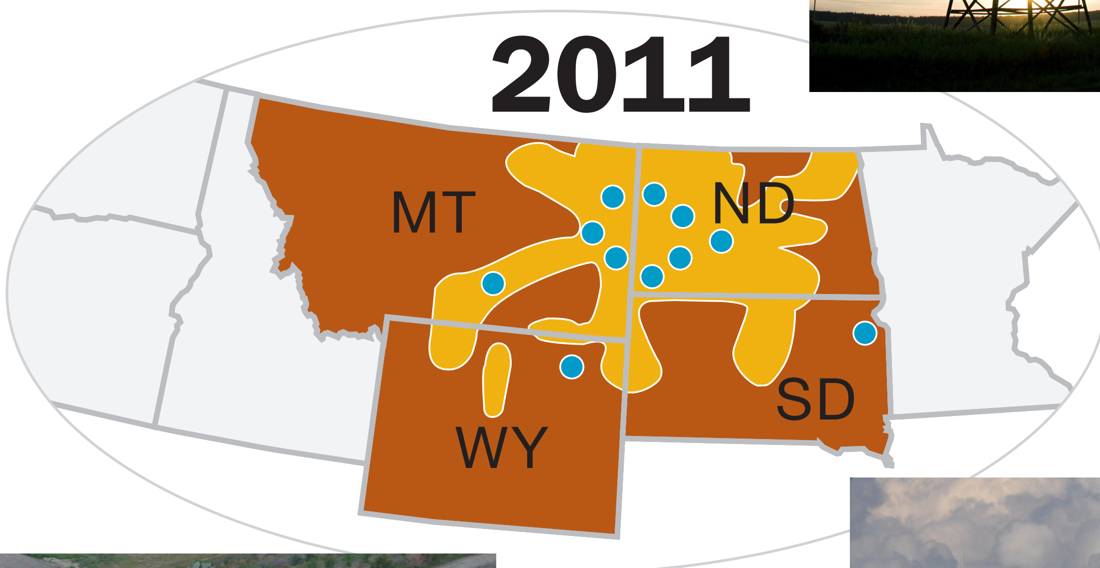
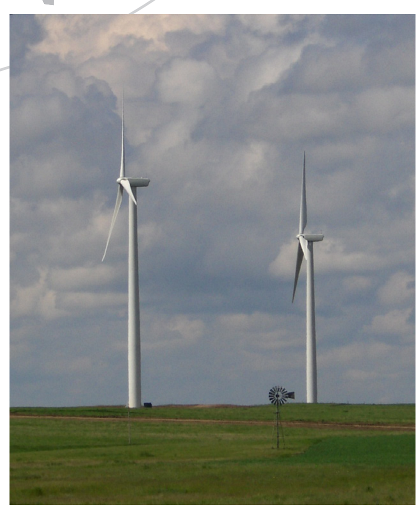
Integrated Resource Plan

2011





Submitted to the
North Dakota Public Service Commission
May 12, 2011

Volume I: Main Report

Montana-Dakota Utilities Co.
2011 Integrated Resource Plan

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Volume I
Main Report

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

INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2011 Integrated Resource Plan (IRP) conducted for the integrated electric system comprised of its service territories in the states of Montana, North Dakota and South Dakota continues a 24-year practice of determining the best value resource plan for its customers. The purpose of integrated resource planning is to consider all resource options reasonably available to meet the end-use customer's demand for reliable, cost-effective, and environmentally responsible electricity, and provide a road map for Montana-Dakota's future resources. Considered resources include a combination of traditional generating stations, distributed generation, renewable resources, demand-side management programs, and new and emerging technologies.

Montana-Dakota's IRP process encompasses four main areas: load forecasting, demand-side analysis, supply-side analysis, and integration and risk analysis. A summary of the IRP study results for each of these areas is provided.

The **load forecasting** activities, as discussed in Chapter 2, employ an econometric forecasting method to predict the integrated system customers' future demand for electricity. The long-term forecast is an estimate of energy requirements and peak demand for twenty years into the future. The results for the base forecast show that, during the 2011-2030 timeframe, the projected average annual growth rate for summer peak demand is 1.8 percent, while annual energy requirements are expected to increase at a rate of 2.1 percent.

The **demand-side analysis** is an evaluation process to identify the feasible demand-side management (DSM) programs for Montana-Dakota's system. As discussed in Chapter 3, Montana-Dakota evaluated a number of energy efficiency and demand response programs, hereinafter referred to collectively as DSM programs, for its customers in Montana, North Dakota, and South Dakota. Montana-Dakota will implement the DSM programs identified in this IRP over the 2011-2013 period with specific program implementation varying by state. A summary of the proposed DSM program plans by state is provided in Chapter 3 Table 3-3.

The **supply-side analysis** is an evaluation process to determine the feasible generation options available to serve Montana-Dakota's system. The future resources to which Montana-Dakota has committed include the extension of the Northern States Power contract for the 2011 summer season, the Basin Electric Power Cooperative contract for 2011, and the WE Energies contract for the 2012-2015 timeframe. The potential resource options studied included simple-cycle combustion turbines, combined cycle combustion turbines, coal-fired generation, wind generation, purchased power and a 25 MW demand response program from bids received as part of a 2010 Request for Proposals (2010 RFP), and the air quality control system (AQCS) required to continue operating the existing Big Stone plant.

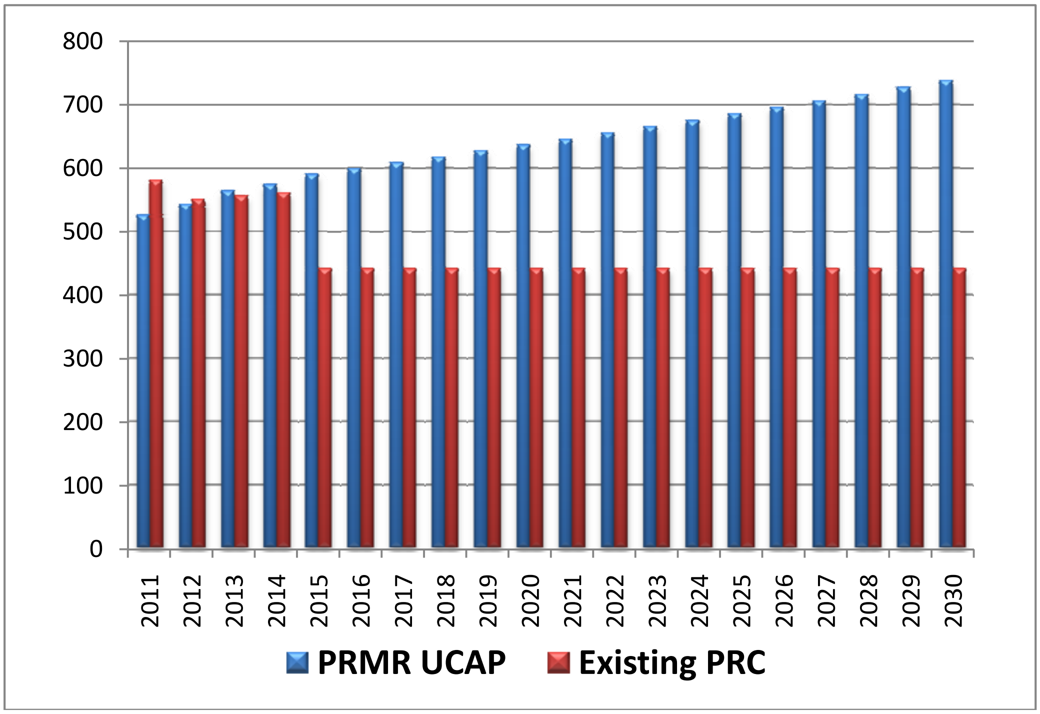
The **integration and risk** process considers the feasible supply-side and demand-side options to determine a least-cost resource expansion plan to economically and reliably meet customer requirements into the future. A number of scenarios were investigated to determine the sensitivity of the least-cost plan to several factors that may impact the expansion plan. The analytical tool used for the integration process was the Electric Generation Expansion Analysis System (EGEAS), a resource expansion program developed by the Electric Power Research Institute. The results of the integration and risk process are then considered as part of the overall decision in determining the best resource plan for Montana-Dakota and its customers.

The **results** of the integration analysis indicate that Montana-Dakota's current least-cost resource plan includes the purchase of a small amount of capacity on a short-term basis between 2012 and 2014, the construction of two 88 MW combustion turbines in 2015 and three additional 43 MW combustion turbines in later years, and the addition of the Big Stone AQCS in 2015. Looking further into the future, 100 MW of wind generation was selected in 2020 to meet energy needs in the least-cost plan. As previously noted, the results of the least-cost model are used to inform the process of selecting the best plan to meet the future needs of Montana-Dakota's customers.

On the demand side, along with a 25 MW demand response program developed under an external contract by 2015, Montana-Dakota will implement or continue to implement the DSM programs described in Chapter 3 Table 3-3 before 2014.

Figure E-1 provides an overview of the identified need for capacity for the period 2011-2030. In this figure, "Peak Load Obligation" represents Montana-Dakota's capacity and reserve margin requirements based upon current 50/50 load forecasts, while "Accredited Installed Generation" represents the amount of accredited generation plus purchased capacity that Montana-Dakota has secured to meet its Peak Load Obligation. The drop in Accredited Installed Generation in 2015 represents the expiration of the WE Energies capacity purchase agreement in May 2015. For resource adequacy purposes, Montana-Dakota must have an amount of Accredited Installed Generation equal to or greater than Peak Load Obligation; otherwise deficiency charges are assessable under the Midwest ISO tariff.

Figure E-1
Planning Resource Credit and Planning Reserve Margin Requirement



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 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014 through the MISO capacity auction or bilateral agreements;
- Contract for the 25 MW demand response program offered by a third party that is expected to provide 5 MW of dispatchable commercial or industrial demand response the summer of 2012, a total of 15 MW the summer of 2013, and the full 25 MW the summer of 2014;
- Implement the DSM programs identified in Chapter 3 Table 3-3 that are expected to provide an additional peak demand reduction of 24.5 MW and annual energy savings of 7.3 MWh by 2015;
- Install the AQCS equipment required to continue operating the Big Stone Plant beyond 2015; and

- Construct one 88 MW simple-cycle combustion turbine (SCCT) to be operational by 2015.

The recommended resource plan is considered to be the best plan to economically and reliably meet customers' requirements over the five-year planning horizon. Montana-Dakota also plans to issue a new request for proposal for capacity and energy resources in 2012 to start the process for the next planning cycle.

The 2011 IRP process and product (report and attachments) were enhanced by the participation of Montana-Dakota's IRP Public Advisory Group (PAG). The PAG has been a valuable tool within the IRP process since 1994. The 2011 advisory group was established at the beginning of the 2011 planning cycle and provided Montana-Dakota with input throughout the 2011 IRP process.

*

For ease of handling, this IRP report is printed and bound in five separate volumes:

Volume I – Main Report (the current document)

Volume II – Attachment A: Load Forecast Documentation

Volume III – Attachment B: Demand-Side Analysis Documentation

Volume IV – Attachment C: Supply-Side and Integration Analysis Documentation
Attachment D: Public Advisory Group Documentation
Attachment E: 2010 Request for Proposal for Capacity and Energy Supply
Attachment F: Combustion Turbine Site Study
Attachment G: Pollution Control Projects
Attachment H: Big Stone Air Quality Control System Project

CHAPTER 1

ENVIRONMENTAL CONSIDERATIONS

MDU Resources Group, Inc.'s Corporate Environmental Statement states:

> *"Our company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. Our environmental goals are:*
>
> - *To minimize waste and maximize resources;*
> - *To support environmental laws and regulations that are based on sound science and cost-effective technology; and*
> - *To comply with or exceed all applicable environmental laws, regulations and permit requirements".*

Montana-Dakota strives to maintain compliance and operate in an environmentally proactive manner, while taking into consideration the cost to customers. Montana-Dakota actively monitors federal and state legislative and regulatory activity related to environmental issues, including air emissions, greenhouse gases (GHG), waste disposal and water discharges. The Company has also established memberships in relevant trade organizations to assist in monitoring the potential impact of proposed legislation and regulation to the Company's operations.

The U.S. Environmental Protection Agency (EPA) has made known that it intends to propose several significant new air emissions regulations that aim to reduce air emissions, including GHGs, at coal-fired electric generating facilities. The culmination of all various pending environmental requirements may result in the retirement of existing coal-fired baseload units earlier than otherwise would occur. Montana-Dakota will continue to monitor the impacts from proposed regulations and will take the regulations into consideration when planning for future resource needs.

Renewable Energy

Montana-Dakota has been involved with renewable energy analysis and development for many years, and has several renewable energy installations.

Montana-Dakota has 50 MW of installed wind generation capacity at two locations, providing approximately seven percent of its customers' electric energy requirements. The Company also owns a 7.5 MW heat recovery facility on the Northern Border Pipeline Compressor Station in central North Dakota, which uses high-temperature exhaust gas as the primary heat source. Given that waste heat is utilized as the "fuel" for this generating facility, no additional fossil fuel is required and therefore incremental emissions to generate electricity are negligible.

Air Quality

Montana-Dakota has been an active sponsor of research on technology that removes mercury from lignite-based electric generation facilities. Montana-Dakota's Lewis & Clark Station in Sidney, Montana conducted testing in the summers of 2007 and 2008 to assess a variety of mercury removal products and equipment. As required by the Montana Department of Environmental Quality, the Lewis & Clark Station installed an activated carbon and oxidizing agent injection system in late 2009 to reduce its mercury emissions by approximately ninety percent starting in 2010.

The Regional Haze Rule (RHR) was promulgated by EPA in 1999 to address visibility impairment in Class I areas in the United States, constituting 156 national parks and wilderness areas. A description of pollution control projects being planned as part of Montana-Dakota's compliance with the RHR is provided in Attachment G.

In addition, as described in Chapters 4 – 6 and in detailed discussion in Attachment H, Montana-Dakota is studying the proposed air quality control system (AQCS) at the Big Stone Plant, of which Montana-Dakota is a 22.7 percent owner. The Big Stone AQCS project will be required to comply with the RHR and the South Dakota Regional Haze State Implementation Plan ("SD Haze SIP") as well as the State of South Dakota's associated rules. Projected to cost a total of $489.4 million, the AQCS project will include installation of the following air pollution control equipment:

- Selective catalytic reduction with separated overfire air, to reduce NOx emissions;
- Semi-dry flue gas desulfurization, to reduce SO_2 emissions; and
- A baghouse, to reduce particulate matter emissions.

The SD Haze 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 Haze SIP. The SIP was filed on January 21, 2011, which may result in the Big Stone AQCS project being required as early as 2016.

Commitment to Reducing Greenhouse Gases

In 2003, Montana-Dakota joined other utilities, through a memorandum of understanding from the Edison Electric Institute to the Department of Energy, to commit to reduce the utility industry's carbon dioxide emission intensity by three to five percent by 2010. Montana-Dakota has shown its commitment by reducing the Company's carbon dioxide emissions intensity in 2008 by approximately seven percent as compared to 2003. The reductions were realized through utility operational changes, customer energy efficiency programs, and renewable energy projects.

In 2010, Montana-Dakota updated its GHG goal, committing to a ten percent reduction of the Company's average GHG emissions intensity from its electric generating facilities by 2012 compared to 2003 levels. The Company is on target to meet this renewed goal through customer energy efficiency and its renewable energy projects.

Montana-Dakota has been active in researching options for carbon dioxide capture, sequestration, and beneficial uses. The Company has been a member of the Plains CO_2 Reduction Partnership (PCOR) since its inception in 2003. The partnership is led by the Energy and Environmental Research Center at the University of North Dakota and is one of seven regional partnerships across the United States. Montana-Dakota has also actively participated in the environmental workgroups of the North Dakota Lignite Energy Council such as the Lignite Technology Development Workgroup and the Environmental Workgroup. In the last few years, these workgroups have focused on CO_2-related issues such as lignite gasification, oxyfuel combustion, pre- and post-combustion CO_2 capture technologies, and beneficial uses of CO_2.

CHAPTER 2

LOAD FORECASTING

Montana-Dakota uses an econometric model as its forecasting tool. The econometric models for the 2011-2030 forecast were developed using the statistical software package called SAS®.

An econometric model is a set of equations that expresses electricity use as a function of underlying factors such as customer income, price of electricity and alternate fuels, and weather. The strengths of econometric forecasting models include:

- Econometric models explicitly measure the effects of underlying causes of trends and patterns.
- Econometric models provide statistical evaluation of forecast uncertainty.
- Econometric models utilize economic and demographic information that is easily understood.
- Econometric models can be readily re-estimated.

The load forecasting process develops a forecast for annual energy sales and a forecast for peak demand. Detail regarding the specific econometric factors used in the energy sales forecast and peak demand forecast is provided in the detailed description of the load forecast included as Attachment A.

<u>Energy Sales Forecast</u>

The energy sales forecast is disaggregated into five sales sectors:

- Residential sector.
- Small Commercial & Industrial (SC&I) sector. This sector consists of those commercial and industrial customers whose peak demand averages less than 50 kilowatts a month over a year's time.
- Large Commercial & Industrial (LC&I) sector. This sector consists of those commercial and industrial customers whose peak demand averages more than 50 kilowatts a month over a year's time.
- Street Lighting. This sector consists of energy for public street and highway lighting.

- Miscellaneous. This sector includes energy for sales to other public authorities, interdepartmental sales, and company use.

The LC&I sector was disaggregated into seven sub-categories which were then forecasted separately. Six large customers were forecasted individually and all other LC&I energy sales were categorized as General LC&I energy sales (energy sales to all other LC&I customers) and forecasted as a group.

Econometric equations were developed to forecast energy sales for the three primary customer categories – residential, SC&I, and General LC&I – while energy sales forecasts for the street lighting and miscellaneous sectors were developed primarily using linear regression. The criteria for acceptance of the variables to be used in the econometric models is 90 percent confidence level, but the final econometric equations resulted in nearly all accepted variables having confidence levels higher than 95 percent. The energy sales forecasts for the six LC&I end-use large customers were developed using a combination of regressions and information available from Montana-Dakota's field personnel regarding these large customers. More detail regarding the specific econometric factors used in the energy sales forecast is described the load forecast in Attachment A.

Peak Demand Forecast

The peak demand forecast is developed for the summer peaking season on a total system basis. From Montana-Dakota's residential appliance saturation surveys and other available information, it is known that air conditioning is becoming more prevalent over time and the air conditioning load is driving much of the increase in summer peak demand.

The peak demand forecast was developed through the use of an econometric analysis where weighted average temperatures for Bismarck, North Dakota (70%), Miles City, Montana (15%) and Williston, North Dakota (15%) were used as part of the equation in order to capture weather diversity across the integrated system.

Any known interruptions (Interruptible Rate 39/Demand Response Rate 38 and/or customer outages) that occurred at the time of the summer peak were added to the historical actual summer peak used in the peak demand econometric model. The summer peak value thus represents the peak as it would have occurred had there not been any interruptions. More detail regarding the specific factors used in the peak demand forecast is described in Attachment A.

Forecast Adjustments

The forecast methodology for both energy sales and peak demand results in an initial energy sales forecast by sales sector and an initial peak demand forecast. Reductions to the energy sales forecasts by sector and to the peak demand forecast are made to reflect demand-side management programs. Once these reductions are reflected in the energy sales forecasts, the total of the energy sales forecasts by class are adjusted by the loss factor to arrive at the final forecast of total energy requirements.

Demand-Side Management (DSM) Reductions

The load forecast presented in this IRP was prepared in 2010 (*Electric Load Forecast 2011-2030*, published December 31, 2010). The DSM programs that were selected for the 2009 IRPs were incorporated in the forecast so that it reflects reductions resulting from the DSM programs planned at that time.

Losses

The energy sales forecast reflects the energy delivered to Montana-Dakota's customers' meters. The total amount of electricity provided by generating resources to meet Montana-Dakota's customers' energy needs is greater than what is delivered to the meters and is called the total energy requirements. The difference between the energy sales and total energy requirements reflects the losses that occur within the transmission and distribution system.

The percentage of the annual energy losses has varied from year to year. The average value for the past ten years is 7.91 percent. Using this value for all future years, the total system hourly loads are calculated for each year during the study period.

Final Energy Requirements and Peak Demand Forecast

The forecasted energy sales and system peak demand are first adjusted to reflect the effects of the DSM programs planned in the 2009 IRP and then adjusted for losses to calculate the total energy requirements and demand forecast. This is the amount of energy and capacity that must be acquired to meet Montana-Dakota's customers' energy needs.

The final forecast results are presented in Table 2-1 summarizing the total energy requirements and seasonal peak demand.

Table 2-1

Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2009 IRP

	Total Energy Requirements (net of DSM)		Summer Peak - MW						Winter Peak */ After DSM	
Year	MWh	% Change	Total Demand Before DSM or Interrupt.	Rate 38/39 Interrupt Loads	Conser-vation DSM	Demand Response DSM	Peak Demand After all DSM (Consvtn, DR & Int)	% Change	MW	% Change
2000	2,077,579						432.3		353.9	
2001	2,104,119	1.28%					452.9	4.77%	328.9	-7.06%
2002	2,158,431	2.58%					458.8	1.30%	343.5	4.44%
2003	2,226,531	3.16%					470.5	2.55%	367.7	7.05%
2004	2,204,012	-1.01%					458.4	-2.57%	383.9	4.41%
2005	2,327,117	5.59%					459.1	0.15%	387.2	0.86%
2006	2,397,793	3.04%					485.5	5.75%	397.2	2.58%
2007	2,510,540	4.70%					525.6	8.26%	407.3	2.54%
2008	2,596,990	3.44%					476.6	-9.32%	455.0	11.71%
2009	2,593,368	-0.14%					473.8	-0.59%	459.6	1.01%
2010	2,718,192	4.81%					502.5	6.06%	Not yet available	
2011	2,745,079	0.99%	513.1	7.6	4.2	1.3	500.0	-0.50%	450.3	
2012	2,849,695	3.81%	532.5	10.3	4.2	1.3	516.7	3.34%	469.4	4.24%
2013	3,000,627	5.30%	552.9	10.3	4.2	1.3	537.1	3.95%	489.5	4.28%
2014	3,058,976	1.94%	561.9	10.3	4.2	1.3	546.1	1.68%	498.3	1.80%
2015	3,157,733	3.23%	577.6	10.3	4.2	1.3	561.8	2.87%	513.5	3.05%
2016	3,212,882	1.75%	586.4	10.3	4.2	1.3	570.6	1.57%	521.8	1.62%
2017	3,267,300	1.69%	595.1	10.3	4.2	1.3	579.3	1.52%	529.9	1.55%
2018	3,322,641	1.69%	603.9	10.3	4.2	1.3	588.1	1.52%	538.2	1.57%
2019	3,378,799	1.69%	612.9	10.3	4.2	1.3	597.1	1.53%	546.7	1.58%
2020	3,433,624	1.62%	621.8	10.3	4.2	1.3	606.0	1.49%	554.9	1.50%
2021	3,489,360	1.62%	630.8	10.3	4.2	1.3	615.0	1.49%	563.2	1.50%
2022	3,545,996	1.62%	640.0	10.3	4.2	1.3	624.2	1.50%	571.7	1.51%
2023	3,603,568	1.62%	649.3	10.3	4.2	1.3	633.5	1.49%	580.4	1.52%
2024	3,662,045	1.62%	658.7	10.3	4.2	1.3	642.9	1.48%	589.1	1.50%
2025	3,721,491	1.62%	668.3	10.3	4.2	1.3	652.5	1.49%	598.0	1.51%
2026	3,781,897	1.62%	678.0	10.3	4.2	1.3	662.2	1.49%	607.1	1.52%
2027	3,843,314	1.62%	687.8	10.3	4.2	1.3	672.0	1.48%	616.3	1.52%
2028	3,905,749	1.62%	697.8	10.3	4.2	1.3	682.0	1.49%	625.7	1.53%
2029	3,969,254	1.63%	708.0	10.3	4.2	1.3	692.2	1.50%	635.2	1.52%
2030	4,033,816	1.63%	718.3	10.3	4.2	1.3	702.5	1.49%	644.9	1.53%

*/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.

Forecast Uncertainty

Forecasting is a process permeated with uncertainty. The demand and energy projections produced by the econometric process results in a forecast based solely on the information used as inputs to the equations. For purposes of integrated resource planning, a single forecast does not allow the analysis of risk and uncertainty associated with the input assumptions. Robust resource decisions cannot be made unless uncertainty is considered. This uncertainty can be expressed by peak demand forecasts that reflect temperatures which correspond to higher confidence levels as well as high-growth and low-growth scenarios in energy forecasts.

Effect of Temperature on Peak Demand

The final forecast results were developed assuming average temperatures at the time of the system peak. However, with an average temperature forecast, by definition actual peak demand would have a 50 percent probability of being lower than the forecast values and a 50 percent probability of exceeding forecast values (50/50 forecast). It can appear that peak demand is under-forecasted when the actual temperature at the time of system peak exceeds average temperatures.

Montana-Dakota conducts a study annually to establish the relationship between summer peak demand and temperature at the time of system peak. As part of the study, the Company's historical July and August demands and corresponding temperatures at times when the temperatures equaled or exceeded 85°F on Mondays through Thursdays are analyzed. The 2010 study results indicated each one degree increase in temperature at the time of summer peak would result in an increase of 5.6 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2009 (prior to 1984 Montana-Dakota was a winter peaking utility) provided the results shown in Table 2-2.

Table 2-2

Temperature Probability at Peak and Effect on Peak Demand

Probability	Weighted Average Temperature	Approximate Increase in Peak Demand (MW)
50.0%	97.0	0.0
75.0%	99.9	16.2
80.0%	100.6	20.2
85.0%	101.5	25.2
90.0%	102.6	31.4
95.0%	104.1	40.0
97.0%	105.2	45.9

As Table 2-2 shows, with a weighted average temperature of 97.0°F at the time of peak, there is a 50 percent probability the temperature at peak would be lower than 97.0°F and a 50 percent probability the temperature at peak would be higher than 97.0°F. This forecast is referred to as the 50/50 demand forecast.

Also from Table 2-2, there is a 90 percent probability actual temperatures at the time of the system peak will not exceed 102.6°F. However, at this temperature (102.6°F), the system peak demand would be 31.4 MW higher than the demand in the base, or 50/50, forecast. This forecast is called the 90/10 forecast and provides a peak demand forecast that represents a 90 percent probability the actual peak demand will not exceed the forecast value and a 10 percent probability the actual peak demand will be higher than the forecast value. Table 2-3 summarizes the results of the 50/50 probability and 90/10 probability demand forecasts.

Table 2-3
Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (97.0 degrees F) 50/50 Forecast (MW)	Growth Rate	Alternate Forecast (102.6 degrees F) 90/10 Forecast (MW) 1/
2011	500.0		531.4
2012	516.7	3.34%	549.1
2013	537.1	3.95%	570.8
2014	546.1	1.68%	580.4
2015	561.8	2.87%	597.1
2016	570.6	1.57%	606.5
2017	579.3	1.52%	615.7
2018	588.1	1.52%	625.1
2019	597.1	1.53%	634.7
2020	606.0	1.49%	644.2
2021	615.0	1.49%	653.8
2022	624.2	1.50%	663.6
2023	633.5	1.49%	673.5
2024	642.9	1.48%	683.5
2025	652.5	1.49%	693.7
2026	662.2	1.49%	704.0
2027	672.0	1.48%	714.4
2028	682.0	1.49%	725.0
2029	692.2	1.50%	735.8
2030	702.5	1.49%	746.7

1/ The growth rate for the 90/10 Forecast scenario is assumed to be the same as that of the 50/50 Forecast scenario.

High-Growth and Low-Growth Scenario Forecasts

Another approach taken to express forecast uncertainty in this study was to simulate high-growth and low-growth scenarios which represent the corresponding economic conditions that may occur. These high-growth and low-growth scenario forecasts were developed as follows.

Historical total energy was analyzed in order to find a period of time during which unusually high growth was experienced and a period of time during which unusually low growth was experienced. Based on the historical sales data, the average growth rate that occurred from

1977 to 1985 was used as the high-growth rate, and the average growth rate that occurred from 1985 to 1993 was used as the low-growth rate. Both of these periods consist of eight years of history.

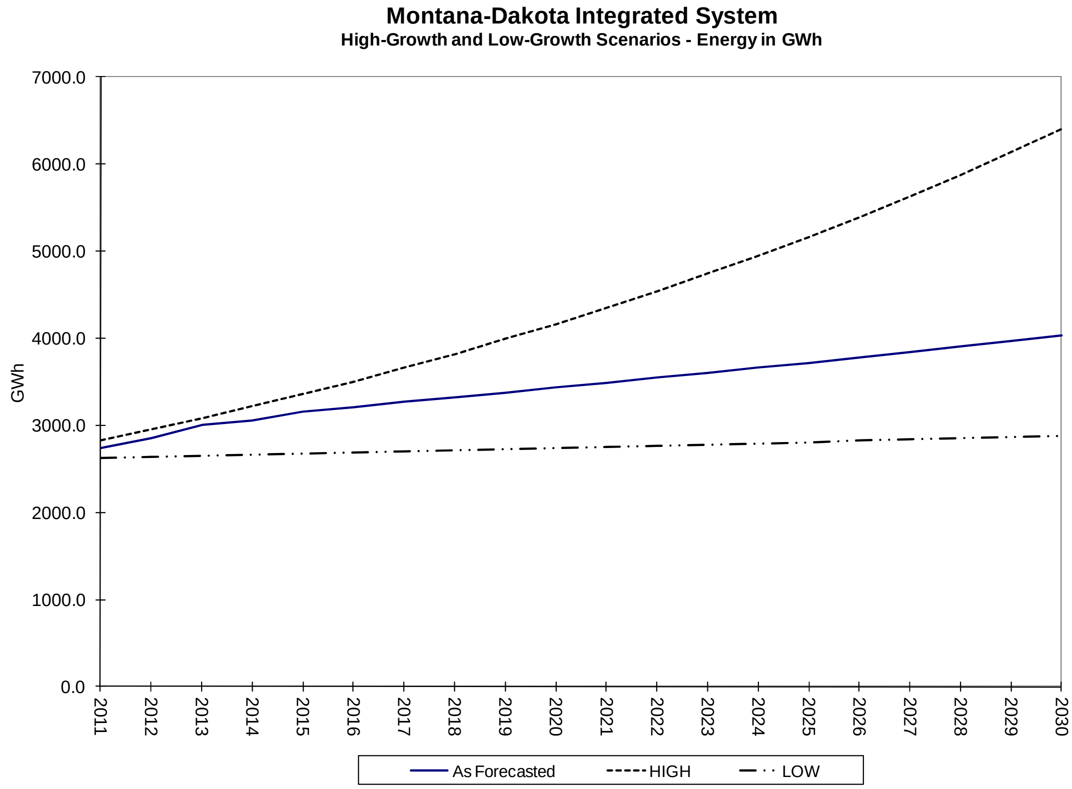
As a result, for the high-growth scenario, an average growth rate of 4.4 percent per year was assumed to occur during the 20-year forecast horizon. For the low-growth scenario, an average growth rate of 0.5 percent per year was assumed to occur during the 20-year forecast horizon. Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy. The results of the high- and low-growth scenarios for energy and demand are shown on Table 2-4. The following page presents the graphs of the numeric results.

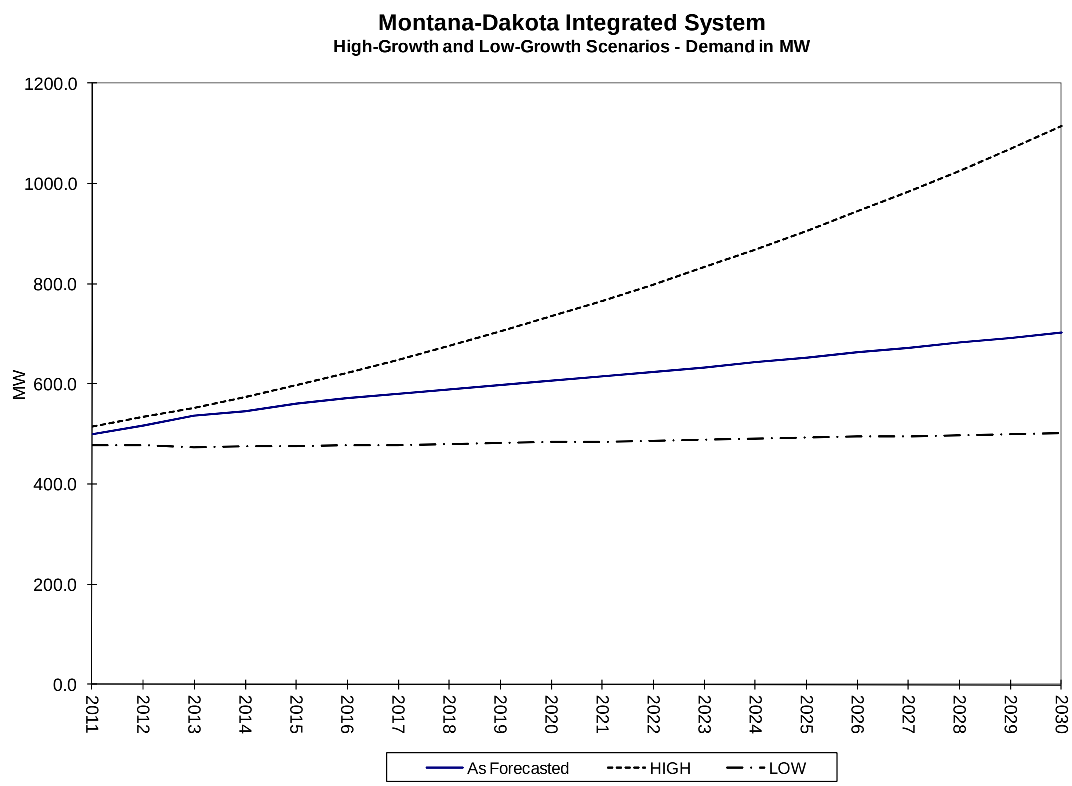
Table 2-4

High-Growth and Low-Growth Scenarios
Total Annual Energy (GWh) and
Summer Peak Demand (MW)

	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2011	2745.1	2826.6	2619.4	500.0	514.9	477.1
2012	2849.7	2951.0	2632.5	516.7	535.1	477.3
2013	3000.6	3080.8	2645.7	537.1	551.5	473.6
2014	3059.0	3216.4	2658.9	546.1	574.2	474.7
2015	3157.7	3357.9	2672.2	561.8	597.4	475.4
2016	3212.9	3505.7	2685.6	570.6	622.6	476.9
2017	3267.3	3659.9	2699.0	579.3	648.9	478.5
2018	3322.6	3821.0	2712.5	588.1	676.3	480.1
2019	3378.8	3989.1	2726.1	597.1	704.9	481.7
2020	3433.6	4164.6	2739.7	606.0	735.0	483.5
2021	3489.4	4347.8	2753.4	615.0	766.3	485.3
2022	3546.0	4539.1	2767.2	624.2	799.0	487.1
2023	3603.6	4738.9	2781.0	633.5	833.1	488.9
2024	3662.0	4947.4	2794.9	642.9	868.6	490.7
2025	3721.5	5165.1	2808.9	652.5	905.6	492.5
2026	3781.9	5392.3	2822.9	662.2	944.2	494.3
2027	3843.3	5629.6	2837.0	672.0	984.3	496.1
2028	3905.7	5877.3	2851.2	682.0	1026.3	497.9
2029	3969.3	6135.9	2865.5	692.2	1070.0	499.7
2030	4033.8	6405.9	2879.8	702.5	1115.6	501.5

1/ High forecast assumes 4.4% growth per year (actual 77-85 growth).
2/ Low forecast assumes 0.5% growth per year (actual 95-93 growth).


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy in GWh
GWh
7000.0
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
As Forecasted
HIGH
LOW


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Demand in MW
MW
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
As Forecasted
HIGH
LOW

Forecast Accuracy

In July 2009, Montana-Dakota conducted a study, “Evaluation of Load Forecast Accuracy,” to examine the accuracy of its forecast. The study provided a statistical validation of the accuracy of the Company’s forecasts and also helped the Company better understand forecast problems and improve forecast accuracy. The evaluation was conducted on three forecasted quantities: annual energy requirements, summer peak demand, and winter peak demand.

The results of the study indicated that Montana-Dakota had produced relatively accurate forecasts. For the five-year-ahead forecasts, where the largest error levels occur, the annual energy requirement forecasts were within seven percent of the actual, while the summer and winter peak demand forecasts were within five percent and three percent of the actual, respectively. In actuality, Montana-Dakota generally underforecasted both the annual energy requirements and the summer peak demand.

CHAPTER 3

DEMAND-SIDE MANAGEMENT ANALYSIS

Demand-Side Management is a resource planning tool a utility can use to meet two objectives: (1) to potentially offset future generation resource costs through load management and/or conservation measures and (2) to enhance customer service by offering programs to customers that will help reduce their overall demand and/or energy requirements.

With the demand for electricity and the need for additional resources growing, Montana-Dakota recognizes the value that Demand-Side Management (DSM) can add in meeting our customer's future energy requirements. However, DSM programs cannot be implemented without cost consideration to the utility's customers and shareholders. Interests need to be balanced to achieve results at an affordable cost to both the utility and its customers.

As in the past IRPs, Montana-Dakota has focused on a proven list of DSM programs that would be best suited for the Company's load shape.

Montana-Dakota historically performed all DSM analysis for the IRP using an Integrated System approach as supply-side resources are approached in the same manner. However, due to the complexities of offering DSM programs across multiple jurisdictions, this IRP includes DSM analysis separately for each state (Montana, North Dakota, and South Dakota), and in total for the Integrated System. The true value of DSM can only be achieved as an integrated resource implemented across all jurisdictions; however, appropriate cost recovery is necessary in each jurisdiction in order for full implementation to occur.

A detailed discussion of Montana-Dakota's demand-side analysis is provided in Attachment B.

<u>DSM Energy Savings Goals</u>

At this time Montana-Dakota has not definitely determined what the achievable potential for energy efficiency is on its Integrated System. As a starting point and as further discussed in Attachment B, Montana-Dakota will commission an Energy Efficiency Potential and Market Assessment Study for Montana customers that will serve as a guide to refining its energy efficiency goals and programs throughout its Integrated System. The study is expected to be completed in mid-2012.

In the interim, Montana-Dakota has established a goal of achieving a reduction of 0.18 percent of annual energy sales by 2013 and 0.25 percent for 2014 through 2030. As shown in Table 3-1, this will result in an annual average reduction of 0.23 percent through 2030.

DSM Energy Savings Goal
2011-2030
Table 3-1

Year	Total kWh Sales	DSM Goal kWh	DSM Goal % of Sales
2011	2,540,830,000	1,000,000	0.04%
2012	2,638,517,000	2,700,000	0.10%
2013	2,778,978,000	5,000,000	0.18%
2014	2,833,174,000	7,086,866	0.25%
2015	2,924,681,000	7,315,666	0.25%
2016	2,975,811,000	7,443,430	0.25%
2017	3,026,203,000	7,569,508	0.25%
2018	3,077,460,000	7,697,719	0.25%
2019	3,129,538,000	7,827,812	0.25%
2020	3,180,299,000	7,954,831	0.25%
2021	3,231,928,000	8,083,954	0.25%
2022	3,284,383,000	8,215,173	0.25%
2023	3,337,691,000	8,348,547	0.25%
2024	3,391,856,000	8,484,029	0.25%
2025	3,446,900,000	8,621,751	0.25%
2026	3,502,842,000	8,761,694	0.25%
2027	3,559,712,000	8,903,982	0.25%
2028	3,617,535,000	9,048,627	0.25%
2029	3,676,345,000	9,195,752	0.25%
2030	3,736,137,000	9,345,340	0.25%
Totals	**63,927,211,900**	**148,604,679**	**0.23%**

Montana-Dakota understands that these goals are lower than national averages for achievable potential; however, based on historical participation, the small rural customer base, and low customer growth in the area, these goals are appropriate in the interim and will be adjusted if the potential is determined to be different in the future.

DSM Peak Demand Savings Goals

As discussed in Attachment B, Montana-Dakota will pursue a demand response portfolio that will include a Residential Air Conditioning Cycling program, a Commercial Demand Response program, and adjustments to the Company's current Interruptible Demand Response rate. Two of these programs will be implemented beginning in 2012 with total program goals expected to be achieved by 2015.

The demand response goal from the three programs is 48 MW or 8.3 percent of the total forecasted Integrated System peak demand in 2015. In addition, 1.5 MW of additional capacity savings is expected from the energy efficiency programs, bringing the total to 49.5 MW or 8.6 percent of the total forecasted Integrated System peak demand in 2015. The expected DSM demand savings from demand response and energy efficiency by year and in total are shown in Table 3-2. The shown savings will replace the anticipated savings developed in the 2009 IRP and reflected in the load forecast described in Chapter 2 and Attachment A, and are not additive to those estimated savings.

DSM Peak Demand Savings Goals
2011-2030
Table 3-2

Year	Total Summer Peak MW	IT Rate Summer Peak MW	Comm DR Summer Peak MW	Res AC DR Summer Peak MW	DR Goal Summer Peak MW	Total DR Program MW	Total DR Program %	Total EE Goal Summer Peak MW	Total EE & DR Summer Peak MW	Total EE & DR Program %
2011	513.1	6.6	0.0	0.0	6.6	6.6	1.3%	0.7	7.3	1.4%
2012	532.5	4.0	5.0	0.0	9.0	15.6	2.9%	0.9	16.5	3.1%
2013	552.9	1.2	10.0	4.0	15.2	30.8	5.6%	1.3	32.1	5.8%
2014	561.9	1.2	10.0	6.0	17.2	48.0	8.5%	1.5	49.5	8.8%
2015	577.6	0.0	0.0	0.0	0.0	48.0	8.3%	1.5	49.5	8.6%
2016	586.4	0.0	0.0	0.0	0.0	48.0	8.2%	1.5	49.5	8.4%
2017	595.1	0.0	0.0	0.0	0.0	48.0	8.1%	1.5	49.5	8.3%
2018	603.9	0.0	0.0	0.0	0.0	48.0	7.9%	1.5	49.5	8.2%
2019	612.9	0.0	0.0	0.0	0.0	48.0	7.8%	1.5	49.5	8.1%
2020	621.8	0.0	0.0	0.0	0.0	48.0	7.7%	1.5	49.5	8.0%
2021	630.8	0.0	0.0	0.0	0.0	48.0	7.6%	1.5	49.5	7.8%
2022	640.0	0.0	0.0	0.0	0.0	48.0	7.5%	1.5	49.5	7.7%
2023	649.3	0.0	0.0	0.0	0.0	48.0	7.4%	1.5	49.5	7.6%
2024	658.7	0.0	0.0	0.0	0.0	48.0	7.3%	1.5	49.5	7.5%
2025	668.3	0.0	0.0	0.0	0.0	48.0	7.2%	1.5	49.5	7.4%
2026	678.0	0.0	0.0	0.0	0.0	48.0	7.1%	1.5	49.5	7.3%
2027	687.8	0.0	0.0	0.0	0.0	48.0	7.0%	1.5	49.5	7.2%
2028	697.8	0.0	0.0	0.0	0.0	48.0	6.9%	1.5	49.5	7.1%
2029	708.0	0.0	0.0	0.0	0.0	48.0	6.8%	1.5	49.5	7.0%
2030	718.3	0.0	0.0	0.0	0.0	48.0	6.7%	1.5	49.5	6.9%

Potential DSM Programs

Montana-Dakota explored the feasibility of offering energy efficiency and demand response DSM programs to its customer base in Montana, North Dakota, and South Dakota. The following is a list of the electric programs included in the analysis. A complete description of each program is provided in Attachment B.

Residential Energy Efficiency Programs

1. Central Air Conditioning Tier 1 (14.5 SEER) – Replacement Only
2. Central Air Conditioning Tier 2 (16 SEER) – Replacement only
3. Central Air Conditioning Tier 2 (16 SEER) – New
4. Window Air Conditioner units
5. Air Conditioner Tune-Up program
6. New Construction Bundle program (central air conditioner, ENERGY STAR® –rated appliances and compact fluorescent lighting (CFL))
7. Thermal storage program with an air source heat pump (ASHP) – in Montana and North Dakota only.
8. Residential Lighting (CFL) – in Montana only.

Residential Demand Response Program

9. Residential Air Conditioner Cycling program (switch-based with annual incentive to participants)

Commercial Energy Efficiency Programs

1. Commercial Lighting
2. Commercial Motors – Replacement
3. Commercial Motors – New equipment or replacement on failure of existing equipment
4. Variable Speed Drives (VFD)
5. Commercial Air Conditioning – Split systems
6. Commercial Air Conditioning – Packaged/Rooftop systems

7. Commercial Air Conditioning– Water-cooled chillers
8. Commercial Air Conditioning – Centrifugal chillers
9. Commercial Partnership program (Custom)

Commercial Demand Response Programs

10. Commercial Demand Response program

Benefit/Cost Analysis

To determine which programs are cost effective, and therefore should be included as resource options in the integration analysis, a benefit/cost analysis by state was performed for each of the potential DSM programs. The basic function of the analysis was to calculate each DSM program's benefits and costs to determine the cost effectiveness of each respective program on a stand-alone basis. The programs were evaluated using five different cost-effectiveness tests: the Participant Test, the Utility Test, the Ratepayer Test, Societal Cost Test and the Total Resource Cost (TRC) Test. The *Participant Test* considers the economic impact of a program on the participating customers, the *Utility Test* considers the impact on the utility, the *Ratepayer Test* includes all quantifiable benefits and costs of a given program and considers its impact on all ratepayers, and the *Societal Cost Test* includes environmental externalities and considers the impact on the "society" (both the participants and non-participants). The *Total Resource Cost Test* reflects the total benefits and costs to all customers (both the participants and non-participants). In determining whether a program is cost effective, Montana-Dakota relied on the resulting benefit/cost ratio of the TRC Test as well as the practicality of implementation and the ongoing administration of that program.

Montana-Dakota's total DSM portfolio also includes expenditures for increasing education and outreach efforts that are designed to increase customer participation, educate customers and Heating, Ventilating, and Air Conditioning (HVAC) dealers about the benefits of conservation and provide energy conservation resources for customer and HVAC dealers to use.

Montana-Dakota's total DSM portfolio also includes expenditures for a conservation program marketing plan. The goal of this plan is to maximize customer awareness and participation in the most economical manner. The marketing plan strives to balance the cost of the advertising/promotional measure with the expected results. Montana-

Dakota's marketing plan for the energy conservation programs will focus on three areas: (1) advertising and promotion, (2) dealer and builder market transformation meetings, and (3) customer education and outreach. A detailed description of the marketing plan is included in Attachment B.

DSM Implementation Plan

Montana-Dakota intends to work towards implementation of all the identified feasible DSM programs over the program years of 2011-2013 with specific program implementation varying by state. The following is a summary discussion of the proposed DSM program plans in each state. Complete implementation plans including program details and the marketing plan are discussed in further detail in Attachment B.

North Dakota

Montana-Dakota will continue with existing programs offered in North Dakota under the American Recovery and Reinvestment Act (ARRA) grant for the remainder of 2011. Montana-Dakota will submit a new request for approval from the North Dakota Public Service Commission to implement a portfolio of programs. Assuming the appropriate cost recovery is obtained, the approved portfolio of programs will be implemented in 2012 and/or 2013. In addition, Montana-Dakota will implement the Commercial Demand Response program in 2012 and the Residential Air Conditioning Cycling program in 2013. The planned DSM activity in North Dakota for 2011-2013 is shown in Table 3-3.

Montana

Montana-Dakota will continue the existing programs offered in Montana for the remainder of 2011 and implement all new feasible programs authorized by the Montana Public Service Commission in 2012 and 2013. In addition, Montana-Dakota will evaluate the use of a third party to provide the program delivery function within its Montana service territory. This third party will work with Montana residential and commercial customers, area contractors, and other trade allies to promote and deliver the program in Montana. The planned DSM activity in Montana for 2011-2013 is shown in Table 3-3.

South Dakota

Montana-Dakota's South Dakota electric service territory represents approximately six percent of the Integrated System demand with a customer base of approximately 8,600 customers. Montana-Dakota intends to implement only programs that are offered in the other two states, which will allow for the allocation of administrative costs for South Dakota that will make those programs cost effective. Montana-Dakota will seek appropriate cost recovery from the South Dakota Public Utilities Commission and, assuming cost recovery is approved, will implement all feasible programs in 2012 and 2013. The planned DSM activity in South Dakota for 2011-2013 is shown in Table 3-3.

Summary of 2011-2013 Portfolio of Programs

Table 3-3

	Montana	**North Dakota**	**South Dakota**
Residential Programs			
Central Air Conditioner Tier 1 (14.5 SEER)	$100/ton		$100/ton
Central Air Conditioner Tier 2 (16 SEER) - Replacement	$200/ton		$200/ton
Central Air Conditioner Tier 2 - New	$200/ton		$200/ton
Window Air Conditioner Units	$50		$50
Air Conditioner Tune-up	$45		$45
Thermal Storage with Air-Source Heat Pump	$60/kW	$60/kW	
Residential Lighting	$2/bulb		
Residential Air Conditioner Cycling	$50/year	$50/year	$50/year
Commercial Programs			
Commercial Lighting	$0.40/watt	$0.40/watt	$0.40/watt
Commercial Motors - Replacement	$15/HP		$15/HP
Commercial Motors - New/On Failure of Exist. Equip.	$4/HP		$4/HP
Variable Speed Drives - VFD	$30/HP		$30/HP
Commercial Air Conditioner - Split Systems	$75/ton		$75/ton
Commercial Air Conditioner - Packaged Systems	$75/ton		$75/ton
Commercial Air Conditioner - Water Cooled Chillers	$25/ton		$25/ton
Commercial Air Conditioner - Centrifugal Chillers	$25/ton		$25/ton
Commercial Partnership Program (Custom)	Project-Specific		Project-Specific
Commercial Demand Response Program	Customer-Specific	Customer-Specific	Customer-Specific
Interruptible Rate Demand Response Program	$2.50/kW	$2.50/kW	

DSM Integration

As discussed in Chapter 2, the load forecasting section of this IRP, the DSM programs planned in the 2009 IRP are accounted for in the current load forecast in which the resulting reduction in energy and peak demand is reflected. Therefore, based on energy and demand savings goals, an incremental DSM level needs to be integrated with the supply-side resources in the integration analysis (Chapter 5). The incremental change that is modeled in the integration analysis is based on the implementation plan discussed above less the adjusted 2009 IRP forecasted amounts reflected in the load forecast.

The incremental DSM package modeled in the integration analysis reflects an average cost of $50/kW year for capacity reductions and $0.038/kWh for the conservation or energy reduction programs. The average cost for energy was based on the total costs and lifetime energy savings from the portfolio of DSM measures planned for implementation.

A total of 8.7 MW of new DSM was integrated in the integration analysis beginning in 2014 and beyond. The kWh values were adjusted based on amounts already included in the load forecast and are based on the annual energy savings goal of 0.25 percent of annual energy sales. The annual energy savings amounts and demand savings modeled in the integration analysis are shown in Attachment B Tables B-9 and B-10.

Future Action Plan

In addition to implementing the DSM programs identified in Table 3-3, Montana-Dakota will focus on two areas of additional study in the 2011-2013 period:

- Energy Efficiency Potential and Market Assessment Study for Montana customers, and
- Completion of an Irrigation Study.

These areas of study will focus on quantifying the magnitude of available energy efficiency and possible additional programs and initiatives. A complete description for each study is provided in Attachment B.

CHAPTER 4

SUPPLY-SIDE RESOURCE ANALYSIS

The objective of the supply side analysis is to identify the available and most cost-effective supply-side capacity resources available to be added to Montana-Dakota's generating portfolio. Capacity resources must be proven technology and be able to maintain the system reliability that Montana-Dakota's customers have come to expect. Selected supply-side resources, together with the feasible Demand-Side Management (DSM) programs are used as inputs to the integration analysis, the final process to determine the least-cost integrated resource plan.

The supply-side analysis considers supply-side alternatives currently available to Montana-Dakota as well as those resources to which Montana-Dakota has made a commitment to install or purchase. A detailed discussion of the supply-side model assumptions, characteristics of the existing generation, the committed resources, and the proposed resources is included in Attachment C.

Committed Supply-Side Options

Current Resources

Montana-Dakota's existing generation serving the Integrated System is comprised of baseload coal-fired generation at Heskett Station (Units I and II), the Lewis & Clark Station, Montana-Dakota's shares of the Coyote and Big Stone Stations, and natural gas-fired peaking generation at Glendive (Units I and II), Miles City, and Williston. Montana-Dakota also owns the Diamond Willow and Cedar Hills wind farms, a 2 MW portable diesel unit, and the Glen Ullin Station 6 waste heat generating unit serving the Integrated System. With a total capacity of 9.6 MW, the Williston combustion turbines, built in 1953, are the oldest in Montana-Dakota's fleet and are modeled to be retired from service in 2011. Total planning resource credits (PRC) available from the existing units is 440.4 PRC in 2011.

Future Capacity Resources

Montana-Dakota entered into an agreement with Xcel Energy Services' operating company Northern States Power (NSP) in December 2005 for the purchase of peaking capacity through 2010. The contract included an option to extend the agreement through the 2011 summer season under the same price and terms as the proceeding years.

Montana-Dakota exercised this option for 105 MW to cover the 2011 summer season (May through October).

As described in the Company's 2009 Integrated Resource Plan, Montana-Dakota has entered into an agreement with Wisconsin Electric Power Company (WE Energies) to purchase peaking capacity during the 2012-2015 timeframe. The contract term begins June 1, 2012 and expires on May 31, 2015. The capacity will be purchased on an annual basis as follows:

- June 2012 through May 2013 – 110 MW
- June 2013 through May 2014 – 115 MW
- June 2014 through May 2015 – 120 MW

On June 1, 2010, Montana-Dakota issued a request for proposal (2010 RFP), a copy of which is included in Attachment E, to solicit proposals for capacity and energy supply for the time period from 2015 and beyond. The results of the 2010 RFP process were used to formulate market resource alternatives modeled in the resource expansion analysis described below.

On September 30, 2010, Montana-Dakota entered into an agreement with Basin Electric Power Cooperative (Basin Electric) to purchase 35 Aggregate Planning Resource Credits (APRCs) for 2011. This contract will fulfill Montana-Dakota's need for capacity during the winter months, as the NSP contract is only available for the summer season.

Considered Supply-Side Resource Alternatives

Coal

Coal-fired baseload generation is characterized as having a high capital cost with low operating and fuel costs, while providing a stable capacity and energy source. With low operating and fuel costs, baseload units produce large amounts of energy at a relatively low cost. The high capital costs are spread over the life of the project. However, as significant new federal air quality, water discharge, and waste management regulations are proposed, new coal-fired baseload generation is unlikely to be considered in the foreseeable future.

Combustion Turbines

Simple-cycle combustion turbines are primarily used to supply low-cost capacity and a limited amount of energy, since they are fueled by either natural gas or fuel oil, which are more costly than coal. Combustion turbines have a relatively low capital cost, but the energy produced is more expensive than coal because of the cost of natural gas and fuel oil. Combustion turbines can be installed with a relatively short lead time (two to three years) and serve peaking capacity needs for the Company.

Combined Cycle

A conventional combined cycle unit burns natural gas or fuel oil in a simple-cycle combustion turbine (SCCT). The hot exhaust gases from the SCCT pass through a heat recovery boiler that produces steam for a steam turbine and generator. Because combined cycle units use natural gas or fuel oil as fuel, the units are higher-cost energy producers and their capital costs are between those of a SCCT and a coal-fired baseload generating unit. The advantage of a combined cycle unit is that it is more efficient to operate than a SCCT, but its hours of operation may be limited because of its high energy costs compared to other available resources.

Wind (Self-Built)

A wind energy resource is characterized as having high installation costs, but very low energy costs associated with its 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 planning resource credits (PRC) by the Midwest ISO. Therefore, the installation of additional wind generation on Montana-Dakota's system requires adding other capacity resources to meet the Midwest ISO planning reserve margin requirements.

This option represents Montana-Dakota's self-built wind generation. A $22/MWh (after tax) Production Tax Credit, which was modeled as a negative variable O&M cost, was assumed to be in effect for new wind generation installed prior to the end of 2012. 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 installation.

Purchased Capacity

Purchased capacity alternatives were assumed to be available for the 2011-2014 timeframe and were used to bridge the capacity deficits Montana-Dakota is forecasting in that timeframe. Purchased capacity was modeled on an annual basis and not limited to the summer season, as Montana-Dakota will need additional capacity for the winter months.

Wind (Purchased Energy)

To reliably and economically serve its customers, Montana-Dakota will not only need additional capacity, but also additional energy supply resources in the future with no new baseload resources built in the planning horizon. This wind energy option, based upon the results of Montana-Dakota's 2010 RFP, was modeled as a power purchase agreement. The wind energy option was modeled in blocks of 25 MW on an energy-only basis with no eligible PRC value.

Demand Response Program

As a result of Montana-Dakota's 2010 RFP, an option for a 25 MW demand response program was identified through a proposal from a third-party provider. This demand-side management (DSM) program consists of dispatchable capacity available from commercial and industrial customers who enter into an arrangement with the third-party provider and agree to curtail their load when requested in exchange for a payment based on load curtailed. The DSM program was modeled as a load reduction resource beginning in 2015.

Big Stone Air Quality Control System (AQCS)

An additional alternative was included in the analysis in order to model the cost effectiveness of the required AQCS project at the existing Big Stone plant of which Montana-Dakota is a 22.7 percent owner. To comply with the anticipated regional haze rules, the Big Stone plant will likely be required to install the Air Quality Control Systems (AQCS) using Best Available Retrofit Technology (BART), which was made available as a resource alternative in the model in 2015. The details of the Big Stone AQCS project are described in Attachment H. In this IRP, the AQCS project was studied to compare the required retrofit against other alternatives to determine if it would be more cost effective to retire the Big Stone plant or install the AQCS required to allow continued operation of the plant. The analysis assumed the retirement of the Big Stone plant (with 103.3 PRCs) 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 PRC value (101.4 PRCs), as the AQCS would slightly reduce the capacity output of the Big Stone plant.

New Purchased Capacity

The "new purchased capacity" options represent market-priced capacity that was available to Montana-Dakota as part of the 2010 RFP process. Two of these options were to purchase capacity from a 155 MW simple cycle combustion turbine at five- and ten-year terms. The third option was to purchase a total capacity of 345 MW, which would comprise 290 MW from a combined cycle combustion turbine unit and 55 MW from a simple cycle combustion turbine, at a twenty-year term.

Load and Capability

Existing and Committed Resources

The need for any type of new planning resource, whether it is a supply-side resource or the implementation of demand-side programs, is primarily driven by the forecast of the peak demand and energy needs of customers. In addition, the retirement of aging and high maintenance existing facilities will also trigger the need for new resources. Montana-Dakota is modeling the retirement of the 1953-vintage 9.6 MW Williston combustion turbines in 2011. The Williston combustion turbines have been accredited with PRCs in the Midwest ISO and also provide an emergency source of energy if required. At this time, the cost of maintaining this resource is beginning to exceed the benefit provided by the units.

As the result of its previous integrated resource planning efforts, Montana-Dakota extended the NSP contract for the 2011 summer season and will purchase capacity from WE Energies during the 2012-2014 timeframe to meet increasing customer demand. For an understanding of Montana-Dakota's capability to serve projected loads, a comparison of planning resource credits (PRCs) and planning reserve margin requirement (PRMR) is shown in Tables 4-1 through 4-3. PRCs are defined as the total resources within the

Midwest ISO available to meet Montana-Dakota's own PRMR. The Midwest ISO requires each generator to determine its summer capability through a Generator Verification Test Capability (GVTC) process that establishes the generator's Installed Capacity (ICAP) value. The ICAP value and each individual generator's equivalent forced outage rate ($XEFOR_d$) are then used to establish an unforced capacity (UCAP) value for the generator:

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

UCAP values are then directly converted to PRCs, which are used to meet Montana-Dakota's peak load obligation required by the Midwest ISO.

As a member of the Midwest ISO, Montana-Dakota is required to maintain a total number of PRCs equal to or greater than the Company's 50/50 forecasted system peak demand with a 1.16 percent adder for Midwest ISO losses, plus a 3.81 percent planning reserve margin (PRM).

Table 4-1 shows that, under the current system load forecast and with the current capacity purchase contracts, Montana-Dakota has adequate capacity to meet its PRMR through 2012. However, to meet customer demand, an additional 8.6 PRC will be needed in 2013. This capacity deficit will increase to 149.5 PRC in 2015 and grow to 234.7 PRC in 2024. With the high-growth scenario forecast, as shown in Table 4-2, a capacity deficit will occur in 2012 (11.5 PRC) and grow to 186.9 PRC in 2015. Under the low-growth scenario forecast, as shown in Table 4-3, a capacity deficit of 58.8 PRC will occur in 2015.

To address future capacity deficits, Montana-Dakota will need additional demand-side and/or supply-side resources. The analyses in this IRP will help provide direction for the best selection of new resources to economically and reliably meet customers' requirements.

Table 4-1

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

BASE FORECAST

Year	Generator Planning Resource Credits	WE Energies Peaking Purchase	NSP & Basin Electric Peaking Purchase	Total Planning Resource Credits	50/50 Summer Peak Demand w/MISO Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2011	440.4		140.0	580.4	505.8	525.0	55.4
2012	440.4	110.0		550.4	522.7	542.6	7.8
2013	440.4	115.0		555.4	543.3	564.0	-8.6
2014	440.4	120.0		560.4	552.3	573.3	-12.9
2015	440.4			440.4	568.3	589.9	-149.5
2016	440.4			440.4	577.2	599.2	-158.8
2017	440.4			440.4	586.0	608.3	-167.9
2018	440.4			440.4	594.9	617.5	-177.1
2019	440.4			440.4	604.0	627.0	-186.6
2020	440.4			440.4	613.0	636.3	-195.9
2021	440.4			440.4	622.1	645.8	-205.4
2022	440.4			440.4	631.4	655.4	-215.0
2023	440.4			440.4	640.8	665.2	-224.8
2024	440.4			440.4	650.4	675.1	-234.7

Table 4-2

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

HIGH-GROWTH FORECAST

Year	Generator Planning Resource Credits	WE Energies Peaking Purchase	NSP & Basin Electric Peaking Purchase	Total Planning Resource Credits	Summer Peak Demand w/Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2011	440.4		140.0	580.4	520.9	540.7	39.7
2012	440.4	110.0		550.4	541.3	561.9	-11.5
2013	440.4	115.0		555.4	557.9	579.1	-23.7
2014	440.4	120.0		560.4	580.9	602.9	-42.5
2015	440.4			440.4	604.3	627.3	-186.9
2016	440.4			440.4	629.8	653.8	-213.4
2017	440.4			440.4	656.4	681.4	-241.0
2018	440.4			440.4	684.1	710.1	-269.7
2019	440.4			440.4	713.1	740.2	-299.8
2020	440.4			440.4	743.5	771.8	-331.4
2021	440.4			440.4	775.2	804.6	-364.2
2022	440.4			440.4	808.3	839.0	-398.6
2023	440.4			440.4	842.8	874.8	-434.4
2024	440.4			440.4	878.7	912.1	-471.7

Table 4-3

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison

LOW-GROWTH FORECAST

Year	Generator Planning Resource Credits	WE Energies Peaking Purchase	NSP & Basin Electric Peaking Purchase	Total Planning Resource Credits	Summer Peak Demand w/Losses	Planning Reserve Margin Requirement	Surplus/ Deficit (+)/(-)
2011	440.4		140.0	580.4	482.6	501.0	79.4
2012	440.4	110.0		550.4	482.8	501.2	49.2
2013	440.4	115.0		555.4	479.1	497.3	58.1
2014	440.4	120.0		560.4	480.2	498.5	61.9
2015	440.4			440.4	480.9	499.2	-58.8
2016	440.4			440.4	482.4	500.8	-60.4
2017	440.4			440.4	484.1	502.4	-62.0
2018	440.4			440.4	485.7	504.1	-63.7
2019	440.4			440.4	487.3	505.8	-65.4
2020	440.4			440.4	489.1	507.7	-67.3
2021	440.4			440.4	490.9	509.6	-69.2
2022	440.4			440.4	492.8	511.5	-71.1
2023	440.4			440.4	494.6	513.4	-73.0
2024	440.4			440.4	496.4	515.3	-74.9

CHAPTER 5

INTEGRATION AND RISK ANALYSIS

The integration process considers all the demand-side programs discussed in Chapter 3 as well as the supply-side options discussed in Chapter 4 and integrates both resource types into a single least-cost plan. The Electric Generation Expansion Analysis System version 9.02 (EGEAS), a computer program developed by the Electric Power Research Institute (EPRI), is used to perform the resource expansion analysis and develop the least-cost integrated resource plan. From this analysis, Montana-Dakota will determine the least-cost integrated resource plan to guide its future resource selections.

Integration of Demand-Side and Supply-Side Resources

As indicated in Chapter 2, the DSM programs planned in the 2009 IRP have been or are expected to be implemented, and the reduction in energy and peak demand is reflected in Montana-Dakota's load forecast, which is modeled in EGEAS. Therefore, those programs have been integrated with the supply-side options in all performed resource expansion analysis.

Included in the load forecast in Chapter 2 were additional and existing interruptible loads associated with the existing programs along with future conservation and demand response programs that had been planned in the 2009 IRP. However, as a result of the demand-side analysis described in Chapter 3, additional new DSM programs were found feasible on a state-by-state basis, and the resulting DSM plan differs from that included in the load forecast. This difference required the demand and energy modeled in EGEAS to be adjusted upward for 2011-2013. The incremental impacts of these new DSM programs are bundled in a "New DSM Package," which was included as a new supply-side option in a separate resource expansion analysis.

Sensitivity Analysis

A sensitivity analysis was performed to see how the resource expansion plans would be affected by variations of certain key parameters that may change in the future from modeled assumptions.

Carbon Tax

With the potential of a future carbon penalty applied to all fossil fuel units and Midwest ISO energy purchases, a carbon tax was modeled to assess the impact on the resource expansion plan. The assumed carbon tax was applied to all carbon emissions from Montana-Dakota's existing coal-fired units and natural gas-fired SCCTs, energy purchases from the Midwest ISO market, and new generating units added to the resource plan starting in 2015. While no carbon tax was modeled in the base 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. 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.

Natural Gas Price Sensitivity

Prices for natural gas supplies as delivered to Montana-Dakota's existing turbines, future combustion turbines, and future combined cycle plants were developed in-house for use in the resource expansion analysis based on Montana-Dakota's view of the long-term outlook of natural gas pricing. For the base case, natural gas was priced for delivery at $5.05/MBTU, as of August 31, 2011, for the base year 2010 and escalated by an average of 3.5 percent. 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 least-cost plan. Therefore, high and low gas price scenarios were also developed, whereby the gas price used in the base case was increased by $3/MBTU and decreased by $1/MBTU from the base case, respectively.

High Environmental Cost

Along with the potential of a future carbon tax, there is the potential for additional future environmental costs such as those of mercury and solid waste regulations for Montana-

Dakota's coal-fired units. This sensitivity scenario simulated a $30/ton carbon tax for all coal-fired and natural gas-fired generating units along with energy purchased from the Midwest ISO market, $1.25/MWh adder for mercury control on coal-fired units, and $3.00/MWh for solid waste regulation for coal-fired units, along with $3/MBTU increase in the natural gas price. While these environmental costs were not included in the base case model, the sensitivity analysis was conducted to provide information on possible impacts to customers and identify potential changes in the Company's future generation resource mix as part of the least-cost plan in the event regulations are adopted resulting in these additional costs.

High- and Low-Growth Scenario Forecasts

The base forecast in Chapter 2 projected that summer peak demand would increase at an average rate of 2.7 percent per year for the next five years and at an average rate of 1.8 percent per year through 2030. Energy requirements would increase at an average rate of 3.2 percent per year for the next five years, and at an average rate of 2.1 percent per year through 2030. The forecast also established high-growth and low-growth scenarios in which energy requirements were assumed to grow at 4.4 percent and 0.5 percent per year respectively over the twenty year period. EGEAS runs were made using both the high- and low-growth load forecasts to determine the least-cost resource plan under those scenarios.

High Combustion Turbine Costs

Historically the costs of materials associated with the construction of generation have generally increased at a rate higher than general inflation both in the United States and the rest of the world. The base case costs for all generation options reflect the present price forecasts, but for purposes of risk analysis, Montana-Dakota considered the impact of higher installed and O&M costs of new generation (i.e., combustion turbines) on the resource plan. Therefore, to determine the sensitivity of the base case to increases in combustion turbine costs, a sensitivity scenario was developed that increased the installed cost and O&M costs of combustion turbines by 20 percent over the base case.

High Big Stone AQCS Cost

As described in Attachment H, a cost based on preliminary studies for the Big Stone AQSC project has been determined and used in the base case analysis. A sensitivity scenario was also developed to address potential fluctuations in project costs. In this sensitivity scenario, the project cost was incrementally increased and, for each project cost point, the resource expansion analysis was performed to determine if other alternatives were selected over the Big Stone AQCS project. With the modeled cost of the Big Stone AQCS project nearly doubled from the original estimated cost, the project was still selected as part of Montana-Dakota's least-cost resource plan and the analysis was stopped.

CHAPTER 6

RESULTS

This section presents the results of the 2011 Integrated Resource Plan, taking into consideration the results of the resource expansion analysis as well as other factors Montana-Dakota deemed critical in evaluating future resources. The additional factors not modeled in EGEAS but considered when determining the final resource plan are as follows.

Economic, Societal, and Customers Issues

Montana-Dakota is committed to providing its customers with competitively priced, highly reliable electricity. The integrated resource planning process must not rely solely on the results of a computer model analysis, but must also consider risks and other factors that are essential to provide the overall best choices for meeting the requirements of customers. The factors considered in the analysis are:

- Fuel price stability,
- Benefits resulting from participation in the Midwest ISO market,
- The possibility of unexpected new large load developing in Montana-Dakota's service territory,
- The integration of renewable generation resources and the economical and social benefits that they provide, and
- Public interest programs.

Midwest Independent Transmission System Operator (Midwest ISO) Market

With the beginning of the Midwest ISO energy market in 2005 and the Ancillary Service Market (ASM) and Capacity markets in 2009, the ability of Montana-Dakota to use its existing resources within these markets has further expanded. Therefore, when considering which resources to consider as benefiting retail customers, the presence of the markets available in the Midwest ISO is a factor.

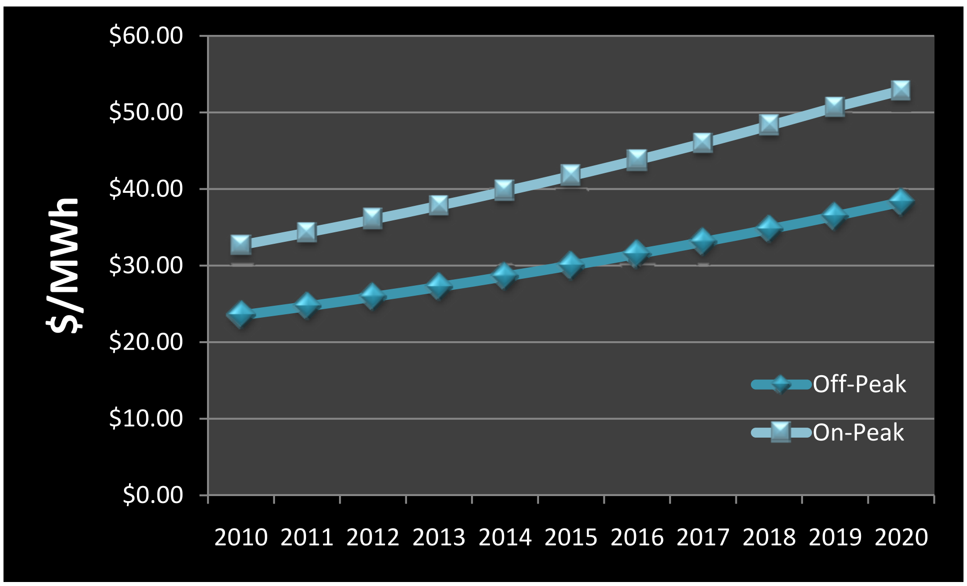
Montana-Dakota continues to perform integrated resource planning based on the obligation to serve its customers with a stable and reliable power supply. The Midwest

ISO energy market provides opportunities and benefits to Montana-Dakota, but Montana-Dakota cannot rely totally on the market for its power supply requirements.

The Midwest ISO market provides a source for energy when prices are lower than Montana-Dakota's generating costs, or when, due to planned maintenance or forced outages, Montana-Dakota needs to purchase energy to maintain reliability. The market also provides a means whereby Montana-Dakota can sell energy into the market from its generating facilities that is not needed by Montana-Dakota customers, with the margins benefiting the customers. Figure 6-1 shows the forecasted Midwest ISO market energy prices used within the model.

Figure 6-1

Forecasted On-Peak and Off-Peak Midwest ISO Market Prices as of August 2010



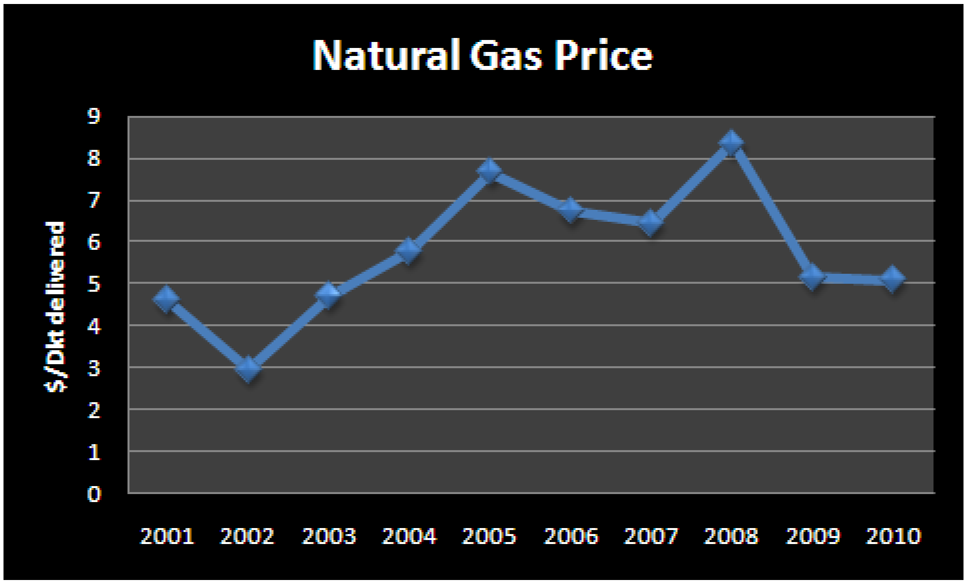
The MISO voluntary capacity market is currently performed on a monthly basis. The Midwest ISO is evaluating future annual auctions. Montana-Dakota will continue to examine the capacity market as a potential source for meeting future monthly or yearly capacity requirements. Montana-Dakota will look to fill short-term capacity needs through 2014 from either bilateral agreements or the Midwest ISO capacity auctions.

Reliance on Natural Gas

About twenty percent of Montana-Dakota's owned generating capacity is natural gas-fired. As shown on Figure 6-2, natural gas prices have been historically volatile. Unlike coal, long-term supply contracts for natural gas are generally not available at competitive prices.

Figure 6-2

Historical Natural Gas Prices Based on 12-Month Average



With some uncertainty as to what future natural gas prices will be, Montana-Dakota must consider whether or not it is prudent to significantly increase the percentage of its generating capacity that is dependent upon natural gas as indicated through the development of the least-cost plan generated by the EGEAS resource expansion analysis, or to wait upon a clearer national energy policy or development of new technologies what will allow for the development of baseload coal-fired generation.

<u>Resource Expansion Analysis Results</u>

The most probable load forecast, fuel prices, and resource installed costs were modeled in the EGEAS base case. The base case least-cost plan consists of the following resource additions for the 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014;
- Install three combustion turbines (two 43 MW units and one 88 MW unit) in 2015;
- Contract for the 25 MW commercial demand response program to be fully implemented by 2015; and

- Install the Big Stone AQCS project in 2015.

For later years, additional combustion turbines were selected in 2022, 2025, and 2028 to meet PRMR, and a wind energy (100 MW) option was selected in 2020 to meet forecasted growth in energy requirements. The net present value of the base case least-cost plan over the 50-year study period equates to $3,724 million in 2010 dollars, as shown in Attachment C Table 3-1.

As identified by the demand-side analysis discussed in Chapter 3, additional new DSM programs were found feasible on a state-by-state basis, and the resulting DSM plan differs from that included in the load forecast. This difference required the demand and energy modeled in EGEAS to be adjusted upward for 2011-2013. The incremental impacts of these new DSM programs are bundled in a "New DSM Package," which was included as a new supply-side option in a separate resource expansion analysis.

When the "New DSM Package" was added as an additional resource option in the base case, it was selected to be implemented in 2014 when full customer participation was expected. The DSM package lowers the NPV over the 50 year study period by about 2.9 percent from the base case. The corresponding least-cost plan consists of the following resource additions for the 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014;
- Install two 88 MW combustion turbines in 2015;
- Contract for the 25 MW commercial demand response program to be fully implemented by 2015; and
- Install the Big Stone AQCS project in 2015.

For the later years, three additional 43 MW combustion turbines were selected in 2021, 2024, and 2027. Also, 100 MW of energy-only wind generation was selected in 2020 to meet future energy requirements.

Sensitivity scenarios indicate that the base case resource plan is very robust under all assumptions. However, load growth makes a significant impact on the resource selection. As expected, the low-growth scenario indicates the need for less peaking capacity and energy, while the high-growth scenario shows much more peaking capacity and energy is needed than is shown in the base case. The high and low gas price scenarios also support the base case selections for capacity, except that the high gas price case also selected a coal-fired baseload resource in 2025.

The cost of materials and labor as well as potential environmental costs put upward pressure on the cost estimates for both baseload coal-fired units and combustion turbines. The scenario in which the installed cost of combustion turbines increased by 20 percent also selected the similar capacity additions as in the base case except for a coal-fired baseload resource in 2028 instead of additional combustion turbines.

The carbon tax sensitivity scenarios show the economic impact of a tax on carbon on Montana-Dakota's generating system and customers. The total production costs increase significantly, and the resource plan includes the addition of more self-built wind projects to reduce the output of fossil fuel units. However, the capacity resource additions are still needed in the future. Similarly, the higher environmental scenario shows that, if additional environmental regulation compliance is required, total production costs increase significantly and new coal-fired baseload resources and additional self-built wind generation are added.

Integrated Resource Model Results

Based on the current results of the supply-side and integration analysis (Attachment C), the resource plan resulting from the base case with the "New DSM Package" added as a resource option is the modeled least-cost result. As noted above, in this plan, the following resources are selected as the least-cost options in meeting the forecasted capacity and energy requirements until 2020 when 100 MW of energy-only wind generation was selected to meet future energy requirements:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014;
- Install two 88 MW combustion turbines in 2015;
- Contract for the 25 MW commercial demand response program to be fully implemented by 2015;
- Install the Big Stone AQCS project in 2015; and
- Implement or continue the DSM programs described in Table 3-3 in the Demand-Side Analysis (Chapter 3) by 2014 that will provide additional capacity reductions of 24.5 MW. These capacity reductions comprise those

reflected in the load forecast and those associated with the modeled "New DSM Package."

Figure 6-3 and 6-4 show a comparison of the resource mix that Montana-Dakota has available to serve its customers' needs in 2011, as compared to the least-cost resource plan in 2015. A Planning Resource Credit (PRC) represents one megawatt of accredited generating capacity under the Midwest ISO resource adequacy rules.

Figure 6-3

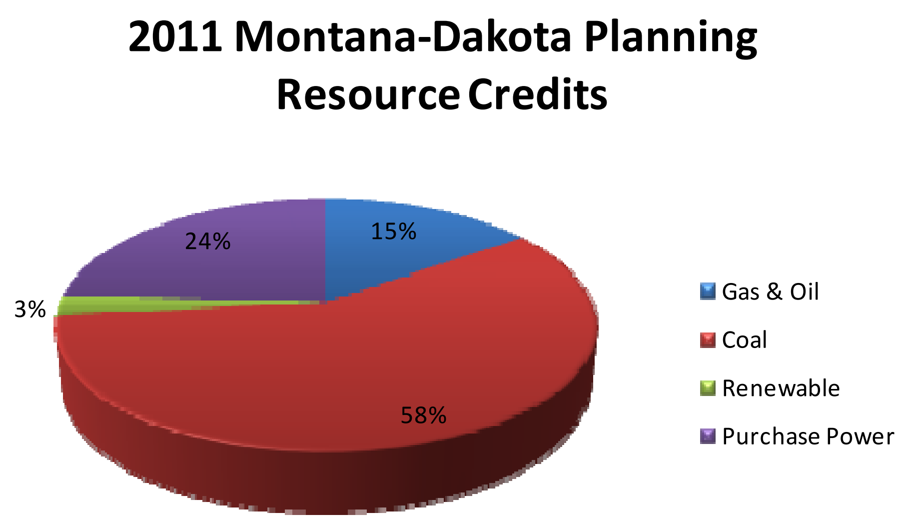
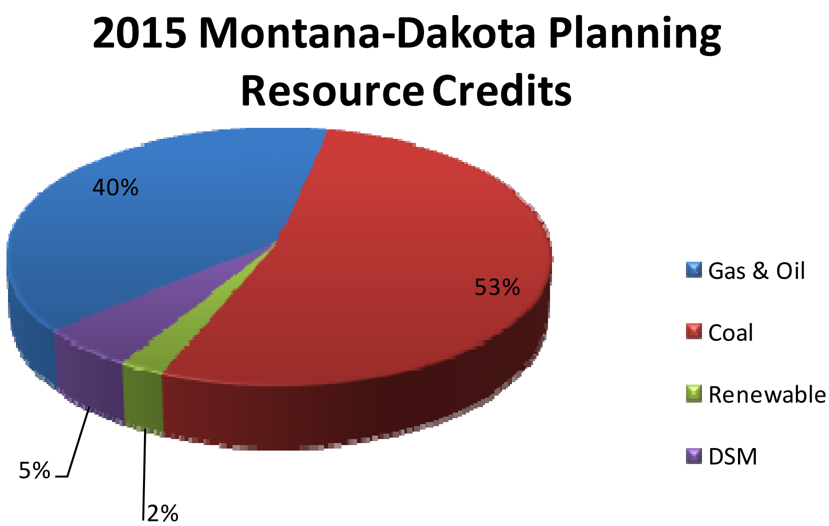


Figure 6-4



As shown in Figures 6-3 and 6-4, in 2011 approximately 15 percent of Montana-Dakota's resource capacity comes from natural gas- and oil-fired combustion turbines while in 2015, based on the least-cost resource plan, approximately 40 percent of the Company's resource capacity would be made up by natural gas and oil-fired combustion turbines. The resource additions were selected mainly to replace the current purchased capacity agreements. In contrast, in the 2015 least-cost resource plan approximately 80 percent of Montana-Dakota's energy requirements would be served from the 53 percent coal-fired capacity and two percent renewable capacity sources. This creates a concern over the imbalance of Montana-Dakota's future generation mix as modeled in the least-cost resource plan, which leaves Montana-Dakota customers vulnerable to future gas and market pricing for 20 percent of their energy needs. The 2009 Integrated Resource Plan identified the Big Stone Unit II project as a least-cost resource, which would have supplied both capacity and energy to meet future customer needs. A clearer national energy policy or development of new technologies may allow the construction of baseload generation for Montana-Dakota in the future.

<u>Future Resource Plan</u>

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 2011-2015 period:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014 through the MISO capacity auction or bilateral agreements;
- Contract for the 25 MW demand response program offered by a third party that is expected to provide 5 MW of dispatchable commercial or industrial demand response the summer of 2012, a total of 15 MW the summer of 2013, and the full 25 MW the summer of 2014;
- Implement the DSM programs identified in Chapter 3 Table 3-3 that are expected to provide an additional peak demand reduction of 24.5 MW and annual energy savings of 7.3 MWh by 2015;
- Install the AQCS equipment required to continue operating the Big Stone Plant beyond 2015; and
- Construct one 88 MW simple-cycle combustion turbine (SCCT) to be operational by 2015.

While this course of action is not strictly taken from the least-cost resource plan, the recommended resource plan is deemed to be the best plan to economically and reliably meet customers' requirements over the five-year planning horizon, as explained below. Montana-Dakota also plans to issue a new request for proposal for capacity and energy resources in 2012 to start the process for the next planning cycle. Each of the resource additions are described in detail in Chapters 3 and 4 and Attachments B, C, and H.

Montana-Dakota has not added a large capacity resource to its generation portfolio since the Glendive Unit II combustion turbine was built in 2002. A power purchase agreement with Basin Electric Power Cooperative for 66 MW of baseload capacity from the Antelope Valley Station Unit II expired in November 2006, which left Montana-Dakota dependent on peaking capacity purchase agreements and market energy prices. Montana-Dakota was unable to acquire additional coal-fired baseload resources when the Big Stone II project was abandoned. Continued reliance on market purchases subjects customers to unknown future prices of capacity and energy. At the expiration of purchased power agreements, there are no remaining assets for continued customer benefit and customers are subjected to the cost impacts of replacement agreements with future market resources.

Montana-Dakota's recommended resource plan satisfies future customer requirements through a balance of a new peaking capacity resource addition, pollution control investments in the Big Stone low-cost energy resource, and expanded demand response and energy efficiency programs. The recommended resource plan does not completely satisfy all customer requirements by 2015. Montana-Dakota is planning to issue a request for proposal of capacity and energy resources in 2012 to acquire additional resources to meet its customers' capacity and energy requirements in 2015 and beyond. In addition, Montana-Dakota will satisfy short-term capacity needs through the Midwest ISO capacity auction or bilateral agreements. Montana-Dakota is also monitoring the development of the mandatory Midwest ISO capacity auction as a potential source of securing future capacity resources.

CHAPTER 7

TWO-YEAR ACTION PLAN

This section of the report provides the two-year action plan resulting from this IRP analysis. The plan describes the specific activities that Montana-Dakota intends to implement for its long-range integrated resource plan.

Load Forecasting

- Montana-Dakota will continue to review its load forecasting assumptions and inputs as part of its routine process.
- Montana-Dakota will continue to evaluate ways to improve its seasonal peak demand forecast in order to better respond to the Midwest ISO market requirements.
- Montana-Dakota will continue to evaluate the accuracy of its forecasts to determine the areas that need improvements.

Demand-Side Resources

- Montana-Dakota expects to implement or continue to implement the DSM programs identified in Table 3-3 (Chapter 3) with specific program implementation varying by state.
- Montana-Dakota expects to implement the 25 MW demand response program through an external contract beginning in 2012 so that it will reach full customer participation by the summer of 2014.
- Montana-Dakota will conduct an Energy Efficiency Potential and Market Assessment Study for Montana customers.

Supply-Side Activities

- Montana-Dakota will continue to work in coordination with the other Big Stone co-owners in designing the AQCS required to continue operating the Big Stone generator beyond 2016. The Company will also submit an Application for an

Advance Determination of Prudence (ADP) for the Big Stone AQCS project. If the AQCS design in South Dakota's State Implementation Plan is ultimately approved by the EPA and regulatory approvals to proceed are obtained, the Big Stone AQCS will be installed to meet the compliance deadline.

- Montana-Dakota will file an ADP in North Dakota for an 88 MW combustion turbine. If regulatory approvals to proceed are obtained, the combustion turbine will be constructed with a spring 2015 in-service date.
- Montana-Dakota will continue to monitor the availability and price of energy and short-term capacity in the Midwest ISO market or through bi-lateral arrangements and will purchase additional capacity as needed to meet customer demand.
- Montana-Dakota will issue a request for proposal in 2012 to investigate and procure the best resource options available in the 2015-2020 timeframe.

<u>Other Activities</u>

Montana-Dakota will maintain the IRP Public Advisory Group to provide input to and review the Company's future IRPs.

CHAPTER 8

PUBLIC ADVISORY GROUP

This chapter describes the role and the workings of Montana-Dakota's IRP Public Advisory Group (PAG), a broad base advisory board for review and evaluation of the Company's IRP process. The first PAG was established for the 1995 IRP, and the PAGs have assisted with all IRPs since then. The 2011 IRP advisory group was established at the beginning of the 2011 planning cycle and held its first meeting in August 2010.

Objective

The objective of the PAG is to provide Montana-Dakota with input to its integrated resource planning process from a non-utility perspective. This advisory group reviews, evaluates, and recommends modifications to Montana-Dakota's planning process, resource plans, resource acquisition processes, and efficiency programs from the perspective of customers, government agencies, and public interest organizations.

Montana-Dakota considers the PAG's role to be one of providing advice and counsel on the planning process. The Company took input from the PAG under advisement in making planning decisions.

Participants

Participants in the PAG are non-utility personnel from the three states served by Montana-Dakota's integrated system: Montana, North Dakota, and South Dakota. The advisory group is structured to approximately reflect the proportions of Montana-Dakota's load in each state: Montana – 30 percent, North Dakota – 60 percent and South Dakota – 10 percent. The PAG members are also selected to balance representation from consumer advocacy groups, government agencies (including regulatory bodies), business concerns, and academia.

As a result, the PAG consists of three members from Montana, five members from North Dakota, and one member from South Dakota. In addition, the North Dakota Public Service Commission appointed a representative to participate as an observer. The names and affiliations of the 2011 PAG participants are shown in Table 8-1.

Table 8-1

The 2011 IRP Public Advisory Group

Montana

Barbara Roberts
Action for Eastern Montana
Glendive, Montana

Dr. LeRoy M. Moline
Glendive, Montana

Jeff Blend
Department of Environmental Quality
Helena, Montana

North Dakota

Mike Fladeland
Zac Weis
North Dakota Department of Commerce
Bismarck, North Dakota

Dr. Patrick O' Neill
Department of Economics
University of North Dakota
Grand Forks, North Dakota

John Klein
Ulteig Engineers, Inc.
Bismarck, North Dakota

Bruce Conway
Ebel Integrators
Williston, North Dakota

Rich Wardner
North Dakota State Senate
Dickinson, North Dakota

Michael Diller
North Dakota Public Service Commission
Bismarck, North Dakota
(Invited as an observer)

South Dakota

Christine Martin-Goldsmith
Goldsmith Heck Engineers, Inc.
Mobridge, South Dakota

Meetings

Input from the PAG to the IRP process occurred through the PAG meetings and communications between the PAG members and Montana-Dakota personnel. The Company funded travel and out-of-pocket expenses for the PAG members to attend the meetings. Their time was absorbed by themselves or by their employers.

At each meeting, the Company presented methods, analysis, and findings to the group. The meetings provided an opportunity for the participants to contribute their comments and concerns about work in progress. In this way, the group could raise issues and discuss them, and the Company could consider incorporation of the group's input into the IRP. The meeting dates and the items discussed at each meeting are contained in Attachment D.

The 2011 IRP public advisory process was designed to make efficient use of the PAG members’ time and expertise and provide the members with updated information on the rapidly changing electric utility industry. The Company’s presentations at the meetings were more result and policy-oriented, rather than focusing on the technical data. Efforts were made to provide the members discussion of recent changes within the Company and in the electric utility industry, which is moving rapidly toward a market environment. The group’s discussions, therefore, tended to concentrate on issues, policies, and overall results. The public advisory process enhances Montana-Dakota’s IRP analysis and reports through the information and suggestions provided by the group.

There were four 2011 IRP PAG meetings held in Bismarck, North Dakota. In addition to presenting the topics for discussion and taking feedback from the PAG members, Montana-Dakota served as a facilitator in setting agendas, taking care of meeting logistics such as meeting notices and expense reimbursements, and documenting the presentations at the meetings.

Since the PAG functions in an advisory role, no formal voting procedures were instituted. Montana-Dakota usually strove, however, for a consensus opinion of the PAG on the issues brought before it. The Company was willing to discuss any IRP-related topics that were of interest to PAG members. It also invited participants to provide written comments to document their opinions or concerns.

Conclusions

Montana-Dakota is pleased with its public advisory process. The public involvement resulted in better study assumptions and provided useful information to both the Company and the PAG participants and their constituents.