MUST	74.600	12447.	2.962	76.57	498.98	18398.	6983.	6438.	31819.	63.77
GE7FA.05 CC			200.000	6719.	5.994	70.71	1235.40	49752.	7333.	3428.	60512.	48.98
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	329.	539.	868.	23.11
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
GLENDIVE CT #2			43.000	8282.	5.994	41.99	157.72	7829.	506.	401.	8736.	55.39
WRTSLA 18V50SG			36.600	8368.	5.994	29.93	95.69	4800.	492.	1704.	6996.	73.11
WRTSLA 18V50SG			36.600	8368.	5.994	20.77	66.42	3331.	341.	1704.	5377.	80.96
WRTSLA 18V50SG			36.600	8368.	5.994	14.25	45.55	2285.	234.	1704.	4223.	92.71
MISO - On peak			30.000	10500.	0.000	12.64	33.11	0.	2097.	0.	2097.	63.33
HESKETT #3			88.000	10655.	5.994	4.23	32.52	2077.	104.	1706.	3887.	119.52
GLENDIVE CT #1			35.500	11250.	5.994	1.73	5.36	361.	17.	317.	696.	129.89
INTERRUPTIBLES		D	13.000	1.	0.000	1.15	1.31	0.	392.	1044.	1436.	1099.58
MILES CITY C.T.			25.200	13050.	5.994	1.12	2.46	192.	8.	410.	610.	248.32
COMMERCIAL DSM		D	10.000	1.	0.000	0.93	0.82	0.	245.	803.	1048.	1284.30
DIESEL 2			2.100	11000.	49.168	0.74	0.14	73.	0.	12.	86.	635.86
DIESEL 3			2.100	11000.	49.168	0.70	0.13	70.	0.	12.	83.	640.17
DIESEL 1			2.000	11000.	49.168	0.69	0.12	65.	0.	12.	77.	642.23

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

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 K\$	COST \$/MWH	
DIAMOND WILLOW		NDT	10.500	0.	0.000	39.22	35.98	0.	118.	403.	521.	14.48	
CEDAR HILLS		NDT	19.500	0.	0.000	39.22	66.81	0.	219.	748.	967.	14.48	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3617.	0.	3617.	42.23	
WIND PPA		NDT	25.000	0.	0.000	39.22	85.66	0.	3617.	0.	3617.	42.23	
MISO - Off peak			30.000	10500.	0.000	100.00	262.08	0.	12317.	0.	12317.	47.00	
COYOTE		MUST	106.800	11250.	2.338	85.81	800.59	21060.	3268.	4212.	28540.	35.65	
BIG STONE AQCS		MUST	106.100	10622.	3.522	83.33	772.38	28892.	4563.	4608.	38064.	49.28	
GE7FA.05 CC		2020	200.000	6719.	6.174	74.41	1300.02	53925.	7948.	3530.	65403.	50.31	
HESKETT #2		MUST	74.600	12447.	3.051	71.78	467.79	17766.	6743.	6631.	31140.	66.57	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	334.	555.	889.	23.67	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	6.174	51.27	192.59	9847.	637.	413.	10896.	56.58	
WRTSLA 18V50SG		2015	36.600	8368.	6.174	37.14	118.76	6135.	629.	1756.	8520.	71.74	
WRTSLA 18V50SG		2015	36.600	8368.	6.174	25.72	82.22	4248.	435.	1756.	6438.	78.31	
WRTSLA 18V50SG		2017	36.600	8368.	6.174	17.43	55.74	2880.	295.	1756.	4930.	88.45	
MISO - On peak			30.000	10500.	0.000	15.86	41.56	0.	2763.	0.	2763.	66.50	
HESKETT #3			88.000	10655.	6.174	5.74	44.10	2901.	146.	1757.	4804.	108.93	
GLENDIVE CT #1			35.500	11250.	6.174	2.26	7.00	486.	23.	327.	836.	119.45	
INTERRUPTIBLES		D	13.000	1.	0.000	1.44	1.64	0.	492.	1075.	1567.	955.64	
MILES CITY C.T.			25.200	13050.	6.174	1.42	3.13	252.	10.	422.	684.	218.90	
COMMERCIAL DSM		D	10.000	1.	0.000	1.16	1.02	0.	305.	827.	1132.	1113.20	
DIESEL 2			2.100	11000.	50.643	0.92	0.17	94.	1.	13.	108.	635.94	
DIESEL 3			2.100	11000.	50.643	0.89	0.16	91.	1.	13.	105.	638.44	
DIESEL 1			2.000	11000.	50.643	0.87	0.15	84.	1.	12.	97.	640.90	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2030 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST \$/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION COST K\$	\$/MWH
WIND PPA	2015	NDT		25.000	0.	0.000	39.22	85.66	0.	3689.	0.	3689.	43.07
WIND PPA	2015	NDT		25.000	0.	0.000	39.22	85.66	0.	3689.	0.	3689.	43.07
MISO - Off peak				30.000	10500.	0.000	94.70	248.19	0.	12247.	0.	12247.	49.35
GE7FA.05 CC	2020			200.000	6719.	6.359	77.95	1361.98	58190.	8577.	3636.	70403.	51.69
COYOTE		MUST		106.800	11250.	2.408	77.23	720.53	19522.	3030.	4338.	26890.	37.32
BIG STONE AQCS		MUST		106.100	10622.	3.627	76.66	710.59	27378.	4324.	4746.	36449.	51.29
HESKETT #2		MUST		74.600	12447.	3.143	76.57	498.98	19519.	7409.	6830.	33757.	67.65
GLEN ULLIN ORMAT		MUST		6.700	1.	0.000	64.17	37.56	0.	339.	571.	911.	24.24
GLENDIVE CT #2				43.000	8282.	6.359	63.80	239.66	12621.	816.	425.	13862.	57.84
WAPA PUR-FT PECK		MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
WRTSLA 18V50SG	2015			36.600	8368.	6.359	52.28	167.17	8895.	912.	1808.	11615.	69.48
WRTSLA 18V50SG	2015			36.600	8368.	6.359	38.78	123.99	6598.	676.	1808.	9082.	73.25
WRTSLA 18V50SG	2017			36.600	8368.	6.359	26.23	83.88	4463.	458.	1808.	6729.	80.22
MISO - On peak				30.000	10500.	0.000	23.62	61.90	0.	4322.	0.	4322.	69.82
HESKETT #3				88.000	10655.	6.359	9.10	69.96	4740.	238.	1810.	6788.	97.03
GLENDIVE CT #1				35.500	11250.	6.359	4.18	12.96	927.	44.	337.	1308.	100.91
MILES CITY C.T.				25.200	13050.	6.359	2.59	5.71	474.	19.	435.	928.	162.48
INTERRUPTIBLES		D		13.000	1.	0.000	2.50	2.83	0.	850.	1107.	1958.	690.64
COMMERCIAL DSM		D		10.000	1.	0.000	1.93	1.69	0.	507.	852.	1358.	804.56
DIESEL 2				2.100	11000.	52.162	1.48	0.27	156.	1.	13.	170.	625.58
DIESEL 3				2.100	11000.	52.162	1.43	0.26	151.	1.	13.	165.	627.36
DIESEL 1				2.000	11000.	52.162	1.38	0.24	139.	1.	13.	152.	629.14

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1 YEAR 2031 * CAPACITY FACTOR ORDER *

UNIT NAME	ALT INST	YEAR	LODNG	RATED CAPACITY MW	HEAT RATE BTU/KWH	FUEL COST \$/MBTU	CAP. FACTOR %	GENERATION GWH	FUEL K\$	VAR. O + M K\$	FIXED O + M K\$	PRODUCTION K\$	COST \$/MWH
WIND PPA	2015	NDT		25.000	0.	0.000	39.22	85.66	0.	3763.	0.	3763.	43.93
WIND PPA	2015	NDT		25.000	0.	0.000	39.22	85.66	0.	3763.	0.	3763.	43.93
MISO - Off peak				30.000	10500.	0.000	92.52	242.47	0.	12564.	0.	12564.	51.81
COYOTE		MUST		106.800	11250.	2.481	85.81	800.59	22342.	3467.	4468.	30278.	37.82
BIG STONE AQCS		MUST		106.100	10622.	3.736	85.00	787.83	31265.	4938.	4889.	41091.	52.16
GE7FA.05 CC	2020			200.000	6719.	6.550	77.74	1358.26	59772.	8810.	3745.	72327.	53.25
HESKETT #2		MUST		74.600	12447.	3.237	76.57	498.98	20104.	7631.	7035.	34770.	69.68
GLEN ULLIN ORMAT		MUST		6.700	1.	0.000	64.17	37.56	0.	344.	589.	933.	24.84
GLENDIVE CT #2				43.000	8282.	6.550	60.53	227.36	12333.	797.	438.	13568.	59.68
WAPA PUR-FT PECK		MUST		2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25
WRTSLA 18V50SG	2015			36.600	8368.	6.550	47.07	150.51	8249.	846.	1862.	10957.	72.80
WRTSLA 18V50SG	2015			36.600	8368.	6.550	33.10	105.82	5800.	595.	1862.	8257.	78.02
WRTSLA 18V50SG	2017			36.600	8368.	6.550	21.83	69.80	3826.	392.	1862.	6080.	87.11
HESKETT #3				88.000	10655.	6.550	11.82	90.87	6341.	319.	1864.	8524.	93.81
MISO - On peak				30.000	10500.	0.000	8.29	21.72	0.	1592.	0.	1592.	73.31
GLENDIVE CT #1				35.500	11250.	6.550	3.33	10.32	760.	36.	347.	1143.	110.80
MILES CITY C.T.				25.200	13050.	6.550	2.00	4.40	376.	15.	448.	839.	190.81
INTERRUPTIBLES		D		13.000	1.	0.000	1.93	2.19	0.	656.	1141.	1797.	821.74
COMMERCIAL DSM		D		10.000	1.	0.000	1.50	1.31	0.	393.	877.	1271.	969.08
DIESEL 2				2.100	11000.	53.727	1.20	0.22	130.	1.	14.	144.	656.36
DIESEL 3				2.100	11000.	53.727	1.16	0.21	125.	1.	14.	140.	658.54
DIESEL 1				2.000	11000.	53.727	1.11	0.19	114.	1.	13.	128.	661.44

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1		YEAR 2032		* 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		
WIND PPA	2015	NDT	25.000	0.	0.000	39.22	85.66	0.	3838.	0.	3838.	44.81	
WIND PPA	2015	NDT	25.000	0.	0.000	39.22	85.66	0.	3838.	0.	3838.	44.81	
WIND20 ND	2032	NDT	20.000	0.	0.000	39.22	68.53	0.	0.	1376.	1376.	20.08	
MISO - Off peak			30.000	10500.	0.000	90.44	237.02	0.	12895.	0.	12895.	54.40	
COYOTE		MUST	106.800	11250.	2.555	85.81	800.59	23012.	3571.	4602.	31186.	38.95	
BIG STONE AQCS		MUST	106.100	10622.	3.848	85.00	787.83	32203.	5086.	5035.	42324.	53.72	
HESKETT #2		MUST	74.600	12447.	3.334	78.16	509.38	21139.	8023.	7246.	36408.	71.48	
GE7FA.05 CC	2020		200.000	6719.	6.746	77.56	1355.11	61422.	9053.	3858.	74333.	54.85	
GLEN ULLIN ORMAT		MUST	6.700	1.	0.000	64.17	37.56	0.	349.	606.	956.	25.44	
WAPA PUR-FT PECK		MUST	2.800	0.	0.000	58.58	14.33	0.	476.	0.	476.	33.25	
GLENDIVE CT #2			43.000	8282.	6.746	53.33	200.32	11192.	724.	451.	12367.	61.74	
WRTSLA 18V50SG	2015		36.600	8368.	6.746	47.01	150.30	8485.	870.	1918.	11273.	75.00	
WRTSLA 18V50SG	2015		36.600	8368.	6.746	34.23	109.45	6178.	633.	1918.	8730.	79.76	
WRTSLA 18V50SG	2017		36.600	8368.	6.746	23.52	75.21	4246.	435.	1918.	6599.	87.74	
HESKETT #3			88.000	10655.	6.746	12.56	96.53	6939.	349.	1920.	9207.	95.38	
MISO - On peak			30.000	10500.	0.000	8.64	22.65	0.	1743.	0.	1743.	76.98	
GLENDIVE CT #1			35.500	11250.	6.746	3.66	11.35	861.	41.	357.	1259.	110.97	
MILES CITY C.T.			25.200	13050.	6.746	2.32	5.10	449.	18.	461.	929.	182.05	
INTERRUPTIBLES		D	13.000	1.	0.000	2.28	2.59	0.	778.	1175.	1953.	753.22	
COMMERCIAL DSM		D	10.000	1.	0.000	1.78	1.55	0.	466.	904.	1370.	881.85	
DIESEL 2			2.100	11000.	55.339	1.40	0.26	156.	1.	14.	171.	666.84	
DIESEL 3			2.100	11000.	55.339	1.35	0.25	151.	1.	14.	165.	668.87	
DIESEL 1			2.000	11000.	55.339	1.30	0.23	138.	1.	13.	152.	670.94	

NOTES - ANNUAL COSTS ARE IN CURRENT DOLLARS.
 - EXTENSION PERIOD COSTS ARE DISCOUNTED TO THE BEGINNING OF 2012.

PLAN 1

YEAR	PEAK LOAD MW	ENERGY GWH	RESERVE CAPACITY MW	RESERVE MARGIN PCT.	EMERGENCY CAPACITY MW	---LOSS OF LOAD--- HOURS PROB.	OPERATING CAPACITY MW	--UNSERVED ENERGY-- GWH PCT.
2013	533.7	3229.40	584.3	9.79	721.8	2.35 0.000269	673.8	0.47 0.01
2014	556.3	3428.39	595.5	7.35	733.0	3.81 0.000436	685.0	0.58 0.02
2015	572.9	3566.99	624.1	9.31	810.6	4.77 0.000546	748.1	1.74 0.05
2016	584.5	3658.69	624.1	7.05	810.6	7.10 0.000813	748.1	3.04 0.08
2017	591.8	3707.79	658.1	11.65	844.5	2.83 0.000324	778.7	0.71 0.02
2018	601.3	3778.79	658.1	9.82	844.5	3.81 0.000437	778.7	0.85 0.02
2019	610.8	3849.89	658.1	8.04	844.5	5.09 0.000582	778.7	1.24 0.03
2020	620.0	3917.09	775.3	26.01	966.5	2.65 0.000303	885.6	0.89 0.02
2021	629.2	3985.68	775.3	24.10	966.5	3.91 0.000448	885.6	0.76 0.02
2022	638.2	4051.58	775.3	22.29	966.5	5.36 0.000613	885.6	1.01 0.02
2023	647.0	4116.17	775.3	20.56	966.5	6.48 0.000742	885.6	1.40 0.03
2024	655.6	4177.97	775.3	18.92	966.5	8.19 0.000937	885.6	1.58 0.04
2025	664.3	4241.47	775.3	17.31	966.5	9.87 0.001129	885.6	2.82 0.07
2026	672.9	4302.67	775.3	15.76	966.5	12.08 0.001383	885.6	2.90 0.07
2027	681.3	4363.77	775.3	14.28	966.5	15.78 0.001806	885.6	2.70 0.06
2028	689.6	4422.07	775.3	12.86	966.5	17.98 0.002058	885.6	3.04 0.07
2029	697.8	4481.26	771.9	10.98	947.0	23.90 0.002736	866.1	4.17 0.09
2030	706.2	4541.26	765.6	8.70	917.0	34.48 0.003946	836.1	7.25 0.16
2031	714.7	4602.16	765.6	7.36	917.0	38.84 0.004446	836.1	5.91 0.13
2032	723.2	4663.96	769.6	6.63	937.0	39.52 0.004524	856.1	6.53 0.14
EXT.	723.2	4663.96	769.6	6.63	937.0	39.52 0.004524	856.1	6.53 0.14

NOTE - RESERVE MARGIN: ANNUAL CALCULATION, CAPACITIES NOT DERATED FOR MAINTENANCE. SEE RESERVE REPORT FOR DETAIL.
 - LOSS OF LOAD: ANNUAL CALCULATION, CAPACITIES NOT 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	
2013	533.7	0.0	-16.8	516.9	567.5	0.0	0.0	567.5	9.79
2014	556.3	0.0	-23.0	533.3	572.5	0.0	0.0	572.5	7.35
2015	572.9	0.0	-23.0	549.9	601.1	0.0	0.0	601.1	9.31
2016	584.5	0.0	-23.0	561.5	601.1	0.0	0.0	601.1	7.05
2017	591.8	0.0	-23.0	568.8	635.1	0.0	0.0	635.1	11.65
2018	601.3	0.0	-23.0	578.3	635.1	0.0	0.0	635.1	9.82
2019	610.8	0.0	-23.0	587.8	635.1	0.0	0.0	635.1	8.04
2020	620.0	0.0	-23.0	597.0	752.3	0.0	0.0	752.3	26.01
2021	629.2	0.0	-23.0	606.2	752.3	0.0	0.0	752.3	24.10
2022	638.2	0.0	-23.0	615.2	752.3	0.0	0.0	752.3	22.29
2023	647.0	0.0	-23.0	624.0	752.3	0.0	0.0	752.3	20.56
2024	655.6	0.0	-23.0	632.6	752.3	0.0	0.0	752.3	18.92
2025	664.3	0.0	-23.0	641.3	752.3	0.0	0.0	752.3	17.31
2026	672.9	0.0	-23.0	649.9	752.3	0.0	0.0	752.3	15.76
2027	681.3	0.0	-23.0	658.3	752.3	0.0	0.0	752.3	14.28
2028	689.6	0.0	-23.0	666.6	752.3	0.0	0.0	752.3	12.86
2029	697.8	0.0	-23.0	674.8	748.9	0.0	0.0	748.9	10.98
2030	706.2	0.0	-23.0	683.2	742.6	0.0	0.0	742.6	8.70
2031	714.7	0.0	-23.0	691.7	742.6	0.0	0.0	742.6	7.36
2032	723.2	0.0	-23.0	700.2	746.6	0.0	0.0	746.6	6.63
EXT.	723.2	0.0	-23.0	700.2	746.6	0.0	0.0	746.6	6.63

PLAN 1

YEAR	FIXED CHARGES	OPERATING COSTS	TOTAL SYSTEM COST	OTHER ELECTRIC REVENUES	SALES GWH	-----SYSTEM AVERAGE RATE-----	
						\$/MWH	PERCENT INCREASE 1 YEAR
2013	0.	92603.	92603.	0.	3228.94	28.679	
2014	0.	103969.	103969.	0.	3427.53	30.333	5.769
2015	35341.	114424.	149765.	0.	3564.93	42.011	38.496
2016	35341.	122527.	157868.	0.	3655.39	43.188	2.802
2017	40164.	125547.	165711.	0.	3706.90	44.704	3.510
2018	40164.	132165.	172329.	0.	3777.77	45.617	2.042
2019	40164.	139734.	179898.	0.	3848.45	46.746	2.475
2020	59025.	148780.	207805.	0.	3916.23	53.063	13.513
2021	59025.	154161.	213186.	0.	3984.95	53.498	0.820
2022	59025.	161645.	220670.	0.	4050.68	54.477	1.831
2023	59025.	169480.	228505.	0.	4115.03	55.529	1.931
2024	59025.	177334.	236359.	0.	4176.72	56.590	1.910
2025	59025.	190611.	249636.	0.	4239.47	58.884	4.054
2026	59025.	199556.	258580.	0.	4300.63	60.126	2.110
2027	59025.	206643.	265668.	0.	4361.86	60.907	1.299
2028	59025.	216183.	275208.	0.	4419.95	62.265	2.229
2029	59025.	229328.	288353.	0.	4478.61	64.385	3.404
2030	59025.	248556.	307580.	0.	4536.73	67.798	5.301
2031	59025.	255752.	314776.	0.	4598.66	68.450	0.962
2032	67542.	265083.	332625.	0.	4659.81	71.382	4.284

TOTAL 967011. 3454081. 4421092.

PRESENT VALUE REVENUE REQUIREMENTS 449185. 1642921. 2092106.
 (THOUSANDS OF 2012 DOLLARS)

LEVELIZED SYSTEM AVERAGE RATE = 49.116 \$/MWH

PERCENT INCREASE IN SYSTEM AVERAGE RATE
 MINIMUM 0.820
 MAXIMUM 38.496
 COMPOUND AVERAGE 4.916

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

EGEAS REPORT VERSION 9.02

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Attachment D

PUBLIC ADVISORY GROUP DOCUMENTATION

ATTACHMENT D

PUBLIC ADVISORY GROUP DOCUMENTATION

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

MONTANA-DAKOTA UTILITIES CO. INTEGRATED RESOURCE PLANNING 2012-2013 PUBLIC ADVISORY GROUP ROSTER

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** Invited as an observer*

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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:

Andrea Stomberg	Vice President—Electric Supply
Abbie Krebsbach	Director, Environmental
Alan Welte	Director, Generation
Henry Ford	Director, Electric Transmission Engineering
Bob Morman	Director, Gas Supply
Jon Madison	Environmental Scientist
Matthew Lund	Engineer I – Power Production

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

October 4, 2012 Meeting Agenda

Overview of the IRP Process	Brian Giggee
2011 IRP Action Plan Updates	Brian Giggee Larry Oswald
Bakken Growth Impacts	Darcy Neigum
MDU Transmission Projects	Henry Ford
Load Forecast	Kayla Kaul
2012 Request for Proposal	Brian Giggee
MT Energy Efficiency Potential Study	Kathy Baerlocher
Environmental Challenges and Uncertainty	Jon Madison
Workings of the IRP Public Advisory Meeting Logistics Discussion Topics for Future Meetings Meeting Schedule through 2012-13	Group Discussion

December 5, 2012 Meeting Agenda

Montana Dakota's Existing Generation	Andrea Stomberg
Heskett CT and Big Stone AQCS	Alan Welte
EMPower ND Commission Recommendations	Mike Fladeland
Montana Energy Overview Updates	Jeff Blend
Regulatory Topics	Tamie Aberle
KLJ Bakken Load Report	Darcy Neigum
Future Supply Side Resource Options	Alan Welte
Wrap-up Meeting Logistics	Group Discussion

Discussion Topics for Future Meetings
Meeting Schedule through 2013

March 27, 2013 Meeting Agenda

Gas Supply Update	Bob Morman
Nexant Potential Study and Next Steps	Kathy Baerlocher
MISO Generation Retirement and Transmission Build Out	Darcy Neigum
High Growth Load Forecast	Kayla Kaul
North Dakota Energy Policy & Stimulus Update	Mike Fladeland
Lewis and Clark MATS Update	Abbie Krebsbach
Supply Side Overview Update	Alan Welte/Matt Lund
DSM Update	Larry Oswald
EGEAS Modeling Results	Brian Giggee
Wrap-up	Group Discussion
Meeting Logistics	
Discussion Topics for Future Meetings	
Meeting Schedule through 2013	

May 23, 2013 Meeting Agenda

MT Legislative Session Review	Jeff Blend
ND Legislative Session Review	Mike Fladeland
DSM Overview	Larry Oswald
Load Forecast Overview	Kayla Kaul
Environmental Overview	Abbie Krebsbach
2013 Request for Proposal	Brian Giggee
Supply Side Results	Brian Giggee
Two Year Action Plan	Darcy Neigum

Wrap-up

IRP Filing Timeline

Feedback from the PAG Members

Future PAG Membership for 2015 IRP

Group Discussion

Attachment E

March 25, 2013 Request for Proposal for Capacity and Energy Supply

Montana-Dakota Utilities Co.

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

March 25, 2013

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

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Exhibit B – Form of Notice of Intent to Bid

Exhibit C – Form of Confidentiality Agreement

1. INTRODUCTION

1.1. Purpose

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

In this Request for Proposal (“RFP”), Montana-Dakota requests competitive proposals (“Proposals”) for capacity and energy totaling at least 20 megawatts (MW) and no more than 150 MW for a period of at least five years, with five year extension options available, with deliveries to begin June 1, 2014. Persons or entities responding to this RFP are referred to as “Respondents.”

1.2. Product Description and Requirements

Montana-Dakota is seeking Proposals involving the purchase of capacity and energy resources for a term of at least five years, with five year extension options available, with deliveries to begin June 1, 2014. Delivery dates after June 1, 2014 will be considered but preference will be given to resources available for delivery no later than June 1, 2014.

All capacity and energy offered in a Proposal must be deliverable to Montana-Dakota’s integrated system, which consists of its service territories in North Dakota, South Dakota and Montana, in order to serve Montana-Dakota retail load customers. Bid pricing should reflect the capacity and energy at the designated delivery point and include all costs to deliver the capacity and energy to such delivery point. Proposals must be for generating capacity of at least 20 MW and no more than 150 MW.

Montana-Dakota’s entire customer load under this RFP is located within Local Resource Zone #1 of the Midwest Independent Transmission System Operator, Inc.’s (MISO) recent Federal Energy Regulatory Commission (“FERC”) approved enhanced resource adequacy construct as set forth in Module E of MISO’s Open Access Transmission, Energy and Operating Reserve Markets Tariff.¹

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

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

If a Proposal involves a generating unit not yet fully operational, in addition to the other requirements outlined in this section, the Respondent must provide Montana-Dakota with sufficient data to establish that the proposed generating unit(s) will achieve the commercial

¹ *Midwest Indep. Transmission Sys. Operator, Inc., (“June 11, 2012 Order”) in FERC Docket ER11-4081.*

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

operation date designated in the Proposal, and at that date will be fully capable of producing the capacity and energy stated in the Proposal. The Proposal must provide an overview and detailed description of the proposed generating unit, including status of any and all necessary permits and regulatory approvals, in a separate attachment as part of the Respondent's response package.

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

1.3. Changes to RFP, Schedules, and Addenda

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

2. BID SUBMITTAL

2.1. General Instructions

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

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

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

2.2. Respondent's Qualifications

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

Each Respondent shall respond fully and accurately to the Statement of Financial Conditions and Creditworthiness Qualifications included in Exhibit A to the RFP. In addition to that

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

information, during the Proposal review process, Montana-Dakota may require each Respondent to provide further credit and financial information in order to assist Montana-Dakota in addressing and weighing the creditworthiness of each Respondent.

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

2.3. RFP Communications

Prior to the Proposal submission deadline, all communications should be directed to the Official Contact's e-mail. Based upon the nature and frequency of the questions Montana-Dakota receives, Montana-Dakota will choose to either respond to individuals directly or address the question through the bidder's conference (see Section 2.5).

2.4. Schedule

The following schedule and deadlines apply to this RFP:

ACTIVITY	DATE*
Issue RFP	March 25, 2013
Bidder's Conference	None
Notice of Intent to Bid Due	April 5, 2013
RFP Responses Due	April 26, 2013
Shortlist Notification	May 10, 2013
Selection Process Complete	May 31, 2013

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

2.5. Bidder's Conference

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

2.6. Notice of Intent to Bid (NOIB)

In order to identify persons or entities interested in submitting a Proposal, and to assure that all those having such an interest receive any subsequent information distributed in the RFP process, interested parties are requested to submit via e-mail or FAX, a non-binding NOIB on or before 5:00 P.M. CST on April 5, 2013. The form for the NOIB is included in Exhibit B to this RFP.

2.7. Proposal Content and Submission Instructions

2.7.1 In addition to the information described elsewhere in this RFP, all Respondents must include as part of their Proposal all relevant information requested in the Response Package. Proposals that do not contain all required information or do not fully reflect the bid requirements may not be considered at Montana-

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

Dakota's sole discretion. In addition to the required information, Respondents should include with their Proposals any other information that may be needed for a thorough understanding or evaluation of their Proposals.

- 2.7.2 Complete Proposals, including all exhibits, must be received on or before 5:00 p.m. CST on April 26, 2013 by Montana-Dakota's Official Contact. Respondents shall submit one hard copy of the original Proposal as well as one electronic version of their Response Package on a compact disc. **Montana-Dakota will not accept late Proposals or Proposals delivered by e-mail, FAX or other electronic means. Only sealed Proposals will be accepted.** On the envelope, Respondent shall indicate **"Response to Montana-Dakota 2013 RFP re. Capacity and Energy Supply Resources."** Any Proposals received after the scheduled date and time will be disqualified and a notice will be sent to the Respondent.
- 2.7.3 All Proposal terms, conditions, and pricing should be valid through the completion of the selection process, currently planned for the close of business (5:00 p.m. CDT) on May 31, 2013. Any accepted Proposal will become binding in accordance with the executed definitive agreement (see Section 4.3), including through the Regulatory Approval Process described in Section 4.4.
- 2.7.4 Respondents will be notified by May 10, 2013 if their bid has been selected for the short-list and further negotiation. This date may be advanced or delayed at Montana-Dakota's sole discretion. Respondents will be notified if the date is changed. Respondents with Proposals not selected for the short-list will be notified. None of the material received by Montana-Dakota from Respondents in response to this RFP will be returned. All Proposals and exhibits will become the property of Montana-Dakota, subject to the confidentiality provisions of Section 2.8.
- 2.7.5 Prices and dollar figures must be stated in U.S. Dollars.

2.8. Confidentiality

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

2.9. Requirements of the Proposals

- 2.9.1 Proposals should be provided in the format outlined in Section 2.9. Montana-Dakota requests that all exhibits, documents, schedules, etc. submitted as a

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

part of a proposal be clearly labeled and organized in a fashion that facilitates easy location and review.

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

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

2.9.4 A single Respondent may submit more than one proposal.

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

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

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

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

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

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

- 2.9.10 Respondents are advised that prior to Montana-Dakota signing a power purchase agreement, the Respondent will be required to provide substantial evidence of credit assurance as detailed in Section 2.9.11.9 of this RFP. Montana-Dakota will approve all forms of credit assurance before entering into the agreement.
- 2.9.11 All Proposals must include the following minimum components in the order provided:
- 2.9.11.1 "Executive summary" which indicates the highlights and special features of the Proposal including a description of the source for the capacity and energy.
- 2.9.11.2 Statement from the Respondent which clearly indicates the time period during which the proposal will remain effective. Montana-Dakota requires that proposals remain effective at least until May 31, 2013.
- 2.9.11.3 Comprehensive listing and description, including a rationale if warranted, of all material contract terms and conditions that the Respondent would seek during contract negotiations.
- 2.9.11.4 Listing of any economic, operational, or system conditions (including sensitivities to anticipated dispatch levels) that might affect the Respondent's ability to deliver capacity and energy, as proposed.
- 2.9.11.5 Information on the cost of the capacity and energy shall be provided including:
- 2.9.11.5.1 Designated delivery point including applicable MISO Local Resource Zone.
- 2.9.11.5.2 Firm price bid. The capacity price must be fixed for the time period(s) quoted and the energy price must be either fixed or based on known and easily measurable indices.
- 2.9.11.5.3 In addition to a firm price bid, the Respondent may submit alternative non-firm price bids. However, these bids must specifically describe the risks that the Respondent is passing on to Montana-Dakota and its customers.
- 2.9.11.5.4 The Respondent should specify the basis (i.e. annually, quarterly, monthly, etc.) and type of all payments it expects to receive. In the case of a fully dispatchable generating resource, such payments might include start-up payments (\$/start) or spinning and supplemental reserve payments (\$/operating hour).

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- 2.9.11.5.5 As applicable, the Respondent's proposal should include all formulas that will be used to calculate the full capacity and energy rate, or any other rate that the Respondent may specify, with all its respective components well defined. A sample calculation illustrating the application of each formula is also required.
- 2.9.11.5.6 The Respondent must provide a printed schedule projecting for each contract year, quarter, or month, as appropriate, depending upon how frequently the Respondent's rate(s) or its respective components will be updated, for the full term of the proposed contract of the following:
- a. Full capacity rate and all components (\$/kW-month, etc.).
 - b. Contract capacity amount in MW.
 - c. Capacity payment (\$/month).
 - d. Total energy rate and all its components (\$/MWh).
 - e. Projected values of any independent variables (e.g. fuel price, heat rates, operating hours, and number of starts) that are to be used in the calculation of payments.
 - f. Sufficient information to allow Montana-Dakota to replicate the proposed contract term data.
 - g. Any proposed revisions to the pricing scheme if the Respondent intends to offer a contract extension option.
- 2.9.11.6 Information on the makeup of the Respondent Company and its parent organization, if any, shall be provided along with the more recent financial report, the current audited annual financial report, and SEC Form 10-K.
- 2.9.11.7 Site locations of the proposed generating units and other drawings that are helpful in describing proposed generation resources shall be included.
- 2.9.11.8 The Respondent must certify that any identified generating unit is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.
- 2.9.11.9 Montana-Dakota requires secure and reliable physical delivery of the capacity and associated energy corresponding to all proposals. Security and reliability of physical delivery will be guaranteed by either (1) contractual credit assurance by a third party, (2) corporation commitment accompanied by an investment level credit rating from a major rating agency, or (3) combinations of 1 and 2. All forms of credit assurance will be approved by Montana-Dakota

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before entering into a power purchase agreement. (Credit Assurances shall include a letter of credit or performance bonds for an amount equal to the costs associated with one year of the contract or as mutually agreed.)

2.9.11.10 The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit. The Respondent shall provide a description of the resource's ability to comply with all presently applicable and anticipated environmental regulations and requirements (including, but not limited to, EPA Greenhouse Gas Clean Air Act permitting requirements for New Source Performance Standards² and New Source Review and Prevention of Significant Deterioration³) and any additional environmental benefits that the resource would, or presently does, afford; a listing of expected emissions (as applicable) and the status of all permit applications; and a listing of any and all potential and known environmental liabilities that may be associated with the generating unit or its sites.

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

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

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

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

² Carbon Pollution Standard for New Power Plants , <http://epa.gov/carbonpollutionstandard/actions.html>, Federal Register / Vol. 77, No. 72, Friday, April 13, 2012 / Environmental Protection Agency "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

³<http://www.epa.gov/nsr/ghgpermitting.html>.

3. EVALUATION PROCESS

3.1. Proposal Review

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

- a)** Does not meet the minimum requirements set forth in the RFP;
- b)** Is not economically competitive with other Proposals or resource alternatives;
- c)** Is submitted by Respondents who are determined by Montana-Dakota to have insufficient creditworthiness, insufficient financial resources and/or insufficient technical qualifications to provide dependable or reliable service; or
- d)** Fails to meet the resource and reliability needs of Montana-Dakota.

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

3.1.2. Montana-Dakota shall evaluate responsive Proposals and select for further review and negotiation a Proposal or Proposals, if any, that Montana-Dakota believes provides the greatest value to its customers. In the event negotiations with a Respondent or Respondents do not produce a final and fully executed

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contract satisfactory to Montana-Dakota, Montana-Dakota reserves the right to pursue any and all other resource options available to it.

- 3.1.3. Montana-Dakota intends to compare system impacts of short-listed Proposals against the system impacts from new-build alternatives and/or market purchases in determining the appropriate purchases and/or acquisitions for Montana-Dakota's future capacity and energy needs.
- 3.1.4. Montana-Dakota reserves the right to accept or reject any or all Proposals for any reason at any time after submittal without explanation to the Respondent, or to make an award at any time to a Respondent who, in the sole opinion and discretion of Montana-Dakota, provides a Proposal Montana-Dakota deems favorable. Montana-Dakota also reserves the right to make an award to other than the lowest price Respondent, if Montana-Dakota determines that to do so would result in the greatest value to its customers.
- 3.1.5. All Proposals related to renewable resources, distributed generation and DSM are invited to compete in this RFP process and will be evaluated in a consistent manner with all other bids, with consideration given to projections as to life-cycle costs, operational compatibility, reliability and availability of the resource(s).
- 3.1.6. Those Respondents who submit Proposals do so without legal recourse against Montana-Dakota or its directors, management, employees, agents or contractors based on Montana-Dakota's rejection, in whole or in part, of their Proposal or for failure to execute any agreement tendered by Montana-Dakota. Montana-Dakota shall not be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to Montana-Dakota's acts or omissions arising out of or in connection with the RFP.
- 3.1.7. If a selected Proposal involves a generating unit not yet operational, the Respondent must provide Montana-Dakota with a full financial guarantee, including performance bonds and/or letters of credit, up to the level of product commitments and in an amount and at a level determined by Montana-Dakota in its sole discretion, expressly including replacement capacity and energy costs and any related penalty fees, in the event the generating unit does not become commercially operational as scheduled.
- 3.1.8. In reviewing and considering Proposals, Montana-Dakota will analyze potential credit and risk concerns in any comparison of Proposals. As part of its detailed evaluation phase, Montana-Dakota will specifically weigh the credit- and risk-related factors and costs underlying each of the Proposals. To assist Montana-Dakota in this review, Montana-Dakota requires that each Respondent include with its response package a detailed description of the proposed credit support. The pricing provided shall expressly include the costs of such credit support. Montana-Dakota will review and assess the sufficiency and adequacy of the proposed credit support, and if Montana-Dakota, in its sole discretion, determines such credit support is insufficient, it

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shall assess additional costs and/or expenses to any such Proposal. Montana-Dakota will include in each Proposal evaluation the cost of any credit requirements from Montana-Dakota.

- 3.1.9. Selection and elimination of Proposals and subsequent notification of Respondents at all stages of the evaluation will remain entirely at Montana-Dakota's discretion.
- 3.1.10 Montana-Dakota reserves the right to award multiple contracts if combinations of proposals provide the lowest overall cost and the highest level of reliability.
- 3.1.11 Montana-Dakota will entertain proposals which contain provisions for an asset sale or option for an asset sale from the Respondent to Montana-Dakota as part of the Respondent's bid.

3.2. Proposal Threshold Requirements

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

3.2.1. General Threshold Requirements

- a. The Proposal is received on time and complies with the submission instructions.
- b. The Proposal is bona fide, and the Respondent (or its guarantor) has sufficient financial capacity to support the Proposal.
- c. Complete and accurate answers are provided to all questions in the RFP.
- d. Capacity must be available for delivery no later than June 1, 2014. Delivery dates after June 1, 2014 will be considered but preference will be given to resources available for delivery no later than June 1, 2014.
- e. The capacity and energy is available and deliverable to Montana-Dakota's system.
- g. The capacity is at least 20 MW and no more than 150 MW.
- h. PPA's of a term shorter than five years will be considered in this RFP. Preference will be given to Proposals with an initial term of five years or longer.

3.2.2. Operating Performance Thresholds

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- a. The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit.
- b. The Respondent must certify that any identified generating unit is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.
- c. Montana-Dakota prefers the identified generating unit be fully dispatchable and has an Automatic Generator Control that is tied into Montana-Dakota's Electric Dispatch Center. The costs associated with this installation are the responsibility of the Respondent.
- e. If a PPA, the Respondent must be willing to coordinate the generating unit's maintenance scheduling with Montana-Dakota.

3.2.3. Transmission Threshold

- a. Deliverability to Montana-Dakota's integrated system, which consists of its service territories in Montana, North Dakota, and South Dakota, will be taken into account.
- b. If the generating unit(s) is or will be located outside of Montana-Dakota's integrated system, the Respondent must provide a transmission plan for deliverability to wheel the generating unit's power to Montana-Dakota's integrated system. Transmission costs to deliver to Montana-Dakota's integrated system are the responsibility of the Respondent.
- c. If the generating unit is not yet in-service, but has a completed Generator Interconnection Study, a copy of this agreement must accompany the Respondent's Proposal.
- d. If the generating unit is not yet in-service and will be interconnected to Montana-Dakota's transmission system, the Respondent must complete an Application for Generator Interconnection Request with the Midwest Independent Transmission System Operator (Midwest ISO or MISO). A copy of this application must accompany the Respondent's Proposal.
- e. For an unfinished resource, the final agreement between Montana-Dakota and the Respondent will require the Interconnection Study to be completed, or will be contingent upon such a study being completed.

3.3. Screening Process

On or before May 10, 2013, Montana-Dakota intends to select Proposals that will be included on a short-list. This date may be advanced or delayed at Montana-Dakota's sole discretion.

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

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

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

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

4. CONTRACTS AND REGULATORY APPROVAL

4.1. General

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

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

4.2. Contract Modifications

It is anticipated that the contract format for an award in response to this RFP will be based on the North American Energy Markets Association (NAEMA) Capacity and Energy Tariff which can be found at <https://www.naema.com>. Respondents may expressly identify and include proposed changes to the NAEMA Capacity and Energy Tariff in their Response Packages. Such proposed revisions will allow Montana-Dakota to assess in its evaluation process the significance and impact to any Proposal of the changes requested by

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Respondents. Montana-Dakota reserves the right to utilize a different contract format, based on its sole discretion, for power purchase agreements under this RFP.

4.3. Definitive Agreement

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

4.4. Regulatory Approval Process

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

4.5. Collusion

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

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Exhibit A – Form of Statement of Financial Conditions and Creditworthiness

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

1. Company Information

Type of Business

- Corporation
 Limited Liability Company
 Partnership
 Other (describe)

Applicant Organization

Legal Corporate Name:
Street Address:
City, State, Zip Code:
Dun & Bradstreet Number:
Federal Tax ID Number:

Applicant Credit Contact

Name:
Title:
Phone Number:
Email Address:

For Corporation/Limited Liability Companies

Date and State of Incorporation/Registration:
Street Address:
City, State, Zip Code:

For General Partnerships

Name of General Partner:
Address of General Partner/Registered Agent:
City, State, Zip Code:

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2. Guarantor

Guarantor Company

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

3. Credit Information

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

10K

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

10Q

Other (describe)

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

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

Yes

No

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

Yes

No

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

Respondent/Guarantor Credit Rating

Standard & Poor’s

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Moody’s

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Fitch

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

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

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

Bank Reference Information

Bank Name:

Street Address:

City, State, Zip Code:

Contact Name:

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Phone Number:

Fax Number:

Account Number:

4. Project-specific Information

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

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

Amount and source(s) of equity financing:

Amount and terms of financing, including:

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

5. Authorization

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

Offering Entity's Company Name: _____

Signature of Authorized Official: _____

Name of Authorized Official (print): _____

Title of Authorized Official (print): _____

Date Signed: _____

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Exhibit B – Form of Notice of Intent to Bid

Date: _____

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

Contact Name: _____

Name of Firm: _____

Address: _____

Phone: _____

E-mail: _____

Alternate Contact: _____

Address: _____

Phone: _____

E-mail: _____

Project Description: _____

Signature: _____

Exhibit C – Form of Confidentiality Agreement

MUTUAL CONFIDENTIALITY AGREEMENT

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., having its principal place of business at 400 North 4th Street, Bismarck, ND 58501 ("Montana-Dakota") and _____, having its principal place of business at _____ ("Respondent"), are discussing details related to the Respondent's reply to a Request for Proposal ("RFP") that Montana-Dakota has issued regarding the purchases of capacity and energy dated March 25, 2013. In the course of the discussions about the RFP each party may disclose certain confidential or proprietary information ("Proprietary Information") to the other party.

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

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

1. Will keep secret and confidential the Proprietary Information supplied to the other party and any discussions and negotiations about the RFP process except as herein provided and in a manner no less restrictive than the manner that the receiving party protects its own confidential information;
2. Will use the Proprietary Information only for the purpose of participating in, evaluating and negotiating the RFP process;
3. Will disclose the Proprietary Information only to its Representatives who need to know the Proprietary Information for the purpose of participating in, evaluating and negotiating the RFP process;

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4. Will not, whether or not the Parties enter into definitive agreements, disclose to any third party (other than its Representatives) any of the Proprietary Information, other than the Proprietary Information which is in, or independently comes into, the public domain;
 5. Will not, engage in any transactions of any kind or description whatsoever with regard to or using the Proprietary Information during the term of this Agreement without the written consent of the other party;
 6. Will, if requested in writing, promptly destroy or return any of the Proprietary Information provided without keeping any copies, except portion of the Proprietary Information that is found in analyses, compilations, studies or other documents prepared by Montana-Dakota and its employees, representatives, consultants and counsel may be held by Montana-Dakota and kept subject to the terms of this Agreement, or destroyed ; and
 7. Will promptly notify the other party if any of the Proprietary Information conveyed to it is required to be disclosed by reason of law or legal process and will cooperate with the other party regarding any action which the other party (at the other party's sole cost and expense) may elect to take to challenge the legality or validity of such requirement.
- B. Montana-Dakota and Respondent also acknowledge and agree:
1. Proprietary Information which is provided will not be considered to be Proprietary information if that information is (i) in the other party's possession prior to disclosure, (ii) is in the public domain prior to disclosure, or (iii) lawfully enters the public domain through no violation of this Mutual Confidentiality Agreement.
 2. No agreement for a power purchase agreement or other transaction shall be deemed to exist unless and until a Definitive Transaction Agreement has been executed and delivered by the parties. The term "Definitive Transaction Agreement" does not include this Mutual Confidentiality Agreement, a letter of interest or any other preliminary written agreement, nor does it include any verbal agreement;
 3. Neither party makes any representation or warranty regarding the completeness or accuracy of any information provided to the other; any and all such representations and warranties shall be made in a written, executed agreement and will then be subject to the provisions thereof;

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4. Money damages would not be a sufficient remedy for a breach of this Mutual Confidentiality Agreement and the injured party is entitled to specific performance and injunctive or other equitable relief and remedies for any breach; such remedies shall not be the exclusive remedies but shall be in addition to all other remedies available at law or in equity;
5. Neither party will make any announcement of the status of the Respondent's reply to the RFP or of any negotiations with respect to a possible power purchase agreement without the prior written consent of the other;
6. This Mutual Confidentiality Agreement is governed by the laws of the state of North Dakota; and
7. The obligations under this Mutual Confidentiality Agreement shall be continuing and shall survive the termination of the RFP process and any discussion or negotiations between the parties, but that all obligations of the parties hereunder will expire two years from the date of this Mutual Confidentiality Agreement.

The parties have executed this Mutual Confidentiality Agreement as of _____, 2013.

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

By: _____

By: _____

Title: _____

Title: _____

Attachment F

Supply Side Resources Analysis

EXPLANATION OF SELF BUILT WIND AND COAL SUPPLY-SIDE ALTERNATIVES

INTRODUCTION

Utilizing Montana-Dakota's knowledge from the construction of three self-built wind farms, as well as a North Dakota lignite coal study completed by WorleyParson's for the Lignite Energy council, Montana-Dakota Utilities Co. (Montana-Dakota) conducted a cost analysis of wind and coal supply-side alternative resources to be used in Montana-Dakota's Integrated Resource Plan (IRP).

PERFORMANCE BASIS

The analysis for the wind farms was based on indicative turbine pricing from General Electric (GE), as well as costs associated with the construction, operation, and maintenance of Montana-Dakota's Cedar Hills wind farm and Diamond Willow wind farms. GE conducted a wind analysis to determine which GE turbine would best fit a new wind farm in either a 20 MW or 50 MW size. Based on GE's assumptions, taken from the Wind Farm Form completed for Montana-Dakota's Diamond Willow II wind farm, their analysis concluded a newly constructed wind farm would utilize GE 1.7 MW wind turbines.

A Study of Lignite-Based Advanced Generation Technology Systems, a research paper completed by WorleyParson's for the Lignite Energy Council, was utilized as the basis for the coal options cost estimation. WorleyParsons assessed various technologies to find which unit had the best suitability for application for a new 175 MW-225 MW North Dakota lignite-fired power plant. The study included estimates for the performance and costs associated with a lignite-fired coal plant with and without carbon capture.

DELIVERABLES

The following deliverables were required as inputs into the IRP resource expansion analysis:

- Power Generation (MW, net)
- Net Heat Rate (Btu/kWh)
- Capital Cost (\$/kW)
- Fixed O&M (\$/kW-month)
- Variable O&M (\$/MWh)
- Major Maintenance (\$/kW-month)

- Carbon Intensity (lb/MWh)

WIND TURBINES

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 to provide indicative pricing for wind turbines that could provide the generation required for these wind farms. Utilizing the same assumptions used for the Diamond Willow II wind farm, GE performed a wind analysis to determine which GE turbine would best fit each farm. The analysis concluded the GE 1.7-100 series 1.7 MW wind turbine to be the best option for both farm sizes. Budgetary prices provided by GE for a 20 MW and 50 MW site are provided in Table 1. The scope of supply for pricing included equipment, transportation, start-up and commissioning, cold-weather extreme, WindSCADA Standard, WindControl with Dynamic VAR, and WindRide-Thru.

Table 1: GE Supplied Budgetary Turbine Price

	North Dakota Site	Montana Site
20 MW Wind Farm or 12 x 1.7MW Wind Turbines	\$2.55M per turbine	\$2.48M per turbine
50 MW Wind Farm or 29 x 1.7 MW Wind Turbines	\$2.53M per turbine	\$2.45M per turbine

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 construction of the 2010 Cedar Hills Wind Farm (Cedar Hills). Engineering and Supervision & 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. Following the subtraction of these costs, the remaining capital costs were split into the costs associated with the purchase of the wind turbines, and the costs associated with construction and installation. Wind turbine costs for Cedar Hills were then replaced by the new indicative pricing supplied by GE, and the construction and installation costs for Cedar Hills were divided into a cost per turbine price and used for each wind turbine in the new wind farm. The construction and installation costs per turbine were escalated at an annual capital cost increase of 4% to bring it to 2013 dollars. O&M costs were determined using the costs incurred over the five cumulative years of data Montana-Dakota has compiled operating and maintaining Diamond Willow I Wind Farm, Diamond

Willow II Wind Farm, and Cedar Hills Wind Farm. The wind option inputs to the resource expansion analysis are shown in Table 2.

Table 2: Wind Inputs for the Resource Expansion Analysis

	ND - 20MW	ND - 50MW	MT - 20MW	MT- 20MW
Plant Size (MW, net)	20.4	49.3	20.4	49.3
Capital Cost (\$/kW)	\$1,897.63	\$1,885.16	\$1,853.75	\$1,836.10
Fixed O&M (\$/kW-month)	\$3.27	\$3.27	\$3.27	\$3.27
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)	-	-	-	-

COAL

For a new coal-fired power plant, Montana-Dakota utilized the results of a study completed by WorleyParsons for the Lignite Energy Council that 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:

- Sub-critical atmospheric fluidized bed combustion,
- Pressurized fluidized bed combustion,
- Gasification, and
- Oxycombustion circulating fluidized bed combustion

The overall assessment, based on a multitude of criteria, evaluated both quantitative and qualitative criteria. The assessed criterion included, but was not limited to: lignite experience, technology development and risk, ability to permit, environmental impact, performance, emissions, capital cost, and operating cost. The results of the study ranked subcritical Circulating Fluidized Bed Combustion (CFBC) technology the best among all other technologies evaluated

when including, and not including, CO₂ capture. The coal option inputs to the resource expansion analysis are included in Table 3.

Table 3: Coal Inputs to the Resource Expansion Analysis

	CFBC with CO₂ Capture	CFBC without CO₂ Capture
Plant Size (MW, net)	122	168
Capital Cost (\$/kW)	\$6,068	\$3,318
Fixed O&M (\$/kW-month)	\$22.55	\$16.43
Variable O&M (\$/MWh)	\$17.6	\$11.1
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

The CO₂ capture option was based on nominally 90% 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.

REFERENCES

WorleyParsons. 2012. *A Study of Lignite-Based Advanced Generation Technology Systems.* Unpublished manuscript.

Montana-Dakota Utilities Co.



Explanation of IRP Supply-Side Resources Cost Analysis

May 2013



Project No. 13-0010

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EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

INTRODUCTION

Montana-Dakota Utilities Co. (Montana Dakota) requested Segra Inc. (Segra) to conduct a cost analysis of several supply-side resources to be used for Montana Dakota's upcoming Integrated Resource Plan (IRP).

PERFORMANCE BASIS

The analysis included evaluations of several supply-side resources at site specific conditions. The site specific conditions used in the analysis were as follows:

- Elevation: 1,977 ft AMSL
- Generator Power Factor: 0.85
- Generator Terminal Voltage: 13.8 kV
- Interconnection Voltage: 115 kV

Site Conditions	Ambient Temperature	Ambient Relative Humidity
Average	81.3 °F	35 percent

SUPPLY-SIDE RESOURCES CONSIDERED

The cost analysis includes the following generating facilities¹:

1. Simple Cycle Combustion Turbines
 - a. GE 7EA (frame, natural gas fired)
 - b. GE LMS100PB (aero-hybrid, natural gas fired)
 - c. GE LM6000PH (aeroderivative, natural gas fired)
 - d. Siemens SGT-900 (frame, landfill gas fired)
2. Combined Cycle Combustion Turbines
 - a. 1x1 GE LM6000PH (aeroderivative, natural gas fired)

¹ Cost analysis of other supply-side generating resources (coal, wind, and the Lewis & Clark Mercury and Air Toxics (MATS) Filterable Particulate Control Project) are provided in other documents separate from this analysis.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

- b. 1x1 GE 7EA (frame, natural gas fired)
 - c. 2x1 GE 7FA.05 (frame, natural gas fired)
3. Reciprocating Internal Combustion Engines (30 MW)
 - a. 2 Wartsila 18V50SG, natural gas fired
 - b. 2 Wartsila 18V50DF, natural gas fired
4. Renewable Fuel Boilers (30 MW)
 - a. Generic solid waste burner
 - b. Generic biomass
5. Renewable Non-Fuel (30 MW)
 - a. Generic photovoltaic solar
 - b. Generic concentrated solar
 - c. Generic thermal solar
 - d. Generic geothermal

DELIVERABLES

Sega performed the cost analysis of these supply-side options by operating a design/costing model, 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 of Appendix A, which is a roll-up summary of the IRP costing spreadsheet for all of the options.

- Plant Size (MW, net) – Based on the data specified in the performance basis
- Capital Cost (\$/kW) – Total Capital Investment (TCI) - Unloaded divided by the Plant Size
- Fixed O&M (\$/kW-month) – Total of the O&M Fixed costs including Labor, Maintenance, and Other Expenses
- Variable O&M (\$/MWh) – Total of the O&M Variable costs including Maintenance, Utilities, and Chemicals
- Major Maintenance (\$/kW-month)
- Full Load Heat Rate (Btu/kWh)
- Carbon Intensity (lb/MWh)
- Fuel Cost (\$/MBtu) – Provided by Montana Dakota

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

The estimated TCI-Unloaded costs do not include the project specific costs listed in Table 1, below. Sega also estimated the TCI-Loaded cost by rerunning the cost analysis and adding to TCI-Unloaded a Project Administration and Developer's Fee of 1 percent, and a Financing Cost of 4 percent for CTGs and 1 percent for boiler options. The TCI-Loaded was used as a basis to calculate the fixed costs of Property Tax and Insurance for combustion turbine generator options.

Table 1. Project Specific Costs *Not* Included in TCI-Unloaded

	Not in TCI-Unloaded
Transmission interconnect and upgrades (except for GSU*)	✓
Fuel supply pipeline	✓
Land	✓
Project administration and developer's fee	✓
Financing	✓

* Generator Step-Up (GSU) transformer cost is included in project TCI.

COMBUSTION TURBINE OPTIONS

A capital cost analysis was performed for the four simple cycle and three combined cycle combustion turbine generators (CTGs) using Thermoflow Inc.'s thermal engineering software 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. As another example, a CTG with water injection for power augmentation will require additional equipment and installation labor, which is captured by the PEACE module.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

For the Thermoflow model runs, the natural gas quality specified in the request for proposal by Montana Dakota (see Table 2) was customized as a user-defined fuel in Thermoflow for the six 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.

Table 2. Natural Gas Quality Assumed for CTG Analyses

Natural Gas Quality	Volume percent
CH ₄	93.3
C ₂ H ₆	3.05
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

Once these assumptions were entered into Thermoflow, the only information that varied between the 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, 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, CO₂ emissions, capital costs, fixed costs, variable costs, and summary for all CTG plant options considered are shown in Tables A-2 through A-5 in Appendix A.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

Simple Cycle CTGs

Table 3 summarizes key performance and descriptors for the three natural gas-fired simple cycle CTGs assessed. The following paragraphs provide a summary of key assumptions in the assessment for each of the CTGs.

Table 3. Summary of Natural Gas-Fired Simple Cycle CTGs

Turbine	ISO Ratings* (MW) Heat Rate (Btu/kWh)	Uncontrolled NOx (ppmdv)	Pre-SCR NOx 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 8,077	25	Dry	900	No	Aero-Hybrid	Some actual models operating
GE LM6000PH	47.0 8,722	15	Dry	700	No	Aero	LM6000 mature; PH very new model

* Ratings at ISO conditions are provided for reference. Site specific ratings are provided in the IRP Cost Analysis Spreadsheet (Appendix A).

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 (ppmdv) referenced to 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 also utilizes DLN but with a NO_x emission level of 25 ppmdv. Sega assumed that an SCR system would be required for permitting to meet BACT. With the relatively high starting point of 25 ppmdv, Sega concludes that the incremental emission

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

reduction cost (\$/ton removed) will be low enough to require the use of SCR to meet BACT. The SCR NO_x reduction effectiveness was set to 90 percent (2.5 ppm_{dv} outlet), ammonia slip was set to 5 ppm_w, and ammonia feed concentration was set to 19 percent. Also, 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. Sega 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 ppm_{dv}. With the starting point of 15 ppm_{dv}, Sega concludes that the incremental emission reduction cost (\$/ton removed) will be low enough to require the use of SCR to meet BACT. The SCR NO_x reduction effectiveness was set to 80 percent (3 ppm_{dv} outlet), ammonia slip was set to 5 ppm_w, and ammonia feed concentration was set to 19 percent. Sega also assumed that an oxidation catalyst for CO emission reduction would not be required for this CTG to meet BACT.

A simple cycle Siemens SGT-900 was modeled to attain a cost estimate for a landfill gas fueled plant. Table 4 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. Table 5 summarizes key performance and descriptors for the CTG assessed. The following paragraph provides a summary of key assumptions in the assessment for the CTG.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

Table 4: Assumed Landfill Gas Properties

Constituent	Volume percent
Hydrogen	2.5
Carbon Dioxide	33.0
Methane	63.5
Hydrogen Sulfide	1.0
Higher Heating Value	9,908 Btu/lb

Table 5. Summary of Landfill Gas-Fired CTG

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
Siemens SGT-900	37.5 12,101	15	Dry	350	Yes	Frame	Mature

* Ratings at ISO conditions are provided for reference. Site specific ratings are provided in the IRP Cost Analysis Spreadsheet (Appendix A).

The simple cycle SGT-900 CTG utilizes DLN 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 requirements given the limited capacity factor of the unit. 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 SGT-900 firing landfill gas. The catalyst was included at 80 percent CO reduction effectiveness.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

Combined Cycle CTGs

Table 6 summarizes key performance and descriptors for the three natural gas-fired combined cycle CTG facilities assessed. The following paragraphs provide a summary of key assumptions in the assessment for each of the facilities.

Table 6. Summary of Natural Gas-Fired Combined Cycle CTGs

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 (1X1)	57.2 6,892	15	Dry	700	No	Aero	LM6000 mature; PH very new model
GE 7EA (1X1)	147 7,149	9	Dry	300	Yes	Frame	Mature
GE 7FA.05 (2X1)	631.0 6,108	9	Dry	400	Yes	Frame	Mature

*** Ratings at ISO conditions are provided for reference. Site specific ratings are provided in the IRP Cost Analysis Spreadsheet (Appendix A).**

The combined cycle with an LM6000PH CTG was set up in a similar way as the simple cycle CTG except that it includes SPRINT (spray intercooling for power augmentation) and a 1 on 1 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. Segal 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). Segal 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.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

The GE 7EA combined cycle was modeled as a dual pressure, no reheat, 1 on 1 combined cycle plant with a mechanical draft cooling tower. A duct burner was included and the firing temperature was specified at 1,200°F. Segal 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 ppmv which is the lowest consistently achievable level. Segal 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 plant output, performance, and all operational parameters for this plant were based on the design site average conditions specified in the request for proposal by Montana Dakota (81.3°F, 35 percent relative humidity). The steam turbine, HRSG and condenser were sized for a cooler condition of 40°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 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, whereas all TCI information (except for the cooling tower) are based on the cooler condition.

The GE 7FA.05 was modeled as a triple pressure, reheat, 2 on 1 combined cycle plant with a mechanical draft cooling tower. For the same reasons described for the GE 7EA combined cycle option, the NO_x reduction effectiveness of SCR was set to 80 percent (2.0 ppmv outlet) and an oxidation catalyst was included at 80 percent CO reduction effectiveness. Like the GE 7EA plant, all plant information (output, performance, operational parameters, etc.) listed in Tables

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

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.

CTG Cost Estimation

The cost basis, capital costs, and annual costs are contained in Tables A-2 through A-4 of the IRP cost analysis spreadsheet in Appendix A. PEACE outputs are current of as 2012 and were escalated to 2013 costs at 3 percent. The estimated annual operation and maintenance (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 NO_x / CO₂ emissions. The performance, capital investment, and CO₂ emissions were outputs from the Thermoflow model for the specific CTGs assessed. The labor rate was provided by Montana Dakota.

The basis for and results of calculating the O&M fixed costs (\$/kW-month, 2013 \$) are shown in Table A-3. The basis for the calculations are from Montana Dakota and discussions with Segal staff. Montana Dakota provided maintenance rates based on 2010 \$, which were escalated to 2013 \$ 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 (\$/MW-hr, 2013 \$). The basis for the calculations were from Montana Dakota, output from the Thermoflow model, and discussions between Segal and Montana Dakota staff. Montana Dakota provided maintenance rates based on 2010 \$, which were escalated to 2013 \$ at a 3 percent per year rate.

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

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

RECIPROCATING INTERNAL COMBUSTION ENGINE OPTIONS

A cost analysis was performed for the two Reciprocating Internal Combustion Engines (RICE) selected for this assessment. Both of these RICE (Wartsila 18V50SG and 18V50DF) are spark ignition 4-stroke engines. Table 7 summarizes key performance and descriptors for the RICE assessed.

Table 7. Summary of Reciprocating Internal Combustion Engines

RICE Model	ISO Ratings* (MW) Heat Rate (Btu/kWh)	NOx Emissions (ppm)	Gas Pressure Needed (psi)	Duel-fuel Capable	Technology Info	Model Maturity
Wartsila 18V50SG	18.3 8,437	5	88	No	4 stroke Spark Ignition	Very few operating units
Wartsila 18V50DF	16.6 9,031	5	88	Yes	4 stroke Spark Ignition	Very few operating units

* Ratings at ISO conditions are provided for reference. Site specific ratings are provided in the IRP Cost Analysis Spreadsheet (Appendix A).

These RICE were assumed to meet the federal New Source Performance Standards (NSPS) and 40 CFR 63 Hazardous Air Pollutant (HAP) emission standards and therefore assumed 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 both RICE plant options considered are shown in Table A-6 in Appendix A.

RICE Cost Estimation

Sega requested budgetary quotations from Wartsila for capital and operational costs for each of the two engine packages assessed. 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

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES 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.

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 as previously described for the CTG options assessed. For both renewable fuel cases (municipal solid waste and biomass) a bubbling fluidized bed (BFB) boiler and a mechanical draft cooling tower were used. All other inputs besides the baseline assumptions and the fuel were left at Thermoflow's defaults. The plant size, performance, emission controls, operational parameters, CO₂ emissions, capital costs, fixed costs, variable costs, and summary for both renewable fuel boiler options considered are shown in Table A-7 in Appendix A.

Municipal Solid Waste

A Thermoflow defined municipal solid waste was selected for the solid waste burner. The composition of this fuel can be found in Table 8 below. 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.

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

Table 8: Assumed Municipal Solid Waste Properties

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

Biomass

Wood pellets, the fuel for the biomass plant, was chosen from Thermoflow’s fuel library and its makeup can be found in Table 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.

Table 9: Assumed Biomass – Wood Pellet Properties

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

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

Cost Estimation

The capital and annual costs are contained in Table A-7 of the IRP cost analysis spreadsheet. PEACE outputs are current of 2012 and were escalated to 2013 costs at 3 percent. The Fixed and Variable O&M are from assumptions made in the Department of Energy Annual Energy Outlook from 2012 which were escalated to 2013 \$ at a 3 percent per year rate.

RENEWABLE NON-FUEL OPTIONS²

A cost analysis was performed for the four non-fuel renewable energy options listed in Table 10. These costs are contained in Table A-8 of the IRP cost analysis spreadsheet in Appendix A.

Table 10. Renewable Non-Fuel Options

Non-Fuel Option	Size (MW)
Photo-Voltaic (PV) Solar	30
Concentrated Solar	30
Thermal Solar	30
Geothermal	30

Sega used estimates from the following three documents to develop costs for the non-fuel options:

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. 2012.** *Assumptions to the Annual Energy Outlook 2012.* 2012.

² Cost analysis for wind as a renewable non-fuel supply-side generating resource is provided in other documents separate from this analysis

EXPLANATION OF IRP SUPPLY-SIDE RESOURCES COST ANALYSIS

Costs from each report were presented in Table A-8 after applying 3 percent escalation to 2013. There was a large variance in the cost for some of the technologies between the different reports. Segal chose DOE/EIA Annual Energy Outlook 2012 as a default (regardless of whether it was higher). Note that in the case of Concentrated Solar Segal 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.

APPENDIX A

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-1. Summary Results for All Supply-Side Options Assessed

	GE 7EA	GE LMS100PB	GE LM6000PH	GE LM6000PH Sprint (CC) ¹	GE 7EA (1X1) ²	GE 7FA.05 (2X1) ³	SIEMENS SGT-900 LANDFILL GAS	WARTSILA 18V50SG	WARTSILA 18V50DF	BOILER SOLID WASTE BURNER ⁴	BOILER BIOMASS ⁵	PV SOLAR	CONC. SOLAR	THERMAL SOLAR	GEOHERMAL
Plant Size (MW _{net})	71.6	87.4	37.4	47.7	129.0	560.0	31.8	36.6	33.3	34.8	37.1	30.0	30.0	30.0	30.0
Capital Cost (\$/kW) ⁶	\$759	\$976	\$1,232	\$1,479	\$1,069	\$828	\$1,166	\$955	\$1,054	\$7,512	\$3,213	\$5,196	\$7,272	\$5,126	\$2,746
Fixed O&M (\$/kW-month)	\$0.96	\$1.42	\$2.06	\$2.10	\$1.05	\$0.72	\$1.73	\$0.71	\$0.71	\$9.16	\$9.16	\$1.52	\$4.29	\$5.83	\$9.89
Variable O&M (\$/MWh)	\$2.70	\$4.45	\$4.24	\$4.65	\$3.37	\$3.81	\$2.70	\$3.30	\$3.30	\$5.46	\$5.46	\$0	\$0	\$0	\$10.53
Major Maintenance (\$/kW-month)	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.87	\$0.92	\$0.03	\$0.03	\$0	\$0	\$0	\$0
Full Load Heat Rate (BTU/kWh)	11,955	9,049	9,943	8,295	7,611	6,719	13,634	8,368	8,467	14,776	11,218	0	0	0	0
Carbon Intensity (lb/MWh)	1,398	1,057	1,168	981	894	792	2,357	921	931	3,042	2,393	0	0	0	0
Fuel Cost (\$/MBtu) ⁷	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

Assumptions:

1. Single pressure CC; extraction condensing turbine; water cooling with mechanical draft cooling tower.
2. Double pressure, no reheat cc.
3. Triple pressure reheat CC, reheat before 1P; water cooling with mechanical draft cooling tower; cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% humidity); duct burner.
4. Municipal solid waste (36% moisture, 32% ash, 17% carbon); water cooling with mechanical draft cooling tower; BFB boiler.
5. Wood pellets; water cooling with mechanical draft cooling tower; BFB boiler.
6. Total Capital Investment - Unloaded, divided by net output
7. Estimated

All based on net output.

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-2. CTG Cost Basis and Capital Cost, 2013 \$

	GE 7EA	GE LMS100PB	GE LM6000PH	GE LM6000PH Sprint (CC) ¹	GE 7EA (1X1) ²	GE 7FA.05 (2X1) ³	SIEMENS SGT-900 LANDFILL GAS
Plant Information							
Number of CTs	1	1	1	1	1	2	1
Unit Size (MW, net)	71.6	87.4	37.4	47.7	129	280	31.8
Unit Size (MMBtu/hr HHV)	854	789	371	395	857	1877	434
Plant Size (MW, net)	71.6	87.4	37.4	47.7	129	560	31.8
Plant Size (MMBtu/hr HHV)	854	789	371	395	857	3,754	434
Net Heat Rate (Btu/kWh HHV)	11,955	9,049	9,943	8,295	7,611	6,719	13,634
SCR Aux Power (MW)		0.136	0.083	0.083	0.176	0.616	
Aq. Ammonia (19%), lb/hr		135.7	41.1	43.7	57.0	239	
Aq. Ammonia (19%), gal/hr		17.5	5.3	5.6	7.4	30.9	0.0
Water (1000 gallons/hr)				9	48	153	
Intercooling Aux Power (MW)		0.326					
Additional Plant Information							
CatOx	N	N	N	Y	Y	Y	Y
SCR	N	Y	Y	Y	Y	Y	N
Water Injection	N	N	N	Y	N	N	N
Intercooling	N	Y	N	N	N	N	N
Aeroderivative or Aero-hybrid	N	Y	Y	Y	N	N	N
Multi-Model combination	N	N	N	N	N	Y	N
Cost Information							
Total Capital Investment (TCI-UL)-Unloaded, 2013 \$ ⁴	54,353,758	85,315,918	46,077,596	70,549,850	137,947,625	463,440,141	37,072,768
Total Capital Investment (TCI)-Loaded, 2013 \$	56,966,920	89,417,644	48,292,864	73,941,640	144,579,722	485,720,917	38,855,113
SCR Capital Investment (TCI), 2013 \$		7,336,060	4,734,307	3,985,070	5,506,337	16,409,265	
Labor Rate (\$/hr), 2013 \$	56.33	56.33	56.33	56.33	56.33	56.33	56.33
FTE Hours (hr/yr), 2013 \$	2,080	2,080	2,080	2,081	2,080	2,080	2,080
FTE Cost (\$/yr), 2013 \$	117,168	117,168	117,168	117,224	117,168	117,168	117,168
Pollutant Information							
CO2 (lb/MWh, net)	1,398	1,057	1,168	981	894	792	2,357
NOx (ppmvd @ 15% O2) (Uncontrolled/Controlled)	9	25/2.5	15/3.0	15/3.0	9/2.0	9/2.0	15

1. Single pressure CC; extraction condensing turbine; water cooling with mechanical draft cooling tower.

2. Double pressure, no reheat cc.

3. Triple pressure reheat CC, reheat before IP; water cooling with mechanical draft cooling tower; cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% humidity); duct burner.

4. Without Owner's AFUDC or Administrative Costs.

Note: Performance and cost results from Thermoflow. Labor rate per MDU.

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-3. CTG O&M Fixed Cost (\$/MW-year), 2013 \$				GE 7EA	GE LMS100PB	GE LM6000PH	GE LM6000PH Sprint (CC) ¹	GE 7EA (1X1) ²	GE 7FA.05 (2X1) ³	SIEMENS SGT-900 LANDFILL GAS
1. Labor										
	Basis									
a. All Models (Operations & Maintenance)	2.25	FTE		\$3,682	\$3,016	\$7,049	\$5,529	\$2,044	\$471	\$8,290
b. All Models (Technical Services)	0.75	FTE		\$1,227	\$1,005	\$2,350	\$1,843	\$681	\$157	\$2,763
c. SCR O&M (FTE)	0.25	FTE		-	\$335	\$783	\$614	\$227	\$52	-
d. Water Injection O&M (FTE)	0.50	FTE		-	-	-	\$1,229	-	-	-
e. Intercooling O&M (FTE)	0.90	FTE		-	\$1,207	-	-	-	-	-
f. Intercooling TS (FTE)	0.10	FTE		-	\$134	-	-	-	-	-
g. Aeroderivative & Aero-hybrid O&M (FTE)	0.20	FTE		-	\$268	\$627	\$492	-	-	-
h. Aero & Aero-hybrid TS (FTE)	0.10	FTE		-	\$134	\$313	\$246	-	-	-
i. Multi-Model O&M (FTE)	1.00	FTE		-	-	-	-	-	\$209	-
	Labor Sub-Total (\$/MW-year)			\$4,909	\$6,100	\$11,122	\$9,953	\$2,952	\$889	\$11,054
2. Maintenance										
	Basis:		2010 \$							
			2013 \$							
a. All Models (I&C and Electric Plant)	200	219	\$/MW-year	\$219	\$219	\$219	\$219	\$219	\$219	\$219
b. All Models (Contracted Services)	250	273	\$/MW-year	\$273	\$273	\$273	\$273	\$273	\$273	\$273
c. SCR Maintenance (1.5% of SCR-only TCI)		1.5%		-	\$1,259	\$1,899	\$1,253	\$640	\$440	-
d. Water Injection (water)	25	27	\$/MW-year	-	-	-	\$27	-	-	-
e. Water Injection (wastewater treatment)	20	22	\$/MW-year	-	-	-	\$22	-	-	-
f. Intercooling (heat rejection)	100	109	\$/MW-year	-	\$109	-	-	-	-	-
g. Intercooling (I&C)	50	55	\$/MW-year	-	\$55	-	-	-	-	-
h. Aeroderivative & Aero-hybrid (CTG)	100	109	\$/MW-year	-	\$109	\$109	\$109	-	-	-
i. Aeroderivative & Aero-hybrid (I&C)	50	55	\$/MW-year	-	\$55	\$55	\$55	-	-	-
j. Multi-Model (CTG)	100	109	\$/MW-year	-	-	-	-	-	\$109	-
	Maintenance Sub-Total (\$/MW-year)			\$492	\$2,079	\$2,554	\$1,958	\$1,132	\$1,041	\$492
3. Other Expenses										
	Basis:		2010 \$							
			2013 \$							
a. All Models (Administration)	400	437	\$/MW-year	\$437	\$437	\$437	\$437	\$437	\$437	\$437
b. All Models (Property Taxes)		0.57%	of TCI Unloaded	\$4,559	\$5,862	\$7,399	\$8,882	\$6,422	\$4,970	\$7,001
c. All Models (Insurance)		0.14%	of TCI Unloaded	\$1,146	\$1,473	\$1,859	\$2,232	\$1,614	\$1,249	\$1,759
d. Aero & Aero-hybrid Insurance		0.11%	of TCI Unloaded	-	\$1,115	\$1,407	\$1,690	-	-	-
	Other Sub-Total (\$/MW-year)			\$6,142	\$8,888	\$11,103	\$13,241	\$8,473	\$6,656	\$9,198
Total Fixed Cost (\$/MW-year)				\$11,543	\$17,066	\$24,779	\$25,152	\$12,557	\$8,586	\$20,743

1. Single pressure CC; extraction condensing turbine; water cooling with mechanical draft cooling tower.

2. Double pressure, no reheat cc.

3. Triple pressure reheat CC, reheat before IP; water cooling with mechanical draft cooling tower; cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% humidity); duct burner.

Note: Performance and cost results from Thermoflow. Labor rate per MDU.

Escalation Rate: 3%

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-4. CTG O&M Major Maintenance (\$/MW-year), 2013 \$				GE 7EA	GE LMS100PB	GE LM6000PH	GE LM6000PH Sprint (CC)	GE 7EA (1X1)	GE 7FA.05 (2X1)	SIEMENS SGT-900 LANDFILL GAS
		Basis: 2010 \$	2013 \$							
All Models (Combustion Turbines)		350	382	\$/MW-year	\$382	\$382	\$382	\$382	\$382	\$382

O&M Variable Cost (\$/MWhr), 2013 \$				GE 7EA	GE LMS100PB	GE LM6000PH	GE LM6000PH Sprint (CC) ¹	GE 7EA (1X1) ²	GE 7FA.05 (2X1) ³	SIEMENS SGT-900 LANDFILL GAS
		Basis: 2010 \$	2013 \$							
1. Maintenance										
a. All Models (Combustion Turbine Generator)		1.950	2.131	\$/MWh	\$2.13	\$2.13	\$2.13	\$2.13	\$2.13	\$2.13
b. SCR Catalyst Replacement			0.190	\$/MWh	-	\$0.19	\$0.19	\$0.19	\$0.19	-
c. Aeroderivative & Aero-hybrid (CTG)		1.000	1.093	\$/MWh	-	\$1.09	\$1.09	-	-	-
d. Multi-Model (CTG)		0.500	0.546	\$/MWh	-	-	-	-	\$0.55	-
Major Maintenance Sub-Total (\$/MWhr)					\$2.13	\$3.41	\$3.41	\$3.41	\$2.32	\$2.87
2. Utilities										
a. All Models		0.030	0.546	\$/MWh	\$0.55	\$0.55	\$0.55	\$0.55	\$0.55	\$0.55
b. SCR Aux Power			25.160	\$/MWh of SCR	-	\$0.04	\$0.06	\$0.04	\$0.03	-
c. Water Injection Water		0.050	0.055	\$/MWh	-	-	\$0.05	-	-	-
d. Intercooling Aux Power			25.160	\$/MWh of IC	-	\$0.09	-	-	-	-
Utilities Sub-Total (\$/MWhr)					\$0.55	\$0.68	\$0.60	\$0.64	\$0.58	\$0.57
3. Chemicals										
a. All Models		0.020	0.022	\$/MWh	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
b. SCR Ammonia Consumption			1.400	\$/gal	-	\$0.28	\$0.20	\$0.17	\$0.08	-
c. Water Consumption			1.000	\$/1000 gal	-	-	\$0	\$0	\$0	-
d. Water Injection Water Treatment		0.200	0.219	\$/MWh	-	-	\$0.22	-	-	-
e. Intercooling Heat Rejection Equipment		0.050	0.055	\$/MWh	-	\$0.05	-	-	-	-
Chemicals Sub-Total (\$/MWhr)					\$0.02	\$0.36	\$0.22	\$0.60	\$0.47	\$0.37
Total Variable Cost (\$/MWhr)					\$2.70	\$4.45	\$4.24	\$4.65	\$3.37	\$3.81

Escalation Rate: 3%

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-5. CTG EGEAS Model Input Summary, 2013 \$	GE 7EA	GE LMS100PB	GE LM6000PH	GE LM6000PH Sprint (CC)¹	GE 7EA (1X1)²	GE 7FA.05 (2X1)³	SIEMENS SGT-900 LANDFILL GAS
Plant Size (MW,net)	71.6	87.4	37.4	47.7	129.0	560.0	31.8
Capital Cost (\$/kW) ⁴	\$759	\$976	\$1,232	\$1,479	\$1,069	\$828	\$1,166
Fixed O&M (\$/kW-month)	\$0.96	\$1.42	\$2.06	\$2.10	\$1.05	\$0.72	\$1.73
Variable O&M (\$/MWh)	\$2.70	\$4.45	\$4.24	\$4.65	\$3.37	\$3.81	\$2.70
Major Maintenance (\$/kW-month)	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03
Full Load Heat Rate (BTU/kWh)	11,955	9,049	9,943	8,295	7,611	6,719	13,634
Carbon Intensity (lb/MWh)	1,398	1,057	1,168	981	894	792	2,357
Fuel Cost (\$/MBtu) ⁵							

1. Single pressure CC; extraction condensing turbine; water cooling with mechanical draft cooling tower.

2. Double pressure, no reheat cc.

3. Triple pressure reheat CC, reheat before IP; water cooling with mechanical draft cooling tower; cooling tower sized for summer conditions; ST, HRSG, condenser sized for winter conditions (40 deg F, 40% humidity); duct burner.

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

5. Estimated

Note: All based on net output.

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-6. RICE Cost Basis and Capital Cost, 2013 \$	WARTSILA 18V50SG¹	WARTSILA 18V50DF¹
Plant Information		
Number of Engines	2	2
Unit Size (MW, net)	18.3	16.7
Unit Size (MMBtu/hr HHV)	153.2	141.1
Plant Size (MW, net)	36.603	33.319
Plant Size (MMBtu/hr HHV)	306	282
Net Heat Rate (Btu/kWh HHV)	8,368	8,467
Additional Plant Information		
CatOx	Y	Y
SCR	Y	Y
Cost Information		
Total equipment cost	\$22,400,000	\$22,510,000
BOP/Engineering	\$11,200,000	\$11,255,000
Owner Soft Cost (Loaded)	\$3,024,000	\$3,038,850
Owner Soft Cost (Unloaded)	\$1,344,000	\$1,350,600
Total Capital Investment (TCI-UL)-Unloaded, 2013 \$ ²	\$34,944,000	\$35,115,600
Total Capital Investment (TCI)-Loaded, 2013 \$	\$36,624,000	\$36,803,850
Pollutant Information		
CO2 (lb/MWh, net)	921	931
NOx (ppmvd @ 15% O2) (Uncontrolled/Controlled)	5	5

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

RICE EGEAS Model Input Summary, 2013 \$	WARTSILA 18V50SG¹	WARTSILA 18V50DF¹
Plant Size (MW,net)	36.6	33.3
Capital Cost (\$/kW) ³	\$955	\$1,054
Fixed O&M (\$/kW-month)	\$0.71	\$0.71
Variable O&M (\$/MWh)	\$3.30	\$3.30
Major Maintenance (\$/kW-month)	\$0.87	\$0.92
Full Load Heat Rate (BTU/kWh)	8,368	8,467
Carbon Intensity (lb/MWh)	921	931
Fuel Cost (\$/MBtu) ⁴		

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. To be provided by MDU.

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

Table A-7. Renewable Fuel Boiler Cost Basis and Results

	BOILER SOLID WASTE BURNER¹	BOILER BIOMASS²
Plant Information		
Number of Boilers	1	1
Unit Size (MW, net)	34.8	37.1
Unit Size (MMBtu/hr HHV)	514	416
Plant Size (MW, net)	34.8	37.1
Plant Size (MMBtu/hr HHV)	514	416
Net Heat Rate (Btu/kWh HHV)	14,776	11,218
Water (kpph)	64	63.9
Additional Plant Information		
CatOx	N	N
SCR	N	N
Cost Information		
Total Capital Investment (TCI-UL)-Unloaded, 2013 \$ ³	261,426,399	119,193,386
Total Capital Investment (TCI)-Loaded, 2013 \$	301,645,847	137,530,830
Labor Rate (\$/hr), 2013 \$	56.33	56.33
FTE Hours (hr/yr), 2013 \$	2,080	2,080
FTE Cost (\$/yr), 2013 \$	117,168	117,168
Pollutant Information		
CO2 (lb/MWh, net)	3,042	2,393

Design Basis
MDU Future Supply-Side Resources Cost Estimation Project

EGEAS Model Input Summary, 2013 \$	BOILER SOLID WASTE BURNER¹	BOILER BIOMASS²
Plant Size (MW,net)	34.8	37.1
Capital Cost (\$/kW) ⁴	\$7,512	\$3,213
Fixed O&M (\$/kW-month) ⁵	\$9.16	\$9.16
Variable O&M (\$/MWh) ⁵	\$5.46	\$5.46
Major Maintenance (\$/kW-month)	\$0.03	\$0.03
Full Load Heat Rate (BTU/kWh)	14,776	11,218
Carbon Intensity (lb/MWh)	3,042	2,393
Fuel Cost (\$/MBtu) ⁶		

Assumptions:

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. Without Owner's AFUDC or Administrative Costs.
 4. Total Capital Investment - Unloaded, divided by net output
 5. Assumptions to the Annual Energy Outlook 2012, EIA/DOE.
 6. Estimated
- All based on net output.

Boiler Input Summary	BOILERS (BIOMASS OR SOLID WASTE)	
	Fixed O&M*	Variable O&M*
Thermoflow Default Cost	\$3.43	\$6.18
Cost and Performance Data for Power Generation Technologies	\$9.18	\$17.39
Assumptions to the Annual Energy Outlook 2012, EIA/DOE	\$9.16	\$5.46

*Values adjusted to 2013 \$

Table A-8. Renewable Non-Fuel Cost Basis and Results	--	--	--	--
	PV SOLAR	CONC. SOLAR	THERMAL SOLAR	GEOHERMAL
Plant Information				
Plant Size (MW)	30	30	30	30

Escalation Rate: 3%

EGEAS Model Input Summary, 2013 \$	--	--	--	--
	PV SOLAR	CONC. SOLAR	THERMAL SOLAR	GEOHERMAL
Plant Size (MW,net)	30	30	30	30
Capital Cost (\$/kW) ¹	\$5,196	\$7,272	\$5,126	\$2,746
Fixed O&M (\$/kW-month)	\$1.52	\$4.29	\$5.83	\$9.89
Variable O&M (\$/MWh)	\$0	\$0	\$0	\$10.53
Major Maintenance (\$/kW-month)	\$0	\$0	\$0	\$0
Full Load Heat Rate (BTU/kWh)	0	0	0	0
Carbon Intensity (lb/MWh)	0	0	0	0
Fuel Cost (\$/MBtu)	\$0.00	\$0.00	\$0.00	\$0.00

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

Goethermal and Solar Input Summary	PV SOLAR		CONC. SOLAR		THERMAL SOLAR		GEOHERMAL		
	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Capital Cost*	Fixed O&M*	Variable O&M*
US technology Choices ,Cost and Opportunities under the Lieberman- Warner Security Act: Assessing Compliance Pathways	\$4,820	\$1.16	\$3,478	\$2.32	\$3,196	\$3.48	\$3,478	\$8.79	\$11.18
Cost and Performance Data for Power Generation Technologies	\$3,183	\$4.29	\$7,272	\$4.29	\$5,057	\$4.29	\$6,118	\$0.00	\$31.93
Assumptions to the Annual Energy Outlook 2012	\$5,196	\$1.52	\$0	\$0	\$5,126	\$5.83	\$2,746	\$9.89	\$10.53

*Values adjusted to 2013 \$

Attachment G

POLLUTION CONTROL PROJECTS

POLLUTION CONTROL PROJECTS

The U.S. Environmental Protection Agency (EPA) has finalized significant air emissions regulations for coal-fired electric generating facilities and has made known that it intends to propose several other significant new regulations that aim to reduce air emissions, including the greenhouse gases at fossil-fired electric generating facilities, and pollutants in wastewater discharges and further regulate the management of coal ash at coal-fired electric generating facilities. Montana-Dakota will continue to monitor the impacts from proposed regulations and will take the regulations into consideration when planning for future resource needs.

The recently finalized air emissions regulations that will have the most immediate impact on operations at Montana-Dakota's electric generating facilities are the federal Regional Haze (RH) Rule and the Mercury and Air Toxics Standard (MATS) Rule. The RH Rule requires states, and in some cases EPA regional offices, to develop and adopt plans to prevent any future, and remedy any existing, impairment of visibility in the federally-protected parks and wilderness areas ("Class I areas"). Emissions reductions from man-made sources, such as coal-fired electric generating facilities, are considered by agencies for improving visibility impairment. The MATS Rule, previously referred to as the EPA "National Emission Standards for Hazardous Air Pollutants (HAP) Rule for Coal-fired Utilities Rule" in Montana-Dakota's 2011 IRP, requires existing coal-fired electric generating facilities to meet HAP emission standards reflecting the application of maximum achievable control technology (MACT). Montana-Dakota has completed detailed review of the RH Rule and MATS Rule for its electric generating facilities and provides a discussion on the impacts of these specific rules in this attachment. Other regulations that Montana-Dakota will be assessing in future are briefly discussed below.

On April 19, 2013, the EPA published a pre-Federal Register version of the proposed Steam Electric Power Generating Effluent Guidelines (EG) Rule. This rule requires reductions in pollutants discharged in wastewater from steam electric generating units through stringent discharge limits and treatment technology requirements, projected to be applicable to several of Montana-Dakota's coal-fired electric generating facilities. Montana-Dakota will complete detailed review of the EG Rule once the EPA publishes an official rule in the Federal Register. Discussion of the significant impacts from the EG Rule will be included in future IRPs.

The EPA's Coal Combustion Residual (CCR) Rule was proposed on June 21, 2010, to adopt federal requirements for management and disposal of coal ash, as well as potential closure requirements for ash impoundments. In the CCR Rule, the EPA has included management approaches for coal ash through either solid waste regulations, similar to current state regulation

of coal ash, or more stringent hazardous waste regulation. The CCR Rule has remained in proposed status these last few years and may not be finalized until after the EG Rule is finalized since the EG rule is expected to have overlapping requirements with the CCR Rule. Discussion of the significant impacts from the final CCR Rule will be included in future IRPs.

The 316(b) Cooling Water Intake Structures Rule was proposed by EPA on April 20, 2011 requiring reductions in impingement and entrainment of aquatic organisms at existing steam electric generating unit cooling water intake structures. The EPA is expected to finalize the rule in June 2013. Montana-Dakota does not believe there will be significant impacts from this rule and will evaluate potential impingement and/or entrainment control requirements for the Company's coal-fired electric generating facilities once the final 316(b) Rule is published in the Federal Register. Discussion of any potential significant impacts identified after the 316(b) Rule becomes final will be included in future IRPs.

New source performance standards (NSPS) for emissions of carbon dioxide (CO₂) for new fossil fuel-fired electric utility generating units (EGUs) were proposed by the EPA under section 111(b) of the Clean Air Act with the proposed rule published in the Federal Register on April 13, 2012. The EPA accepted comments on the rule until June 25, 2012 and had planned to respond to comments and finalize the rule by April 2013, however, the agency has now indicated that a final rule is delayed and there is no projected date for making the rule final. Also, the EPA has made known the agency's plans to propose an NSPS to regulate CO₂ emissions from existing fossil-fired EGUs, however, the EPA has stated that it wants to complete an NSPS regulating CO₂ emission from new EGUs before it would develop a proposed NSPS rule for existing EGUs. When the EPA proposes an NSPS rule for existing EGUs, Montana-Dakota will conduct detailed review for potential impacts to its coal- and natural gas-fired electric generating facilities and provide discussion of any significant impacts in a future IRP.

Regional Haze Rule (RH Rule)

The RH Rule is one of the most immediate rules that will impact operations at Montana-Dakota's electric generating facilities. The EPA promulgated the Regional Haze Rule (RH) in 1999 to address visibility impairment in Class I areas in the United States, constituting 156 national parks and wilderness areas. This rule was developed in accordance with the Clean Air Act's (CAA) national goal of remedying existing and preventing future visibility impairment of Class I areas due to man-made air pollution. In 2005, the EPA published a revised rule that included guidelines for control technology determinations under the RH Rule for Best Available Retrofit Technology (BART) sources and for sources addressed for reasonable progress.

State environmental agencies like the South Dakota Department of Environment and Natural Resources (DENR) and North Dakota Department of Health (NDDH) are required to submit State Implementation Plans (SIPs) to EPA that develop and implement their strategy to reduce emissions that may contribute to regional haze, and to set reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064. The first round of RH SIPs were finalized in 2012 and considered emission reductions from BART sources, as well as other emissions sources in consideration of reasonable progress toward improving visibility in Class I areas. Periodic reviews, every five to ten years, will continue to be completed by States and the EPA to continue progress toward the 2064 goal with the next round of emissions reductions to be determined in approximately 2018.

R.M. Heskett Station – RH Rule

Montana-Dakota will implement limestone addition at R.M. Heskett Station Unit 2 to reduce SO₂ emissions for compliance with the RH Rule under the rule's reasonable progress goal requirements. The limestone addition project entails replacing a portion of the sand that is currently utilized in the fluidized bed of Unit 2 with limestone to increase capture of SO₂ and is expected to be completed at a cost of approximately \$5 million. According to the State of North Dakota Regional Haze State Implementation Plan (ND RH SIP), Unit 2 must demonstrate compliance with the SO₂ emissions reductions as expeditiously as practicable, but not later than five years from the EPA's approval of the ND RH SIP. There were no emissions reductions required for R.M. Heskett Station Unit 1 in the ND RH SIP for this reasonable progress goal review.

The SO₂ reductions for Unit 2 were approved by the EPA on May 7, 2012 in the Federal Register

Coyote Station – RH Rule

Montana-Dakota will implement separated overfire air (SOFA) at the Coyote Station to reduce nitrogen oxide (NO_x) emissions for compliance with the RH Rule under the rule's reasonable progress goal requirements. Montana-Dakota is a 25 percent owner of Coyote and committed to this reduction with the plant's other joint owners. SOFA involves modifying the boiler to inject air at different staged zones, diverting a portion of the combustion air from the burners and injecting it through ports located at higher levels in the boiler. Staging the combustion air reduces NO_x formation by cooling the flame and limiting the amount of oxygen that reacts with the fuel. SOFA is expected to be completed at a total plant cost of approximately \$8 million.

According to the ND RH SIP, approved by the EPA on May 7, 2012 in the Federal Register, Coyote Station must demonstrate compliance with the NO_x emissions reductions by July 1, 2018.

The EPA received a petition for reconsideration within 60 days of approving the ND RH SIP which took issue with the EPA's approval of Coyote Station's NO_x reductions. Environmental interest groups also submitted a petition for review to the 8th Circuit Court of Appeals stating that the EPA's approval of NO_x controls for Coyote Station was arbitrary and capricious and that more stringent controls should be required. Coyote Station owners, through legal counsel, submitted an amicus brief to the court to provide support for the EPA's May 7, 2012 approval of Coyote Station's emission reductions. Montana-Dakota agrees that the EPA lawfully approved Coyote Station's emissions reductions in the ND RH SIP and, as a co-owner of Coyote Station, will remain involved in the court proceedings as necessary.

Lewis & Clark Station – RH Rule

Lewis & Clark Station (L&C) was reviewed directly by EPA Region 8 for RH Rule emissions reductions under the rule's reasonable progress goal requirements. The State of Montana returned administration of the RH Rule to EPA in 2006, requiring EPA to develop and implement the strategy for reducing emissions that may contribute to regional haze within Montana's Class I areas. The EPA finalized a Regional Haze Federal Implementation Plan (MT RH FIP) for the State of Montana on September 18, 2012 that did not require emissions reductions from L&C. Montana-Dakota expects L&C emissions reductions to be reviewed in future EPA Region 8 reasonable progress goal reviews, of which the next round of emissions reductions are expected to be determined in approximately 2018.

Big Stone Plant - RH Rule

Montana-Dakota is implementing an air quality control system (AQCS) project at the Big Stone Plant, of which Montana-Dakota is a 22.7 percent owner. The Big Stone AQCS project is required to comply with the RH Rule and the South Dakota Regional Haze State Implementation Plan (SD RH SIP) as well as the State of South Dakota's associated rules. The SD RH SIP and its implementing rules require that the Big Stone AQCS be installed as expeditiously as practicable, but not later than five years from the EPA's approval of the SD RH SIP, which was approved by the EPA on April 26, 2012. The Big Stone AQCS project began construction in 2013 and is expected to be operational by 2016.

Mercury and Air Toxics Standards (MATS) Rule

The other rule that will have immediate impact on Montana-Dakota's electric generating facility operations is the MATS Rule. The MATS Rule, published as a final rule in the Federal Register on February 16, 2012, requires existing coal-fired electric generating units (EGUs) to meet hazardous air pollutant (HAP) emission standards reflecting the application of maximum achievable control technology (MACT). The rule includes HAP emission limits for mercury (Hg), non-Hg trace metals, and acid gases and applies to all new and existing coal- and oil-fired EGUs. An EGU is defined in the rule as a fossil fuel-fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale, which applies to all of Montana-Dakota's coal-fired electric generating facilities. The deadline to demonstrate compliance with the MATS Rule emission limits and operating requirements is April 16, 2015, with a potential additional year extension for installation of pollution control projects approved through the state air permitting authority. The significant pollution control projects that will be implemented at each of the Montana-Dakota's facilities to comply with the MATS Rule are described below.

R.M. Heskett Station – MATS Rule

Montana-Dakota has determined through stack emissions testing conducted at R.M. Heskett Station that both Unit 1 and Unit 2 can comply with the MATS emissions limits without implementing a significant pollution control project.

Coyote Station – MATS Rule

The co-owners of Coyote Station, of which Montana-Dakota has 25 percent ownership, have determined that mercury emissions reductions are required in order to comply with the MATS mercury emission limit of 4 lb per trillion btu for units that fire lignite coal. An activated carbon injection system to control mercury emissions is proposed to be installed in 2014 at a total plant capital cost of approximately \$2.4 million.

Lewis & Clark Station – MATS Rule

Montana-Dakota has determined through stack emissions testing conducted at L&C that filterable particulate matter emissions reductions are required to comply with the MATS non-mercury emissions limit. In order to comply with this limit, a filterable particulate matter pollution control project (i.e. fabric filter baghouse with an enhanced wet scrubber mist eliminator) was modeled in the 2013 IRP to be installed at L&C from 2014 to 2015 at a cost of approximately \$27.7 million. Montana-Dakota is continuing to review filterable particulate matter pollution control options for L&C, including a fabric filter baghouse.

Big Stone Plant – MATS Rule

The co-owners of Big Stone Plant, of which Montana-Dakota has 22.7 percent ownership, have determined that mercury emissions reductions are required in order to comply with the MATS mercury emissions limit of 1.2 lb per trillion btu for units that fire subbituminous coal. To meet this emission limit, an activated carbon injection system is proposed for installation in 2014 at a total plant capital cost of approximately \$1.5 million.

Attachment H
Bakken Impacts

Bakken Impacts

OVERVIEW

High growth levels in communities served within the area of the Bakken Formation in Western North Dakota and Eastern Montana are providing many unique opportunities and challenges for Montana-Dakota. The Bakken region has experienced very robust growth levels the past three years. Many of the communities that Montana-Dakota serves in Western North Dakota and Eastern Montana are expected to double and/or triple their pre-2010 electric demand requirements by 2015.

Several challenges associated with providing electric service in the Bakken region include: local area load forecasting, identifying the timing of future impacts on high-voltage transmission facilities, being able to construct transmission facilities to keep pace with growth, and being able to mitigate potential transmission impacts with local generation and load modifying resources.

Bakken Formation

The Williston Basin, high-lighted in yellow on Figure 1, is an oval-shaped, subsurface sedimentary basin with the deepest point near Watford City, ND. The Bakken Formation, high-lighted in red on Figure 1, is located within the Williston Basin and found primarily in far northeastern Montana and northwestern North Dakota. These geological features underlie areas served by Montana-Dakota.



Figure 1 – Bakken Formation

Load Forecasting

Prior to 2010, the communities served by Montana-Dakota in the Bakken region had experienced flat to negative growth levels over the prior twenty year period. Montana-Dakota's historic modeling techniques, which produced continued flat growth levels, were unable to adequately forecast community growth levels that Montana-Dakota experienced from 2010 to 2012 within the Bakken region.

The majority of electrical load that Montana-Dakota serves with the Bakken region consists of residential, commercial, and industrial loads within city limits. Montana-Dakota does not service the oil wells in North Dakota nor any of the natural gas processing plants. The majority of the new electric customer growth in the Bakken region is being served by the local electric cooperatives. Montana-Dakota is serving approximately ten percent of the total new electric growth in Western North Dakota and Eastern Montana.

Because of the high grow levels that Montana-Dakota experienced in the Bakken region in 2011, the Company started performing community-by-community forecasts the winter of 2012-2013 based on potential new commercial and industrial customers and new residential meter installations. This process involved frequent coordination meetings with field personnel to discuss anticipated community growth levels which were used to create future transmission system models that could determine anticipated transmission constraints. This information was used to identify system areas of concern and formulate mitigation plans and timing.

Figure 2 illustrates the summer and winter load levels experienced by Montana-Dakota in the Williston area from summer 2010 to winter 2012-2013.

Williston Area Peak - Summer

Date of MDU Summer Peak	8/9/2010	7/19/2011	7/19/2012
Time of Peak	5 PM	5 PM	6 PM
Temperature in Williston	88 F	99 F	99 F
MDU Peak Demand:	81.9 MW	95.1 MW	111.3 MW

Williston Area Peak - Winter

Date of MDU Winter Peak	12/30/2010	1/18/2012	1/31/2013
Time of Peak	6 PM	7 PM	10 AM
Temperature in Williston	-14 F	-17 F	-20 F
MDU Peak Demand:	91.8 MW	123.2 MW	137.1 MW

Figure 2 – Williston Area System Peak

Montana-Dakota also participated in a load growth study of the Bakken region with Basin Electric Power Cooperative (Basin Electric). The study was commissioned by the North Dakota Industrial Commission and conducted by KLJ Engineering. A copy of the study can be found at <http://www.nd.gov/ndic/ic-press/Power2012.pdf>. Montana-Dakota participated in the study to help identify the potential residential and commercial load growth that could be expected with the development of the Bakken Formation over the next 20 years. The information in the KLJ study was used to validate the assumptions that Montana-Dakota used in its community by community load forecast as well as its long-term system load forecast.

Transmission System

The electric transmission system in the Williston area has been created over time through joint partnerships between Western Area Power Administration (WAPA), Basin Electric, and Montana-Dakota Utilities Co. These companies built and own various transmission facilities in the Williston area and provide reciprocal transmission services to each other. Figure 3 is a map of the Williston Load Pocket, shaded in grey, as defined by WAPA who is the primary transmission operator in the area.

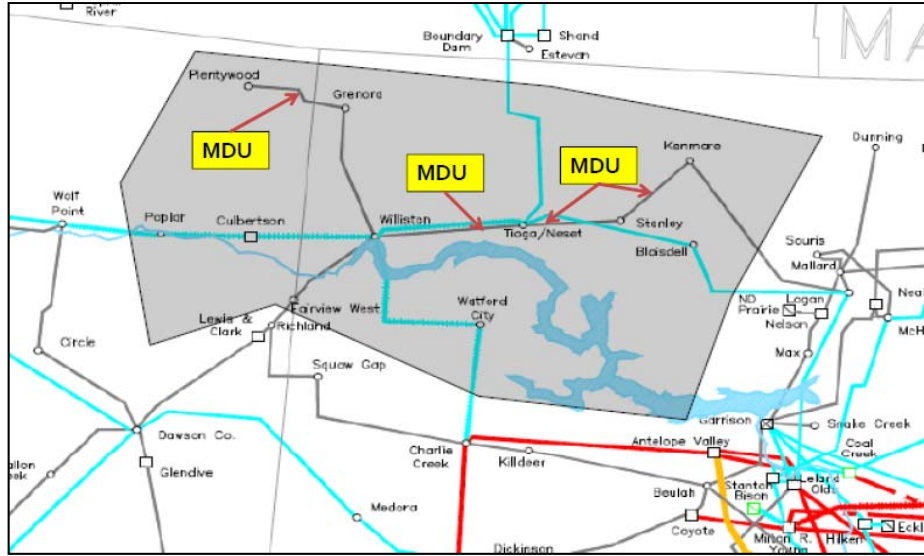


Figure 3 – Williston Load Pocket

Grey lines on Figure 3 are 115 kV transmission facilities. Blue lines are 230 kV facilities. Red lines are 345 kV facilities, and orange lines are high-voltage direct current facilities. The 115 kV transmission facilities that Montana-Dakota owns in the Williston Load Pocket are high-lighted by the yellow text boxes and red arrows.

Montana-Dakota is a transmission customer of WAPA in the Williston Load Pocket. Montana-Dakota has a long-standing transmission service agreement (TSA) with WAPA which expires December 31, 2015. This TSA allows Montana-Dakota to utilize WAPA’s transmission facilities based on community load levels identified in 1993. To serve load growth above the 1993 levels, Montana-Dakota has entered into a network integrated transmission service (NITS) agreement with WAPA under its Integrated System tariff. With the expiration of the WAPA TSA on December 31, 2015; all of the Montana-Dakota transmission service under the TSA will move to WAPA NITS service.

The Williston Load Pocket is a transmission limited area with little generation currently installed within its boundaries. New transmission facilities are being developed by WAPA, Basin Electric and Montana-Dakota to provide higher levels of transmission system deliveries into this area. Montana-Dakota will continue to be a transmission customer of WAPA to serve its customer’s requirements in the Williston Load Pocket.

Load Serving and Mitigation Plans

Montana-Dakota's customer load within the Bakken region is served as MISO load and is a part of Montana-Dakota's Interconnected System. Montana-Dakota has ample supplies of capacity and energy available from MISO to meet the growing customer load requirements in the Williston Load Pocket and the Bakken region.

Montana-Dakota currently has three two MW mobile generators available within the Bakken region to alleviate local load serving limitations and offset potential load curtailment requests that WAPA may impose on its transmission customers. WAPA load curtailments could occur based upon under-forecasted loads at peak system conditions or at lower loads under various outage and maintenance contingencies. To date, Montana-Dakota has not had to implement any load curtailment or mitigation plans in the Bakken region or Williston Load Pocket.

Other load curtailment mitigation plans that Montana-Dakota is pursuing include adding additional demand response customers in the Williston Load Pocket as part of its contracted commercial and industrial demand response program or as direct company load management customers under the Interruptible Service rate schedules. Montana-Dakota is also in contact with other energy supplying companies in the area to ensure that if they have local generation available in the area that agreements and arrangements are in place to call upon these available resources if needed. Montana-Dakota is also considering the possibility of installing additional fixed generation, including partnerships with other providers, in the Williston Load Pocket if needed in the future to reliably serve its customer load.