DIVIDER

STATE OF NORTH DAKOTA

□INFORMATION TECHNOLOGY DEPARTMENT

SFN 2053 (4-2002)

PU-07-394
Montana-Dakota Utilities Co., a Division of MDU Re
Integrated Resource Plan
Biennial Filing 07
Filed 7/2/2007 **Closed** 7/5/2007

Fahn, Patrick J.

From: Diller, Michael R.
Sent: Friday, July 13, 2007 11:06 AM
To: -Grp-PSC Commissioners; -Grp-PSC Public Utilities
Subject: MDU IRP (Case No. PU-07-394)

I noticed in the recently filed IRP that MDU is adding 20 MW's of wind in Montana to meet legislated mandates. We heard from MDU at the BS2 hearing that wind is never the least cost resource. I called Rita Mulkern to discuss the allocation of mandated wind in Montana to North Dakota. She stated that it will be part of their integrated system and therefore North Dakota will be allocated its share of the wind farm (about 60%).

Naturally, I have concerns about MDU procuring higher cost electricity than necessary to satisfy a Montana mandate and then billing North Dakota for most of it. I thought about requiring MDU to report its annual results without MT wind but that gets a little tricky. It would be easy enough to exclude related capital costs and O&M but then the energy side of things would have to be worked through. Simply excluding capital costs and O&M would not take into consideration the relatively low cost of energy produced by wind or the relatively high cost of energy required to back up wind when it doesn't blow.

Rita argues that any wind energy will replace the more costly MISO purchases currently being made and therefore the MT wind project will have little effect on overall rates. I think she might be right--but the economics will surely change when BS2 comes on-line. Best Guess: There is likely a slight advantage to North Dakota in requiring MT to pay for their own mandates in the initial years and likely a greater advantage when BS2 comes on-line and the dependence on MISO purchases diminishes.

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This does not have to be addressed today (wind farm won't be on-line until the end of 2007) but wanted to give you a heads up and share my thoughts. Annette is our MDU IRP advisory group representative but sometimes I get curious. Mike

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

400 North Fourth Street
Bismarck, ND 58501
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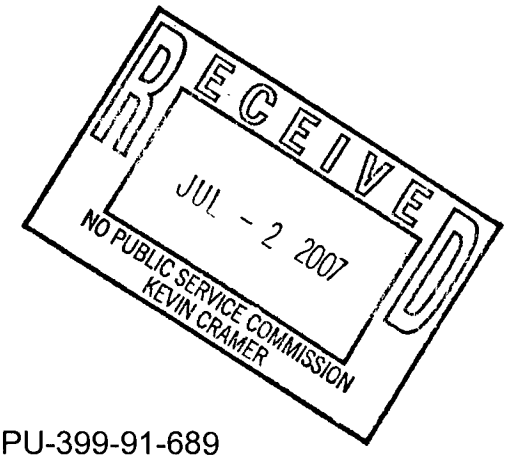
ORIGINAL

July 2, 2007



Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Case No. PU-399-91-689
Integrated Resource Plan
Biennial Filing

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc., herewith submits ten (10) copies of its biennial report for its Electric Integrated Resource Plan in accordance with the Amended Order issued March 11, 1992 in Case No. PU-399-91-689.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Vice President - Regulatory Affairs

Enclosure

The final forecast results are presented on the following several pages. A table summarizing the Integrated System energy requirements and seasonal peak demand is given first, followed by a graph with historical and forecasted seasonal peak demand and energy requirements. A table summarizing historical and forecasted sales by sales sector is given next followed by a graph of that table's data. The next two pages of this section give historical and forecasted sales by end-use within the LC&I sales sector followed by a graph of the LC&I end-uses. The last page of this section is a table detailing the historical and forecasted residential sales, customers, and use per customer.

Refer to Appendices C-1 through C-5 for graphs of the historical and forecasted sales by sector.

greater than what is delivered to the meters and is called the 'Total Energy Requirements.' The difference between the sales and energy requirements is due to losses.

The total system losses can be calculated based on the percentage of the annual energy losses, which is defined as

$$\frac{TotalSystemLosses(MWh)}{TotalSystemLoad(MWh)} \quad x \quad 100$$

in which the total system load consists of the end-use load at the customer level and the total system losses.

Historically, the percentages of the annual energy losses varied from year to year, as shown in the table below. The average value for the past ten years is 7.85%. Using this value for all future years, the total system hourly loads are calculated for each year during the study period.

Percentages of Annual Energy Losses

Year	Percent
2005	6.9
2004	9.6
2003	6.1
2002	5.3
2001	8.3
2000	8.2
1999	8.3
1998	8.6
1997	8.6
1996	8.6
Average:	7.85%

3.3. Final Energy Requirements Forecast

After reducing the forecasted sales and system peak demand to reflect the effects of the DSM programs that are being implemented as explained in Section 3.1 and then adjusting the total sales forecast for the losses outlined in Section 3.2, the final energy requirements and demand forecast is known. This is the amount of energy that needs to be generated at our power plants or purchased to meet Montana-Dakota's customers' energy needs.

3. Forecast Results – Sales and Demand

The forecast methodology for both sales and demand as described in Sections 1 and 2 above result in the initial sales forecasts by sales class and the initial demand forecast. However, there are reductions to the sales forecasts by class and the demand forecast that need to be made to reflect Demand-Side Management programs that are being implemented. Once these reductions are reflected in the sales forecasts, the total of the sales forecasts by class are adjusted by the loss factor to arrive at the final forecast energy requirements.

3.1. Demand-Side Management (DSM) Reductions

As the result of the 2005 Integrated Resource Plans (IRP) filed with the North Dakota and Montana Public Service Commissions on September 15, 2005, the following two DSM program were implemented beginning in 2006 and the reduction in energy and peak demand is reflected in the forecast:

- The Residential High Efficiency Air-Conditioning program is to be phased in over a three-year period of time beginning in 2006. The total annual energy to be saved per participant has been identified to be approximately 617 kWh with a total of 1,102 participants expected to be added in equal numbers over the three-year phase-in period. The reduction in demand and energy saved as a result of the Residential High Efficiency Air-Conditioning program was allocated to the summer air conditioning months of April through October.

- The High-Efficiency Commercial Lighting Retrofit program will be phased in equally over a five-year time period beginning in 2006. The total energy to be saved per participant has been identified to be approximately 2,145 kWh per year with 1,659 participants to be added in total over the five-year phase-in period. It was assumed that for commercial applications where hours of operation usually don't vary from month to month, energy and demand reductions for retrofitted lighting fixtures will be equal each month of the year.

3.2. Losses

The sales forecasts reflect the energy delivered to Montana-Dakota's customers' meters. The total amount of electricity generated at the power plants to meet Montana-Dakota's customers' energy needs is

in the Montana Oil Fields as detailed in Section 1.3.3 as well as some other new known load that will be added in 2007 and 2008 for the Northern Plains Commerce Center – Bobcat Building, Bobcat expansion, BSC Career and Technical Education building, and two motors to be added by Northern Border Pipeline near Lignite, ND. The summer peak as forecasted through the regression was adjusted by these new expected loads as follows:

Year	Incremental Load Due to New Projects
2007	6.1 MW
2008	8.6 MW
2009	10.5 MW
2010	11.8 MW

To calculate the winter peak demand forecast, the ratio of the ten-year (1996-2005) actual average winter peak to summer peak demand (81.3%) was used.

temperature was used in the regression equation. Montana-Dakota has available the historical hourly temperatures for three major load centers: Bismarck, ND; Williston, ND; and Miles City, MT. Weighted average temperatures for Bismarck (70%), Miles City (15%) and Williston (15%) were used at the time of the system peak. This weighting method has been tested and used in the company's short-term demand forecast as well as in other informal in-house analyses.

Any known customer load interruptions due to Interruptible Rate 39 and/or forced distribution outages that occurred at the time of the summer peak were added to the summer peak used in the regression analysis so that the summer peak value represented the peak as it would have occurred had there not been any interruptions. Interruptions to the load at customers served on Interruptible Large Power Service Rate 39 typically occur at the time of the system peak. A forced distribution outage also occurred at the time of the system peak in the summer of 2002.

The multiple regression was run on summer peak demands with the adjustments noted above as the dependent variable. Several variables were tested for statistical significance as the independent variables. The independent variables tested for statistical significance were the following:

- Bismarck maximum temperature on the day prior to the system peak
- Bismarck temperature at the time of the peak
- Weighted average temperature at the time of the peak
- Integrated System counties population
- Personal Income per Capita
- Residential Electricity Price
- Integrated System counties employment
- Year (time)

The regression equation for summer peak demand is as follows:

SummerPeak = -10,851.9 + (3.40858 x WtdAvgTemp) + (5.47731 x Year)

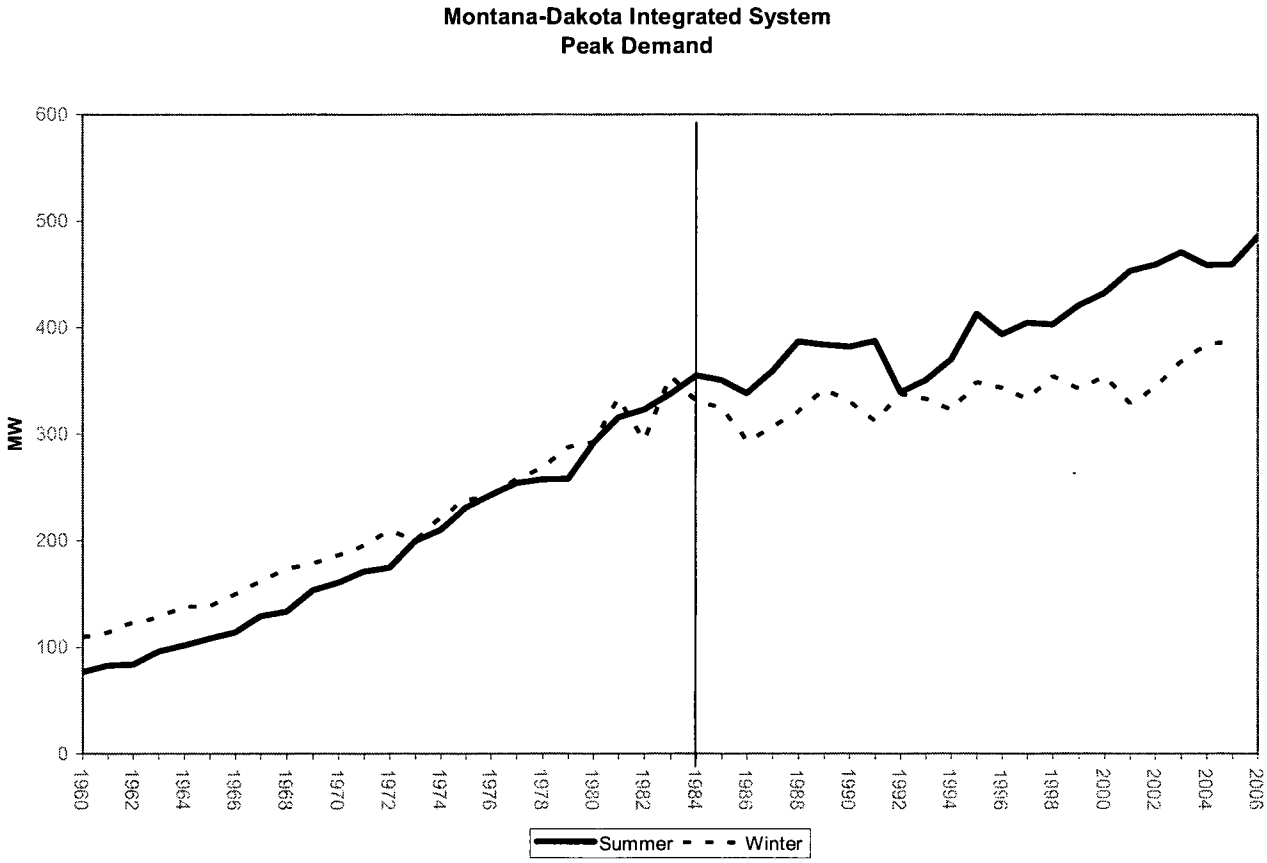
where WtdAvgTemp is the weighted average temperature at the time of the system peak for Bismarck, Williston, and Miles City.

For the forecast, the actual weighted average temperature at the time of the system peak for the most recent ten years (1997-2006) was used. This weighted average temperature value is 98.67°F.

The summer peak demand forecast that results from this regression equation reflects the load growth based on the historical trend that Montana-Dakota has experienced. However, there are several new loads that have been announced to be added in 2007-2010 due to the addition of several projects

2. Forecast Methodology – Peak Demand

Integrated System historical peak demand is shown on the chart below.



Montana-Dakota was a winter peaking utility prior to 1984. From 1973 to 1983, the spread between the winter and summer peaks began to narrow and in 1984 Montana-Dakota became a summer peaking utility. The difference between the summer and winter peaks has generally been widening since that time with Montana-Dakota's system becoming a summer peaking utility. From Montana-Dakota's residential appliance saturation surveys and from other information available, it is known that air conditioning is becoming more prevalent over time and air conditioning load is driving much of the increase in summer peak demand.

The Integrated System peak demand forecast is developed on a total system basis; it is not disaggregated by sector. The summer peak demand forecast was developed through the use of regression analysis. Weighted average

1.5. Miscellaneous

The miscellaneous sales sector is made up of sales for the following three end-uses:

1. Interdepartmental sales – gas utility use of electricity
2. Other public sales – sales to government authorities which includes municipal pumping and some city sales (these sales are served under special contracts that are applicable only to public authorities)
3. Company use - Montana-Dakota offices

The forecast for interdepartmental sales was based on a linear regression on actual 1989-2005 sales while the forecast for other public sales was based on a linear regression on actual 1994-2005 sales. The forecast for company use was held constant at the actual 2005 level.

CDD	= Cooling Degree Days
e	= Equation error term
t	= time (1983-2005)

and the a_i's are equation coefficients to be estimated. All variables are actual calendar year values.

Personal Income per Capita for the historical period is available from the W&P data. CDD are from the NOAA for Bismarck, ND.

The forecasted personal income per capita was from data projected by W&P. For the forecasted time period, normal CDD values for Bismarck, ND were used.

The Chained GDP Deflator, shown on Appendix B-7, was used to place personal income per capita into real dollar terms for both the historical and forecasted time periods.

After the General LC&I sales are projected using the equation developed above, adjustments are made to the projected sales to reflect additional load growth that is expected due to the addition of several new General LC&I customers that are in the process of being added or that will be added in 2006, 2007, and 2008. Information regarding the specific LC&I customers that are expected to come on line is provided by Montana-Dakota's field personnel who have contact with these customers. Sales are added to the General LC&I sales sector in 2007 and 2008 for the following new loads:

- Wal-Mart Supercenter – Bismarck
- Sam's Club – Bismarck
- Northern Plains Commerce Center – Bobcat Bldg - Bismarck
- Bobcat Expansion – Bismarck
- BSC Career & Technical Education Bldg – Bismarck
- Northern Border Pipeline Compressor Motors – Lignite, ND

1.4. Street Lighting

Electric sales for the street lighting sector (public street and highway lighting) were forecasted based on the results of a linear regression analysis of actual 1989-2005 sales.

The forecast for the Cedar Creek Anticline sales excluding Encore Acquisition is added to the forecast for Poplar to arrive at the Other Oil Fields forecast.

1.3.4. Sabin Metals

The Sabin Metals plant in Williston, ND has been recycling petroleum and petrochemical catalysts used in chemical and petroleum manufacturing in order to isolate and refine the small amounts of gold, silver, platinum, and other precious metals contained in them at the old Dakota Catalyst plant in Williston, ND since mid-2001. Montana-Dakota's field personnel, through contact with management at Sabin Metals, estimates the load at Sabin Metals will experience increases from the addition of a new 1500 kW arc furnace in 2010 that will begin with a 50% load factor and ramp up to a load factor of 95% by the year 2015. The sales forecast for Sabin Metals reflects an expected value of 70% based on the estimated probability that this new furnace will be added.

1.3.5. General LC&I

General LC&I sales (sales to all other LC&I customers that are not to the Tesoro Refinery, Westmoreland Coal, Montana Oil Fields, or Sabin Metals) could depend on variables such as the LC&I price of electricity, alternate fuel prices for LC&I customers (natural gas), personal income per capita, heating degree days, cooling degree days, and year. Higher electricity prices and lower income can result in less electricity use, while higher alternate fuel prices as well as colder than normal winters (more heating degree days) and hotter than normal summers (more cooling degree days) could result in more electricity consumption. Historical and forecasted values for these variables are available and were tested for statistical significance in developing the General LC&I econometric equation. It was found that the price of electricity, alternate fuel prices (natural gas) for LC&I customers, and HDD were not statistically significant and therefore these variables were not used in the equation.

The general form of the final General LC&I sales equation is:

$$GenLC\&ISales_t = a_0 + a_1 \times PI_t + a_2 \times Year_t + a_3 \times CDD_t + e_t$$

where:

GenLC&ISales	= General LC&I Sales
PI	= Personal Income per Capita
Year	= Year

The forecast methods are described below.

Encore Acquisition

Encore Acquisition operates oil wells in the Cedar Creek Anticline that are metered by Montana-Dakota at twelve sites. The starting point for the forecast for Encore Acquisition was based on a log-linear least squares curve fit through 1996 to 2005 actual sales for these "customers" excluding new extraordinary load added beginning in 2000. Total load associated with new growth experienced during the 2000-2005 time period due to the installation of new equipment and changes in operations was added to the forecast that resulted from the log-linear least squares analysis.

Additional load for projects that are fairly certain to occur at Pine 1, Pine 2, Lookout Butte, Coral Creek, and Little Beaver have been identified by Montana-Dakota's field personnel through contact with the customer. The new load anticipated totals approximately 4.5 MW that is in the process of being added and another 1.7 MW of load expected to be added in 2007. Other increases in conventional drilling and air injection/fire flood of approximately 2.5 MW have been identified as well for 2008 through 2010. Therefore, these additional loads were added to the sales forecast for Encore Acquisition. The Encore Acquisition forecast is projected to increase at a higher rate through 2010 and then return to a more normal rate of growth beginning in 2011.

Other Oil Fields

The majority of the sales at the Cedar Creek Anticline that are not to Encore Acquisition are to Burlington Resources. The forecast at the Cedar Creek Anticline that are not Encore Acquisition sales was based on a log-linear least squares curve fit through 1987-2005 sales excluding new load that was added by Burlington Resources in 1999, 2000, 2003, 2004 and 2005. Montana-Dakota's field personnel who work closely with the oil field customers expect that the sales will remain fairly stable in the future.

The forecast for the Poplar oil field which is a small part of the Other Oil Field class in Montana was developed from a log-linear least squares analysis through 1986-2005 actual sales. Poplar oil field sales are projected to decline.

Historical employment as well as employment as forecasted by W&P and the revised employment forecast are given on Appendix B-8.

1.3. Large Commercial & Industrial

1.3.1. Tesoro Refinery

The sales forecast for the Tesoro Refinery in Mandan, ND is based on a linear regression of 1981 to 2005 actual historical sales. Information available from Montana-Dakota's field personnel who have contact with the Tesoro Refinery supports this forecast.

1.3.2. Westmoreland Coal

Westmoreland Coal currently operates three mines that are served on Montana-Dakota's electric system – one at Beulah, ND, one at the Coyote Power Station at Beulah, ND, and one in Savage, MT. The sales forecast for Westmoreland Coal is being held flat at a level that is roughly the average for the past five years.

1.3.3. Montana Oil Fields

Oil field sales are made up of two Montana oil fields: the Cedar Creek Anticline near Baker and the Poplar oil field near Poplar, MT. Sales at the Cedar Creek Anticline are further broken down into sales to Encore Acquisition and all other sales at the Cedar Creek Anticline. Sales to Encore Acquisition account for about 74% of all Montana Oil Field sales in total. In the forecast, the sales to Encore Acquisition and sales for Other Oil Field (the Poplar Oil Field plus the Cedar Creek Anticline sales that are not Encore Acquisition sales) are listed separately.

Historical sales for each of the three oil field customers individually are shown on the graph on Appendix A-7. Sales to the oil fields in total have generally declined each year from 1986 to 1997. New equipment was added by Encore Acquisition and Burlington Resources causing sales to increase in 1999 through 2005. Sales are expected to increase rather significantly through 2010 due to new Encore Acquisition projects that are underway or that are expected to be in place over the next five years. Because of the uncertainty beyond that point, sales are projected to increase at the rate experienced historically excluding the extraordinary load growth that was added in that time period.

developing the SC&I econometric equation. The historical and forecasted values for these variables are given in Appendix B.

The general form of the final SC&I sales equation is:

$$SC\&ISales_t = a_0 + a_1 \times PG_t + a_2 \times Emp_t + a_3 \times Year + e_t$$

where:

SC&ISales	= SC&I Sales
PG	= SC&I Price of Natural Gas (competing fuel)
Emp	= Employment
Year	= Year
e	= Equation error term
t	= time (1979-2005)

and the a_i's are equation coefficients to be estimated. All variables are actual calendar year values. The price of electricity for the SC&I sector, personal income per capita, HDD, and CDD were also tested in the equation but these variables were not found to provide statistical significance to the equation.

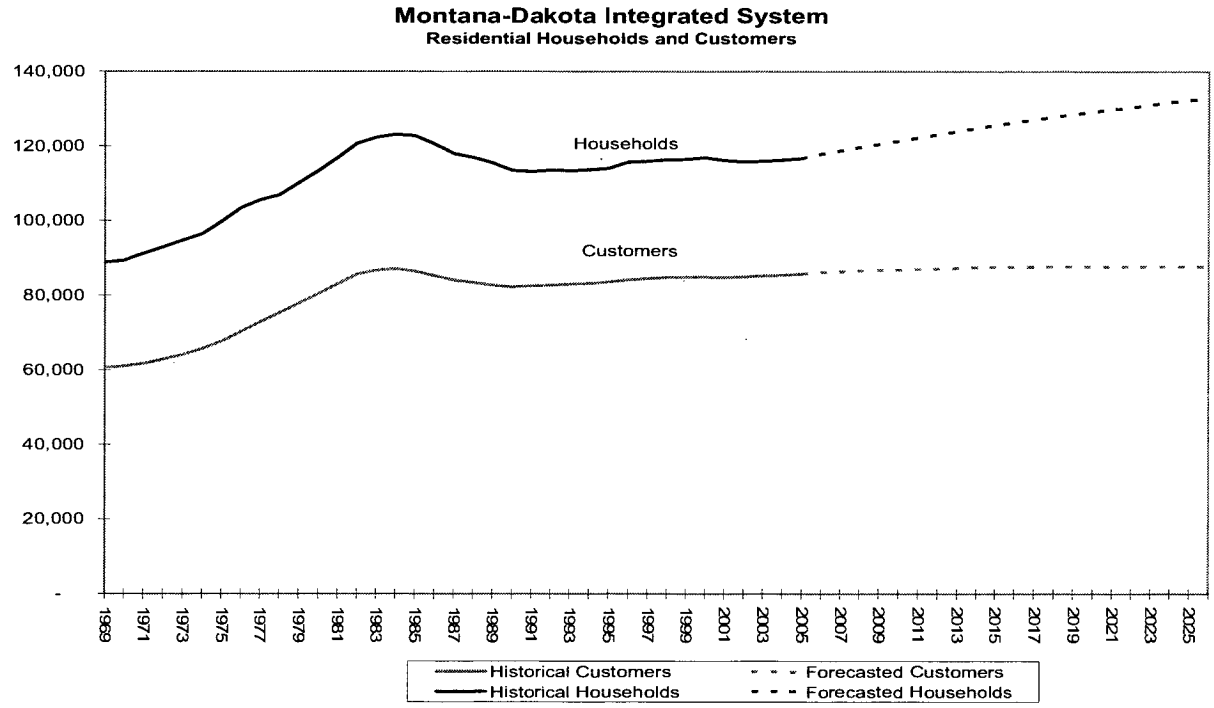
The historical SC&I price of natural gas for Montana-Dakota's Integrated System is available from company records. Historical employment is available from the W&P data from the U.S. Department of Commerce.

Forecasted SC&I natural gas prices were provided by Montana-Dakota's Regulatory Affairs and Financial Forecasting Departments. Employment was projected by W&P.

The Chained GDP Deflator, whose values are given on Appendix B-7, was used to place natural gas prices into real dollar terms for both the historical and forecasted time periods.

Employment numbers are available from W&P for the historical time period from the U.S. Department of Commerce, Bureau of Economic Analysis. Employment projections for the Integrated System service territory counties are made by W&P. While actual historical growth in employment for the counties in Montana-Dakota's service territory was 1.55% per year for the ten year time period of 1993-2003, W&P has projected that employment will grow at 1.27% per year for the next ten years and at 1.19% per year for the next twenty. Since employment growth for the last ten years was higher than what is now projected by W&P, it was decided that growth in employment for the sector would be allowed to increase at historical levels (1.55% per year) for the next ten years and at 1.2% per year thereafter.

number of residential customers was arrived at by adjusting the number of households by a customer-to-household ratio. This ratio was calculated to account for the difference between the number of households and the number of actual customers in Montana-Dakota's service territory. Residential customer numbers were held constant beginning in 2018 to reflect the assumption that the Territorial Integrity Act will remain in effect diminishing the company's opportunity to add new residential customers. Historical and forecasted customers and households are plotted on the chart below while the values are given in Appendix B-6.



1.2. Small Commercial & Industrial

Small commercial & industrial (SC&I) sales could potentially depend on variables such as the SC&I price of electricity, alternate fuel prices for SC&I customers (natural gas), personal income per capita, employment, heating degree days, cooling degree days, and year. Higher electricity prices and lower income can result in less electricity use, while higher alternate fuel prices and employment as well as colder than normal winters (more heating degree days) and hotter than normal summers (more cooling degree days) can result in more electricity consumption. Historical and forecasted values for these variables are available and were tested for statistical significance in

significance in developing the residential econometric equation. The historical and forecasted values for these variables are given in Appendix B. It was found that alternate fuel prices for residential customers and year were not statistically significant and therefore these variables were not used in the equation.

The general form of the final residential sales equation is:

$$ResSales_t = a_0 + a_1 \times PE_t + a_2 \times PI_t + a_3 \times HDD_t + a_4 \times CDD_t + e_t$$

where:

ResSales	= Residential Sales
PE	= Residential Price of Electricity
PI	= Personal Income per Capita
HDD	= Heating Degree Days
CDD	= Cooling Degree Days
e	= Equation error term
t	= time (1979-2005)

and the a_i's are equation coefficients to be estimated. All variables are actual calendar year values.

The historical residential price of electricity for Montana-Dakota's Integrated System is available from company records. Personal income per capita for the historical period is available from the W&P data. HDD and CDD are available for Bismarck, ND from the NOAA data.

Forecasted electricity prices were provided by Montana-Dakota's Regulatory Affairs and Financial Forecasting Departments. The personal income per capita was from data projected by W&P. For the forecasted time period, normal HDD and CDD values for Bismarck, ND were used.

The Personal Consumption Expenditure Deflator was used to place residential electricity prices, residential natural gas prices, and personal income per capita into real dollar terms for both the historical and forecasted time periods. See Appendix B-5 for the Personal Consumption Expenditure Deflator.

A residential customer forecast is also needed and helps Montana-Dakota to analyze the residential sales forecast and the resulting use per residential customer. Residential household numbers are available from W&P for the historical time period from the U.S. Department of Commerce, and household projections for the Integrated System service territory counties are made by W&P. The forecast of the

1. Forecast Methodology - Sales

The Integrated System 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 further broken down into four end-use categories which were then forecasted separately: Tesoro Refinery sales, Westmoreland Coal Mining sales, Montana Oil Field sales, and Sabin Metals sales. All other LC&I sales that did not fall into these four end-uses were categorized as *General LC&I* sales (sales to all other LC&I customers).

Econometric equations were developed to forecast sales for the three primary customer categories -- residential, SC&I, and General LC&I – while sales forecasts for the street lighting and miscellaneous sectors were developed primarily using linear regression. The sales forecasts for the four LC&I end-uses were developed using a combination of regressions and information available from Montana-Dakota's field personnel regarding these large customers.

The development of the sales forecasts for each of the five end-use sectors is explained below.

1.1. Residential

It is possible for residential sales to depend on variables such as the residential price of electricity, alternate fuel prices for residential customers (natural gas), personal income per capita, heating degree days, cooling degree days, and year. Higher electricity prices and lower income can result in less electricity use, while higher alternate fuel prices as well as colder than normal winters (more heating degree days) and hotter than normal summers (more cooling degree days) can result in more electricity consumption. Historical and forecasted values for these variables are available and were tested for statistical

Integrated System

Overview

Econometric equations were used to develop a long-range (20-year) electric load forecast for Montana-Dakota's Integrated System, which is comprised of Montana-Dakota's service territories in Montana, North Dakota, and South Dakota.

At the time this analysis was begun (July 2006), the most recent year for which a complete set of weather, prices, monthly sales by sector, and other historical information was available was for year-ending 2005. The equations developed used historical data available through 2005 and were designed to forecast the time period 2006-2026.

Montana-Dakota's Integrated System consists of the counties listed in the table below. These counties are located in eastern Montana, north-central South Dakota, and western and central North Dakota.

Counties by State in Montana-Dakota's Integrated System

Montana	South Dakota	North Dakota	
Custer	Campbell	Adams	Logan
Daniels	Corson	Bowman	McIntosh
Dawson	Edmunds	Burke	McKenzie
Fallon	Faulk	Burleigh	Mercer
Prairie	Harding	Dickey	Morton
Richland	McPherson	Divide	Mountrail
Roosevelt	Perkins	Dunn	Oliver
Rosebud	Potter	Emmons	Renville
Sheridan	Walworth	Golden Valley	Slope
Wibaux		Grant	Stark
		Hettinger	Williams
		Kidder	

Montana-Dakota also provides electric service to a small part of Brown county of South Dakota. However, Brown County is excluded from the database because it includes the town of Aberdeen which is not served by Montana-Dakota but which comprises the majority of the population for the county. Including Brown county would reflect too much of the economic activity that occurs in Aberdeen.

Historical company data used in the development of the forecasts are included in Appendix A. Appendices A-1 through A-4 list annual sales by customer class for Montana, North Dakota, South Dakota, and the Integrated System for the years 1966-2005, respectively. Appendix A-5 lists the seasonal peaks and load factors of the Integrated System for the years 1960-2005. Appendix A-6 lists demand by state at the time of the system peak for the summer and winter seasons.

Appendix B contains historical and forecasted values for the exogenous variables.

Employment
North Dakota Gross State Product (GSP)

The variables that were found to be statistically significant in each equation are noted in the narrative that follows for each sales sector forecast.

Data Sources

At the time this analysis was begun (July 2006), the most recent year for which a complete set of weather and actual monthly sales by sector was available was 2005.

The data used in the development of the forecast that are available in-house include Montana-Dakota's rate projections, residential energy use surveys, and historical sales, energy, demand, losses, natural gas and electricity prices, and number of customers. In addition to the data available in-house, most of the economic and demographic data are obtained from Woods & Poole Economics, Inc. (W&P) of Washington, D.C. by county. The W&P data are apportioned and adjusted to represent the data for the Montana-Dakota service territory. Other data sources include the National Oceanic and Atmospheric Administration (NOAA), U.S. Census Data, and others.

Degree days are used to estimate how hot or cold the climate is and how much energy may be needed to keep buildings cool or warm. Heating degree days, HDDs, are calculated by subtracting the mean daily temperature from 65°F, and summing only positive values over a given period of time, while cooling degree days, CDDs, are calculated by subtracting 65°F from the mean daily temperature, and summing only positive values over a given period of time. Bismarck and Mandan, ND account for approximately one-third of Montana-Dakota's electric sales annually. For this reason and because HDD and CDD numbers are annual values and the actual value is not as important as the magnitude of change, Bismarck HDD and CDD values were used to represent the weather in each year any time that degree day information was needed in the econometric equations developed. HDD and CDD are from NOAA for Bismarck, ND.

Personal income per capita for Montana-Dakota is calculated to be personal income divided by the total population for those counties in which Montana-Dakota provides electric utility service. Historical personal income is available from the W&P data which are from the U.S. Department of Commerce, Bureau of Economic Analysis. Historical population data is also from the U.S. Department of Commerce. Forecasted personal income and population data are projections provided by W&P.

Econometric Overview

From 1988 through 2005, Montana-Dakota used SHAPES II, an integrated end-use forecasting model from New Energy Associates, A Siemens Company of Atlanta, Georgia, as its forecasting tool. Prior to 1988, econometric and time-series methods of forecasting were used.

Beginning with this forecast, Montana-Dakota returns to the econometric model as its forecasting tool. An econometric model is a set of equations that expresses electricity use as a function of underlying factors such as 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.
- Econometrics provides statistical evaluation of forecast uncertainty.
- Econometric models utilize economic and demographic information that is easily understood.
- Econometric models can be readily re-estimated.

The econometric method combines economics theory and statistical techniques to produce a system of simultaneous equations. The method starts with estimating causal relationships between electric energy consumptions (the dependent variable) and factors influencing electricity use (the independent variables). The relationship is estimated by applying regression analysis or other more sophisticated methods to time-series data. Once the relationships are established, inserting forecasts of the independent variables into the equation yields projections of the dependent variable.

A number of demographic and econometric variables were tested for fit in the process of developing the Integrated System forecast. Various combinations of variables were tested for statistical significance when evaluating the data to be used in each final equation. The following is a list of variables that were available for both the historical time period being analyzed as well as for the forecasted time period:

Residential price of electricity
Small Commercial & Industrial price of electricity
Large Commercial & Industrial price of electricity
Residential price of alternate fuel (natural gas)
Commercial price of alternate fuel (natural gas)
Personal Income per Capita
Heating Degree Days (HDD) for Bismarck, ND
Cooling Degree Days (CDD) for Bismarck, ND
Population

Executive Summary

A new long-range (20-year) forecast of Montana-Dakota Utilities Co.'s (Montana-Dakota) electric energy requirements and peak demands for the Integrated System of Montana, North Dakota, and South Dakota has been prepared by the Electric System Operations & Planning Department. From 1988 through 2005, Montana-Dakota used SHAPES II, an end-use forecasting model, as its forecasting tool. Montana-Dakota has returned to an econometric methodology of forecasting with the forecast developed this year.

INTEGRATED SYSTEM

Total sales for the Integrated System are projected to grow at an average rate of 1.65% per year for the next five years and at an average rate of 1.23% per year for the next twenty years. Integrated System peak demand is projected to grow at an average rate of 1.3% per year for the next five years and an average rate of 1.1% per year for the next twenty years. The faster rate of growth in the first few years of the forecast can primarily be attributed to several projects and/or new customers that will be added in the Large Commercial & Industrial sales sector.

The effects of the demand-side management (DSM) programs that are being implemented in the Integrated System are reflected in the sales and peak demand forecasts. Montana-Dakota's 2005 Integrated Resource Plans in North Dakota and Montana recommended the implementation of a portfolio of DSM programs beginning in 2006, two of which will impact sales and demand. These impacts are reflected in the forecast.

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Attachment A

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC LOAD FORECAST
INTEGRATED SYSTEM (MT, ND, SD)
2007–2026

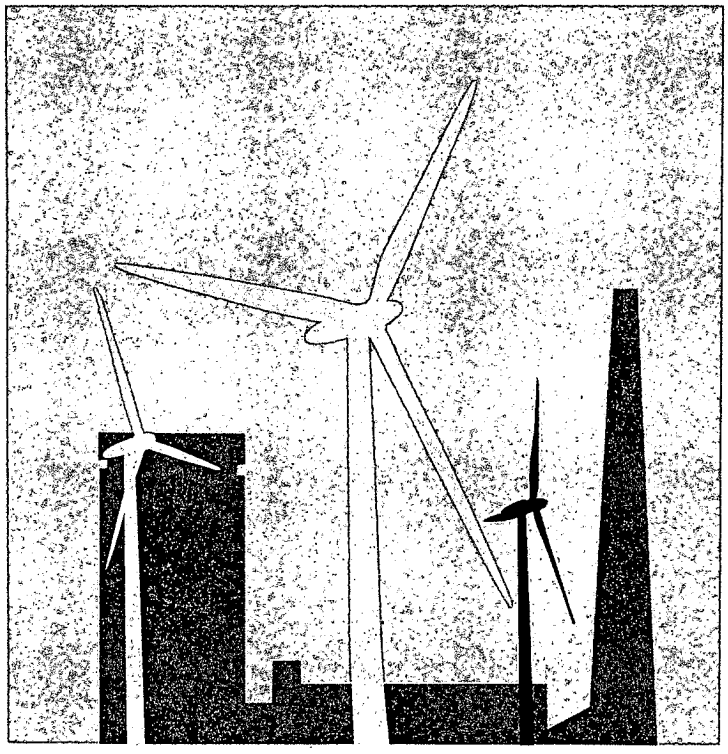
Prepared by
Montana-Dakota Utilities Co.
Electric System Operations & Planning Department

December 31, 2006

ATTACHMENT A

-

LOAD FORECAST DOCUMENTATION



Integrated Resource Plan 2007

Submitted to the
North Dakota Public Service Commission
July 1, 2007

Montana-Dakota Utilities Co.
2007 Integrated Resource Plan

Submitted to the North Dakota Public Service Commission
July 1, 2007

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

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EXECUTIVE SUMMARY

Montana-Dakota Utilities Co.'s (Montana-Dakota) 2007 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 20-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 clean electricity. Such resources may consist of a combination of traditional central station generation, distributed generation, renewable fueled resources, customer demand side management programs, and new and emerging technologies.

The IRP process at Montana-Dakota encompasses four main areas: load forecasting, demand-side analysis, supply-side analysis and integration and risk analysis (Figure E-1). A summary of the study results for each of these areas is provided.

The load forecasting activities 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 2007-2026 time period, the projected average annual growth rate for the summer peak demand is 1.1 percent, while the annual energy requirements are expected to increase at a rate of 1.23 percent annually. The base forecast, increased by the Mid-Continent Area Power Pool (MAPP) Generation and Reserve Sharing Pool's (GRSP) fifteen percent reserve capacity obligation, is greater then the existing generating capacity of Montana-Dakota. Montana-Dakota has purchased capacity for a five-year period to provide sufficient capacity to meet its customer's demands as well as the GRSP requirements until such time as permanent resources can be developed to cover the forecasted energy and capacity deficiencies.

The demand-side analysis is an evaluation process to determine the potentially feasible demand-side management (DSM) programs applicable to Montana-Dakota's system. The DSM evaluation is performed on a list of residential and commercial programs selected through a joint effort between Montana-Dakota and the IRP Public Advisory Group (PAG). Based on the

demand-side analysis discussed in Chapter 3, plus the continuation of the DSM programs implemented in 2006, a package of nine DSM programs was chosen to provide the best fit and the most cost-effective options for Montana-Dakota's customers as part of its total resource plan. Those nine programs are:

1. Promote ENERGY STAR® refrigerators
2. Promote ENERGY STAR® freezers
3. Implement and promote interruptible rates in Montana and South Dakota
4. Promote residential central air conditioning cycling
5. Promote light-emitting diode (LED) exit lights
6. Promote commercial air conditioner cycling
7. Implement a refrigerator roundup program
8. Promote commercial high efficiency air conditioning
9. Promote high efficiency motors

The nine programs will provide an estimated non-coincident demand reduction of 13.8 MW upon full implementation.

The supply-side analysis is an evaluation process to determine the potentially feasible generation options applicable to Montana-Dakota's system. The potential options studied included Lignite Vision 21 Gascoyne, Big Stone II and Elk Run base load plants, other generic base load generation, as well as peaking and renewable generation options.

The integration and risk process considers the feasible supply-side and demand-side options to determine a 'least cost' resource expansion plan. Supply-side and demand-side options were allowed to compete against each other without bias based on the individual characteristics of the various options. Several scenarios were investigated to determine the robustness of the 'least cost' plan. The analytical tool used for the integration process was Strategist®, a capacity expansion program developed by NewEnergy Associates. 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.

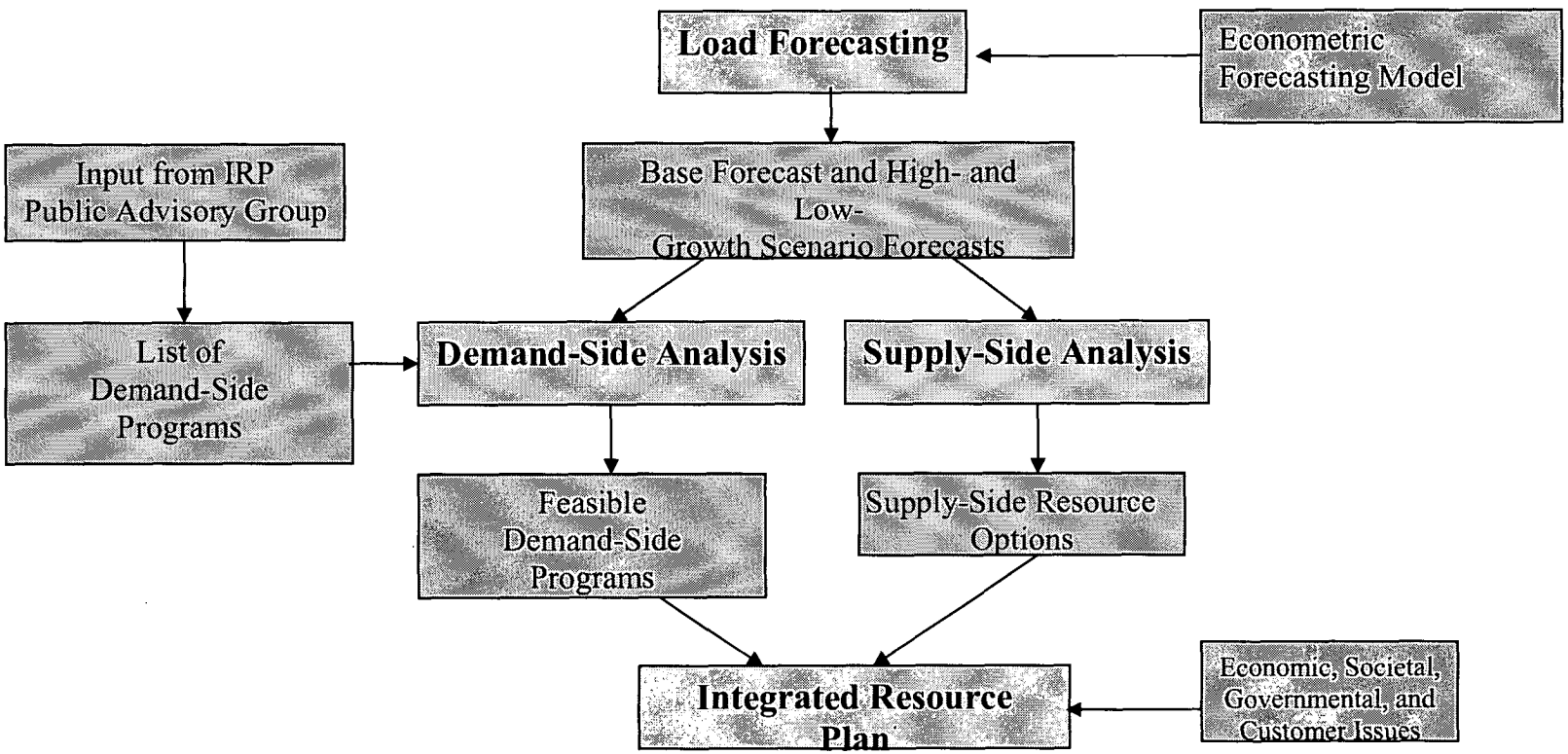
The results of the integrated resource planning process for 2007, considering the computer modeling, scenario analysis, and risk assessment, consist of the addition of Big Stone II in 2012 as well as the implementation of 13.8 MW of additional demand side resources between 2008 and 2011. The following table presents Montana-Dakota's total resource by type and percent as it will be in 2012 upon implementation of the resources identified in this IRP.

Natural Gas/Oil Glendive 1 and 2 Miles City Williston	110.8 MW	(17%)
Wind Diamond Willow	20.0 MW	(3%)
Demand-side Conservation Interruptible	19.3MW	(3%)
Coal Heskett 1 and 2 Lewis and Clark Big Stone 1 and 2 Coyote	488.3 MW	(77%)

The 2007 IRP process and product (report and appendices) were enhanced with 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 2007 advisory group was established at the beginning of the 2007 planning cycle and provided Montana-Dakota with input throughout the 2007 IRP process.

FIGURE E-1

MONTANA-DAKOTA UTILITIES CO.



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 meet or surpass all applicable environmental laws, regulations and permit requirements".*

Montana-Dakota is committed to comply with the corporate environmental statement. Montana-Dakota strives to maintain compliance and operate in an environmental proactive manner, while taking into consideration the cost to customers. Montana-Dakota has been involved with renewable energy analysis for many years. Montana-Dakota's commitment to environmental stewardship is evidenced as follows:

Wind Resources

In July 1993, Montana-Dakota was instrumental in developing a seven utility agreement to coordinate the installation of seven wind-monitoring towers in North Dakota. At the end of three years, the data collected from the seven sites were delivered free of charge to the state of North Dakota to be used by any interested party.

Montana-Dakota initiated a program, approved by the North Dakota Public Service Commission, in April 2001 to provide green power to its customers located in North Dakota to add wind generation to its system in the amount contracted by those customers who signed up for the program. There were not enough customers willing to sign up to cost effectively build or purchase an increment of wind generation; therefore the program was abandoned.

In 2002, Montana-Dakota executed a power purchase agreement to purchase approximately 20 MW of wind generation from a wind farm proposed to be built near Ellendale, North Dakota. This agreement was the first agreement to be signed for a wind farm built in North Dakota. However, the developer never built the wind farm and the

contract was terminated. In 2005, Montana-Dakota entered into another power purchase agreement to purchase up to 31.5 MW of wind energy from a wind farm located near Java, South Dakota. However, that contract went into default in November 2006.

In 2006 the Montana legislature passed a law requiring the purchase of renewable energy up to fifteen percent of a utility's retail energy in Montana by 2015. The legislation requires five percent by 2008, another five percent by 2010, and the remaining five percent by 2015. Montana-Dakota is in the process of constructing a 20 MW wind farm near Baker, Montana (known as the Diamond Willow Wind Farm) to meet the first two phases of the Montana requirement, and will be installing an additional 10 MW in 2014 to meet the third phase.

Air Quality

All power generation owned or operated by Montana-Dakota complies with federal and state air quality requirements. In some cases it has been possible to exceed those requirements. For instance, Montana-Dakota has reduced emissions at the Heskett Station by installing a fluidized bed boiler on Unit 2 in 1987 which significantly reduced sulfur dioxide emissions.

The design of the proposed Big Stone II unit includes state of the art emission equipment as well as having a super-critical boiler and a joint scrubber with Big Stone I. Overall, when built, the Big Stone complex (Units I and II) will have fewer emissions then the existing Big Stone I plant.

Waste

The stoker boiler at Heskett Unit 1 has allowed the burning of waste tires, railroad ties, and tar sands from manufactured gas plant clean-up. Distressed corn, tires, and refuse derived fuels have also been burned at the jointly owned Big Stone Plant, of which Montana Dakota is a co-owner.

SF6 Reduction

Sulfur hexafluoride gas (SF6) has been used for many years in the industry as a means of arc suppression in high voltage circuit breakers. However, SF6 has been identified as a greenhouse gas. Montana-Dakota has replaced a number of high-volume and leaking SF6

breakers with significantly smaller volume breakers to reduce the potential of SF6 gas being released into the atmosphere due to a leak in the breakers.

Canadian Clean Power Coalition

Montana-Dakota continues to be heavily involved in researching technologies that will continue to allow coal to play a part in our energy mix. Montana-Dakota is a participating member within the Canadian Clean Power Coalition (CCPC) which was formed as an association of generating companies in Canada along with the Electric Power Research institute (EPRI) with a mandate to research, develop, and demonstrate commercially viable clean coal technology. Through the Lignite Research Coalition, Montana-Dakota became a member of the CCPC and has access to all research information generated. The clean coal technology indicated within this organization is a technology that essentially eliminates all air emissions, including carbon dioxide from a coal fired generating facility.

The first phase of the research into identifying commercially available technologies was completed in 2004. Additional studies of these technologies were completed in the spring of 2007. The goal of the organization is to have a demonstration facility operational in the 2012 to 2015 timeframe that will address removal of all greenhouse gas emissions.

DSM activities

Montana-Dakota has been involved in activities to reduce customer's bills and save capacity through demand-side measures since the late 1970s. Montana-Dakota has offered time-of-day rates, dual fuel space heating rates, a large commercial interruptible rate, and a radio controlled load management system since the mid-1980s in various parts of its system. Montana-Dakota's commitment to DSM continues with its membership in ENERGY STAR® and its implementation in 2006 of high-efficiency lighting and air conditioning programs.

As part of the IRP process Montana-Dakota continues to analyze and make decisions taking into consideration environmental stewardship and customer cost impacts.

CHAPTER 2

LOAD FORECASTING

From 1988 through 2005, Montana-Dakota used SHAPES II, an integrated end-use forecasting model from New Energy Associates, a Siemens company of Atlanta, Georgia, as its forecasting tool. Prior to 1988, econometric and time-series methods of forecasting were used. Beginning with this forecast, Montana-Dakota returns to the econometric model as its forecasting tool.

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.
- Econometrics provides 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.

Energy Sales Forecast

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 five categories which were then forecasted separately. Four large customers were forecasted independently 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. In all resulting regression analysis, the level of confidence is at or above 95 percent. The energy sales forecasts for the four LC&I end-users 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 are included in the detailed description of the load forecast in Attachment A.

Peak Demand Forecast

The peak demand forecast is developed on a total system basis; it is not disaggregated by sector. Montana-Dakota's peak demand occurs in the summer. From Montana-Dakota's residential appliance saturation surveys and from other information available, it is known that the air conditioning is becoming more prevalent over time and air conditioning load is driving much of the increase in summer peak demand.

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

Any known interruptions (Interruptible Rate 39 and/or outages) that occurred at the time of the summer peak were added to the historical actual summer peak used in the regression analysis so that the summer peak value represented 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 are included in the detailed description of the load forecast in Attachment A.

Forecast Adjustments

The forecast methodology for both energy sales and peak demand result in an initial energy sales forecast by sector and an initial peak demand forecast. However, there are reductions to the energy sales forecasts by sector and the peak demand forecast that need to be made to reflect demand-side management programs that are in the process of being implemented. 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

As the result of the 2005 Integrated Resource Plan filed with the North Dakota and Montana Public Service Commissions, the following two DSM programs were implemented beginning in 2006 and the reduction in energy and peak demand is reflected in the final forecast:

- The Residential High Efficiency air conditioning program is to be phased in over a three-year period of time beginning in 2006. The total annual energy to be saved per participant has been identified to be approximately 617 kWh with a total of 1,102 participants expected to be added in equal numbers over the three-year phase-in period. The reduction in demand and energy saved as a result of the Residential High Efficiency air Conditioning program was allocated to the summer air conditioning months of April through October.

- The High-Efficiency Commercial Lighting Retrofit program will be phased in equally over a five-year time period beginning in 2006. The total energy to be saved per participant has been identified to be approximately 2,145 kWh per year with 1,659 participants to be added in total over the five-year phase-in period. It was assumed that for commercial applications where hours of operation usually don't vary from month to month, energy and demand reductions for retrofitted lighting fixtures will be equal each month of the year.

In addition to the two DSM programs implemented in 2006, Montana-Dakota also has an interruptible rate available in North Dakota. Since the interruptible rate reduces only peak demand and not significant energy, the peak demand forecast is reduced by the coincident demand of the interruptible customers after the forecast is completed as

described above. The present coincident demand of the interruptible customers is 5.5 MW.

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 is due to losses that occur on the transmission and distribution system.

Historically, the percentages of the annual energy losses vary from year to year. The average value for the past ten years is 7.85 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

After reducing the forecasted energy sales and system peak demand to reflect the effects of the DSM programs that are being implemented and then adjusting the energy sales and peak demand forecast for losses, the total energy requirements and demand forecast is known. This is the amount of energy that needs to be generated or purchased to meet Montana-Dakota's customers' energy needs.

The final forecast results are presented on the following 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
WITH DSM REDUCTIONS

	TOTAL ENERGY REQUIREMENTS		SUMMER PEAK - MW				WINTER PEAK */	
YEAR	MWh	%GROWTH	INTERRUPTIBLE LOADS NOT INTERRUPTED	INTRPT LOADS	INTERRUPTIBLE LOADS INTERRUPTED	% CHG	MW	%GROWTH
1996	2,014,830				393.3		343.1	
1997	2,005,195	-0.48%			404.6	2.87%	332.8	-3.00%
1998	2,007,534	0.12%			402.5	-0.52%	354.2	6.43%
1999	1,996,647	-0.54%			420.6	4.50%	342.4	-3.33%
2000	2,077,579	4.05%			432.3	2.78%	353.9	3.36%
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	2,509,450	4.66%	480.8	5.5	475.3	-2.10%	390.8	-1.61%
2008	2,562,077	2.10%	487.4	5.5	481.9	1.39%	396.2	1.38%
2009	2,602,851	1.59%	493.4	5.5	487.9	1.25%	400.9	1.19%
2010	2,652,679	1.91%	499.2	5.5	493.7	1.19%	405.3	1.10%
2011	2,688,443	1.35%	504.7	5.5	499.2	1.11%	409.8	1.11%
2012	2,721,863	1.24%	510.2	5.5	504.7	1.10%	414.2	1.07%
2013	2,755,403	1.23%	515.6	5.5	510.1	1.07%	418.7	1.09%
2014	2,789,264	1.23%	521.1	5.5	515.6	1.08%	423.2	1.07%
2015	2,822,464	1.19%	526.6	5.5	521.1	1.07%	427.6	1.04%
2016	2,852,931	1.08%	532.1	5.5	526.6	1.06%	432.1	1.05%
2017	2,883,458	1.07%	537.6	5.5	532.1	1.04%	436.6	1.04%
2018	2,914,059	1.06%	543.0	5.5	537.5	1.01%	441.0	1.01%
2019	2,944,723	1.05%	548.5	5.5	543.0	1.02%	445.4	1.00%
2020	2,975,546	1.05%	553.9	5.5	548.4	0.99%	450.0	1.03%
2021	3,006,438	1.04%	559.5	5.5	554.0	1.02%	454.3	0.96%
2022	3,037,435	1.03%	564.9	5.5	559.4	0.97%	458.9	1.01%
2023	3,068,564	1.02%	570.4	5.5	564.9	0.98%	463.2	0.94%
2024	3,099,744	1.02%	575.9	5.5	570.4	0.97%	467.7	0.97%
2025	3,131,087	1.01%	581.4	5.5	575.9	0.96%	472.2	0.96%
2026	3,162,646	1.01%	586.9	5.5	581.4	0.96%	476.7	0.95%

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

Forecast Uncertainty

The projected demand and energy produced by the econometric process results in a forecast based solely on the information used as inputs to the equations. Forecasting is a process permeated with uncertainty. 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. That uncertainty is dealt with by developing demand forecasts reflecting temperatures that correspond to higher confidence levels as well as developing high-growth and low-growth scenarios for energy forecasts.

Effect of Temperature on Peak Demand

The final forecast results were developed assuming ten-year average temperatures at the time of the system peak. However, there are some shortcomings associated with this methodology. First, with an average temperature forecast, by definition actual peak demand would have approximately a 50 percent probability of being lower than the forecast values and a 50 percent probability of exceeding forecast values (50/50 forecast). Second, there is an appearance that demand is under-forecasted when the actual temperature at the time of system peak exceeds the ten-year average temperature.

In 2004, a study titled "MDU Summer Peak Demand versus Ambient Temperature" was performed by Montana-Dakota's System Operations & Planning staff to establish the relationship between summer peak demand and temperature at the time of system peak. As part of the study, a trend analysis was performed of Montana-Dakota's historical July and August demands and corresponding temperatures at times when the temperatures on Mondays through Thursdays equaled or exceeded 85°F. The study indicated that each one degree increase in temperature at the time of peak would result in an increase of approximately five megawatts in peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2006 (prior to 1984 Montana-Dakota was a winter peaking utility) provided the results shown in the following 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%	98.7	0.0
75.0%	99.6	4.5
80.0%	100.3	8.0
85.0%	101.1	12.0
90.0%	102.1	17.0
95.0%	103.6	24.5

As Table 2-2 shows, with a weighted average temperature of 98.7°F at the time of peak, there is a 50 percent probability that the temperature at peak would be lower than 98.7°F and a 50 percent probability that the temperature at peak would be higher than 98.7°F. This forecast is the 50/50 demand forecast.

Also from Table 2-2, there is a 90 percent probability that actual temperatures at the time of the system peak will not exceed 102.1°F. However, at this temperature (102.1°F), the system peak demand would be17.0 MW higher then the demand at the base, or 50/50 forecast. This forecast is called the 90/10 forecast and provides a peak demand forecast that represents a probability of 90 percent that the actual peak demand would not exceed the forecast value and a 10 percent probability that the actual peak demand would 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 (98.7 degrees F) 50/50 Forecast (MW)	Growth Rate (%)	Alternate Forecast (102.1 degrees F) 90/10 Forecast (MW)
2007	475.3		492.3
2008	481.9	1.39%	499.1
2009	487.9	1.25%	505.4
2010	493.7	1.19%	511.4
2011	499.2	1.11%	517.1
2012	504.7	1.10%	522.8
2013	510.1	1.07%	528.3
2014	515.6	1.08%	534.0
2015	521.1	1.07%	539.7
2016	526.6	1.06%	545.4
2017	532.1	1.04%	551.1
2018	537.5	1.01%	556.7
2019	543.0	1.02%	562.4
2020	548.4	0.99%	568.0
2021	554.0	1.02%	573.8
2022	559.4	0.97%	579.4
2023	564.9	0.98%	585.1
2024	570.4	0.97%	590.8
2025	575.9	0.96%	596.5
2026	581.4	0.96%	602.2

Growth rates are assumed to be the same for both scenarios

High-Growth and Low-Growth Scenario Forecasts

Another approach used to deal with forecast uncertainty in this study was to simulate high-growth and low-growth scenarios which represent the extreme 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 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-growth 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

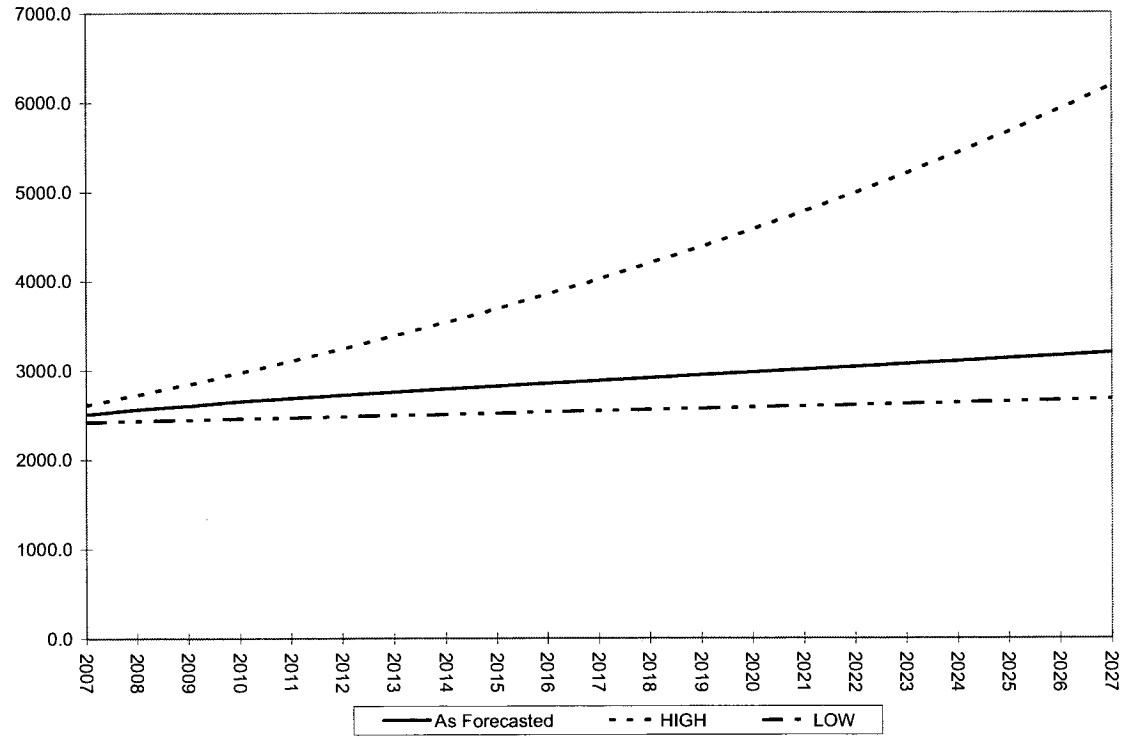
HIGH-GROWTH AND LOW-GROWTH SCENARIOS
TOTAL ANNUAL ENERGY (GWh) AND
SUMMER PEAK DEMAND (MW)

	ENERGY			DEMAND		
	Forecast	HIGH 1/	LOW 2/	Forecast	HIGH	LOW
2007	2509.5	2613.4	2421.8	475.3	495.0	458.7
2008	2562.1	2728.4	2433.9	481.9	513.2	457.8
2009	2602.9	2848.5	2446.1	487.9	533.9	458.5
2010	2652.7	2973.8	2458.3	493.7	553.5	457.5
2011	2688.4	3104.7	2470.6	499.2	576.5	458.8
2012	2721.9	3241.3	2483.0	504.7	601.0	460.4
2013	2755.4	3383.9	2495.4	510.1	626.5	462.0
2014	2789.3	3532.8	2507.9	515.6	653.0	463.6
2015	2822.5	3688.2	2520.4	521.1	680.9	465.3
2016	2852.9	3850.5	2533.0	526.6	710.7	467.6
2017	2883.5	4019.9	2545.7	532.1	741.8	469.8
2018	2914.1	4196.8	2558.4	537.5	774.1	471.9
2019	2944.7	4381.5	2571.2	543.0	807.9	474.1
2020	2975.5	4574.3	2584.1	548.4	843.1	476.3
2021	3006.4	4775.5	2597.0	554.0	880.0	478.6
2022	3037.4	4985.6	2610.0	559.4	918.2	480.7
2023	3068.6	5205.0	2623.0	564.9	958.2	482.9
2024	3099.7	5434.0	2636.1	570.4	1000.0	485.1
2025	3131.1	5673.1	2649.3	575.9	1043.5	487.3
2026	3162.6	5922.8	2662.6	581.4	1088.8	489.5
2027	3194.4	6183.4	2675.9	587.0	1136.2	491.7

1/ HIGH FORECAST ASSUMES 4.4% GROWTH PER YEAR (ACTUAL 77-85 GROWTH).
2/ LOW FORECAST ASSUMES 0.5% GROWTH PER YEAR (ACTUAL 85-93 GROWTH).

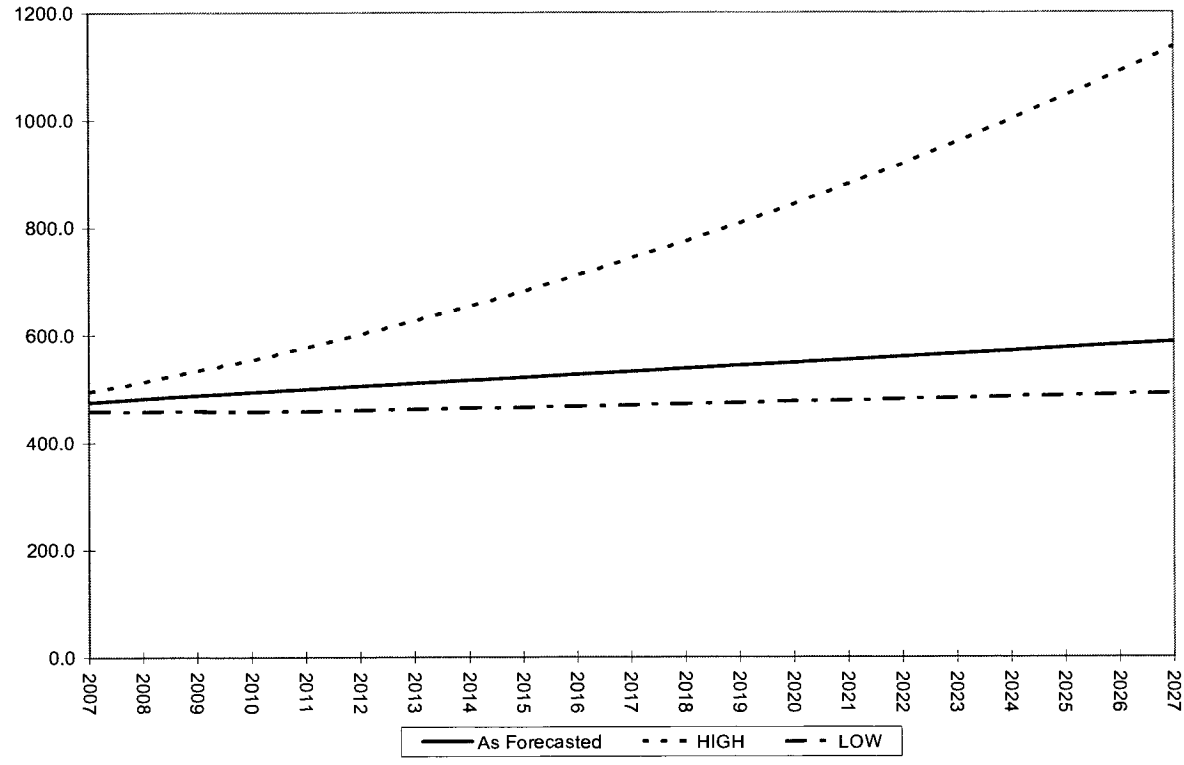
Montana-Dakota Integrated System

High-Growth and Low-Growth Scenarios - Energy



Montana-Dakota Integrated System

High-Growth and Low-Growth Scenarios - Demand



Load And Capability

Existing and Committed Resources

The need for any type of new 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. At present, Montana-Dakota is not planning to retire any of its existing generation facilities. However, due to the termination of the Antelope Valley Station Unit #2 contract in 2006 and increasing demand for electricity by its customers, Montana-Dakota will need to install new resources to maintain reliable serve to its customers (see Chapter 4 for a discussion of the short term capacity purchases from NSP that Montana-Dakota will be making through 2011). For an understanding of Montana-Dakota's capability to serve the projected loads, a comparison of its summer accredited capability and peak load obligation is shown in Table 2-5.

The accredited capability, defined as the capacity available to serve Montana-Dakota's own load, is equal to its net generating capability, including purchased power (see Chapter 5). As a member of the MAPP GRSP, Montana-Dakota is required to maintain an accredited capability equal to or greater than it's maximum system demand plus a 15 percent reserve capacity obligation. Therefore, the peak load obligation shown on the tables is the projected summer peak demand plus the 15 percent reserve capacity obligation.

Table 2-5 shows that, with the base forecast and the capacity purchase contracts, Montana-Dakota has adequate capacity to meet its peak load obligation through 2011. However, if Montana-Dakota is to have sufficient capacity to meet its customers' demand as well as the fifteen percent minimum reserve capacity obligation, in 2012 an additional 88.1 MW of capacity will be needed. The capacity deficit will widen to 117 MW in 2015 and 148.4 MW in 2020. With the high-growth scenario forecast, as shown in Table 2-6, a capacity deficit would occur in 2008 (7.9 MW) growing to 300.8 MW in 2015. The low-growth scenario forecast shown in Table 2-7 would not result in a capacity deficit until 2012 (37.2 MW) increasing to 52.8 MW in 2015.

In order to address future capacity deficits Montana-Dakota will need new demand-side and/or supply-side resources. This IRP will provide the direction for the selection of new resources to effectively and reliably meet customers' requirements.

Table 2-5
Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison -- 01 May 2007

BASE FORECAST

Year	Summer Generating Capability	WAPA Bill Crediting	NSP Peaking Purchase	Summer Total Capability	Summer Peak Demand	Peak Load Obligation	Surplus/Deficit (+)/(-)
2007	479.1	3.2	95.0	577.3	475.3	546.6	30.7
2008	479.1	3.2	100.0	582.3	481.9	554.2	28.1
2009	479.1	3.2	105.0	587.3	487.9	561.1	26.2
2010	479.1	3.2	110.0	592.3	493.7	567.8	24.5
2011	479.1	3.2	115.0	597.3	499.2	574.1	23.2
2012	479.1	3.2	10.0	492.3	504.7	580.4	-88.1
2013	479.1	3.2		482.3	510.1	586.6	-104.3
2014	479.1	3.2		482.3	515.6	592.9	-110.6
2015	479.1	3.2		482.3	521.1	599.3	-117.0
2016	479.1	3.2		482.3	526.6	605.6	-123.3
2017	479.1	3.2		482.3	532.1	611.9	-129.6
2018	479.1	3.2		482.3	537.5	618.1	-135.8
2019	479.1	3.2		482.3	543.0	624.5	-142.2
2020	479.1	3.2		482.3	548.4	630.7	-148.4

Table 2-6

Montana-Dakota Utilities Co. Integrated System
Load and Capability Comparison -- 01 May 2007

HIGH GROWTH FORECAST

Year	Summer Generating Capability	WAPA Bill Crediting	NSP Peaking Purchase	Summer Total Capability	Summer Peak Demand	Peak Load Obligation	Surplus/Deficit (+)/(-)
2007	479.1	3.2	95.0	577.3	495.0	569.3	8.0
2008	479.1	3.2	100.0	582.3	513.2	590.2	-7.9
2009	479.1	3.2	105.0	587.3	533.9	614.0	-26.7
2010	479.1	3.2	110.0	592.3	553.5	636.5	-83.0
2011	479.1	3.2	115.0	597.3	576.5	663.0	-65.7
2012	479.1	3.2	10.0	492.3	601.0	691.2	-198.9
2013	479.1	3.2		482.3	626.5	720.5	-238.2
2014	479.1	3.2		482.3	653.0	751.0	-268.7
2015	479.1	3.2		482.3	680.9	783.1	-300.8
2016	479.1	3.2		482.3	710.7	817.3	-335
2017	479.1	3.2		482.3	741.8	853.1	-370.8
2018	479.1	3.2		482.3	774.1	890.2	-407.9
2019	479.1	3.2		482.3	807.9	929.1	-446.8
2020	479.1	3.2		482.3	843.1	969.6	-487.3

Table 2-7

Montana-Dakota Utilities Co.
Integrated System
Load and Capability Comparison -- 01 May 2007

LOW GROWTH FORECAST

Year	Summer Generating Capability	WAPA Bill Crediting	NSP Peaking Purchase	Summer Total Capability	Summer Peak Demand	Peak Load Obligation	Surplus/Deficit (+)/(-)
2007	479.1	3.2	95.0	577.3	458.7	527.5	49.8
2008	479.1	3.2	100.0	582.3	457.8	526.4	55.9
2009	479.1	3.2	105.0	587.3	458.5	527.3	60
2010	479.1	3.2	110.0	592.3	457.5	526.1	66.2
2011	479.1	3.2	115.0	597.3	458.8	527.6	69.7
2012	479.1	3.2	10.0	492.3	460.4	529.5	-37.2
2013	479.1	3.2		482.3	462.0	531.3	-49.0
2014	479.1	3.2		482.3	463.6	533.1	-50.8
2015	479.1	3.2		482.3	465.3	535.1	-52.8
2016	479.1	3.2		482.3	467.6	537.7	-55.4
2017	479.1	3.2		482.3	469.8	540.3	-58.0
2018	479.1	3.2		482.3	471.9	542.7	-60.4
2019	479.1	3.2		482.3	474.1	545.2	-62.9
2020	479.1	3.2		482.3	476.3	547.7	-65.4

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 through the offering of programs to customers that will help reduce their overall demand and/or energy requirements. Demand-Side Management, or DSM, is defined by the Electric Power Research Institute (EPRI) as:

> *The planning and implementation of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape -- i.e., changes in the pattern and magnitude of a utility load.*

With the demand for electricity growing, Montana-Dakota recognizes the value DSM can play in meeting its future energy requirements. Montana-Dakota looked at potential DSM programs that would be best suited to the Company's load shape. These potential programs were selected through a joint effort between Montana-Dakota and the IRP PAG. However, the implementation of DSM programs cannot be done without cost consideration to the utility, its customers/ratepayers and society. All interests need to be balanced to achieve the results at an affordable cost to both the utility and its customers.

Potential DSM Programs

Montana-Dakota explored the feasibility of offering fourteen DSM programs to its customer base. Programs that are being implemented currently were also included. Montana-Dakota selected the following programs to evaluate:

Residential Programs:

1. Promote ENERGY STAR® clothes washers to electric water heating customers.
2. Promote ENERGY STAR® dishwashers to electric water heating customers.
3. Promote ENERGY STAR® refrigerators.
4. Promote ENERGY STAR® freezers.

5. Promote ENERGY STAR® central air conditioners.
6. Promote a central air conditioning cycling program through the use of a controllable thermostat.
7. Promote a refrigerator round-up program, whereby customers are offered a cash incentive in exchange for the Company removing the customer's second refrigerator.
8. Promote high efficient ground source heat pumps

Commercial Programs Evaluated:

1. Promote Interruptible Demand Response rate in North Dakota and implement in South Dakota and Montana.
2. Promote high efficiency motors.
3. Promote ENERGY STAR® central air conditioner.
4. Promote a central air conditioning cycling program through the use of a controllable thermostat.
5. Promote a high-efficiency lighting program.
6. Promote LED exit sign lighting program

Benefit/Cost Analysis

To determine which programs should be considered most beneficial, and therefore be included as part of the integration process, a benefit/cost analysis was made for each of the fourteen 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 four different cost-effectiveness tests: the Participant Test, the Utility Test, the Societal Cost Test and the Ratepayer 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 Societal Cost Test considers the impact on both the participating and non-participating customers as well as including environmental externalities and the Ratepayer Test includes all quantifiable benefits and costs of a given program and its impact on all ratepayers. In determining whether a program is beneficial, Montana-Dakota relied on the resulting benefit/cost ratio of the Ratepayer Test as well as factors such as practicality of installation.

Beneficial DSM Programs

Based on the benefit/cost analysis and practicality of installation, the following programs have been identified as beneficial DSM programs and will be included in the integration process:

1. ENERGY STAR® refrigerators
2. ENERGY STAR® freezers
3. Residential air conditioner cycling
4. Refrigerator round-up
5. Interruptible Demand Response rate in North Dakota, South Dakota, and Montana
6. High efficiency motors
7. ENERGY STAR® commercial central air conditioners
8. Commercial air conditioner cycling
9. LED exit sign lighting

The nine demand-side programs were placed into four separate groups generally representing their similar characteristics for purposes of integration. The grouping allowed Strategist® to find the programs most attractive to select which represent the largest amount of potential savings. Due to the small size of some of the programs, they may not get selected if Strategist® had to look at each one individually. The program groupings are as follows:

Conservation 1	Available Date	Annual kWh Savings	Peak kW Savings	Installed Cost/kWh	Installed Cost/kW
ENERGY STAR® refrigerators		312,191	195	$0.027	$636
ENERGY STAR® freezers		175,574	127	$0.042	$867
Refrigerator round-up		473,999	503	$0.034	$324
LED exit signs		86,944	124	$0.014	$971
Total Conservation 1	**2008**	**1,048,708**	**949**	**$0.025**	**$545**
Conservation 2					
Residential A/C Cycling		238,782	7,151	$0.126	$419
Commercial A/C Cycling		29,157	873	$0.126	$421
Total Conservation 2	**2009**	**267,939**	**8,024**	**$0.126**	**$420**
Conservation 3					
Commercial High Efficiency A/C		203,689	199	$0.054	$835
High Efficiency Motors		567,063	138	$0.017	$1045
Total Conservation 3	**2008**	**770,752**	**337**	**$0.027**	**$ 921**

Conservation 4					
IT Rate - Demand Response		340,025	4,500	$0.163	$123
Total Conservation 4	**2008**	**340,025**	**4,500**	**$0.163**	**$123**

Implementing the nine DSM programs will provide Montana-Dakota an estimated additional demand reduction of 13.8 MW once implementation is complete. The DSM program cost is approximately $344/kW or $0.076/kWh. The first year program costs are estimated to be approximately $1,988,179, with a total estimated cost of approximately $4,747,576 over the implementation period. The addition of the DSM programs to Montana-Dakota's portfolio will benefit all customers as shown by the Ratepayer Test results included 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 resources to be added to Montana-Dakota's generating system. The resources must be proven technology and be able to maintain the system reliability that Montana-Dakota's customers have come to expect. The selected supply-side resources, together with the beneficial DSM programs are then used as input to the integration analysis, the final process to determine the least cost integrated resource plan.

The supply-side analysis considers all 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

Existing Generation

Montana-Dakota's existing generation is comprised of base load generation at Heskett Station (Units I and II), Lewis & Clark, and its share of Coyote and Big Stone I, and peaking generation at Glendive (Units I and II), Miles City, and Williston. None of the existing generating units are scheduled for retirement during this planning period. Total summer capacity available from the existing units is 479.1 MW.

Montana Wind

In 2006 the Montana legislature passed a law requiring the purchase of renewable energy up to fifteen percent of a utility's energy sold in Montana. The legislation required five percent by 2008, an additional five percent by 2010, and the remaining five percent by 2015. On October 1, 2006, Montana-Dakota issued a Request for Proposal (RFP) to secure wind energy resources to meet the Montana requirement. Five bids were received

by October 27, 2006 and based on the analysis of the bids and interviews with the developers, Montana-Dakota chose to implement the self-build option at Baker, Montana proposed by Crown Butte Wind Power LLC (known as the Diamond Willow Wind Farm). The Montana Public Service Commission certified the project as meeting the intent of the law on March 6, 2007 and the initial 19.5 Mw of capacity is expected to be operational by the end of 2007. The remaining 10 MW of required capacity will be installed by 2015.

Purchased Power

Montana-Dakota entered into an agreement with Excel Energy's operating company Northern States Power (NSP) in December 2005 for the purchase of peaking capacity for the following summer seasons:

- 2007 Summer – 85 MW
- 2008 Summer – 90 MW
- 2009 Summer – 95 MW
- 2010 Summer – 100 MW

In April 2007, Montana-Dakota was negotiating with NSP to purchase an additional ten megawatts of summer peaking capacity for 2007 through 2012. The purpose of the additional capacity purchase is to cover the potential impacts on peak demand associated with hot summer weather as determined using the 90/10 forecast probability. In the event that Montana-Dakota does not meet the MAPP required fifteen percent reserve capacity margin, Montana-Dakota will be required to pay $96,940 per MW for every megawatt that it fell short of the MAPP reserve capacity obligation. As shown in Chapter 3, Montana-Dakota can expect to see approximately five megawatts additional peak demand for every one degree increase in temperature above the normal peak temperature of 98.7 degrees. Without the additional ten megawatt capacity purchase Montana-Dakota would be potentially two megawatts deficit in 2008 with the potential deficit increasing each year under the 90/10 forecast scenario. Also, the purchase of capacity in advance of the summer season functions much like an insurance policy, the payment for the capacity is significantly less then what the penalty would be for not meeting the fifteen percent

reserve obligation. The ten megawatt capacity purchase was shown as a committed resource for 2008 through 2012.

The Western Area Power Administration (WAPA) Ft. Peck Bill Crediting arrangement will continue whereby Montana-Dakota will receive from 2.5 to 3.2 MW of capacity, associated reserves, and energy from WAPA.

Proposed Supply Side Options

NSP Contract Extension

Montana-Dakota has the option to extend the NSP contract through the 2011 summer. The capacity would increase to 105 MW under the same price and terms and conditions as the previous years.

Big Stone II

Montana-Dakota has been participating in the development of the proposed jointly-owned Big Stone II project, as described in the 2005 IRP. The project involves the construction of a nominal 630 MW base load, super critical sub-bituminous-fired plant planned to be on-line in the 2011 – 2012 timeframe. The current list of participants of the unit includes:

- Central Minnesota Municipal Power Agency,
- Great River Energy,
- Heartland Consumers Power District,
- Missouri River Energy Services,
- Montana-Dakota Utilities Co.,
- Otter Tail Power Company, and
- Southern Minnesota Municipal Power Agency.

Montana-Dakota's capacity share of the unit would be 19.3 percent or 121.6 MW (116 MW at time of summer peak). The final decision as to participation in BSP II has not been made yet, so this IRP readdresses the feasibility of participating in BSP II.

The Big Stone II partners have applied for and expect to receive in the second quarter of 2007 a Certificate of Need from the Minnesota Public Service Commission for the transmission facilities associated with the unit that will be constructed in Minnesota. The partners have received an Energy Conversion Facility Siting Permit and a special waste permit in South Dakota. Other studies to support permitting and construction are being conducted.

Elk Run, Waterloo, IA

On July 10, 2006, Montana-Dakota issued a request for proposal for the purchase of base load capacity and energy for the 25 to 35-year time period beginning June 1, 2011 and June 1, 2016 for its Integrated System. The only feasible response was from LS Power proposing a 30-year power purchase agreement for 120-170 MW beginning spring 2012 from a 750 MW coal-fired plant near Waterloo, Iowa.

Lignite Vision 21 (LV21)

LV21 is a proposed 175 MW base load plant located at Gascoyne, North Dakota. LV21 was included in previous IRPs and was originally intended to be a jointly owned 500 MW unit. However, due to the inability to secure co-owners, the plant was scaled back to 175 MW with Montana-Dakota as the sole owner.

Generic Base load

In addition to modeling Big Stone II and Elk Run, generic base load generation was also modeled to provide options for base load generation additions in years other then the specific in-service years associated with Big Stone II and Elk Run. Generic base load generation, in this study, refers to coal-fired generation. Other base load options such as combined cycle and integrated gasification combined cycle plants are modeled separately. No nuclear option was modeled. Base load generation is generally characterized as having a high capital cost with low operating costs providing a stable capacity and energy source. With a low operating cost, base load units produce large amounts of energy at a relatively low cost. The high capital costs are then spread over the large amount of energy.

Generic Combustion Turbines

Simple cycle combustion turbines are primarily used for supplying a limited amount of energy since they are fired by either natural gas or oil. Combustion turbines have a relatively low capital cost, but the energy produced is at a high cost because of the high price of their fuel source. Combustion turbines can be installed in a relatively short time period (two to three years).

Generic Combined Cycle

A conventional combined cycle (CC) unit burns a low sulfur distillate oil or natural gas in a combustion turbine/electric generator. The hot exhaust gases from the turbine pass through a heat recovery steam generator that produces steam for a conventional steam turbine/electric generator. Because combined cycle units use natural gas or fuel oil as a fuel source, the units are high-cost energy producers and their capital costs are between those of a combustion turbine and a base load plant. The advantage of a combined cycle unit is that it can operate more hours then a combustion turbine, but its hours of operation could be limited because of the high energy costs.

Generic Integrated Gasification and Combined Cycle (IGCC)

IGCC units are a new technology that is touted as having the ability to allow CO2 capture more easily. In an IGCC unit, coal is gasified and injected into a combined cycle arranged unit. There are a number of IGCC plants in operation in the world, but most of the units are not of a sufficient size, nor is the technology developed sufficiently, to make the technology commercially competitive with conventional base load generation without some form of governmental subsidy. IGCC units have high capital costs because of the gasification plant required at the front end of the process. IGCC units are projected to have moderate energy costs.

Generic Wind

In addition to the Diamond Willow Wind Farm, generic wind generation was also allowed to compete to be the least cost resource. Wind is characterized as having high

installation costs, but very low energy costs, since there is no cost for the wind, only some operating and maintenance costs. However the disadvantage of wind is that it is considered an intermittent resource because of its variability. Therefore, the installation of wind requires some other generation to produce energy during times of less than desirable wind conditions.

CHAPTER 5
INTEGRATION AND RISK ANALYSIS

The integration process involves the development of a resource plan that considers all the demand-side programs discussed in Chapter 3 and the supply-side programs discussed in Chapter 4 and integrating them into a single plan that is 'least cost'. Previous IRPs have used a computer program called Electric Generation Expansion Analysis System (EGEAS) developed by the Electric Power Research Institute (EPRI). The EGEAS program at Montana-Dakota has not been updated by EPRI since the early 1990s, so the company decided to use the Strategist® program developed by NewEnergy Associates to perform the integration. Strategist® uses the same basic algorithm and mathematical techniques as EGEAS. Montana-Dakota retained PA Consulting Group, Inc. to perform the integration analysis for this IRP.

Sensitivity Analysis

Because business and economic conditions are changing rapidly today, many of the parameters used in this study may change in the future. Sensitivity analysis was performed to see how the resource expansion plans would be affected by variations of certain key parameters.

High- and Low-Growth Scenario Forecasts

The base forecast in Chapter 2 projected summer peak demand would increase at an average rate of 1.1 percent per year, and energy requirements at 1.23 percent per year during the study period. 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. Strategist® runs were made using both the high and low growth load forecasts to determine the least cost resource plan under those two conditions.

High Natural Gas Prices

Natural gas purchased from a 3rd party marketer and delivered under a transportation service arrangement was used for fuel for the generic combustion turbines and combined cycle plants. The forecast price of natural gas was developed by Montana-Dakota's Gas Supply Department for rate forecasting and internal budgeting. The gas was priced for delivery at Mobridge, South Dakota, which is a preferred site for a combined cycle unit.

However, with the volatility of natural gas prices, there is a need to consider what impact higher gas prices would have on the least cost plan. Therefore, a 'high gas' scenario was also developed, whereby the gas price used in the base model was increased between two and seventeen percent.

Installed costs

Costs of materials associated with the construction of generation have increased significantly globally and in the United States. The increase in cost impacted the projected installed cost of Big Stone II, and the increase required a re-evaluation of the economic feasibility of the project. The base case costs for Big Stone II and all generation options reflect the present price forecasts, but for purposes of risk analysis, Montana-Dakota considered what the impact would be on the least cost plan if prices were to escalate again. Therefore, to determine the sensitivity of the base case to price escalation, a sensitivity scenario with a base load generation installed cost increase of fifteen percent was considered.

CHAPTER 6
RESULTS

This section presents the results of the Integrated Resource Plan taking into consideration the results of the Strategist® runs as well as other factors Montana-Dakota deems critical in determining the resource plan to implement. The additional factors not modeled in Strategist® but considered when determining the final resource plan are as follows:

Economic, Societal, Governmental, and Customers Issues

Montana-Dakota is committed to providing its customers with competitively priced, highly reliable electricity. The integrated resource planning process relies not only on the results of a least cost computer model analysis but must also take into consideration other factors and risks. These factors are important considerations in developing future resources that provide the overall best choices for meeting the requirements of customers. The other factors considered in the analysis are:

- Fuel price stability.
- The proven benefits resulting from wholesale sales of off-peak energy provided by low energy cost base load units.
- The possibility of unexpected new large load developing in Montana-Dakota's service territory.
- Renewable resources that may not be price competitive but which have societal support.
- Public interest programs

Midwest ISO (MISO) Market

The addition of base load generation almost always results in a period of surplus energy because of the upfront lumpy investment. Revenues from wholesale sales can provide a means to offset the initial high capital cost impact before the energy is needed by retail customers. In addition, even when the energy is needed by retail customers, there are still a significant number of hours in a year when a base load generator can supply energy into a regional market to offset higher cost units elsewhere. Montana-Dakota has been able to

sell energy into the regional market for the last twenty years, and the benefits of those wholesale sale margins brought long term rate stability to the retail customers, with Montana-Dakota not requesting an electric rate increase over that time span.

With the beginning of the Midwest ISO energy market in 2005, the ability of Montana-Dakota to gain benefits from energy available from its base load plants has been further expanded. Therefore, when considering which resources to consider as benefiting retail customers, the margins received from wholesale sales is a significant factor.

Montana-Dakota continues to perform integrated resource planning based on the obligation it has to assure its customers have a stable and reliable power supply. The MISO energy market provides new opportunities and benefits to Montana-Dakota, but Montana-Dakota cannot rely totally on the market for its power supply requirements. MISO is only an energy market, at present, so capacity requirements, which are needed to supply energy to meet customer requirements must be provided from Montana-Dakota owned generation or bilateral purchases, such as the NSP contract. To rely on energy from the MISO market and only install peaking turbines to meet peak demand would subject Montana-Dakota's customers to excessive price volatility. Therefore, the MISO 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 are not needed at the moment by Montana-Dakota customers with the margins benefiting the customers by offsetting generation costs.

MISO is in the process of designing an ancillary services market which is intended to be operational in 2008. The ancillary services market should provide an easier means for load and generation, including wind, to acquire their ancillary services requirements at more stable and predictable rates then are currently in place with each utility providing this service.

Unexpected New Load

The load forecast does not include unexpected new commercial and industrial loads in Montana-Dakota's service territory that had not been announced at the time the forecast was prepared. For example, in 2005, plans were announced for a new shopping mall in Bismarck and within two years the load had increased in such a manner that a new substation was required to maintain reliable service. Also, new oil activity in eastern Montana resulted in unexpected new load for Montana-Dakota. In the business world, often new large projects are not announced until such time as marketing studies, feasibility studies, and financing have been arranged. The load forecast takes a conservative approach regarding those types of loads, but in order to be able to serve them reliably, Montana-Dakota must have adequate generation resources to meet their demand when they come on line.

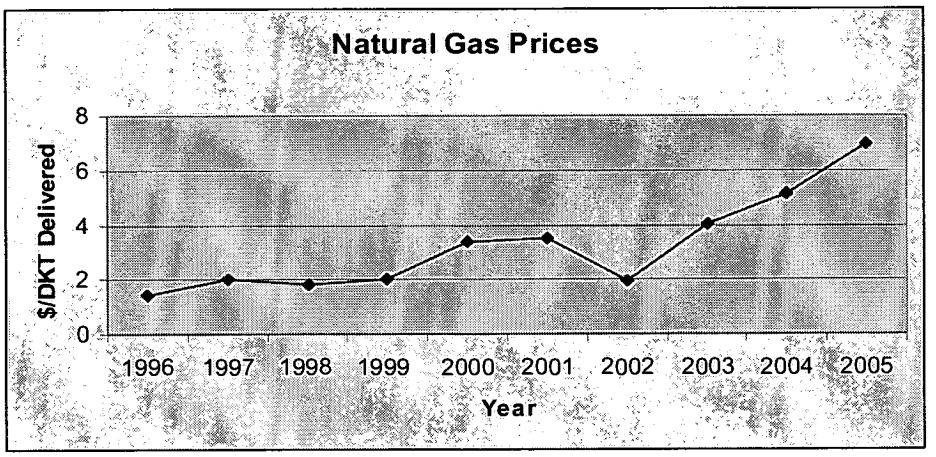
Renewable Resource Development

Montana-Dakota's service territory and its surrounding area have been called the "Saudi Arabia of Wind". Wind development and proposed wind development, driven by environmental concerns primarily, cannot be ignored when considering new resources. Even though wind technology and costs have made wind more competitive, total costs for wind turbines (including capital recovery) are still dependent on governmental incentives, which are not based on economic evaluations. In addition, legislative requirements are driving the need for increased wind generation which is a factor to be considered regardless of the economics of installing renewable generation sources.

Reliance on Natural Gas

Twenty-three percent of Montana-Dakota's owned generating capacity is natural gas fired. As shown on Figure 6-1, natural gas prices have been volatile and increasing over the last six years.

Figure 6-1



With uncertainty as to what will happen with gas prices, Montana-Dakota must consider whether or not it is prudent to increase the percentage of its capacity that is dependent upon natural gas as its fuel source in its evaluation of the least cost plans generated by Strategist®.

Strategist® Results

The results of the base case, for identifying resource additions, which used the most probable load forecast, fuel prices, and installed costs show that the installation of combustion turbines in 2010 and 2023, the Elk Run base load unit in 2012, and the extension of the NSP contract to 2011, is the least cost supply-side plan. In addition, the base case for both perspectives selected eight of the nine DSM programs identified in Chapter 3 to be implemented by 2009, with the Interruptible Rate program the only one not selected.

The sensitivity scenarios indicate that the base-case plan is very robust under all assumptions. Load growth makes a significant impact on the resource selection; however, all load growth scenarios indicate the need for base load generation albeit, the high growth scenario shows much more base load is needed than is currently planned.

The high gas price scenario also supports the selection of base load generation.
The cost of materials and labor, as well as potential environmental costs put upward pressure on the cost estimates for both base load coal units and combustion turbines. The two scenarios that increased the installed cost of base load and combustion turbines by fifteen percent also selected Elk Run as the preferred capacity addition.

Resource Plan

A comparison of the cost differential between the Elk Run option and the Big Stone II option shows that there 2.7 percent difference in the present worth of revenue requirements between the two plans. Because of the uncertainties associated with the Elk Run proposal and the minimal cost differential between Big Stone II and Elk Run, a risk analysis of the Elk Run proposal as compared to the Big Stone II option was made. Big Stone II has received or applied for most of its critical permits (plant siting, air quality, water appropriation and transmission certificate of need) whereas Elk Run has received no approvals at the time of this IRP preparation. LS Power has indicted that currently Montana-Dakota is the only potential participant in the plant. The remaining 570 - 630 MW of the plant are currently uncommitted. Transmission siting, transmission interconnection costs, power delivery costs as well as plant costs due to material cost increases are uncertain. With Elk Run having so many uncertainties associated with its final cost, Montana-Dakota will continue to participate in the Big Stone II unit.

Instead of installing the 2010 combustion turbine as shown in the Strategist® base case, Montana-Dakota will implement Conservation 4, the interruptible rate program, in Montana and South Dakota, which will provide approximately 4.5 MW additional capacity in 2010 and 2011.

In addition to Conservation 4, the following demand-side programs will also be implemented:

- Conservation 1(2008):
    - Promote ENERGY STAR refrigerators
    - Promote ENERGY STAR freezers

- Promote LED exit lights
- Implement a refrigerator roundup

- Conservation 2 (2009):
  - Promote residential central air conditioning cycling
  - Promote commercial air conditioner cycling
- Conservation 3 (2008):
  - Promote commercial high efficiency AC
  - Promote high efficiency motors

Montana-Dakota's strategic goal is to not have high dependence upon natural gas fueled generation because of concerns with long-term availability and the volatility of natural gas prices. The proposed resource expansion plan supports the strategic goal. The following table shows the capacity mix (in megawatts and percent) by fuel and unit type for 2007, 2011, and 2012 for the preferred plan.

Fuel/Unit Type	2007	2011	2012
Natural Gas/Peaking	110.8 (19%)	110.8 (17%)	110.8 (17%)
Purchased Peaking Power	95.0 (16%)	115.0 (18%)	0.0 (0%)
Wind/Intermittent	0.0 (0%)	20.0 (3%)	20.0 (3%)
Demand-side	5.5 (1%)	19.3 (3%)	19.3 (3%)
Fossil/Base Load	368.3 (64%)	368.3 (59%)	488.3 (77%)

Carbon Legislation

Greenhouse gas emissions and global climate change awareness have high visibility in the media and legislatures. The U.S. Congress, as well as some states, is considering legislation to address the issue. As addressed in Chapter 1, Montana-Dakota is committed to environmental stewardship and takes into consideration environmental concerns in its resource planning. Montana-Dakota is prepared to comply with whatever legislation is ultimately passed. However, without knowing the final rules that will

ultimately be implemented make it difficult to specifically model the impacts of the legislation. The increased price sensitivity runs do indicate that the addition of coal-fired base load generation is still the best option to meet the immediate need for new capacity and energy to meet Montana-Dakota's customer's needs. The implementation of the DSM programs also provides benefits as the reduction in customer demand assists in the reduction of carbon dioxide.

CHAPTER 7

TWO-YEAR ACTION PLAN

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

Load Forecasting

- Montana-Dakota will continue to review its load forecasting assumptions and inputs as part of its routine process.

Demand-Side Resources

- Based on the proposed resource plan discussed in Chapter 6, Montana-Dakota will implement the following DSM programs:
    - Continue the implementation of the DSM programs identified in the 2005 IRP;
    - Implement the eight DSM programs identified as Conservation 1, 2, and 3 in the resource plan and
    - Plan for the design and implementation of an interruptible rate (Conservation 4) in Montana and South Dakota.
- Explore additional demand response technology for commercial customers with a demand less than 500kW.

Supply-Side Activities

- Montana-Dakota will continue to pursue ownership in Big Stone II.
- Montana-Dakota will continue to monitor the progress of the Elk Run unit.
- Montana-Dakota will continue to investigate feasible base load opportunities in the MISO market area.
- Montana-Dakota will continue to investigate feasible renewable energy options.

Other Activities

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 2007 IRP advisory group was established at the beginning of the 2007 planning cycle and held its first meeting in August 2006.

Objective

The objective of the PAG was to provide Montana-Dakota with input to its integrated resource planning process from a non-utility perspective. This advisory group reviewed, evaluated, and recommended 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 were non-utility personnel from the three states served by Montana-Dakota's integrated system: Montana, North Dakota, and South Dakota. The advisory group was 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 were also selected as to balance representation from consumer advocacy groups, government agencies (including regulatory bodies), business concerns, and academia.

As a result, the PAG consisted 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 2007 PAG participants are shown in Table 8-1.

Table 8-1

The 2007 IRP Public Advisory Group

Montana

Sheri Shepherd
Energy Program Director
Action for Eastern Montana
Glendive, Montana

Dr. LeRoy M. Moline
Glendive, Montana

Paul Cartwright
Department of Environmental Quality
Helena, Montana

North Dakota

Bill Huether
North Dakota Department of Commerce
Bismarck, North Dakota

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

William Ellig
Ritterbush-Ellig-Hulsing PC
Bismarck, North Dakota

Bruce Conway
Williston, North Dakota

Rich Wardner
North Dakota State Senator
Dickinson, North Dakota

Annette Bendish
North Dakota Public Service Commission
Bismarck, North Dakota
(Participated as an observer)

South Dakota

Kenny Jensen
Jensen Rock & Sand, 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 2007 IRP public advisory process was designed to make more 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 recent changes within the Company and in the electric utility industry, which is moving rapidly toward a market environment. The group's discussions, therefore, tend to concentrate on issues, policies, and overall results. As a result of the public advisory process, Montana-Dakota was able to produce better analyses and reports with the information and suggestions provided by the group.

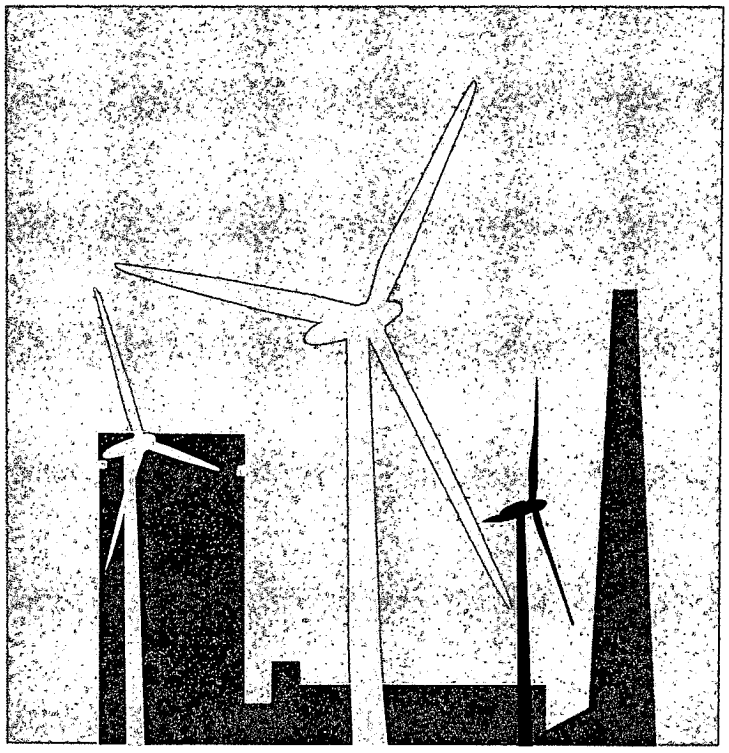
The 2007 IRP PAG meetings were held in Bismarck, North Dakota. In addition to presenting the topics for discussion and taking feedback from the PAG members, Montana-Dakota served as a facilitator in setting agendas, taking care of meeting logistics such as meeting notices and expense reimbursements, and documenting the presentations at the meetings.

In addition to the five meetings held, Montana-Dakota worked closely with representatives from the North Dakota Department of Commerce, Office of Renewable Energy and Energy Efficiency and the Montana Department of Environmental Quality to choose demand-side programs for consideration and to evaluate those demand-side programs.

Since the PAG functioned 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 whenever they wanted to document their opinions or concerns.

Conclusions

Montana-Dakota is pleased with its public advisory process. The process improved the 2007 IRP process and product (report and appendices). The public involvement resulted in better study assumptions and provided useful information to both the company and the PAG participants and their constituents.



Integrated Resource Plan 2007

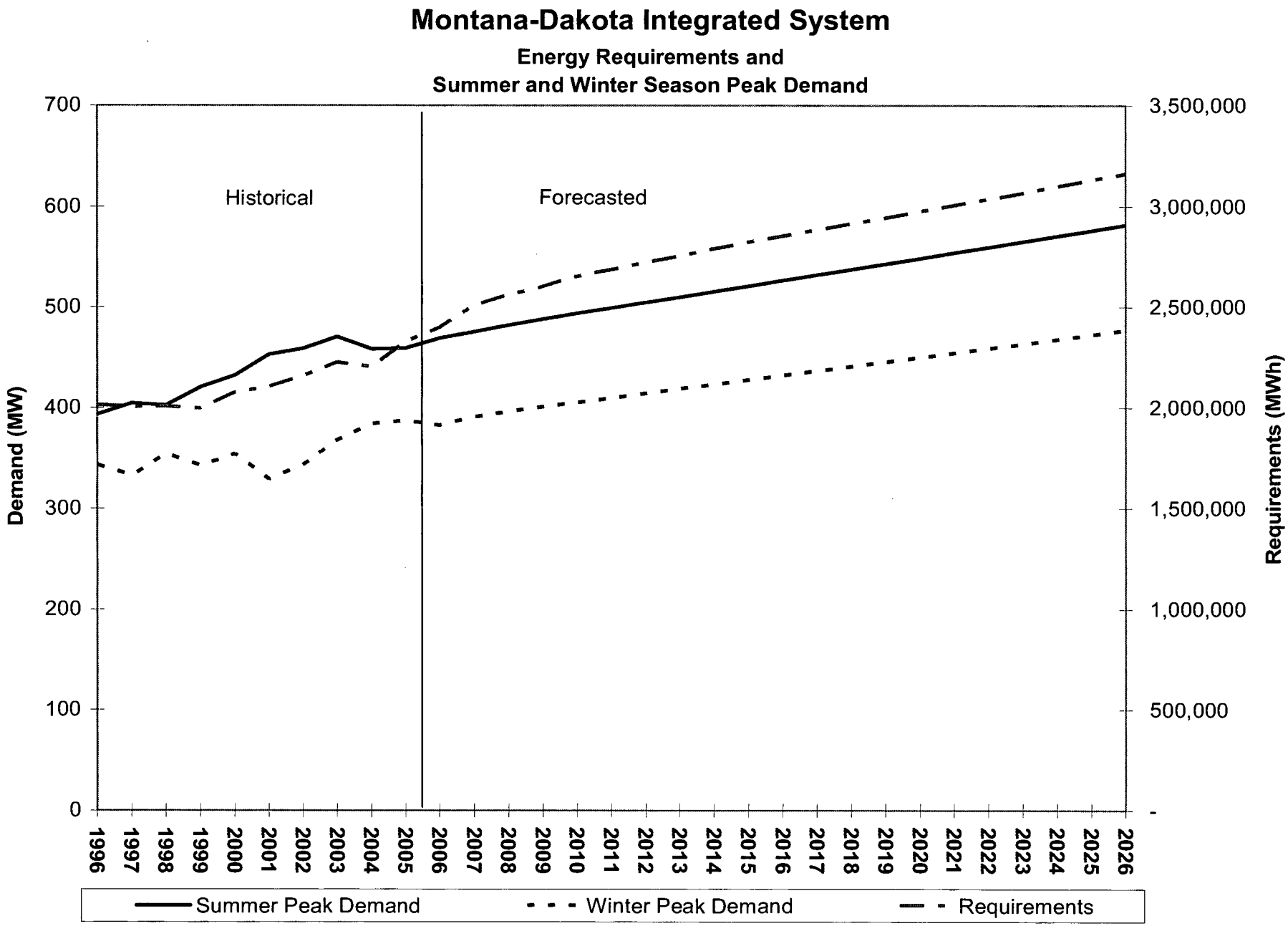
Submitted to the
North Dakota Public Service Commission
July 1, 2007

ATTACHMENTS

MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ENERGY AND DEMAND
INTEGRATED SYSTEM
WITH DSM REDUCTIONS

	TOTAL ENERGY REQUIREMENTS		SUMMER PEAK - MW				WINTER PEAK */	
YEAR	MWh	%GROWTH	INTERRUPTIBLE LOADS NOT INTERRUPTED	INTRPT LOADS	INTERRUPTIBLE LOADS INTERRUPTED	% CHG	MW	%GROWTH
1996	2,014,830				393.3		343.1	
1997	2,005,195	-0.48%			404.6	2.87%	332.8	-3.00%
1998	2,007,534	0.12%			402.5	-0.52%	354.2	6.43%
1999	1,996,647	-0.54%			420.6	4.50%	342.4	-3.33%
2000	2,077,579	4.05%			432.3	2.78%	353.9	3.36%
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	2,509,450	4.66%	480.8	5.5	475.3	-2.10%	390.8	-1.61%
2008	2,562,077	2.10%	487.4	5.5	481.9	1.39%	396.2	1.38%
2009	2,602,851	1.59%	493.4	5.5	487.9	1.25%	400.9	1.19%
2010	2,652,679	1.91%	499.2	5.5	493.7	1.19%	405.3	1.10%
2011	2,688,443	1.35%	504.7	5.5	499.2	1.11%	409.8	1.11%
2012	2,721,863	1.24%	510.2	5.5	504.7	1.10%	414.2	1.07%
2013	2,755,403	1.23%	515.6	5.5	510.1	1.07%	418.7	1.09%
2014	2,789,264	1.23%	521.1	5.5	515.6	1.08%	423.2	1.07%
2015	2,822,464	1.19%	526.6	5.5	521.1	1.07%	427.6	1.04%
2016	2,852,931	1.08%	532.1	5.5	526.6	1.06%	432.1	1.05%
2017	2,883,458	1.07%	537.6	5.5	532.1	1.04%	436.6	1.04%
2018	2,914,059	1.06%	543.0	5.5	537.5	1.01%	441.0	1.01%
2019	2,944,723	1.05%	548.5	5.5	543.0	1.02%	445.4	1.00%
2020	2,975,546	1.05%	553.9	5.5	548.4	0.99%	450.0	1.03%
2021	3,006,438	1.04%	559.5	5.5	554.0	1.02%	454.3	0.96%
2022	3,037,435	1.03%	564.9	5.5	559.4	0.97%	458.9	1.01%
2023	3,068,564	1.02%	570.4	5.5	564.9	0.98%	463.2	0.94%
2024	3,099,744	1.02%	575.9	5.5	570.4	0.97%	467.7	0.97%
2025	3,131,087	1.01%	581.4	5.5	575.9	0.96%	472.2	0.96%
2026	3,162,646	1.01%	586.9	5.5	581.4	0.96%	476.7	0.95%

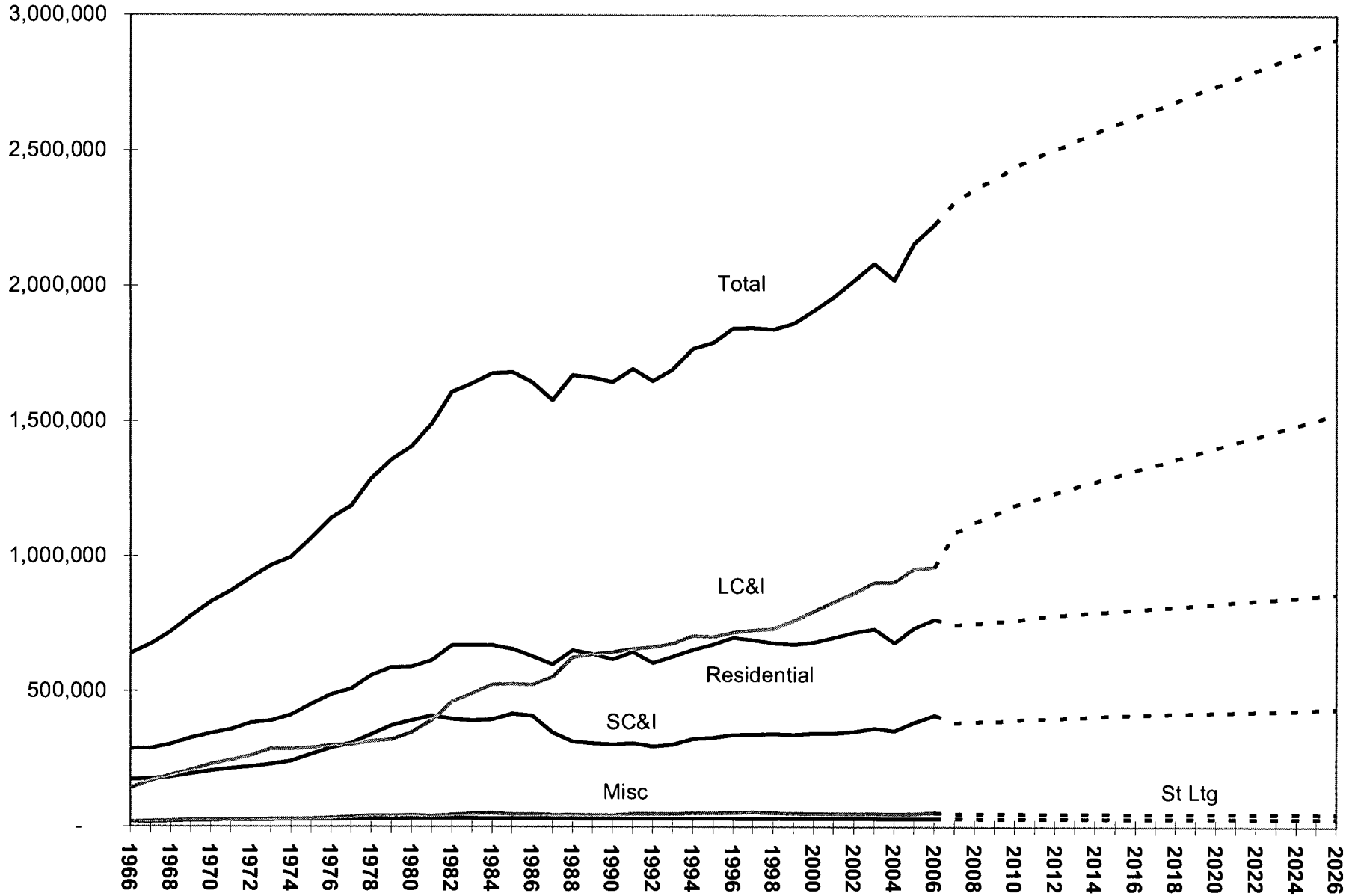
*/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.


Montana-Dakota Integrated System
Energy Requirements and
Summer and Winter Season Peak Demand
Historical
Forecasted
Demand (MW)
Requirements (MWh)
700
600
500
400
300
200
100
0
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
Summer Peak Demand
Winter Peak Demand
Requirements

MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ANNUAL SALES BY SECTOR
INTEGRATED SYSTEM
BILLING MONTH BASIS
WITH DSM REDUCTIONS

	RESIDENTIAL		SMALL C&I		LARGE C&I		STREET LTG		MISCELLANEOUS		TOTAL SALES		TOTAL ENERGY REQUIREMENTS	
YEAR	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	MWh	%GROWTH
1996	700,642		340,545		720,501		30,708		52,469		1,844,865		2,014,830	
1997	691,325	-1.33%	341,525	0.29%	728,808	1.15%	30,492	-0.70%	54,256	3.41%	1,846,406	0.08%	2,005,195	-0.48%
1998	680,290	-1.60%	345,012	1.02%	733,236	0.61%	30,848	1.17%	51,342	-5.37%	1,840,728	-0.31%	2,007,534	0.12%
1999	675,658	-0.68%	341,967	-0.88%	764,768	4.30%	30,980	0.43%	50,072	-2.47%	1,863,445	1.23%	1,996,647	-0.54%
2000	683,435	1.15%	347,350	1.57%	799,555	4.55%	30,718	-0.85%	48,958	-2.22%	1,910,016	2.50%	2,077,579	4.05%
2001	700,552	2.50%	346,870	-0.14%	833,248	4.21%	30,792	0.24%	48,931	-0.06%	1,960,393	2.64%	2,104,119	1.28%
2002	720,346	2.83%	353,778	1.99%	866,901	4.04%	30,778	-0.05%	49,387	0.93%	2,021,190	3.10%	2,158,431	2.58%
2003	733,030	1.76%	365,259	3.25%	905,860	4.49%	30,857	0.26%	50,013	1.27%	2,085,019	3.16%	2,226,531	3.16%
2004	680,614	-7.15%	355,984	-2.54%	907,267	0.16%	30,555	-0.98%	48,062	-3.90%	2,022,482	-3.00%	2,204,012	-1.01%
2005	737,106	8.30%	386,746	8.64%	957,169	5.50%	30,376	-0.59%	49,328	2.63%	2,160,725	6.84%	2,327,117	5.59%
2006	768,952	4.32%	413,147	6.83%	962,186	0.52%	30,602	0.74%	53,472	8.40%	2,228,359	3.13%	2,397,793	3.04%
2007	754,070	-1.94%	387,283	-6.26%	1,089,674	13.25%	30,388	-0.70%	49,065	-8.24%	2,310,480	3.69%	2,507,310	4.57%
2008	760,592	0.86%	389,360	0.54%	1,130,073	3.71%	30,393	0.02%	49,003	-0.13%	2,359,421	2.12%	2,560,420	2.12%
2009	765,905	0.70%	392,681	0.85%	1,158,652	2.53%	30,399	0.02%	48,941	-0.13%	2,396,578	1.57%	2,600,742	1.57%
2010	776,445	1.38%	395,525	0.72%	1,191,758	2.86%	30,404	0.02%	48,878	-0.13%	2,443,010	1.94%	2,651,130	1.94%
2011	784,352	1.02%	398,600	0.78%	1,213,920	1.86%	30,410	0.02%	48,816	-0.13%	2,476,098	1.35%	2,687,037	1.35%
2012	789,637	0.67%	402,013	0.86%	1,236,081	1.83%	30,415	0.02%	48,754	-0.13%	2,506,900	1.24%	2,720,463	1.24%
2013	794,902	0.67%	405,528	0.87%	1,258,239	1.79%	30,421	0.02%	48,692	-0.13%	2,537,782	1.23%	2,753,976	1.23%
2014	800,311	0.68%	409,431	0.96%	1,280,208	1.75%	30,427	0.02%	48,629	-0.13%	2,569,006	1.23%	2,787,860	1.23%
2015	805,660	0.67%	413,279	0.94%	1,301,772	1.68%	30,432	0.02%	48,567	-0.13%	2,599,710	1.20%	2,821,179	1.20%
2016	811,088	0.67%	414,978	0.41%	1,322,761	1.61%	30,438	0.02%	48,505	-0.13%	2,627,770	1.08%	2,851,630	1.08%
2017	816,537	0.67%	416,771	0.43%	1,343,713	1.58%	30,443	0.02%	48,442	-0.13%	2,655,906	1.07%	2,882,163	1.07%
2018	822,081	0.68%	418,659	0.45%	1,364,531	1.55%	30,449	0.02%	48,380	-0.13%	2,684,100	1.06%	2,912,758	1.06%
2019	827,768	0.69%	420,662	0.48%	1,385,158	1.51%	30,454	0.02%	48,318	-0.13%	2,712,360	1.05%	2,943,426	1.05%
2020	833,477	0.69%	422,818	0.51%	1,405,746	1.49%	30,460	0.02%	48,256	-0.13%	2,740,757	1.05%	2,974,242	1.05%
2021	839,248	0.69%	425,073	0.53%	1,426,240	1.46%	30,466	0.02%	48,193	-0.13%	2,769,220	1.04%	3,005,130	1.04%
2022	845,000	0.69%	427,446	0.56%	1,446,735	1.44%	30,471	0.02%	48,131	-0.13%	2,797,783	1.03%	3,036,126	1.03%
2023	850,733	0.68%	429,932	0.58%	1,467,232	1.42%	30,477	0.02%	48,069	-0.13%	2,826,443	1.02%	3,067,228	1.02%
2024	856,585	0.69%	432,538	0.61%	1,487,576	1.39%	30,482	0.02%	48,007	-0.13%	2,855,188	1.02%	3,098,421	1.02%
2025	862,469	0.69%	435,260	0.63%	1,507,904	1.37%	30,488	0.02%	47,944	-0.13%	2,884,065	1.01%	3,129,758	1.01%
2026	868,434	0.69%	438,151	0.66%	1,528,157	1.34%	30,493	0.02%	47,882	-0.13%	2,913,117	1.01%	3,161,285	1.01%
1996-2006 AVG YEARLY GROWTH (10 YRS HIST)		0.86%		1.56%		3.32%		-0.06%		-0.43%		1.96%		1.84%
2001-2006 AVG YEARLY GROWTH (5 YRS HIST)		1.32%		3.24%		2.95%		-0.23%		1.15%		2.34%		2.51%
2007-2012 AVG YEARLY GROWTH (5 YEARS)		0.93%		0.75%		2.55%		0.02%		-0.13%		1.65%		1.65%
2007-2017 AVG YEARLY GROWTH (10 YEARS)		0.80%		0.74%		2.12%		0.02%		-0.13%		1.40%		1.40%
2007-2026 AVG YEARLY GROWTH (19 YEARS)		0.75%		0.65%		1.80%		0.02%		-0.13%		1.23%		1.23%

Integrated System Historical and Forecasted Sales by Class



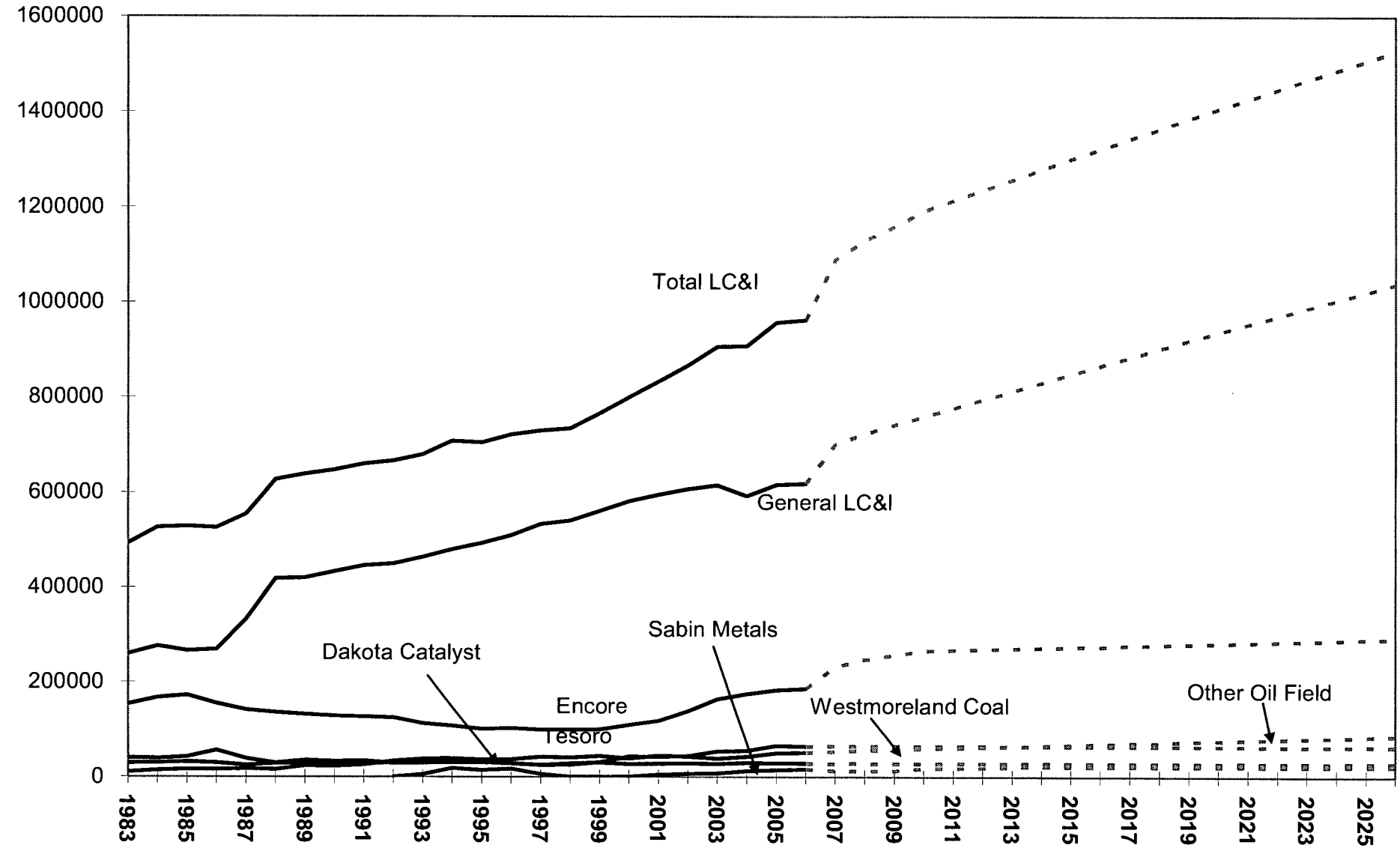
MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED ANNUAL SALES BY LC&I END-USE
INTEGRATED SYSTEM
BILLING MONTH BASIS
WITH DSM REDUCTIONS

	GENERAL LC&I 1/		TESORO REFINERY 2/		WESTMORELAND COAL 3/		ENCORE ACQUISITION 4/		OTHER OIL FIELD 5/		SABIN METALS 6/		TOTAL LC&I	
YEAR	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH	SALES(MWh)	%GROWTH
1996	508,989		36,206		28,052		102,508		28,159		16,587		720,501	
1997	532,895	4.70%	41,807	15.47%	24,484	-12.72%	99,132	-3.29%	24,818	-11.86%	5,671	-65.81%	728,807	1.15%
1998	540,627	1.45%	40,444	-3.26%	28,047	14.55%	99,203	0.07%	24,915	0.39%	-	-100.00%	733,236	0.61%
1999	560,751	3.72%	43,424	7.37%	30,069	7.21%	99,887	0.69%	30,637	22.97%	-		764,768	4.30%
2000	581,857	3.76%	38,375	-11.63%	26,816	-10.82%	109,618	9.74%	42,539	38.85%	350		799,555	4.55%
2001	595,601	2.36%	44,744	16.60%	27,993	4.39%	118,215	7.84%	42,218	-0.75%	4,478	1179.43%	833,249	4.21%
2002	607,360	1.97%	42,022	-6.08%	28,091	0.35%	139,392	17.91%	43,529	3.11%	6,507	45.31%	866,901	4.04%
2003	615,084	1.27%	38,669	-7.98%	27,362	-2.60%	164,191	17.79%	53,153	22.11%	7,401	13.74%	905,860	4.49%
2004	592,905	-3.61%	42,057	8.76%	29,498	7.81%	175,376	6.81%	54,951	3.38%	12,480	68.63%	907,267	0.16%
2005	615,993	3.89%	49,717	18.21%	28,563	-3.17%	183,284	4.51%	65,278	18.79%	14,334	14.86%	957,169	5.50%
2006	618,450	0.40%	50,341	1.26%	28,301	-0.92%	186,144	1.56%	63,390	-2.89%	15,560	8.55%	962,186	0.52%
2007	699,949	13.18%	53,354	5.99%	28,000	-1.06%	231,544	24.39%	64,329	1.48%	12,498	-19.68%	1,089,674	13.25%
2008	722,439	3.21%	55,056	3.19%	28,000	0.00%	247,852	7.04%	64,228	-0.16%	12,498	0.00%	1,130,073	3.71%
2009	740,230	2.46%	56,758	3.09%	28,000	0.00%	257,038	3.71%	64,128	-0.16%	12,498	0.00%	1,158,652	2.53%
2010	757,932	2.39%	58,460	3.00%	28,000	0.00%	266,240	3.58%	64,029	-0.15%	17,097	36.80%	1,191,758	2.86%
2011	776,100	2.40%	60,162	2.91%	28,000	0.00%	267,710	0.55%	63,931	-0.15%	18,017	5.38%	1,213,920	1.86%
2012	794,249	2.34%	61,864	2.83%	28,000	0.00%	269,197	0.56%	63,834	-0.15%	18,937	5.11%	1,236,081	1.83%
2013	812,378	2.28%	63,566	2.75%	28,000	0.00%	270,701	0.56%	63,738	-0.15%	19,856	4.85%	1,258,239	1.79%
2014	830,297	2.21%	65,268	2.68%	28,000	0.00%	272,224	0.56%	63,643	-0.15%	20,776	4.63%	1,280,208	1.75%
2015	848,254	2.16%	66,970	2.61%	28,000	0.00%	273,764	0.57%	63,548	-0.15%	21,236	2.21%	1,301,772	1.68%
2016	866,076	2.10%	68,672	2.54%	28,000	0.00%	275,322	0.57%	63,455	-0.15%	21,236	0.00%	1,322,761	1.61%
2017	883,841	2.05%	70,374	2.48%	28,000	0.00%	276,899	0.57%	63,363	-0.14%	21,236	0.00%	1,343,713	1.58%
2018	901,453	1.99%	72,076	2.42%	28,000	0.00%	278,495	0.58%	63,271	-0.15%	21,236	0.00%	1,364,531	1.55%
2019	918,854	1.93%	73,778	2.36%	28,000	0.00%	280,109	0.58%	63,181	-0.14%	21,236	0.00%	1,385,158	1.51%
2020	936,197	1.89%	75,480	2.31%	28,000	0.00%	281,742	0.58%	63,091	-0.14%	21,236	0.00%	1,405,746	1.49%
2021	953,425	1.84%	77,182	2.25%	28,000	0.00%	283,395	0.59%	63,002	-0.14%	21,236	0.00%	1,426,240	1.46%
2022	970,634	1.80%	78,884	2.21%	28,000	0.00%	285,067	0.59%	62,914	-0.14%	21,236	0.00%	1,446,735	1.44%
2023	987,824	1.77%	80,586	2.16%	28,000	0.00%	286,759	0.59%	62,827	-0.14%	21,236	0.00%	1,467,232	1.42%
2024	1,004,841	1.72%	82,288	2.11%	28,000	0.00%	288,470	0.60%	62,741	-0.14%	21,236	0.00%	1,487,576	1.39%
2025	1,021,820	1.69%	83,990	2.07%	28,000	0.00%	290,202	0.60%	62,656	-0.14%	21,236	0.00%	1,507,904	1.37%
2026	1,038,703	1.65%	85,692	2.03%	28,000	0.00%	291,955	0.60%	62,571	-0.14%	21,236	0.00%	1,528,157	1.34%
1996-2006 AVG YEARLY GROWTH (10 YRS HIST)		1.89%		2.13%		0.61%		7.92%		10.94%		-		3.32%
2001-2006 AVG YEARLY GROWTH (5 YRS HIST)		0.56%		3.42%		0.52%		9.44%		9.83%		-		2.95%
2007-2012 AVG YEARLY GROWTH (5 YEARS)		2.56%		3.00%		0.00%		3.06%		-0.15%		8.67%		2.55%
2007-2017 AVG YEARLY GROWTH (10 YEARS)		2.36%		2.81%		0.00%		1.80%		-0.15%		5.44%		2.12%
2007-2026 AVG YEARLY GROWTH (19 YEARS)		2.10%		2.53%		0.00%		1.23%		-0.15%		2.83%		1.80%

1/ GENERAL LARGE COMMERCIAL & INDUSTRIAL FORECAST WAS DEVELOPED FROM AN ECONOMETRIC FORECAST.
2/ TESORO REFINERY SALES ARE BASED ON A LINEAR REGRESSION OF 81-05 SALES.
3/ WESTMORELAND COAL IS HELD CONSTANT AT 2002 ACTUAL LEVELS.
4/ ENCORE ACQUISITION SALES FORECAST IS BASED ON AN EXPONENTIAL CURVE FIT THROUGH 96-05 BASE SALES AND NEW LOAD IS ADDED TO THE FORECAST FOR EXPECTED PROJECTS.
5/ OTHER OIL FIELDS SALES FORECAST IS BASED ON AN EXPONENTIAL CURVE FIT THROUGH SALES AT EACH OIL FIELD INDIVIDUALLY (POPLAR AND ALL OTHER MT OIL FIELD SALES).
6/ SABIN METALS EXPECTS TO ADD ANOTHER ARC FURNACE IN 2010.

Montana-Dakota Integrated System

Historical and Forecasted Sales by LC&I Customer



MONTANA-DAKOTA UTILITIES CO.
HISTORICAL AND FORECASTED
RESIDENTIAL SALES, CUSTOMERS, AND USE PER CUSTOMER
INTEGRATED SYSTEM
With DSM Reductions

YEAR	SALES (MWh)	%GROWTH	AVG CUSTS	CUST NO INC/(DEC)	AVG USE PER CUST (kWh/YR)	
1996	700,642		84,153		8,326	
1997	691,325	-1.33%	84,510	357	8,180	
1998	680,290	-1.60%	84,833	323	8,019	
1999	675,658	-0.68%	84,935	102	7,955	*/
2000	683,435	1.15%	84,914	(21)	8,049	
2001	700,552	2.50%	84,866	(48)	8,255	
2002	720,346	2.83%	85,012	146	8,473	
2003	733,030	1.76%	85,278	266	8,596	
2004	680,614	-7.15%	85,498	220	7,961	
2005	737,106	8.30%	85,791	293	8,592	
2006	768,952	4.32%	86,150	359	8,926	
2007	754,070	2.30%	86,216	66	8,746	
2008	760,592	0.86%	86,412	196	8,802	
2009	765,905	0.70%	86,590	178	8,845	
2010	776,445	1.38%	86,749	159	8,950	
2011	784,352	1.02%	86,894	145	9,027	
2012	789,637	0.67%	87,043	149	9,072	
2013	794,902	0.67%	87,190	147	9,117	
2014	800,311	0.68%	87,337	147	9,163	
2015	805,660	0.67%	87,436	99	9,214	
2016	811,088	0.67%	87,547	111	9,265	
2017	816,537	0.67%	87,624	77	9,319	
2018	822,081	0.68%	87,687	63	9,375	
2019	827,768	0.69%	87,722	35	9,436	
2020	833,477	0.69%	87,722	-	9,501	
2021	839,248	0.69%	87,722	-	9,567	
2022	845,000	0.69%	87,722	-	9,633	
2023	850,733	0.68%	87,722	-	9,698	
2024	856,585	0.69%	87,722	-	9,765	
2025	862,469	0.69%	87,722	-	9,832	
2026	868,434	0.69%	87,722	-	9,900	

	SALES	**CUSTS**
1995-2005 AVG YEARLY GROWTH (10 YRS HIST)	0.86%	0.19%
2000-2005 AVG YEARLY GROWTH (5 YRS HIST)	1.32%	0.30%
2007-2012 AVG YEARLY GROWTH (5 YEARS)	0.93%	0.19%
2007-2017 AVG YEARLY GROWTH (10 YEARS)	0.80%	0.16%
2007-2026 AVG YEARLY GROWTH (19 YEARS)	0.75%	0.09%

*/ AVG CUSTS and AVG USE PER CUST for 1999 are only estimates. Due to the installation of a new CIS in 1999, actual customer numbers are not available.

4. Forecast Uncertainty

The projected demand and energy produced by the econometric process described in the first four sections results in a forecast based solely on the information input to the equations. The presence of forecasting errors or chance variations is a fact of life; forecasting is a process permeated with uncertainty. 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. That uncertainty is dealt with by developing demand forecasts reflecting extreme weather conditions as well as developing high-growth and low-growth scenarios for energy forecasts.

4.1. Effect of Temperature on Peak Demand

The final forecast results given in Section 3 were developed assuming ten-year average temperatures at the time of the system peak. However, there are some shortcomings associated with this methodology. First, with an average temperature forecast, by definition actual peak demand would have approximately a 50% probability of being lower than the forecast values and a 50% probability of exceeding forecast values (50/50 forecast). Second, there is an appearance that demand is underforecasted when the actual temperature at the time of system peak exceeds the ten-year average temperature.

In 2004, a study titled "MDU Summer Peak Demand versus Ambient Temperature" was performed by Montana-Dakota's System Operations & Planning staff to establish the relationship between summer peak demand and temperature at the time of system peak. As part of the study, a trend analysis of 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 was performed. The study indicated that each one degree increase in temperature at the time of summer peak would result in an increase of approximately 5 MW in summer peak demand.

Further statistical analysis of temperatures at the time of system peak for the years 1984 through 2006 (prior to 1984 the company was a winter peaking utility) provided the results shown in the following table:

Temperature Probability at Peak and Effect on Peak Demand

Probability	Weighted Average Temperature	Approximate Increase in Peak Demand (MW)
50.0%	98.7	0.0
75.0%	99.6	4.5
80.0%	100.3	8.0
85.0%	101.1	12.0
90.0%	102.1	17.0
95.0%	103.6	24.5

As the table shows, there is a 90% probability that actual temperatures at the time of the system peak will not exceed 102.1°F. At this temperature, 17.0 MW of capacity in addition to that which was forecasted is needed to meet the system peak demand that may occur. This is called the 90/10 forecast and provides a peak demand forecast for extreme weather conditions. It represents a probability of 90% that the actual peak demand would not exceed the forecast value and a 10% probability that the actual peak demand would be higher than the forecast value. The following table summarizes the results of the 50/50 probability and 90/10 probability demand forecasts.

Alternate Summer Peak Demand Forecast Comparison

Year	Base Forecast (98.7 degrees F) 50/50 Forecast (MW)	Growth Rate (%)	Alternate Forecast (102.1 degrees F) 90/10 Forecast (MW)
2007	475.3		492.3
2008	481.9	1.39%	499.1
2009	487.9	1.25%	505.4
2010	493.7	1.19%	511.4
2011	499.2	1.11%	517.1
2012	504.7	1.10%	522.8
2013	510.1	1.07%	528.3
2014	515.6	1.08%	534.0
2015	521.1	1.07%	539.7
2016	526.6	1.06%	545.4
2017	532.1	1.04%	551.1
2018	537.5	1.01%	556.7
2019	543.0	1.02%	562.4
2020	548.4	0.99%	568.0
2021	554.0	1.02%	573.8
2022	559.4	0.97%	579.4
2023	564.9	0.98%	585.1
2024	570.4	0.97%	590.8
2025	575.9	0.96%	596.5
2026	581.4	0.96%	602.2

Growth rates are assumed to be the same for both scenarios

4.2. High-Growth and Low-Growth Scenario Forecasts

Another approach used to deal with forecast uncertainty in this study was to simulate high-growth and low-growth scenarios which represent the extreme 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 given on Appendix A-10 and graphed on Appendix A-11, 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 periods consist of eight years of history.

As a result, for the high-growth scenario, an average growth rate of 4.4% per year was assumed to occur during the 20-year forecast horizon. For the low-growth scenario, an average growth rate of 0.5% per year was assumed to occur during the 20-year forecast horizon.

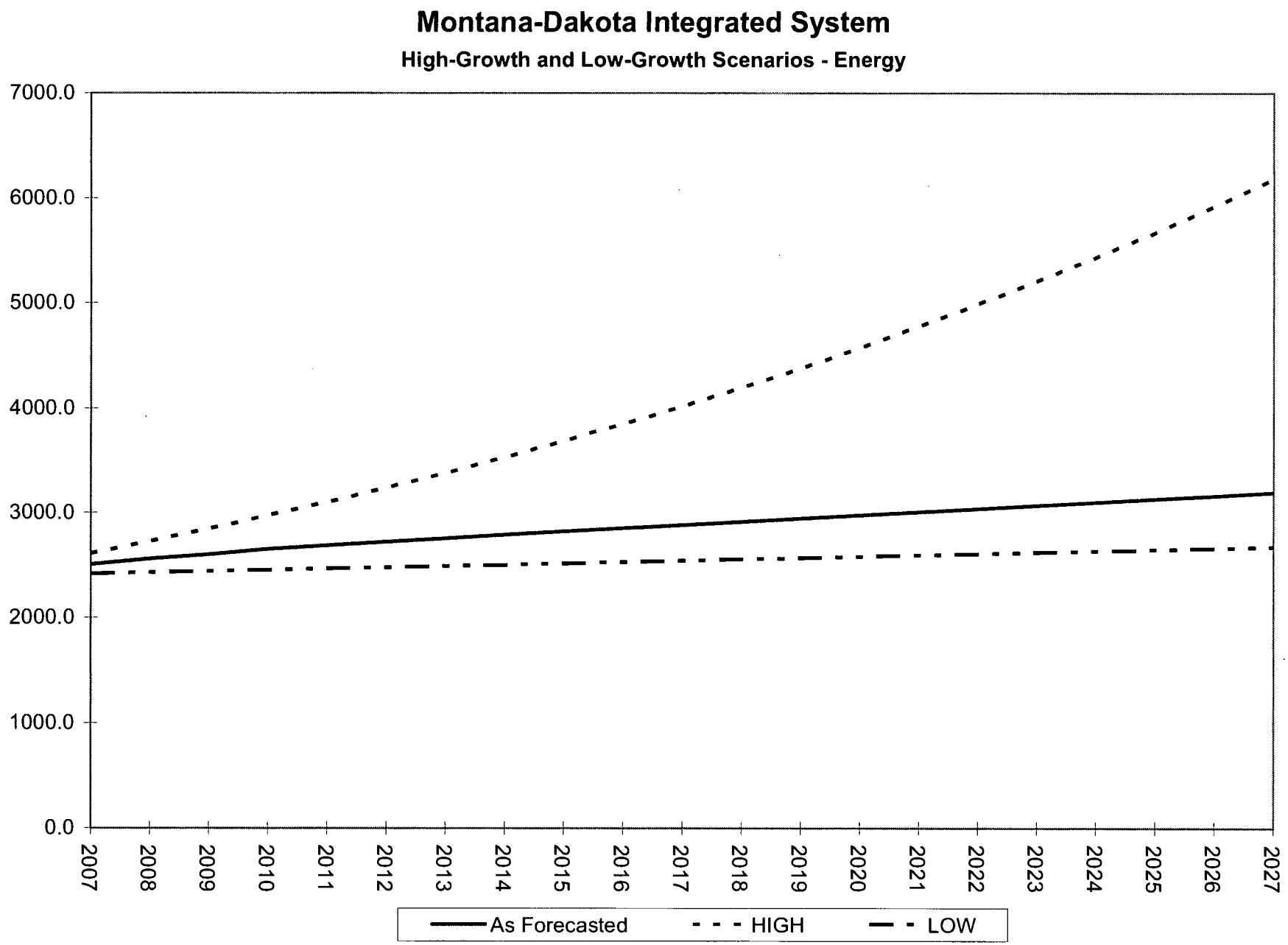
Demand for each scenario was derived by applying the load factors calculated from the base forecast to the high-growth and low-growth scenario forecasted energy.

The results of the high-growth and low-growth scenarios for energy and demand are given below. The following two pages present the graphs of the numeric results.

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
2007	2509.5	2613.4	2421.8	475.3	495.0	458.7
2008	2562.1	2728.4	2433.9	481.9	513.2	457.8
2009	2602.9	2848.5	2446.1	487.9	533.9	458.5
2010	2652.7	2973.8	2458.3	493.7	553.5	457.5
2011	2688.4	3104.7	2470.6	499.2	576.5	458.8
2012	2721.9	3241.3	2483.0	504.7	601.0	460.4
2013	2755.4	3383.9	2495.4	510.1	626.5	462.0
2014	2789.3	3532.8	2507.9	515.6	653.0	463.6
2015	2822.5	3688.2	2520.4	521.1	680.9	465.3
2016	2852.9	3850.5	2533.0	526.6	710.7	467.6
2017	2883.5	4019.9	2545.7	532.1	741.8	469.8
2018	2914.1	4196.8	2558.4	537.5	774.1	471.9
2019	2944.7	4381.5	2571.2	543.0	807.9	474.1
2020	2975.5	4574.3	2584.1	548.4	843.1	476.3
2021	3006.4	4775.5	2597.0	554.0	880.0	478.6
2022	3037.4	4985.6	2610.0	559.4	918.2	480.7
2023	3068.6	5205.0	2623.0	564.9	958.2	482.9
2024	3099.7	5434.0	2636.1	570.4	1000.0	485.1
2025	3131.1	5673.1	2649.3	575.9	1043.5	487.3
2026	3162.6	5922.8	2662.6	581.4	1088.8	489.5
2027	3194.4	6183.4	2675.9	587.0	1136.2	491.7

1/ HIGH FORECAST ASSUMES 4.4% GROWTH PER YEAR (ACTUAL 77-85 GROWTH).
2/ LOW FORECAST ASSUMES 0.5% GROWTH PER YEAR (ACTUAL 85-93 GROWTH).


Montana-Dakota Integrated System
High-Growth and Low-Growth Scenarios - Energy
7000.0
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
2007
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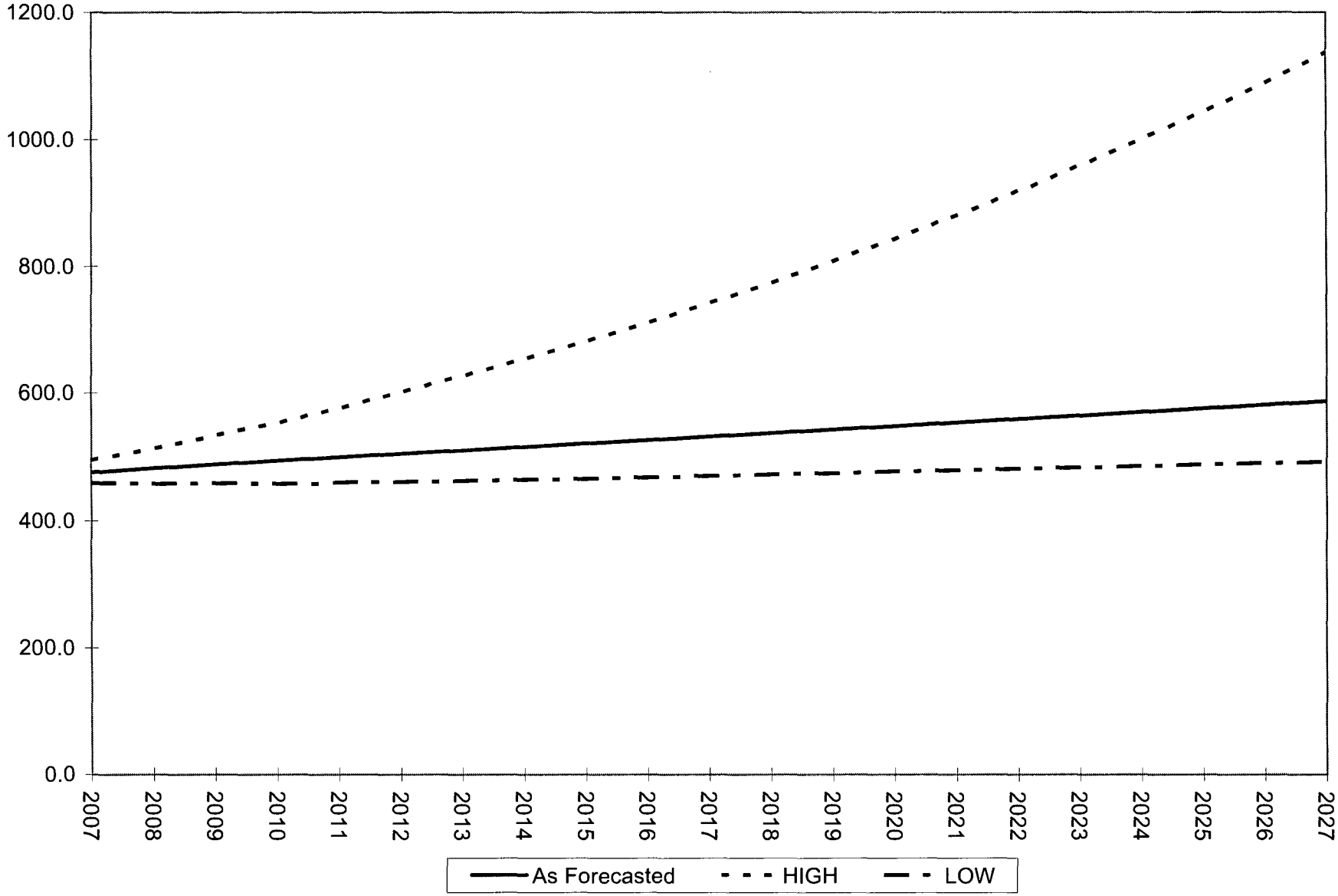
2027
As Forecasted
HIGH
LOW

Montana-Dakota Integrated System

High-Growth and Low-Growth Scenarios - Demand



5. Allocations

Montana-Dakota's Integrated System consists of the service territories in Montana, North Dakota, and South Dakota. The forecasts developed by sector and in total as described up to this point are for Montana-Dakota's Integrated System in total. Montana-Dakota's Financial Forecasting Department requires forecasts of monthly peak demands by state, and monthly sales and energy requirements by sector and by state. Therefore, disaggregating the Integrated System forecast into state and monthly numbers is necessary.

5.1. Sales and Customer Allocations by State

Historical data indicates that each state's portion of the system demand and energy has not remained constant and no consistent trend has emerged. The portions (or ratios) of each sector within the three states also does not indicate any consistent trend. Since the most meaningful time period for Montana-Dakota financial forecasting is five years or less, it was decided to use the ratios from the most recent year (2005) for allocating energy and customers to the states by sales sector. The tables below show the percent of total electric sales and customers allocated to each state by customer class.

Percent of Sales by Sector Allocated to Each State

	ND	SD	MT
Residential	0.71242	0.08312	0.20446
SC&I	0.64647	0.08967	0.26386
MT Oil Fields	-	-	1.00000
Sabin Metals	1.00000	-	-
Westmoreland Coal	0.92361	-	0.07639
Tesoro Refinery	1.00000	-	-
General LC&I	0.76269	0.04654	0.19077
Street Lighting	0.67434	0.08758	0.23808
Other Public Sales	0.78943	0.05921	0.15136
Interdepartmental	0.54904	0.02215	0.42881
Company Use	0.87434	0.05050	0.07516

Percent of Customers by Sector Allocated to Each State

	ND	SD	MT
Residential	0.70685	0.07749	0.21566
SC&I	0.59356	0.11396	0.29248
General LC&I	0.69682	0.06545	0.23773
Street Lighting	0.77570	0.06542	0.15888
Other Public Sales	0.82031	0.06473	0.11496
Interdepartmental	0.57065	0.00544	0.42391

5.2. Sales and Customer Allocations by Month

The Financial Forecasting Department requires a monthly calendar month forecast for each state. This is accomplished through a two-step process. First, monthly estimates of energy and customers by sector are determined by calculating the ratio of the monthly bill cycle value to the annual amount for the 15-year period 1991-2005. Results were averaged for each month for each sector for each state. These ratios were then applied to the annual amounts calculated as described in section 4.1 to arrive at billing-cycle sales. The allocation factors for billing-cycle sales for each state, month and sector are shown in Appendix A-8. Billing-month to calendar-month apportionment factors are then used to convert from billing-month to calendar-month sales. These apportionment factors are shown in Appendix A-9.

5.3. Peak Demand Allocations by Month

Allocating peak demand on a monthly basis consists of several steps:

1. Ratios of each monthly peak to the seasonal peak were calculated for the Integrated System for the period May 1991 through April 2006. (The summer season is May through October and the winter season is November through April of the next year.)
2. The ratios determined in Step 1 from each month were averaged to determine which month of the season was to be the peak month, second highest month, etc. Final results of this step indicate that July and December are the peak months for the summer and winter seasons, respectively, August and January have the second highest peaks for their respective seasons, etc. (See the table below which gives the monthly ranks for each month by season.)

Monthly Average of the Ratios of Monthly Peak To Seasonal Peak for the Integrated System (Number in Parenthesis is Rank)

Summer Season			Winter Season		
May	(5)	0.7062	November	(4)	0.9038
June	(3)	0.8961	December	(1)	0.9811
July	(1)	0.9728	January	(2)	0.9667
August	(2)	0.9740	February	(3)	0.9230
September	(4)	0.8254	March	(5)	0.8598
October	(6)	0.6901	April	(6)	0.8064

3. For each season, the monthly ratios determined in Step 1 were sorted into rank sequence for each year of historical data and averaged across the years for each ranking. Applying the ranked average ratios from this step to the proper month according to the rank determined in Step 2 results in the monthly assignments given in the following table.

15-Year Average Monthly Ratios of Seasonal Peaks For the Integrated System

January	0.9617	July	1.0000
February	0.9248	August	0.9672
March	0.8540	September	0.8178
April	0.8059	October	0.6678
May	0.7129	November	0.8943
June	0.8989	December	1.0000

5.4. Peak Demand Allocation by Month and State

The methodology to allocate monthly demands to each state is essentially the same as described in Section 4.1 only demand is not allocated by sector. Therefore, only the 2005 monthly ratios by state were used. Appendix A-8 lists the monthly peak demand ratios for each state.

5.5. Annual Energy and Seasonal Peak Demand by State

Historical and forecasted sales by sector and in total are shown on the graphs on Appendices C-1 through C-8.

The forecasts of summer and winter peak demands and annual energy through the year 2026 for the states of Montana, North Dakota, and South Dakota are also given in Appendix C. The peak demand and annual energy for Montana, North Dakota, South Dakota, and the Integrated System are shown on Appendix C-9, C-10, C-11, and C-12. Appendices C-13, C-14, and C-15 graphically portray the tables in Appendices C-9 through C-12.

5.6. Sales Forecasts by Sector

The monthly forecasts for the ten year period 2007-2016, which result from the allocation method described above, are shown in Appendices D, E, F, and G for Montana, North Dakota, South Dakota, and the Integrated System, respectively.

APPENDIX A

Historical Data

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE STATE OF MONTANA
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	68,502,477	49,977,929	72,419,095	3,866,284	3,808,210	1,015,211	377,210	-	199,966,416
1967	68,579,218	50,233,896	98,914,908	4,015,663	3,715,582	1,091,354	810,948	-	227,361,569
1968	71,874,276	52,477,560	118,039,208	4,249,304	3,535,121	1,375,297	723,627	-	252,274,393
1969	78,325,684	53,242,727	138,245,825	5,604,625	3,863,692	1,249,804	709,401	-	281,241,758
1970	82,496,690	55,175,717	153,459,061	6,083,320	3,897,568	1,160,863	737,641	-	303,010,860
1971	85,705,748	55,865,479	163,248,877	6,492,393	4,104,508	958,540	960,127	-	317,335,672
1972	90,077,273	58,161,951	172,396,207	6,600,222	3,795,853	992,915	890,585	-	332,915,006
1973	92,338,476	61,367,352	190,984,413	6,706,073	4,211,624	1,158,025	902,676	-	357,668,639
1974	96,505,351	66,904,551	186,287,388	6,840,674	4,153,930	1,315,961	945,082	-	362,952,937
1975	105,048,515	69,452,309	178,400,297	7,087,080	3,913,278	1,506,121	984,351	-	366,391,951
1976	115,110,425	77,612,604	175,313,131	7,268,240	4,495,249	1,583,748	1,004,267	-	382,387,664
1977	120,454,365	81,073,772	172,531,607	7,359,231	4,657,927	1,548,399	1,036,205	-	388,661,506
1978	129,852,166	87,526,266	175,599,086	7,353,808	4,677,788	4,820,487	1,049,471	-	410,879,072
1979	136,672,460	96,589,760	178,879,168	7,359,189	5,467,739	2,283,782	1,029,716	-	428,281,814
1980	136,149,204	101,715,349	198,015,998	7,459,268	6,123,304	1,797,126	972,817	-	452,233,066
1981	144,334,391	111,228,786	206,717,766	7,487,108	6,381,820	1,715,542	752,755	-	478,618,168
1982	153,313,720	125,817,634	213,636,154	7,407,897	5,634,466	2,943,589	1,651,780	-	510,405,240
1983	150,623,962	108,187,279	249,492,431	7,481,435	7,159,425	1,709,185	917,496	-	525,571,213
1984	149,973,668	101,423,250	272,228,601	7,379,668	6,998,461	3,442,266	900,229	-	542,346,143
1985	142,726,940	106,608,809	281,467,351	7,188,874	6,516,453	1,001,594	639,636	-	546,149,657
1986	133,656,316	101,534,376	277,264,926	7,266,290	5,968,032	189,694	590,579	-	526,470,213
1987	126,119,227	95,806,617	248,018,234	7,290,415	6,493,543	195,663	580,473	-	484,504,172
1988	139,327,515	87,777,108	259,622,149	7,217,742	7,711,112	211,260	616,658	-	502,483,544
1989	133,923,369	85,321,774	255,852,368	7,076,958	7,254,814	226,885	599,867	-	490,256,035
1990	130,093,020	84,487,870	253,081,235	7,009,344	7,148,412	226,321	714,125	-	482,760,327
1991	135,844,961	85,054,308	253,947,072	7,232,332	6,944,172	225,952	606,717	-	489,855,514
1992	126,265,220	82,097,610	246,018,931	7,228,554	6,937,275	215,649	560,531	-	469,323,770
1993	131,148,008	85,150,142	239,566,466	7,228,736	6,709,227	223,166	621,957	-	470,647,702
1994	137,293,020	91,734,345	237,573,170	7,257,426	7,110,947	232,838	679,830	-	481,881,576
1995	139,222,942	92,004,117	231,710,303	7,224,945	6,846,494	228,038	621,915	-	477,858,754
1996	147,421,480	96,007,848	231,515,420	7,237,827	7,135,267	233,336	574,831	-	490,126,009
1997	144,515,075	94,430,882	238,928,697	7,237,555	7,244,423	201,302	556,239	-	493,114,173
1998	144,374,643	96,561,060	237,770,443	7,271,601	7,162,112	213,369	549,751	-	493,902,979
1999	139,939,058	93,535,156	251,450,993	7,241,875	7,037,487	201,768	551,485	-	499,957,822
2000	143,298,426	94,947,102	276,845,617	7,212,210	6,819,914	218,795	456,819	-	529,798,883
2001	144,170,040	94,133,492	282,466,554	7,242,218	6,677,075	218,859	453,240	-	535,361,478
2002	147,916,359	96,252,274	306,159,986	7,240,913	6,893,847	195,977	448,893	-	565,108,249
2003	153,518,427	100,463,048	340,070,071	7,208,314	6,991,783	190,115	501,557	-	608,943,315
2004	141,249,319	98,150,615	348,097,119	7,249,849	6,709,211	178,934	469,139	-	602,104,186
2005	150,705,819	102,045,511	364,489,268	7,232,015	6,481,903	194,114	454,825	-	631,603,455

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE STATE OF NORTH DAKOTA
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	177,839,445	101,454,865	62,248,779	12,065,801	9,778,523	242,324	627,634	35,481	364,292,852
1967	178,648,631	101,511,079	66,238,823	12,404,851	10,627,735	235,590	1,496,352	68,626	371,231,687
1968	189,586,695	108,098,127	68,327,053	13,528,733	11,306,057	1,075,808	1,514,551	68,231	393,505,255
1969	203,352,077	117,146,235	69,429,138	14,548,153	11,781,023	3,257,680	1,710,576	66,543	421,291,425
1970	215,129,232	128,966,438	74,006,755	15,405,493	12,432,105	2,976,220	1,632,669	66,670	450,615,582
1971	224,660,134	137,368,067	78,485,841	15,852,055	12,356,099	1,532,592	3,570,747	68,888	473,894,423
1972	241,177,868	141,541,263	85,849,701	16,145,159	12,610,906	230,775	5,480,921	72,184	503,108,777
1973	245,827,613	146,917,105	92,262,004	16,519,767	14,113,173	198,917	5,488,128	71,349	521,398,056
1974	259,763,946	151,905,722	95,263,639	16,812,962	14,147,896	207,547	5,388,873	64,700	543,555,285
1975	284,712,928	174,078,088	107,153,806	17,229,492	14,613,377	194,573	5,283,319	54,272	603,319,855
1976	307,231,757	188,990,076	119,225,930	17,788,799	17,287,746	233,931	5,201,276	58,861	656,018,376
1977	322,066,615	202,204,724	123,518,797	18,705,610	20,388,865	775,960	5,329,555	61,312	693,051,438
1978	360,829,206	226,814,052	131,861,024	19,233,630	22,666,150	448,114	5,583,243	55,953	767,491,372
1979	385,274,877	251,074,945	134,220,720	19,899,710	23,913,957	263,925	5,383,105	56,305	820,087,544
1980	390,283,221	265,468,707	140,987,413	20,492,222	26,160,460	382,762	5,040,756	44,390	848,859,931
1981	408,735,140	273,869,995	175,505,109	21,076,949	24,329,774	244,375	4,212,597	46,134	908,020,073
1982	452,363,924	245,889,852	236,334,289	21,499,821	26,288,435	261,436	4,964,613	47,986	987,650,356
1983	456,184,125	258,134,530	230,553,333	21,370,120	28,270,730	382,443	8,659,379	41,916	1,003,596,576
1984	455,285,616	267,515,911	240,737,178	20,966,383	28,884,506	2,020,361	6,602,362	42,325	1,022,054,642
1985	450,793,794	284,254,986	233,446,499	20,793,870	28,421,516	194,570	6,810,757	39,484	1,024,755,476
1986	434,367,094	282,091,350	232,968,286	20,399,709	29,251,485	283,486	8,387,924	37,451	1,007,786,785
1987	414,769,777	226,151,695	289,829,031	20,488,538	27,652,568	306,718	6,531,047	46,880	985,776,254
1988	449,769,976	199,876,624	348,910,521	20,488,320	27,128,548	233,035	6,339,307	34,969	1,052,781,300
1989	443,827,623	195,738,987	362,960,433	20,407,635	26,027,847	236,202	6,825,024	38,865	1,056,062,616
1990	430,825,093	192,983,257	373,076,254	20,510,585	25,648,820	243,363	6,283,396	37,303	1,049,608,071
1991	450,333,411	196,030,842	383,766,958	20,458,655	30,828,407	266,645	6,137,808	33,378	1,087,856,104
1992	423,260,909	188,693,144	398,197,743	20,663,341	31,720,268	282,076	6,211,805	48,627	1,069,077,913
1993	439,344,573	191,672,169	416,752,959	20,565,116	31,146,204	322,281	5,956,790	46,519	1,105,806,611
1994	456,342,312	203,783,580	445,849,305	20,574,807	32,828,420	316,899	6,987,912	41,960	1,166,725,195
1995	473,310,757	207,631,769	447,406,363	20,664,316	32,139,766	311,888	7,116,061	43,365	1,188,624,285
1996	489,581,963	212,394,753	463,633,627	20,598,257	33,617,666	293,678	7,112,634	42,287	1,227,274,865
1997	485,185,916	215,341,328	464,356,987	20,448,097	35,525,187	276,970	7,039,295	37,836	1,228,211,616
1998	476,555,259	216,137,378	470,352,073	20,780,506	33,387,706	268,955	6,460,961	35,675	1,223,978,513
1999	476,150,870	215,933,149	487,339,322	20,930,538	32,535,686	269,387	6,214,785	24,378	1,239,398,115
2000	480,611,397	220,082,001	496,752,971	20,765,723	32,298,343	276,507	5,758,461	-	1,256,545,403
2001	495,264,092	219,718,551	524,934,913	20,801,786	32,839,971	283,411	5,380,094	-	1,299,222,818
2002	510,649,026	223,725,158	534,095,959	20,845,828	33,601,388	245,882	4,924,187	-	1,328,087,428
2003	518,362,506	230,831,463	538,714,606	20,964,805	33,818,825	243,012	5,146,364	-	1,348,081,581
2004	482,828,358	224,924,291	532,079,391	20,632,572	32,251,096	238,077	5,030,082	-	1,297,983,867
2005	525,132,818	250,022,338	563,792,863	20,484,092	33,806,432	248,541	5,291,349	-	1,398,778,433

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE STATE OF SOUTH DAKOTA
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	42,230,739	22,427,449	6,732,280	2,095,903	1,697,150	1,424	126,325	-	75,311,270
1967	41,997,237	25,800,957	4,063,750	1,979,052	1,847,881	1,153	260,654	-	75,950,684
1968	43,952,926	23,284,225	3,940,603	2,575,843	1,707,100	1,608	268,857	-	75,731,162
1969	46,482,606	24,758,227	929,501	2,598,403	1,841,636	2,207	287,654	-	76,900,234
1970	47,361,709	22,775,007	3,464,385	2,547,642	1,759,567	2,154	269,189	-	78,179,653
1971	49,310,679	22,255,017	4,727,415	2,716,302	1,834,084	2,362	315,769	215	81,161,843
1972	52,980,235	22,785,758	5,347,104	2,813,232	1,918,580	2,270	365,122	-	86,212,301
1973	53,570,804	23,259,175	5,400,790	2,859,812	1,987,540	2,559	432,365	-	87,513,045
1974	56,666,860	23,203,748	5,840,707	2,994,179	2,138,696	2,487	428,561	-	91,275,238
1975	62,824,496	24,817,191	6,748,459	3,128,822	2,030,891	2,433	480,797	-	100,033,089
1976	66,343,302	25,800,602	7,756,873	3,103,016	2,053,227	2,370	467,531	-	105,526,921
1977	65,963,975	26,111,838	8,474,190	3,124,296	1,840,714	3,151	478,536	-	105,996,700
1978	68,589,710	27,328,956	9,693,110	3,113,948	1,774,321	2,966	607,731	-	111,110,742
1979	67,938,559	26,971,950	10,123,460	3,121,871	1,904,825	2,983	620,674	-	110,684,322
1980	64,325,468	26,196,596	10,851,108	3,140,131	2,170,017	3,737	507,507	-	107,194,564
1981	61,878,613	25,902,182	11,243,318	3,083,603	1,830,577	2,970	356,399	-	104,297,662
1982	65,558,005	27,156,570	11,426,316	3,030,031	1,871,552	2,943	607,247	-	109,652,664
1983	65,118,829	26,884,079	12,353,692	3,006,759	1,716,506	2,486	557,667	-	109,640,018
1984	65,920,772	27,933,476	12,698,954	2,964,197	1,816,219	1,782	545,965	-	111,881,365
1985	64,222,969	27,289,287	13,297,147	2,968,984	1,826,822	7,425	829,238	-	110,441,872
1986	62,444,941	27,005,631	14,820,308	2,987,404	1,637,375	22,258	571,879	-	109,489,796
1987	59,644,668	26,773,933	16,227,633	2,986,179	1,857,719	28,687	363,754	-	107,882,573
1988	63,622,038	28,168,260	18,064,220	2,953,900	1,925,245	14,449	419,470	-	115,167,582
1989	61,747,940	28,578,702	19,249,467	2,937,751	2,019,854	13,359	456,236	-	115,003,309
1990	59,041,129	27,674,002	20,540,349	2,938,991	1,879,111	9,908	369,286	-	112,452,776
1991	60,709,134	28,371,913	20,800,179	2,944,664	2,119,069	10,945	398,192	-	115,354,096
1992	56,416,333	27,113,531	21,125,368	2,920,263	2,354,085	10,701	343,584	-	110,283,865
1993	59,615,263	27,986,509	22,314,105	2,921,246	2,116,180	11,786	397,837	-	115,362,926
1994	61,124,471	30,267,538	23,784,346	2,922,998	2,427,771	11,901	422,267	-	120,961,292
1995	62,959,707	31,134,415	24,670,253	2,854,516	3,097,276	11,484	404,093	-	125,131,744
1996	63,638,266	32,141,951	25,352,355	2,872,136	3,137,175	12,172	352,311	-	127,506,366
1997	61,623,748	31,753,237	25,522,619	2,805,901	3,058,443	11,319	342,786	-	125,118,053
1998	59,360,287	32,313,292	25,113,488	2,796,107	3,003,078	9,777	286,457	-	122,882,486
1999	59,567,949	32,498,800	25,977,705	2,807,423	2,954,190	9,857	297,480	-	124,113,404
2000	59,525,312	32,320,913	25,956,274	2,740,106	2,810,931	9,227	308,855	-	123,671,618
2001	61,117,630	33,018,447	25,846,819	2,748,375	2,742,790	9,414	325,833	-	125,809,308
2002	61,780,443	33,800,702	26,645,097	2,691,584	2,737,670	9,884	329,617	-	127,994,997
2003	61,149,061	33,964,499	27,075,451	2,683,876	2,791,070	10,319	319,687	-	127,993,963
2004	56,535,958	32,909,312	27,090,632	2,672,475	2,885,412	9,788	290,260	-	122,393,837
2005	61,267,370	34,678,560	28,886,389	2,660,320	2,535,633	10,026	305,636	-	130,343,934

MONTANA DAKOTA UTILITIES CO.
ANNUAL SALES BY CLASS FOR THE INTEGRATED SYSTEM
(KILOWATT HOURS)

Year	Residential	Small C&I	Large C&I	Street Lighting	Other Public Sales	Interdepart-mental	Company Use	Unbilled	Total
1966	288,572,661	173,860,243	141,400,154	18,027,988	15,283,883	1,258,959	1,131,169	35,481	639,570,538
1967	289,225,086	177,545,932	169,217,481	18,399,566	16,191,198	1,328,097	2,567,954	68,626	674,543,940
1968	305,413,897	183,859,912	190,306,864	20,353,880	16,548,278	2,452,713	2,507,035	68,231	721,510,810
1969	328,160,367	195,147,189	208,604,464	22,751,181	17,486,351	4,509,691	2,707,631	66,543	779,433,417
1970	344,987,631	206,917,162	230,930,201	24,036,455	18,089,240	4,139,237	2,639,499	66,670	831,806,095
1971	359,676,561	215,488,563	246,462,133	25,060,750	18,294,691	2,493,494	4,846,643	69,103	872,391,938
1972	384,235,376	222,488,972	263,593,012	25,558,613	18,325,339	1,225,960	6,736,628	72,184	922,236,084
1973	391,736,893	231,543,632	288,647,207	26,085,652	20,312,337	1,359,501	6,823,169	71,349	966,579,740
1974	412,936,157	242,014,021	287,391,734	26,647,815	20,440,522	1,525,995	6,762,516	64,700	997,783,460
1975	452,585,939	268,347,588	292,302,562	27,445,394	20,557,546	1,703,127	6,748,467	54,272	1,069,744,895
1976	488,685,484	292,403,282	302,295,934	28,160,055	23,836,222	1,820,049	6,673,074	58,861	1,143,932,961
1977	508,484,955	309,390,334	304,524,594	29,189,137	26,887,506	2,327,510	6,844,296	61,312	1,187,709,644
1978	559,271,082	341,669,274	317,153,220	29,701,386	29,118,259	5,271,567	7,240,445	55,953	1,289,481,186
1979	589,885,896	374,636,655	323,223,348	30,380,770	31,286,521	2,550,690	7,033,495	56,305	1,359,053,680
1980	590,757,893	393,380,652	349,854,519	31,091,621	34,453,781	2,183,625	6,521,080	44,390	1,408,287,561
1981	614,948,144	411,000,963	393,466,193	31,647,660	32,542,171	1,962,887	5,321,751	46,134	1,490,935,903
1982	671,235,649	398,864,056	461,396,759	31,937,749	33,794,453	3,207,968	7,223,640	47,986	1,607,708,260
1983	671,926,916	393,205,888	492,399,456	31,858,314	37,146,661	2,094,114	10,134,542	41,916	1,638,807,807
1984	671,180,056	396,872,637	525,664,733	31,310,248	37,699,186	5,464,409	8,048,556	42,325	1,676,282,150
1985	657,743,703	418,153,082	528,210,997	30,951,728	36,764,791	1,203,589	8,279,631	39,484	1,681,347,005
1986	630,468,351	410,631,357	525,053,520	30,653,403	36,856,892	495,438	9,550,382	37,451	1,643,746,794
1987	600,533,672	348,732,245	554,074,898	30,765,132	36,003,830	531,068	7,475,274	46,880	1,578,162,999
1988	652,719,529	315,821,992	626,596,890	30,659,962	36,764,905	458,744	7,375,435	34,969	1,670,432,426
1989	639,498,932	309,639,463	638,062,268	30,422,344	35,302,515	476,446	7,881,127	38,865	1,661,321,960
1990	619,959,242	305,145,129	646,697,838	30,458,920	34,676,343	479,592	7,366,807	37,303	1,644,821,174
1991	646,887,506	309,457,063	658,514,209	30,635,651	39,891,648	503,542	7,142,717	33,378	1,693,065,714
1992	605,942,462	297,904,285	665,342,042	30,812,158	41,011,628	508,426	7,115,920	48,627	1,648,685,548
1993	630,107,844	304,808,820	678,633,530	30,715,098	39,971,611	557,233	6,976,584	46,519	1,691,817,239
1994	654,759,803	325,785,463	707,206,821	30,755,231	42,367,138	561,638	8,090,009	41,960	1,769,568,063
1995	675,493,406	330,770,301	703,786,919	30,743,777	42,083,536	551,410	8,142,069	43,365	1,791,614,783
1996	700,641,709	340,544,552	720,501,402	30,708,220	43,890,108	539,186	8,039,776	42,287	1,844,907,240
1997	691,324,739	341,525,447	728,808,303	30,491,553	45,828,053	489,591	7,938,320	37,836	1,846,443,842
1998	680,290,189	345,011,730	733,236,004	30,848,214	43,552,896	492,101	7,297,169	35,675	1,840,763,978
1999	675,657,877	341,967,105	764,768,020	30,979,836	42,527,363	481,012	7,063,750	24,378	1,863,469,341
2000	683,435,135	347,350,016	799,554,862	30,718,039	41,929,188	504,529	6,524,135	-	1,910,015,904
2001	700,551,762	346,870,490	833,248,286	30,792,379	42,259,836	511,684	6,159,167	-	1,960,393,604
2002	720,345,828	353,778,134	866,901,042	30,778,325	43,232,905	451,743	5,702,697	-	2,021,190,674
2003	733,029,994	365,259,010	905,860,128	30,856,995	43,601,678	443,446	5,967,608	-	2,085,018,859
2004	680,613,635	355,984,218	907,267,142	30,554,896	41,845,719	426,799	5,789,481	-	2,022,481,890
2005	737,106,007	386,746,409	957,168,520	30,376,427	42,823,968	452,681	6,051,810	-	2,160,725,822

MONTANA-DAKOTA UTILITIES CO.
INTEGRATED SYSTEM SEASONAL PEAKS AND PEAK MONTH LOAD FACTORS 1/
1960 THROUGH 2005

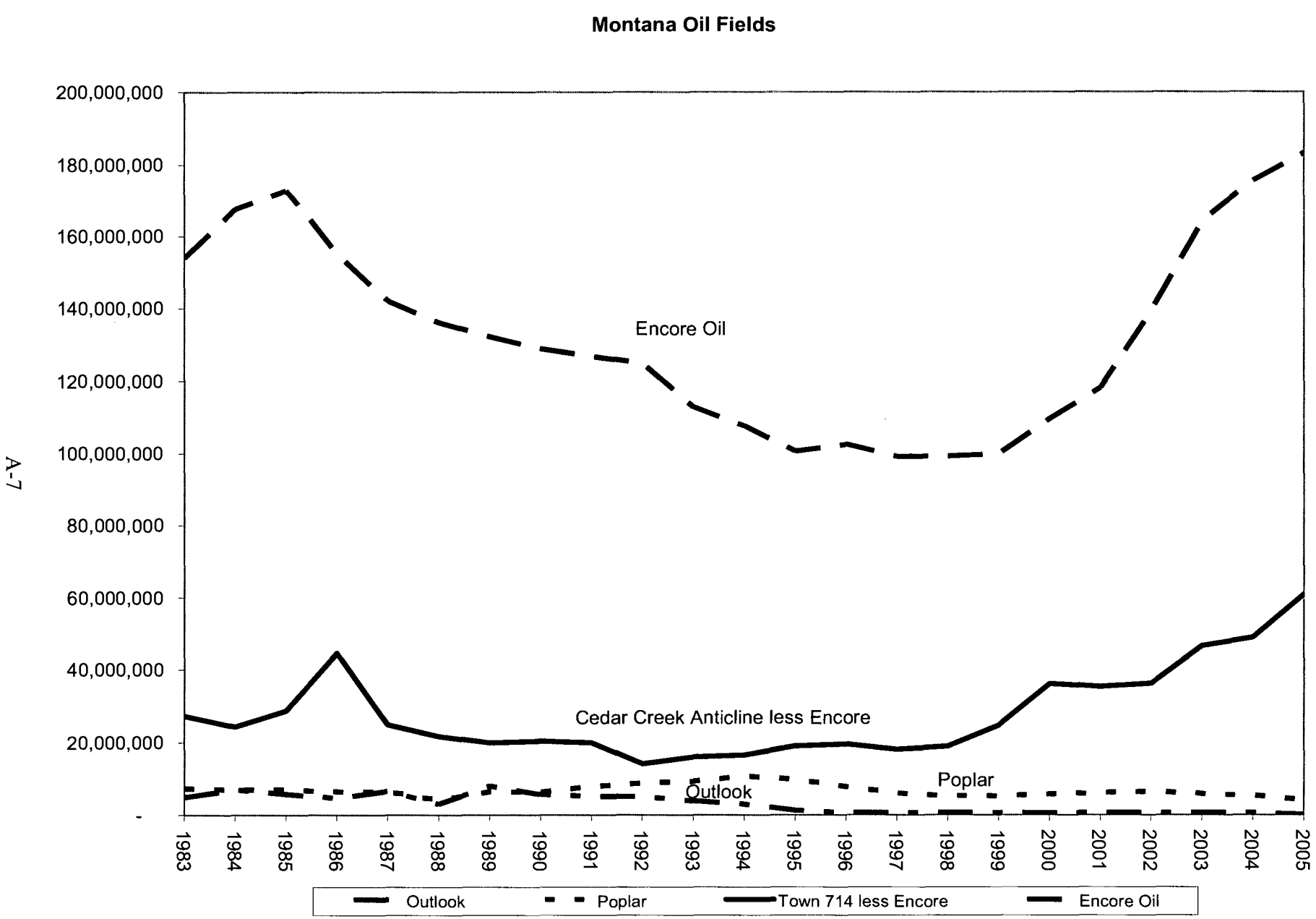
	SUMMER			WINTER			ANNUAL	
YEAR	MW	MONTH	LOAD FACTOR	MW	MONTH 2/	LOAD FACTOR	LOAD FACTOR	PEAK RATIO 3/
1960	76.7	AUG	70.7	109.3	DEC	58.8	50.9	1.425
1961	82.8	AUG	73.7	113.7	JAN	62.0	52.5	1.373
1962	83.8	AUG	76.4	123.2	JAN	65.4	53.7	1.470
1963	95.9	JUL	68.9	127.6	DEC	63.3	52.5	1.331
1964	101.8	AUG	68.2	138.2	DEC	64.2	51.8	1.358
1965	108.4	AUG	68.7	138.0	JAN	68.5	56.5	1.273
1966	114.0	JUL	70.5	149.6	JAN	65.4	58.2	1.312
1967	129.0	JUL	71.3	161.8	JAN	68.1	60.0	1.254
1968	133.3	JUL	69.9	173.5	DEC	65.1	55.0	1.302
1969	153.4	AUG	70.0	178.2	JAN	70.3	62.0	1.162
1970	160.5	JUL	70.2	186.2	DEC	67.6	59.5	1.160
1971	170.9	AUG	72.2	195.7	JAN	70.5	58.2	1.145
1972	174.5	AUG	72.6	209.1	DEC	69.4	58.5	1.198
1973	199.6	AUG	69.9	200.1	DEC	67.3	63.2	1.003
1974	210.0	JUL	71.9	222.0	JAN	66.6	62.7	1.057
1975	230.8	JUL	68.3	238.2	JAN	67.8	59.5	1.032
1976	242.6	AUG	64.8	241.3	JAN	78.1	59.7	0.995
1977	253.7	JUL	61.2	257.8	DEC	71.3	57.9	1.016
1978	257.2	SEP	59.9	268.1	JAN	79.0	62.9	1.042
1979	257.6	JUL	65.0	287.5	JAN	73.7	63.1	1.116
1980	291.2	JUL	64.4	292.0	DEC	73.4	61.7	1.003
1981	315.4	JUL	61.6	333.4	JAN	75.2	59.0	1.057
1982	322.7	AUG	60.8	293.7	DEC	74.9	59.6	0.910
1983	337.5	AUG	68.5	354.1	DEC	72.7	57.5	1.049
1984	354.6	AUG	64.3	330.6	JAN	74.3	58.3	0.932
1985	350.4	JUL	62.7	324.2	DEC	74.2	59.8	0.925
1986	338.0	JUN	57.9	293.2	DEC	73.4	59.2	0.867
1987	358.6	JUL	58.7	306.2	FEB	76.2	54.6	0.854
1988	386.7	JUN	61.6	320.9	FEB	74.1	54.2	0.830
1989	383.6	AUG	57.1	341.6	DEC	69.8	54.4	0.891
1990	381.6	JUL	55.4	330.2	DEC	70.8	53.5	0.865
1991	387.1	JUL	58.0	311.8	DEC	74.3	54.2	0.805
1992	339.1	AUG	60.9	337.5	DEC	73.1	61.4	0.995
1993	350.3	AUG	62.3	332.7	JAN	77.5	61.0	0.950
1994	369.8	AUG	61.8	322.6	DEC	74.5	59.7	0.872
1995	412.7	AUG	59.8	348.7	FEB	68.6	54.0	0.845
1996	393.3	AUG	62.6	343.1	JAN	78.4	58.3	0.872
1997	404.6	JUL	61.6	332.8	JAN	74.4	56.6	0.823
1998	402.5	AUG	63.6	354.2	DEC	70.1	56.9	0.880
1999	420.6	JUL	61.3	342.4	DEC	70.7	54.2	0.814
2000	432.3	AUG	61.3	353.9	DEC	77.4	54.9	0.819
2001	452.9	AUG	62.3	328.9	DEC	78.2	53.0	0.726
2002	458.8	JUL	64.9	343.5	JAN	78.4	53.7	0.749
2003	470.5	AUG	64.3	367.7	JAN	77.2	54.0	0.782
2004	458.4	JUL	60.4	383.4	JAN	76.7	54.9	0.836
2005	459.1	JUL	65.9	387.2	DEC	76.8	57.9	0.843

1/ MDU only net peak on combined system as calculated by MDU (excludes REC adjusted peak).
2/ January and February is of the following year.
3/ Ratio of winter peak to preceding summer peak.

MONTANA-DAKOTA UTILITIES CO.
DEMAND BY STATE AT TIME OF SYSTEM SEASONAL PEAK
(MEGAWATTS)

	SUMMER				WINTER				
YEAR	ND	SD	MT	INT SYS	ND	SD	MT	INT SYS	
1975	139.4	22.1	69.3	230.8	145.1	22.8	70.3	238.2	*
1976	147.4	24.2	71.0	242.6	147.3	24.1	69.9	241.3	*
1977	155.9	23.5	74.6	254.0	155.1	24.3	78.4	257.8	
1978	165.5	20.4	70.3	256.2	165.5	23.9	78.7	268.1	*
1979	166.4	16.4	74.8	257.6	177.2	24.1	86.2	287.5	*
1980	181.5	21.5	88.2	291.2	180.8	21.8	89.4	292.0	
1981	202.3	21.0	92.1	315.4	201.5	24.9	106.9	333.3	*
1982	208.0	20.8	93.9	322.7	185.0	21.1	87.6	293.7	
1983	221.2	20.9	95.4	337.5	225.7	27.5	100.9	354.1	
1984	234.8	23.9	96.0	354.7	209.4	23.0	98.2	330.6	*
1985	233.3	24.4	92.7	350.4	206.9	22.4	94.9	324.2	
1986	224.2	22.5	91.4	338.1	196.4	21.2	75.7	293.3	
1987	242.1	28.5	88.1	358.7	204.6	22.8	78.8	306.2	*
1988	265.6	28.4	92.7	386.7	212.1	23.7	85.0	320.8	*
1989	265.1	27.6	90.9	383.6	225.6	26.9	89.1	341.6	
1990	261.2	26.2	94.2	381.6	218.2	24.1	87.9	330.2	
1991	271.9	30.0	85.2	387.1	217.5	19.9	74.4	311.8	
1992	234.4	20.9	83.7	339.0	233.4	23.9	80.1	337.4	
1993	251.1	23.3	75.9	350.3	225.6	25.5	81.6	332.7	*
1994	253.7	27.9	88.2	369.8	220.9	24.5	77.2	322.6	
1995	290.6	27.1	95.0	412.7	236.1	22.5	90.1	348.7	*
1996	272.0	27.1	94.1	393.2	233.6	21.3	88.2	343.1	*
1997	288.0	22.4	94.3	404.7	225.0	20.0	87.8	332.8	*
1998	285.1	25.7	91.7	402.5	248.2	21.6	84.4	354.2	
1999	295.0	28.7	96.9	420.6	237.3	21.6	83.6	342.5	
2000	302.9	30.1	99.3	432.3	234.7	22.8	96.4	353.9	
2001	317.8	29.8	105.4	453.0	235.0	14.3	79.6	328.9	
2002	326.0	26.4	106.4	458.8	242.9	14.4	86.2	343.5	*
2003	328.4	28.4	113.7	470.5	251.4	19.4	96.9	367.7	*
2004	320.2	28.4	109.8	458.4	258.8	21.9	102.7	383.4	*
2005	311.6	27.7	119.8	459.1	265.0	21.8	100.4	387.2	

* WINTER PEAK IS IN THE FOLLOWING YEAR.


Montana Oil Fields
200,000,000
180,000,000
160,000,000
140,000,000
120,000,000
100,000,000
80,000,000
60,000,000
40,000,000
20,000,000
-
Encore Oil
Cedar Creek Anticline less Encore
Poplar
Outlook
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Outlook
Poplar
Town 714 less Encore
Encore Oil

BILLING CYCLE ALLOCATION FACTORS BY STATE

NORTH DAKOTA

SALES	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Residential	0.107910	0.092023	0.084407	0.077640	0.068684	0.069633	0.085325	0.092655	0.083611	0.068938	0.077616	0.091558
Small C&I	0.095433	0.086838	0.082327	0.077899	0.073897	0.076115	0.087097	0.092045	0.088372	0.073810	0.080219	0.085947
Large C&I	0.087087	0.082012	0.079033	0.079270	0.077825	0.081000	0.088904	0.090061	0.089946	0.081698	0.080451	0.082713
Street Lighting	0.092088	0.086893	0.084332	0.082453	0.079471	0.077873	0.077028	0.079156	0.081293	0.083252	0.086601	0.089561
Other Public Sales	0.083362	0.076389	0.080473	0.072028	0.078246	0.087661	0.099051	0.103862	0.094937	0.075360	0.072012	0.076620
Interdepartmental	0.101947	0.091482	0.085549	0.085425	0.079700	0.074925	0.075203	0.073990	0.075911	0.078067	0.083877	0.093923
Company Use	0.089760	0.083678	0.078097	0.078823	0.078025	0.083604	0.089821	0.095140	0.085857	0.072279	0.086082	0.078835
Tesoro Refinery	0.078010	0.068799	0.076780	0.082574	0.076099	0.091772	0.091509	0.089317	0.093889	0.083760	0.085853	0.081636
Westmoreland Coal	0.109098	0.098664	0.087476	0.091082	0.076089	0.073142	0.064569	0.066672	0.072754	0.081336	0.086512	0.092607
CUSTOMERS												
Residential	0.997431	0.997571	0.997801	0.998010	0.998706	1.000209	1.000810	1.001449	1.001772	1.001880	1.002232	1.002129
Small C&I	0.987504	0.986072	0.986105	0.993223	1.002661	1.008458	1.009057	1.011867	1.010368	1.003361	1.000385	1.000940
Large C&I	0.988409	0.993031	0.994764	0.999242	1.001553	1.000831	1.001986	1.002275	1.002419	1.005308	1.005453	1.004730
Street Lighting	1.001424	1.016928	1.018510	1.023572	1.025154	1.025787	0.976744	0.978643	0.979592	0.982756	0.983389	0.987502
Other Public Sales	0.993886	0.993479	0.994495	1.001406	1.009129	1.009129	1.009332	1.006690	1.004455	0.997951	0.992869	0.987178
PEAK DEMAND	0.6749	0.6680	0.6913	0.6942	0.6994	0.6913	0.6787	0.6796	0.6940	0.6891	0.6851	0.6843

SOUTH DAKOTA

SALES	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Residential	0.109625	0.094216	0.087430	0.080610	0.070230	0.068747	0.082525	0.090190	0.082077	0.067120	0.077064	0.090168
Small C&I	0.094906	0.086012	0.081272	0.076895	0.071049	0.074006	0.086981	0.097875	0.091429	0.074254	0.079494	0.085827
Large C&I	0.088180	0.080873	0.079954	0.079150	0.078399	0.077213	0.081128	0.089369	0.088280	0.085561	0.086212	0.085681
Street Lighting	0.084070	0.083020	0.083712	0.083387	0.083348	0.083601	0.083243	0.083240	0.083268	0.083589	0.083158	0.082364
Other Public Sales	0.083201	0.072550	0.073393	0.074005	0.073621	0.087728	0.102959	0.109986	0.094531	0.083113	0.071587	0.073327
Interdepartmental	0.151520	0.126406	0.101255	0.070933	0.055088	0.047989	0.047137	0.048909	0.055914	0.059823	0.106059	0.128966
Company Use	0.168275	0.161943	0.135479	0.093768	0.054786	0.058750	0.021006	0.045801	0.043377	0.039531	0.067007	0.110277
CUSTOMERS												
Residential	0.996274	0.995658	0.995526	0.996816	1.000467	1.003003	1.007343	1.006580	1.004821	1.001874	0.997329	0.994309
Small C&I	0.975409	0.973880	0.976258	0.992168	1.013569	1.023591	1.023364	1.022685	1.017816	0.999188	0.991658	0.990413
Large C&I	0.998169	0.998169	0.998169	0.999738	1.001308	1.001308	0.998169	0.998169	1.001308	1.001308	1.002877	1.001308
Street Lighting	1.002301	1.013346	1.016107	1.024390	1.027151	1.027151	0.985734	0.985734	0.985734	0.977451	0.974689	0.980212
Other Public Sales	0.946270	0.943951	0.946270	0.978740	1.050638	1.076150	1.080789	1.066873	1.043680	0.978740	0.950908	0.936993
PEAK DEMAND	0.0572	0.0600	0.0610	0.0605	0.0607	0.0621	0.0604	0.0632	0.0571	0.0534	0.0586	0.0563

MONTANA

SALES	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Residential	0.106674	0.091135	0.082962	0.076711	0.068686	0.069726	0.085247	0.098544	0.086299	0.068707	0.076143	0.089166
Small C&I	0.092974	0.085398	0.081298	0.077625	0.074057	0.077307	0.088852	0.097843	0.089397	0.074622	0.076699	0.083929
Large C&I	0.094074	0.084428	0.079524	0.082686	0.075672	0.075831	0.078700	0.081587	0.083219	0.086041	0.079590	0.098648
Street Lighting	0.085923	0.084921	0.083691	0.082441	0.083302	0.082347	0.081540	0.082492	0.082614	0.083169	0.083621	0.083938
Other Public Sales	0.078339	0.071561	0.067000	0.068710	0.074597	0.090237	0.106735	0.119116	0.106673	0.078343	0.069407	0.069283
Interdepartmental	0.107071	0.092789	0.087494	0.083488	0.077509	0.073459	0.073946	0.077585	0.077067	0.073081	0.082598	0.093913
Company Use	0.104419	0.112724	0.095201	0.085166	0.079966	0.065608	0.076380	0.084260	0.075059	0.062284	0.071237	0.087694
Oil Fields	0.089228	0.077976	0.084114	0.082260	0.080936	0.078501	0.082050	0.081937	0.083532	0.086569	0.083483	0.089413
Westmoreland Coal	0.119412	0.109866	0.100317	0.091507	0.078653	0.064357	0.058274	0.056387	0.060960	0.065955	0.086445	0.107868
CUSTOMERS												
Residential	1.001835	1.001583	1.000421	0.997555	0.997801	0.998134	0.998996	0.999467	0.999848	1.000560	1.001851	1.001948
Small C&I	0.982455	0.982205	0.983343	0.993516	1.007512	1.013088	1.015751	1.016752	1.013725	1.002141	0.996019	0.993493
Large C&I	0.977455	0.979508	0.982792	0.990182	1.007834	1.015224	1.020971	1.022202	1.014403	1.003318	0.995108	0.991003
Street Lighting	1.043425	1.072646	1.056818	1.056818	1.054383	1.049513	0.938718	0.942370	0.944805	0.944805	0.946023	0.949675
Other Public Sales	0.965783	0.961446	0.970120	0.996145	1.032289	1.036627	1.038072	1.035181	1.013494	0.996145	0.981687	0.973012
PEAK DEMAND	0.2679	0.2720	0.2477	0.2453	0.2399	0.2466	0.2609	0.2572	0.2489	0.2575	0.2563	0.2594

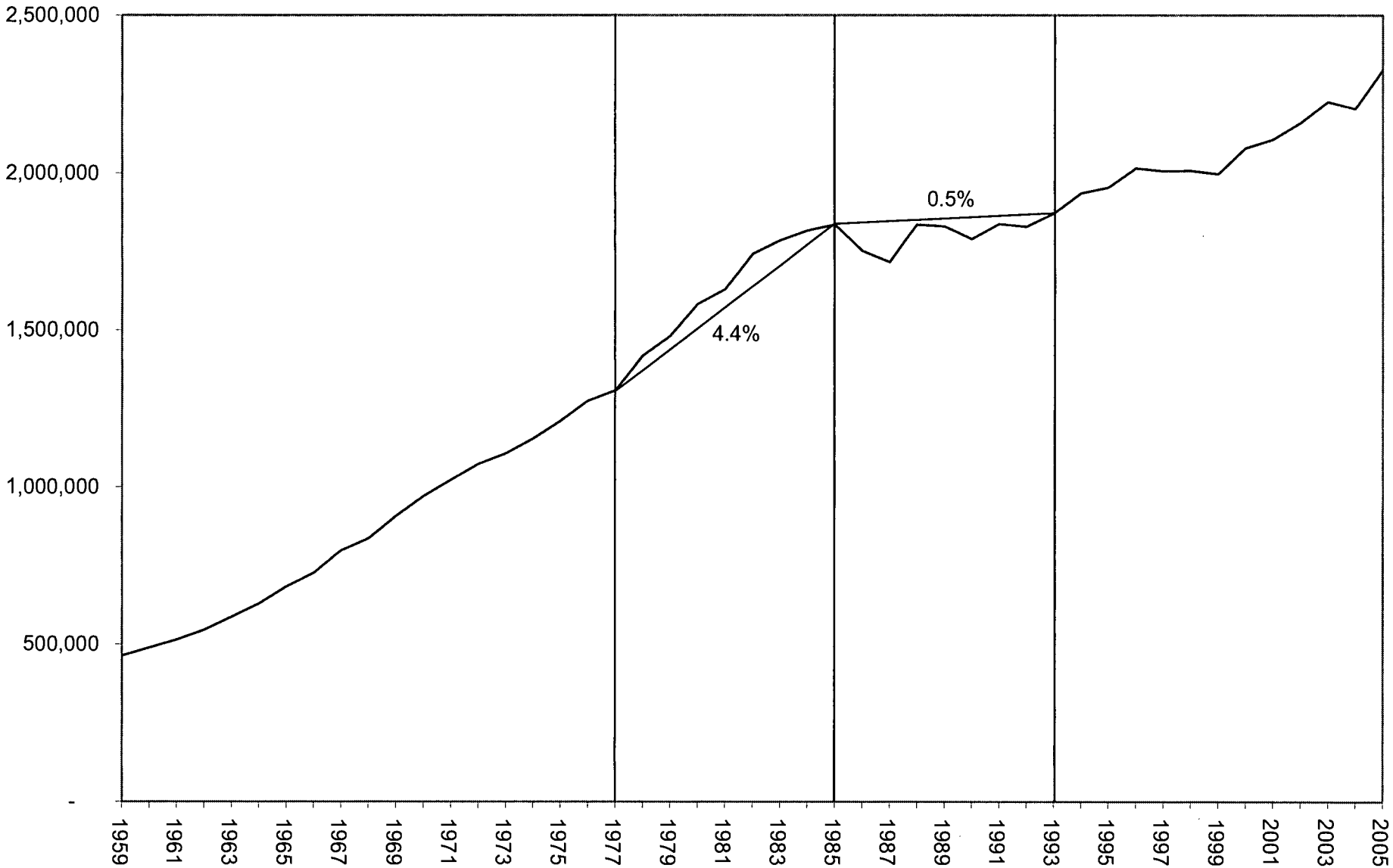
BILLING-MONTH TO CALENDAR-MONTH APPORTIONMENT FACTORS

Residential	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
North Dakota	47.9%	46.5%	46.4%	47.8%	46.6%	48.7%	43.4%	48.8%	49.2%	46.6%	47.5%	49.4%
South Dakota	49.0%	50.3%	48.3%	51.2%	49.6%	52.0%	47.1%	52.1%	50.7%	48.2%	50.0%	50.8%
Montana	53.0%	52.8%	50.6%	53.3%	52.3%	54.8%	48.2%	54.7%	54.2%	50.5%	52.9%	54.1%
Small Commercial & Industrial												
North Dakota	46.4%	44.0%	40.2%	45.5%	44.7%	47.3%	42.5%	46.2%	47.0%	44.7%	46.6%	48.8%
South Dakota	51.0%	51.6%	50.8%	51.5%	50.0%	51.8%	45.9%	52.4%	50.4%	48.6%	52.9%	53.1%
Montana	50.6%	50.7%	49.2%	50.9%	48.2%	52.4%	46.6%	51.6%	50.4%	47.7%	49.5%	50.5%
Large Commercial & Industrial												
North Dakota	44.9%	40.7%	41.6%	42.2%	42.6%	44.6%	40.7%	42.8%	45.1%	42.7%	44.6%	46.2%
South Dakota	59.9%	61.9%	62.8%	64.6%	62.2%	65.8%	57.0%	65.9%	59.9%	58.4%	62.5%	60.7%
Montana	38.7%	28.9%	28.9%	25.2%	25.1%	27.2%	26.9%	28.0%	27.1%	24.4%	28.6%	34.6%
Street Lighting												
North Dakota	39.3%	37.6%	35.1%	36.5%	35.9%	38.9%	35.5%	37.0%	37.3%	36.3%	38.0%	40.7%
South Dakota	40.4%	41.3%	38.3%	39.8%	40.4%	42.1%	40.4%	40.1%	41.5%	40.1%	42.9%	43.6%
Montana	43.0%	42.8%	35.8%	39.2%	36.9%	42.3%	38.3%	37.3%	40.5%	38.1%	42.8%	41.9%
Other Public Sales												
North Dakota	43.0%	41.5%	39.2%	41.4%	39.7%	42.4%	40.0%	41.7%	43.2%	41.6%	44.6%	45.6%
South Dakota	70.5%	70.4%	74.9%	73.3%	67.6%	71.4%	59.7%	68.4%	66.0%	67.6%	69.6%	70.4%
Montana	52.6%	51.1%	50.1%	53.4%	50.4%	52.2%	46.5%	50.6%	49.5%	51.4%	54.1%	54.1%
Interdepartmental												
North Dakota	51.1%	48.9%	49.9%	50.0%	48.3%	51.8%	45.4%	50.7%	50.1%	46.9%	51.5%	49.6%
South Dakota	10.3%	9.7%	7.7%	9.1%	23.8%	11.1%	11.8%	10.3%	11.4%	12.1%	34.8%	10.9%
Montana	47.7%	46.7%	45.5%	49.2%	45.8%	47.6%	40.8%	48.8%	46.1%	42.3%	42.5%	41.1%
Company Use												
North Dakota	40.3%	34.7%	32.3%	31.7%	32.5%	34.0%	31.8%	32.7%	35.1%	36.2%	39.0%	39.8%
South Dakota	64.0%	67.7%	61.8%	64.4%	65.2%	66.0%	64.8%	63.9%	65.7%	65.1%	68.1%	67.8%
Montana	57.8%	58.5%	56.9%	59.9%	56.0%	58.6%	52.0%	55.4%	54.3%	53.3%	55.7%	60.4%

Integrated System
Historical Energy Requirements

YEAR	TOTAL ENERGY REQUIREMENTS MWh	%INC/DEC
1959	463,307	
1960	488,316	5.40%
1961	514,086	5.28%
1962	545,306	6.07%
1963	586,589	7.57%
1964	628,616	7.16%
1965	682,214	8.53%
1966	725,389	6.33%
1967	798,855	10.13%
1968	837,504	4.84%
1969	908,231	8.44%
1970	970,490	6.85%
1971	1,021,876	5.29%
1972	1,073,560	5.06%
1973	1,107,691	3.18%
1974	1,155,351	4.30%
1975	1,210,168	4.74%
1976	1,274,391	5.31%
1977	1,307,542	2.60%
1978	1,418,366	8.48%
1979	1,481,019	4.42%
1980	1,581,612	6.79%
1981	1,629,323	3.02%
1982	1,740,859	6.85%
1983	1,783,753	2.46%
1984	1,815,453	1.78%
1985	1,834,294	1.04%
1986	1,751,503	-4.51%
1987	1,716,377	-2.01%
1988	1,834,232	6.87%
1989	1,828,665	-0.30%
1990	1,788,854	-2.18%
1991	1,836,243	2.65%
1992	1,827,866	-0.46%
1993	1,870,268	2.32%
1994	1,934,561	3.44%
1995	1,952,872	0.95%
1996	2,014,830	3.17%
1997	2,005,195	-0.48%
1998	2,007,534	0.12%
1999	1,996,647	-0.54%
2000	2,077,579	4.05%
2001	2,104,119	1.28%
2002	2,158,431	2.58%
2003	2,226,531	3.16%
2004	2,204,012	-1.01%
2005	2,327,117	5.59%

Total Energy Requirements



APPENDIX B

Historical and Forecasted Exogenous Variables

INTEGRATED SYSTEM ELECTRICITY PRICES
Historical and Forecasted Prices
cents/kWh

YEAR	RESIDENTIAL PRICE	SMALL C&I PRICE	LARGE C&I PRICE
1967	2.760	3.739	1.616
1968	2.734	3.690	1.524
1969	2.697	3.599	1.463
1970	2.674	3.516	1.462
1971	2.660	3.484	1.448
1972	2.637	3.506	1.430
1973	2.684	3.558	1.444
1974	2.797	3.721	1.724
1975	2.916	3.792	1.857
1976	3.504	4.402	2.322
1977	3.900	4.586	2.530
1978	4.231	4.701	2.660
1979	4.358	4.749	2.729
1980	4.447	4.767	2.773
1981	5.589	5.732	3.786
1982	6.664	6.169	4.709
1983	6.671	6.288	4.750
1984	6.966	6.610	5.133
1985	7.135	6.624	5.102
1986	7.208	6.686	5.160
1987	7.430	7.231	5.444
1988	7.331	7.410	5.495
1989	7.245	7.397	5.449
1990	7.253	7.395	5.412
1991	7.255	7.445	5.403
1992	7.267	7.470	5.360
1993	7.231	7.436	5.314
1994	7.234	7.384	5.258
1995	7.125	7.305	5.238
1996	7.078	7.246	5.219
1997	7.156	7.336	5.292
1998	7.187	7.348	5.277
1999	7.155	7.310	5.181
2000	7.073	7.222	5.082
2001	7.136	7.312	5.176
2002	7.062	7.242	5.146
2003	7.107	7.268	5.159
2004	7.387	7.372	5.276
2005	7.250	7.190	5.193
2006	7.320	7.384	5.407
2007	7.572	7.623	5.611
2008	7.675	7.727	5.735
2009	8.278	8.278	6.246
2010	9.126	9.041	6.938
2011	9.695	9.629	7.486
2012	9.942	9.871	7.671
2013	10.193	10.114	7.866
2014	10.445	10.366	8.061
2015	10.705	10.627	8.260
2016	11.167	11.066	8.658
2017	11.649	11.523	9.075
2018	12.152	11.999	9.513
2019	12.676	12.494	9.972
2020	13.223	13.010	10.453
2021	13.793	13.547	10.957
2022	14.388	14.106	11.485
2023	15.009	14.688	12.039
2024	15.656	15.294	12.619
2025	16.331	15.925	13.227
2026	17.036	16.582	13.865

SOURCES:
1967-2005: Historical prices calculated from Montana-Dakota Utilities Co., *Electric Operating Revenues Reports*
2006-2026: Forecasted prices

INTEGRATED SYSTEM NATURAL GAS PRICES
Historical and Forecasted Prices
$/Dk

YEAR	RESIDENTIAL PRICE	FIRM GENERAL
1979	$2.460	$2.140
1980	3.170	2.740
1981	3.560	3.100
1982	3.950	3.560
1983	5.070	4.700
1984	6.090	5.790
1985	5.160	4.870
1986	4.650	4.670
1987	5.290	4.890
1988	4.870	4.520
1989	4.400	4.060
1990	4.460	4.070
1991	4.570	4.200
1992	4.840	4.460
1993	5.050	4.690
1994	4.860	4.430
1995	4.380	3.910
1996	4.130	3.710
1997	4.540	4.090
1998	4.850	4.300
1999	5.080	4.540
2000	5.920	5.390
2001	7.420	6.870
2002	4.570	4.030
2003	6.830	6.290
2004	8.560	7.970
2005	10.490	9.840
2006	10.710	10.076
2007	11.246	10.590
2008	11.358	10.696
2009	11.642	10.953
2010	11.852	11.150
2011	12.089	11.339
2012	12.331	11.566
2013	12.528	11.763
2014	12.778	11.998
2015	12.983	12.202
2016	13.263	12.464
2017	13.550	12.732
2018	13.843	13.006
2019	14.142	13.286
2020	14.448	13.571
2021	14.760	13.863
2022	15.079	14.161
2023	15.405	14.465
2024	15.738	14.776
2025	16.078	15.094
2026	16.425	15.418

SOURCES:
1979-2005: CSBEPFL Rate Reporting Class Report
Gas Year-to-Date Report for Year-end
2006-2026: Forecasted prices

BISMARCK, NORTH DAKOTA
HEATING DEGREE DAYS (HDD)
AND
COOLING DEGREE DAYS(CDD)
(ANNUAL)

	HDD	CDD
1970	9,481	545
1971	9,280	423
1972	9,560	461
1973	8,516	411
1974	9,194	409
1975	9,039	433
1976	8,434	663
1977	8,636	367
1978	9,595	475
1979	9,998	365
1980	8,352	502
1981	7,685	441
1982	9,761	394
1983	8,706	658
1984	8,830	501
1985	9,590	297
1986	8,154	374
1987	7,314	532
1988	8,525	860
1989	9,086	672
1990	8,061	611
1991	8,052	709
1992	8,162	255
1993	9,144	217
1994	8,866	432
1995	9,027	522
1996	10,027	480
1997	8,450	609
1998	7,765	633
1999	7,710	457
2000	8,412	549
2001	8,039	668
2002	8,532	745
2003	8,493	737
2004	8,183	379
2005	7,792	555
NORMAL	8,802	471

Personal Income per Capita
Integrated System

Year	1996 $s
1969	11,351
1970	11,566
1971	12,107
1972	14,349
1973	18,515
1974	16,545
1975	15,858
1976	14,563
1977	14,445
1978	16,463
1979	16,080
1980	14,932
1981	17,830
1982	17,473
1983	17,085
1984	17,421
1985	16,590
1986	16,896
1987	16,826
1988	15,430
1989	16,738
1990	17,348
1991	17,313
1992	18,485
1993	18,806
1994	18,558
1995	18,319
1996	19,620
1997	19,220
1998	20,890
1999	21,024
2000	22,056
2001	22,661
2002	21,884
2003	23,668
2004	24,020
2005	24,375
2006	24,598
2007	24,884
2008	25,171
2009	25,469
2010	25,771
2011	26,075
2012	26,380
2013	26,686
2014	27,003
2015	27,318
2016	27,640
2017	27,965
2018	28,298
2019	28,642
2020	28,989
2021	29,342
2022	29,696
2023	30,051
2024	30,415
2025	30,781
2026	31,152

SOURCES:
1969-2003 U.S. Dept. of Commerce
2004-2026 Woods & Poole Economics

PERSONAL CONSUMPTION EXPENDITURE DEFLATOR

Year	Personal Consumption Expenditure Deflator (1996=100)	Inflation Rate
1969	27.00	--
1970	28.27	4.7%
1971	29.48	4.3%
1972	30.50	3.5%
1973	32.16	5.4%
1974	35.48	10.3%
1975	38.44	8.3%
1976	40.57	5.5%
1977	43.20	6.5%
1978	46.23	7.0%
1979	50.31	8.8%
1980	55.67	10.7%
1981	60.63	8.9%
1982	63.99	5.5%
1983	66.74	4.3%
1984	69.26	3.8%
1985	71.55	3.3%
1986	73.30	2.4%
1987	75.84	3.5%
1988	78.84	4.0%
1989	82.28	4.4%
1990	86.05	4.6%
1991	89.17	3.6%
1992	91.74	2.9%
1993	93.86	2.3%
1994	95.84	2.1%
1995	97.89	2.1%
1996	100.00	2.2%
1997	101.69	1.7%
1998	102.60	0.9%
1999	104.31	1.7%
2000	106.90	2.5%
2001	109.14	2.1%
2002	110.68	1.4%
2003	112.80	1.9%
2004	115.71	2.6%
2005	118.99	2.8%
2006	122.38	2.8%
2007	125.90	2.9%
2008	129.53	2.9%
2009	133.30	2.9%
2010	137.21	2.9%
2011	141.26	3.0%
2012	145.47	3.0%
2013	149.87	3.0%
2014	154.49	3.1%
2015	159.33	3.1%
2016	164.39	3.2%
2017	169.70	3.2%
2018	175.27	3.3%
2019	181.10	3.3%
2020	187.23	3.4%
2021	193.65	3.4%
2022	200.39	3.5%
2023	207.46	3.5%
2024	214.89	3.6%
2025	222.58	3.6%
2026	230.55	3.6%

SOURCES:
1969-2004 U.S. Department of Commerce
2005-2026 Woods & Poole Economics, Inc.

INTERCONNECTED SYSTEM
RESIDENTIAL SECTOR
HOUSEHOLDS AND CUSTOMERS

YEAR	NUMBER OF HOUSEHOLDS	GROWTH RATE	AVERAGE CUSTOMERS	GROWTH RATE
1971	91,246		61,781	
1972	92,956	1.87%	62,857	1.74%
1973	94,768	1.95%	64,131	2.03%
1974	96,439	1.76%	65,760	2.54%
1975	99,759	3.44%	67,700	2.95%
1976	103,434	3.68%	70,269	3.79%
1977	105,549	2.04%	72,854	3.68%
1978	106,886	1.27%	75,276	3.32%
1979	110,044	2.95%	77,814	3.37%
1980	113,293	2.95%	80,419	3.35%
1981	116,881	3.17%	83,073	3.30%
1982	120,678	3.25%	85,712	3.18%
1983	122,290	1.34%	86,732	1.19%
1984	123,126	0.68%	87,126	0.45%
1985	122,774	-0.29%	86,510	-0.71%
1986	120,544	-1.82%	85,316	-1.38%
1987	117,963	-2.14%	84,070	-1.46%
1988	116,944	-0.86%	83,497	-0.68%
1989	115,536	-1.20%	82,720	-0.93%
1990	113,499	-1.76%	82,260	-0.56%
1991	113,134	-0.32%	82,555	0.36%
1992	113,546	0.36%	82,730	0.21%
1993	113,382	-0.14%	83,038	0.37%
1994	113,640	0.23%	83,242	0.25%
1995	114,053	0.36%	83,639	0.48%
1996	115,737	1.48%	84,153	0.61%
1997	115,959	0.19%	84,510	0.42%
1998	116,370	0.35%	84,833	0.38%
1999	116,447	0.07%	84,935 */	0.12%
2000	116,918	0.40%	84,914	-0.02%
2001	116,186	-0.63%	84,866	-0.06%
2002	115,826	-0.31%	85,012	0.17%
2003	115,970	0.12%	85,278	0.31%
2004	116,273	0.26%	85,498	0.26%
2005	116,691	0.36%	85,791	0.34%
2006	117,892	1.03%	86,216	0.50%
2007	118,787	0.76%	86,412	0.23%
2008	119,663	0.74%	86,590	0.21%
2009	120,518	0.71%	86,749	0.18%
2010	121,360	0.70%	86,894	0.17%
2011	122,213	0.70%	87,043	0.17%
2012	123,069	0.70%	87,190	0.17%
2013	123,932	0.70%	87,337	0.17%
2014	124,730	0.64%	87,436	0.11%
2015	125,551	0.66%	87,547	0.13%
2016	126,328	0.62%	87,624	0.09%
2017	127,090	0.60%	87,687	0.07%
2018	127,815	0.57%	87,722	0.04%
2019	128,484	0.52%	87,722	0.00%
2020	129,149	0.52%	87,722	0.00%
2021	129,800	0.50%	87,722	0.00%
2022	130,446	0.50%	87,722	0.00%
2023	131,081	0.49%	87,722	0.00%
2024	131,670	0.45%	87,722	0.00%
2025	132,255	0.44%	87,722	0.00%
2026	132,819	0.43%	87,722	0.00%

*/ Actual customer numbers for 1999 are unavailable due to the installation of a new CIS. This number is an estimate.

SOURCES:
Households
1971-2003: U.S. Department of Commerce
2004-2026: Woods & Poole Economics Inc.
Customers
1971-2005: Actuals from Montana-Dakota Utilities Co. Electric Operating Revenues Reports
2006-2026: Montana-Dakota forecast

GROSS DOMESTIC PRODUCT DEFLATOR

Year	GDP Deflator (1996=100)	Inflation Rate
1969	26.2	--
1970	27.5	5.0%
1971	28.9	5.1%
1972	30.2	4.5%
1973	31.9	5.6%
1974	34.7	8.8%
1975	38.0	9.5%
1976	40.2	5.8%
1977	42.8	6.5%
1978	45.8	7.0%
1979	49.6	8.3%
1980	54.1	9.1%
1981	59.1	9.2%
1982	62.7	6.1%
1983	65.2	4.0%
1984	67.7	3.8%
1985	69.7	3.0%
1986	71.3	2.3%
1987	73.2	2.7%
1988	75.7	3.4%
1989	78.6	3.8%
1990	81.6	3.8%
1991	84.5	3.6%
1992	86.4	2.2%
1993	88.4	2.3%
1994	90.3	2.1%
1995	92.1	2.0%
1996	93.9	2.0%
1997	95.4	1.6%
1998	96.5	1.2%
1999	97.9	1.5%
2000	100.0	2.1%
2001	102.4	2.4%
2002	104.2	1.8%
2003	106.3	2.0%
2004	109.1	2.6%
2005	112.2	2.8%
2006	115.5	2.9%
2007	117.6	1.8%
2008	120.0	2.0%
2009	122.5	2.1%
2010	125.3	2.3%
2011	128.3	2.4%
2012	131.5	2.5%
2013	134.5	2.3%
2014	137.6	2.3%
2015	140.8	2.3%
2016	144.0	2.3%
2017	147.3	2.3%
2018	150.7	2.3%
2019	154.2	2.3%
2020	157.7	2.3%
2021	161.3	2.3%
2022	165.0	2.3%
2023	168.8	2.3%
2024	172.7	2.3%
2025	176.7	2.3%
2026	180.7	2.3%

SOURCES:

1969-2005 Actuals - U.S. Department of Commerce
2006-2012 GDP forecasted by The Conference Board
2013-2026 Estimates based on the 2006-2012 average yearly growth in GDP forecasted by The Conference Board.

INTEGRATED SYSTEM
EMPLOYMENT DATA

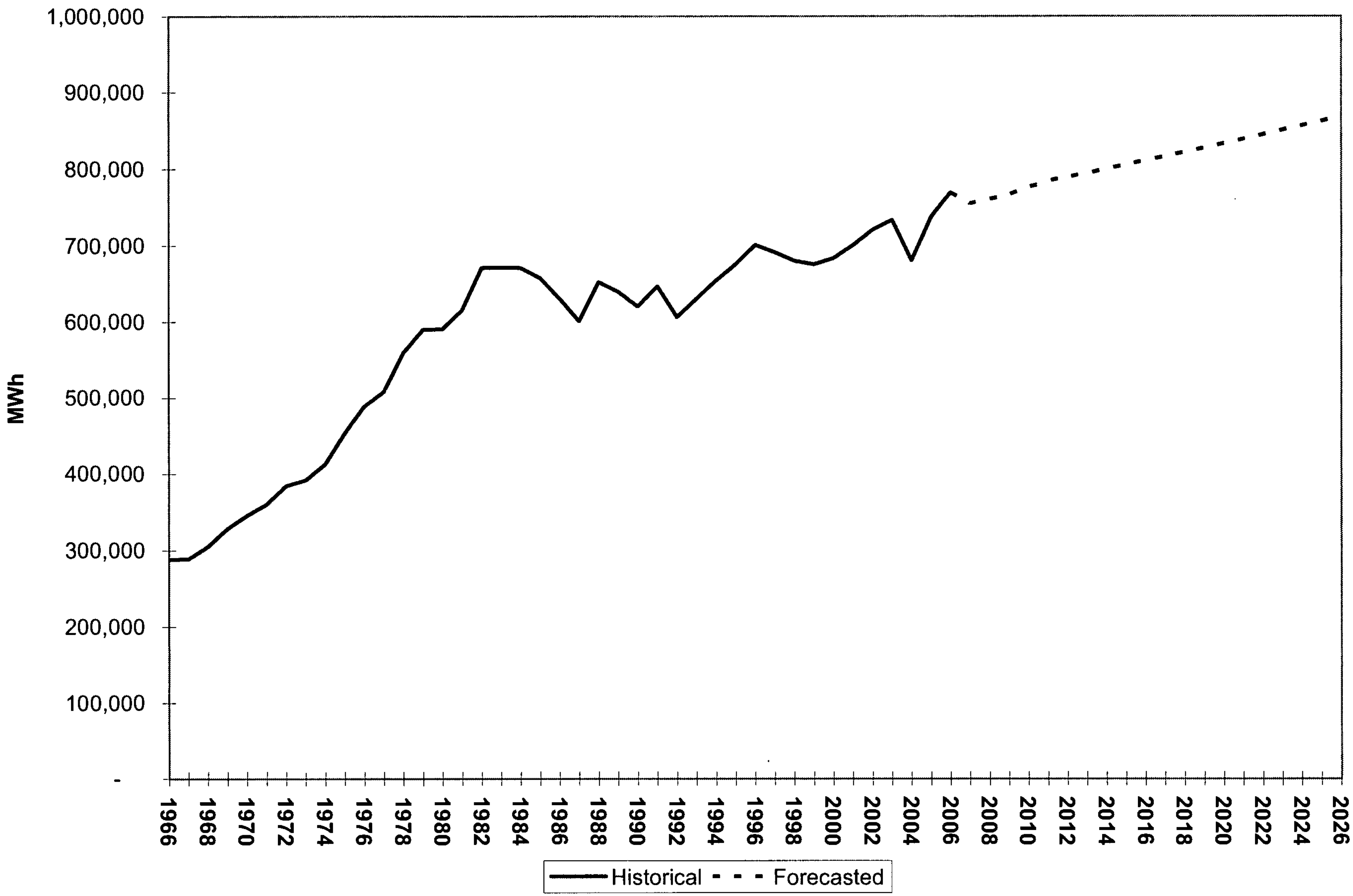
YEAR	NUMBER OF EMPLOYEES	GROWTH RATE	ADJUSTED EMPLOYMENT	GROWTH RATE
1969	93,205			
1970	94,447	1.33%		
1971	94,687	0.25%		
1972	97,706	3.19%		
1973	102,813	5.23%		
1974	106,581	3.66%		
1975	110,848	4.00%		
1976	115,446	4.15%		
1977	119,047	3.12%		
1978	125,818	5.69%		
1979	131,715	4.69%		
1980	136,239	3.43%		
1981	139,688	2.53%		
1982	144,872	3.71%		
1983	145,173	0.21%		
1984	142,357	-1.94%		
1985	138,452	-2.74%		
1986	134,123	-3.13%		
1987	133,468	-0.49%		
1988	134,029	0.42%		
1989	136,189	1.61%		
1990	138,420	1.64%		
1991	140,936	1.82%		
1992	142,003	0.76%		
1993	145,517	2.47%		
1994	152,664	4.91%		
1995	152,837	0.11%		
1996	155,126	1.50%		
1997	157,054	1.24%		
1998	160,783	2.37%		
1999	162,704	1.19%		
2000	165,058	1.45%		
2001	164,925	-0.08%		
2002	167,023	1.27%		
2003	169,756	1.64%		
2004	172,061	1.36%		
2005	174,385	1.35%		
2006	176,684	1.32%	177,088	1.55%
2007	178,980	1.30%	179,833	1.55%
2008	181,294	1.29%	182,620	1.55%
2009	183,597	1.27%	185,451	1.55%
2010	185,907	1.26%	188,325	1.55%
2011	188,217	1.24%	191,244	1.55%
2012	190,521	1.22%	194,209	1.55%
2013	192,808	1.20%	197,219	1.55%
2014	195,124	1.20%	200,276	1.55%
2015	197,437	1.19%	203,380	1.55%
2016	199,738	1.17%	205,821	1.20%
2017	202,023	1.14%	208,290	1.20%
2018	204,329	1.14%	210,790	1.20%
2019	206,633	1.13%	213,319	1.20%
2020	208,937	1.12%	215,879	1.20%
2021	211,249	1.11%	218,470	1.20%
2022	213,548	1.09%	221,091	1.20%
2023	215,846	1.08%	223,745	1.20%
2024	218,128	1.06%	226,430	1.20%
2025	220,442	1.06%	229,147	1.20%
2026	222,759	1.05%	231,896	1.20%

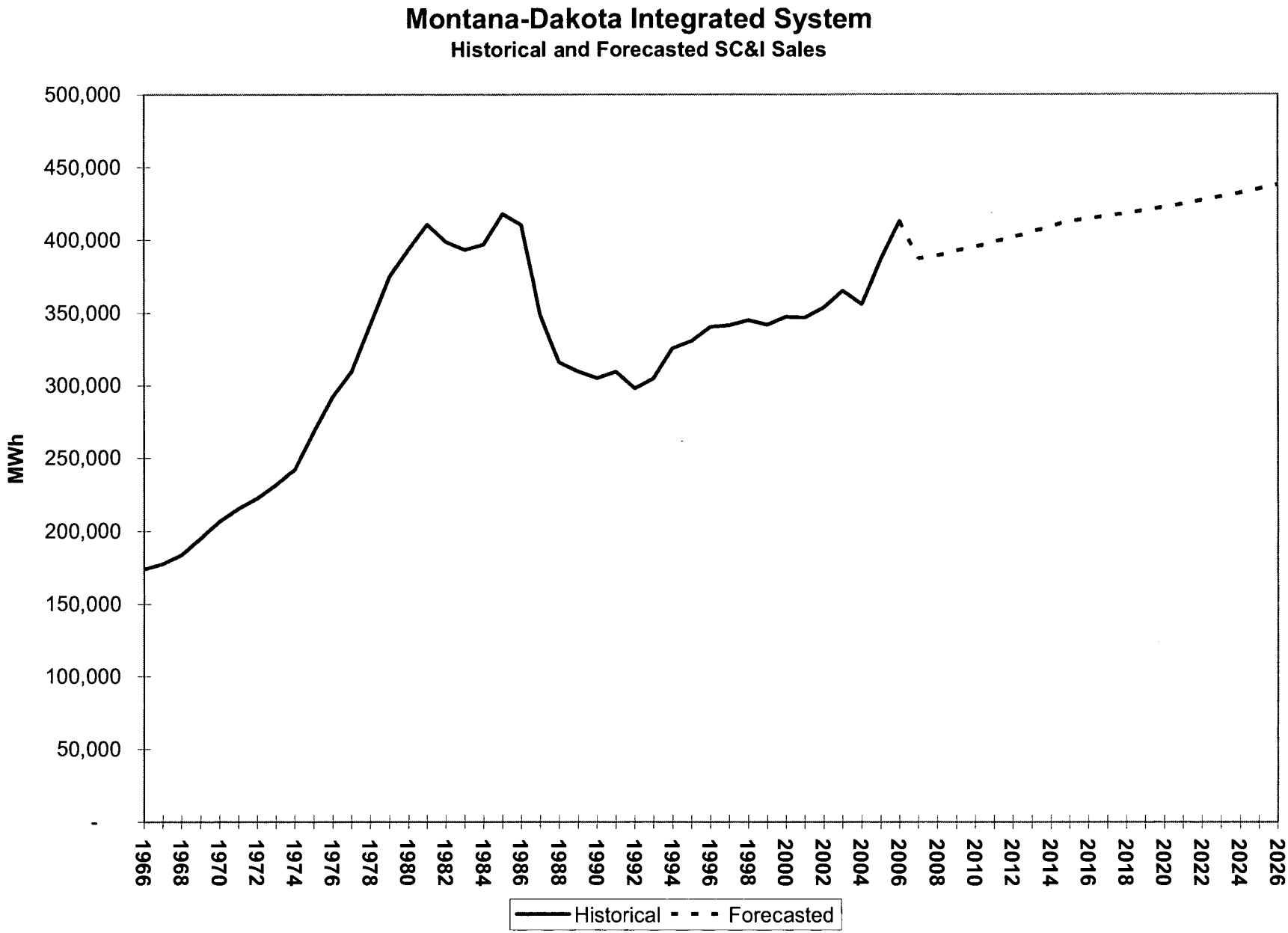
SOURCES:
Number of Employees
1969-2003: U.S. Department of Commerce
2004-2026: Woods & Poole Economics Inc.
Adjusted Employment
2006-2015: Employment growth set to 10-year actual historical growth for 1993-2003 (1.55%)
2016-2026: Employment growth set to W&P forecasted growth for 2004-2024 (1.20%)

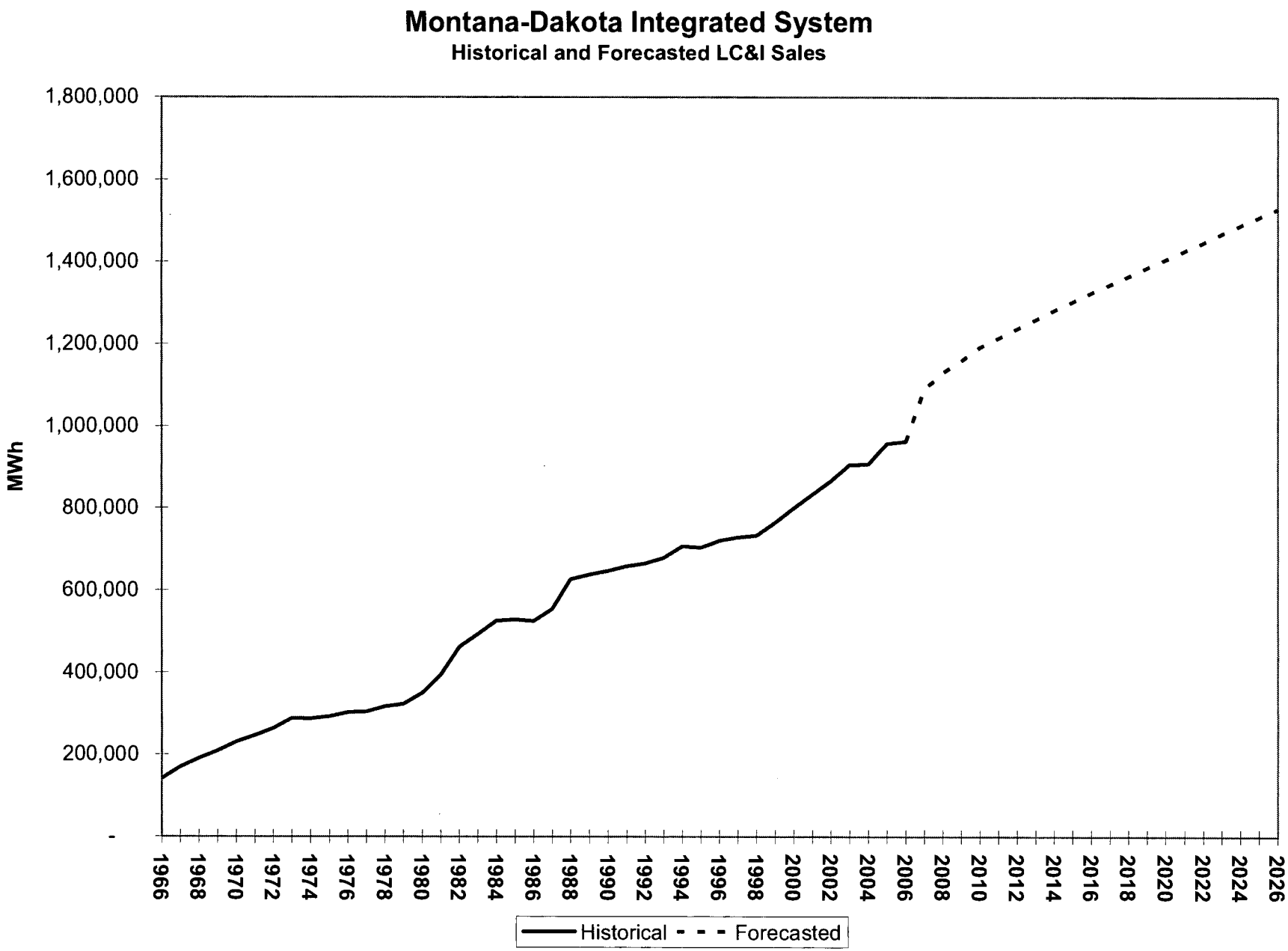
APPENDIX C

Forecast Result

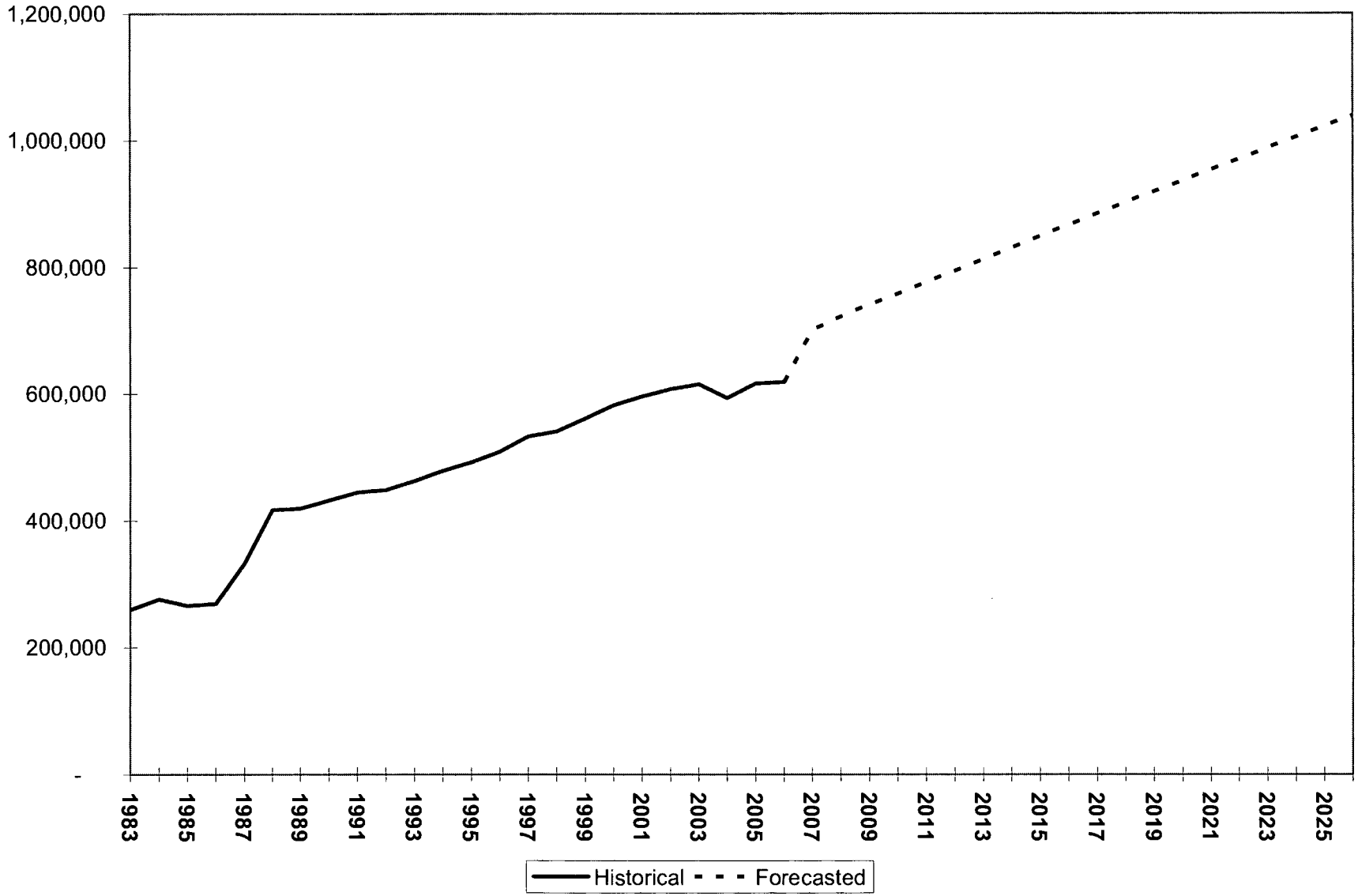
Montana-Dakota Integrated System
Historical and Forecasted Residential Sales




Montana-Dakota Integrated System
Historical and Forecasted SC&I Sales
MWh
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
Historical
Forecasted

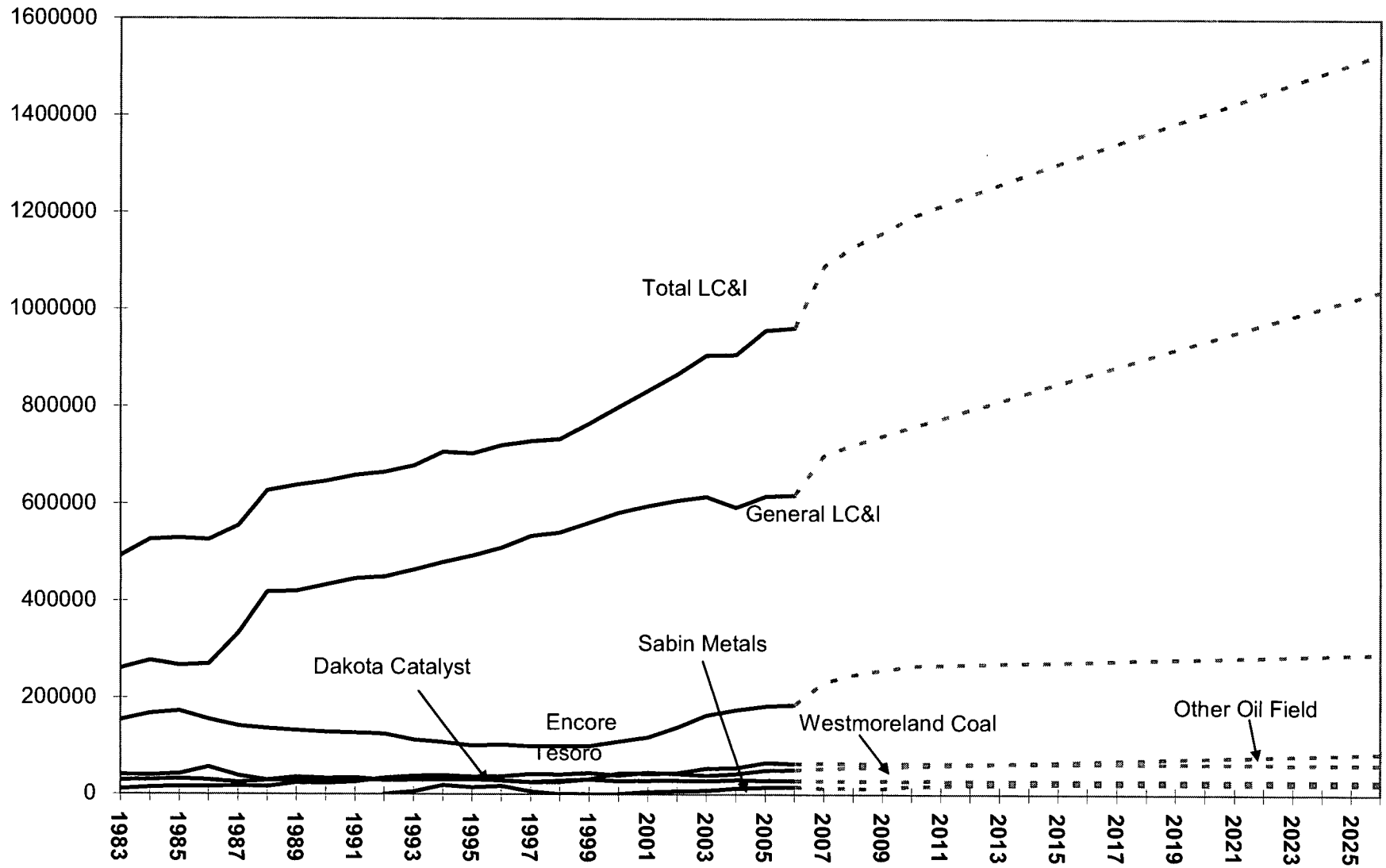

Montana-Dakota Integrated System
Historical and Forecasted LC&I Sales
MWh
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
Historical
Forecasted

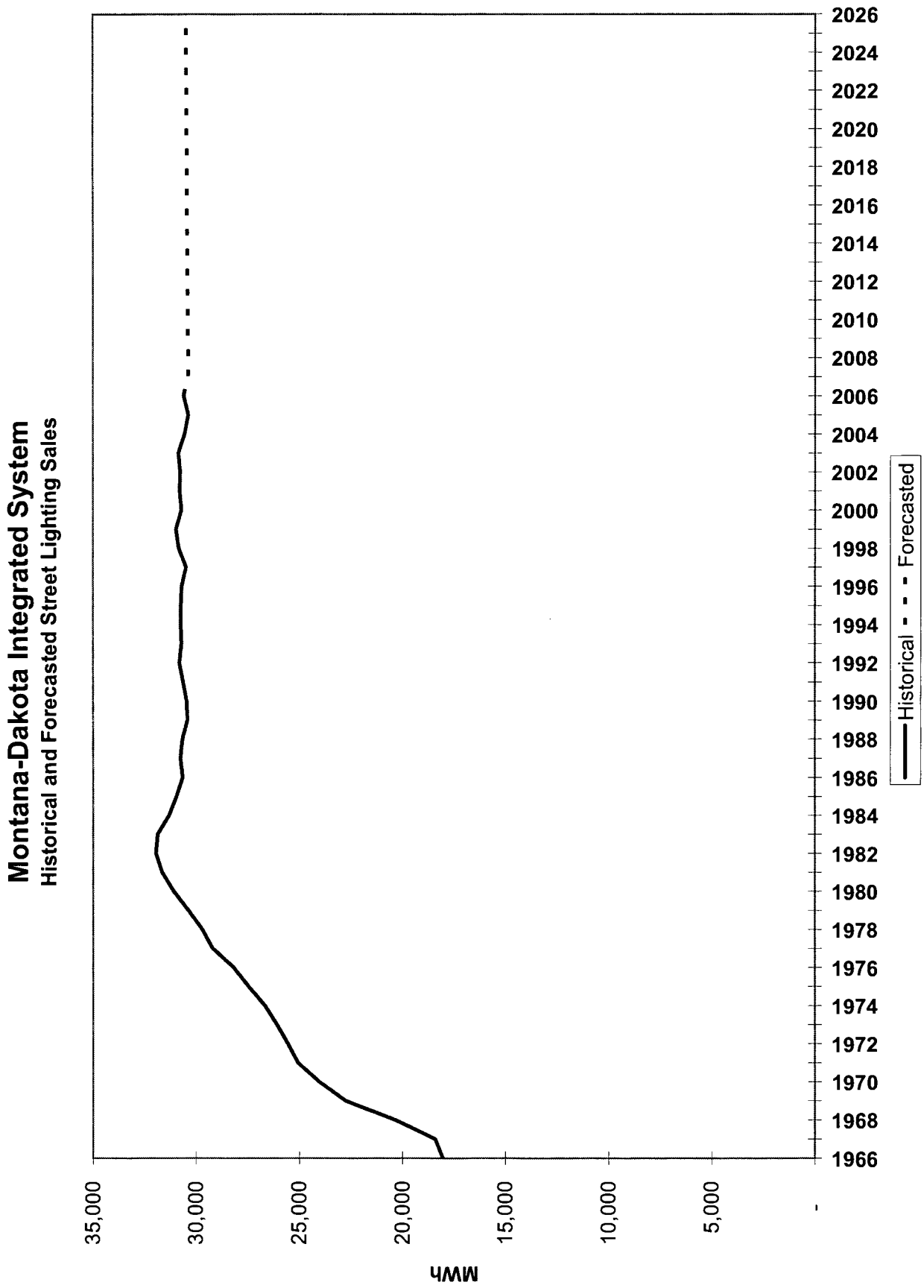
Montana-Dakota Integrated System
Historical and Forecasted General LC&I Sales



Montana-Dakota Integrated System

Historical and Forecasted Sales by LC&I Customer




Montana-Dakota Integrated System
Historical and Forecasted Street Lighting Sales
MWh
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
2026
2024
2022
2020
2018
2016
2014
2012
2010
2008
2006
2004
2002
2000
1998
1996
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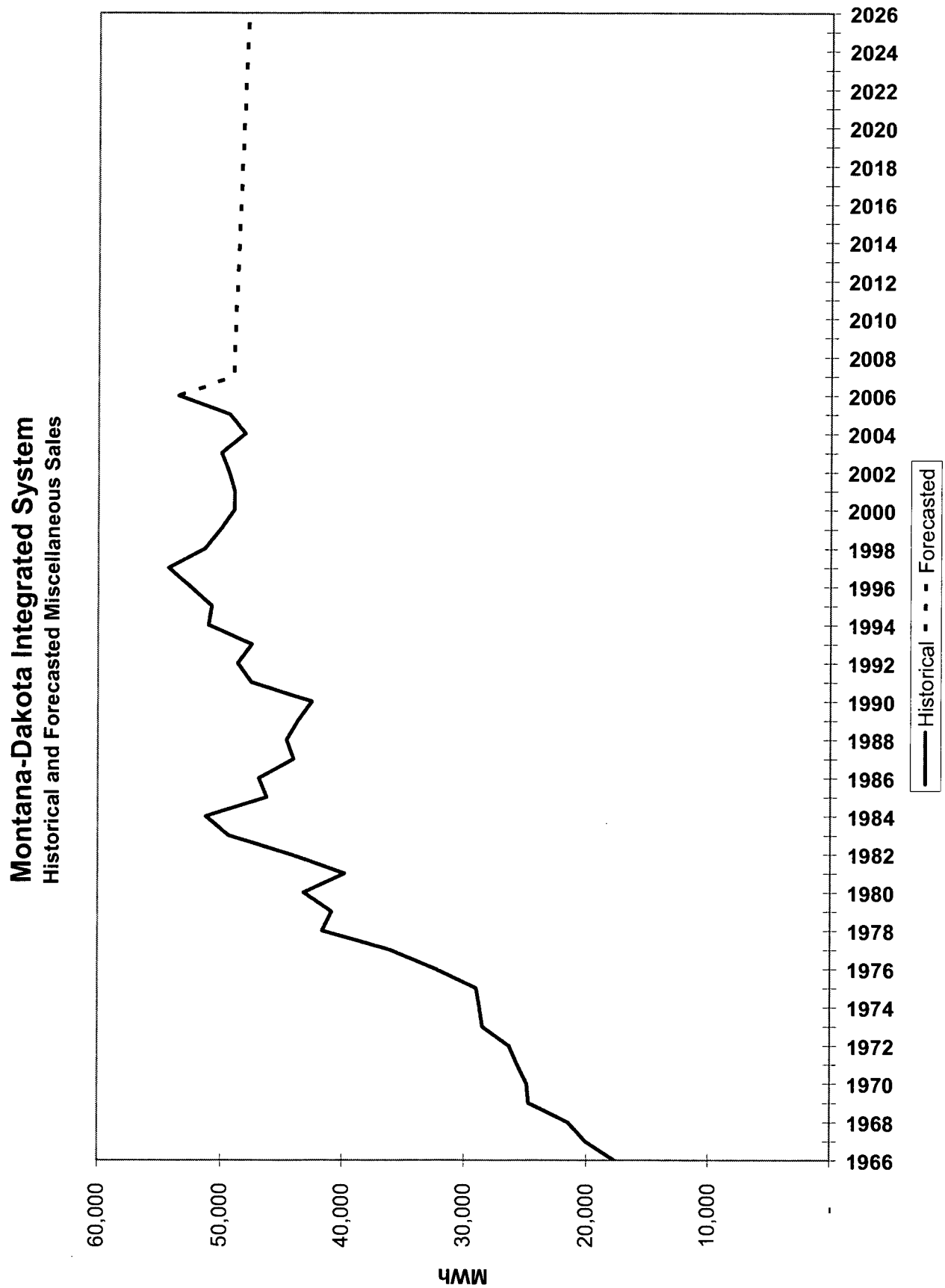
1992
1990
1988
1986
1984
1982
1980
1978
1976
1974
1972
1970
1968
1966
Historical
Forecasted


Montana-Dakota Integrated System
Historical and Forecasted Miscellaneous Sales
MWh
60,000
50,000
40,000
30,000
20,000
10,000
-
2026
2024
2022
2020
2018
2016
2014
2012
2010
2008
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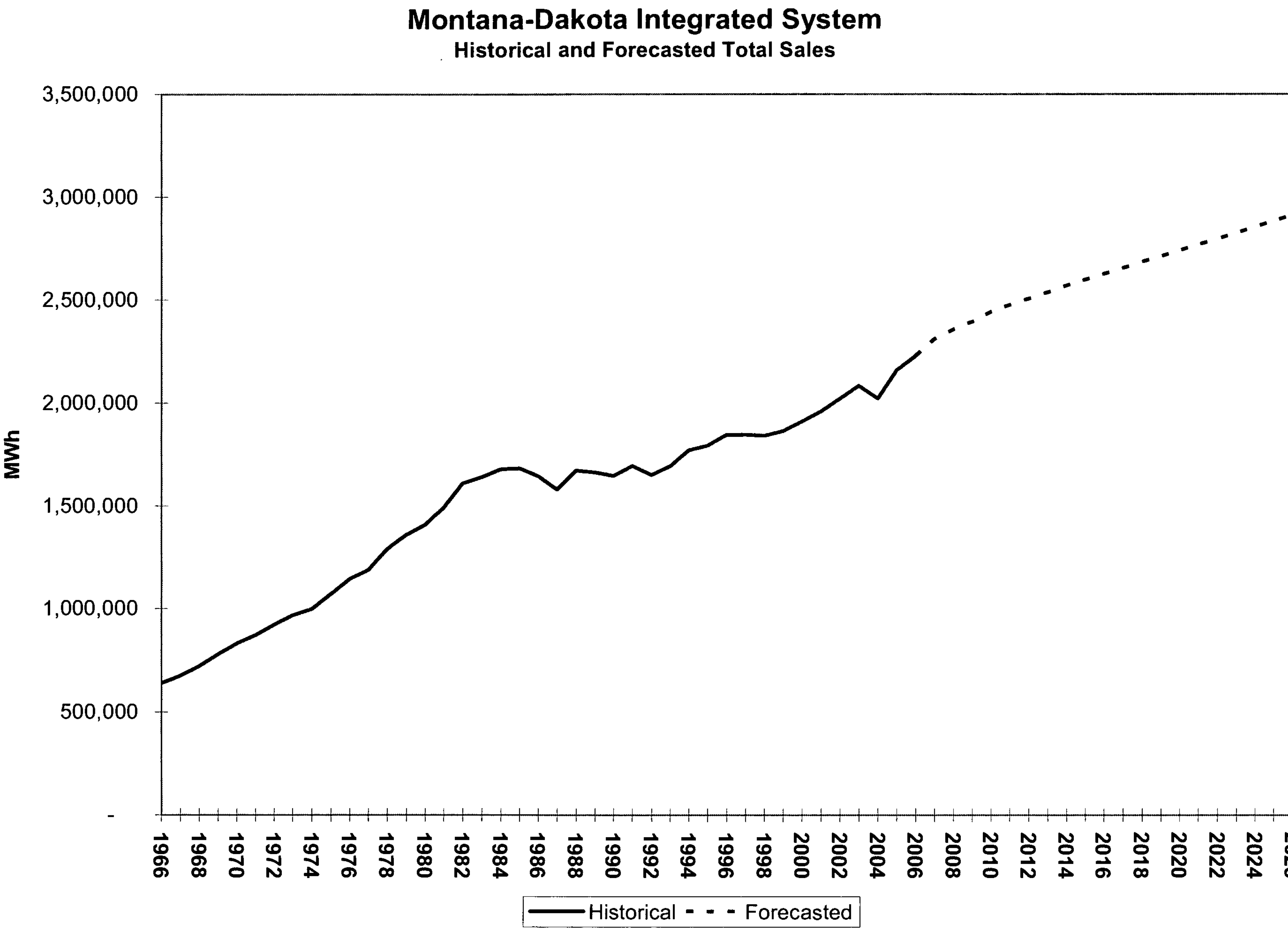
1968
1966
Historical
Forecasted



Montana-Dakota Integrated System
Historical and Forecasted Total Sales
MWh
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
Historical
Forecasted

MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
MONTANA

YEAR	SUMMER PEAK (MW)	% CHG	SUMMER PEAK NET OF INT LOADS (MW)	% CHG	WINTER PEAK (MW)	% CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	% CHG	LOAD FACTOR (%) 1/
2007	125.4		125.4		101.4		763.0		69.44%
2008	127.2	1.37%	127.2	1.37%	102.8	1.38%	786.9	3.13%	70.45%
2009	128.7	1.23%	128.7	1.23%	104.0	1.19%	802.7	2.01%	71.18%
2010	130.2	1.18%	130.2	1.18%	105.1	1.10%	819.0	2.03%	71.78%
2011	131.7	1.10%	131.7	1.10%	106.3	1.11%	826.9	0.96%	71.69%
2012	133.1	1.09%	133.1	1.09%	107.4	1.07%	834.3	0.89%	71.35%
2013	134.5	1.06%	134.5	1.06%	108.6	1.09%	841.7	0.89%	71.43%
2014	136.0	1.07%	136.0	1.07%	109.8	1.07%	849.3	0.90%	71.31%
2015	137.4	1.06%	137.4	1.06%	110.9	1.04%	856.8	0.88%	71.19%
2016	138.8	1.04%	138.8	1.04%	112.1	1.05%	863.8	0.82%	70.84%
2017	140.3	1.03%	140.3	1.03%	113.3	1.04%	870.8	0.81%	70.87%
2018	141.7	1.00%	141.7	1.00%	114.4	1.01%	877.9	0.82%	70.74%
2019	143.1	1.01%	143.1	1.01%	115.5	1.00%	884.9	0.80%	70.59%
2020	144.5	0.98%	144.5	0.98%	116.7	1.03%	892.1	0.81%	70.28%
2021	146.0	1.01%	146.0	1.01%	117.8	0.96%	899.3	0.81%	70.33%
2022	147.4	0.97%	147.4	0.97%	119.0	1.01%	906.5	0.80%	70.21%
2023	148.8	0.97%	148.8	0.97%	120.2	0.94%	913.8	0.81%	70.10%
2024	150.3	0.96%	150.3	0.96%	121.3	0.97%	921.1	0.80%	69.79%
2025	151.7	0.96%	151.7	0.96%	122.5	0.96%	928.5	0.80%	69.88%
2026	153.1	0.95%	153.1	0.95%	123.7	0.95%	935.9	0.80%	69.77%

1/ Load Factor is calculated using demand net of interruptible loads.

MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
NORTH DAKOTA

YEAR	SUMMER PEAK (MW)	% CHG	SUMMER PEAK NET OF INT LOADS (MW)	% CHG	WINTER PEAK (MW)	% CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	% CHG	LOAD FACTOR (%) 1/
2007	326.3		320.8		267.4		1,599.4		56.91%
2008	330.8	1.37%	325.3	1.40%	271.1	1.38%	1,626.2	1.68%	56.91%
2009	334.9	1.23%	329.4	1.25%	274.3	1.19%	1,649.5	1.43%	57.17%
2010	338.8	1.18%	333.3	1.20%	277.3	1.10%	1,680.9	1.90%	57.57%
2011	342.5	1.10%	337.0	1.12%	280.4	1.11%	1,706.9	1.55%	57.81%
2012	346.3	1.09%	340.8	1.11%	283.4	1.07%	1,731.2	1.42%	57.83%
2013	349.9	1.06%	344.4	1.08%	286.5	1.09%	1,755.5	1.40%	58.18%
2014	353.7	1.07%	348.2	1.08%	289.6	1.07%	1,780.0	1.40%	58.36%
2015	357.4	1.06%	351.9	1.07%	292.6	1.04%	1,804.0	1.35%	58.52%
2016	361.1	1.04%	355.6	1.06%	295.7	1.05%	1,825.9	1.21%	58.45%
2017	364.9	1.03%	359.4	1.05%	298.8	1.04%	1,847.9	1.20%	58.70%
2018	368.5	1.00%	363.0	1.02%	301.8	1.01%	1,869.9	1.19%	58.80%
2019	372.3	1.01%	366.8	1.03%	304.8	1.00%	1,891.9	1.18%	58.88%
2020	375.9	0.98%	370.4	1.00%	307.9	1.03%	1,914.0	1.17%	58.82%
2021	379.7	1.01%	374.2	1.03%	310.9	0.96%	1,936.0	1.15%	59.06%
2022	383.4	0.97%	377.9	0.98%	314.0	1.01%	1,958.2	1.15%	59.15%
2023	387.1	0.97%	381.6	0.99%	317.0	0.94%	1,980.4	1.13%	59.24%
2024	390.9	0.96%	385.4	0.98%	320.0	0.97%	2,002.6	1.12%	59.16%
2025	394.6	0.96%	389.1	0.97%	323.1	0.96%	2,025.0	1.12%	59.41%
2026	398.3	0.95%	392.8	0.96%	326.2	0.95%	2,047.4	1.11%	59.50%

1/ Load Factor is calculated using demand net of interruptible loads.

MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
SOUTH DAKOTA

YEAR	SUMMER PEAK (MW)	% CHG	SUMMER PEAK NET OF INT LOADS (MW)	% CHG	WINTER PEAK (MW)	% CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	% CHG	LOAD FACTOR (%) 1/
2007	29.0		29.0		22.0		147.1		57.82%
2008	29.4	1.37%	29.4	1.37%	22.3	1.38%	149.0	1.29%	57.62%
2009	29.8	1.23%	29.8	1.23%	22.6	1.19%	150.7	1.14%	57.73%
2010	30.2	1.18%	30.2	1.18%	22.8	1.10%	152.8	1.39%	57.85%
2011	30.5	1.10%	30.5	1.10%	23.1	1.11%	154.7	1.24%	57.93%
2012	30.8	1.09%	30.8	1.09%	23.3	1.07%	156.4	1.10%	57.78%
2013	31.1	1.06%	31.1	1.06%	23.6	1.09%	158.1	1.09%	57.95%
2014	31.5	1.07%	31.5	1.07%	23.8	1.07%	159.9	1.14%	57.99%
2015	31.8	1.06%	31.8	1.06%	24.1	1.04%	161.7	1.13%	58.03%
2016	32.1	1.04%	32.1	1.04%	24.3	1.05%	163.2	0.93%	57.81%
2017	32.5	1.03%	32.5	1.03%	24.6	1.04%	164.8	0.98%	57.94%
2018	32.8	1.00%	32.8	1.00%	24.8	1.01%	166.3	0.91%	57.88%
2019	33.1	1.01%	33.1	1.01%	25.1	1.00%	167.9	0.96%	57.85%
2020	33.5	0.98%	33.5	0.98%	25.3	1.03%	169.5	0.95%	57.68%
2021	33.8	1.01%	33.8	1.01%	25.6	0.96%	171.1	0.94%	57.80%
2022	34.1	0.97%	34.1	0.97%	25.8	1.01%	172.8	0.99%	57.81%
2023	34.5	0.97%	34.5	0.97%	26.1	0.94%	174.4	0.93%	57.79%
2024	34.8	0.96%	34.8	0.96%	26.3	0.97%	176.0	0.92%	57.60%
2025	35.1	0.96%	35.1	0.96%	26.6	0.96%	177.7	0.97%	57.77%
2026	35.4	0.95%	35.4	0.95%	26.8	0.95%	179.3	0.90%	57.74%

1/ Load Factor is calculated using demand net of interruptible loads.

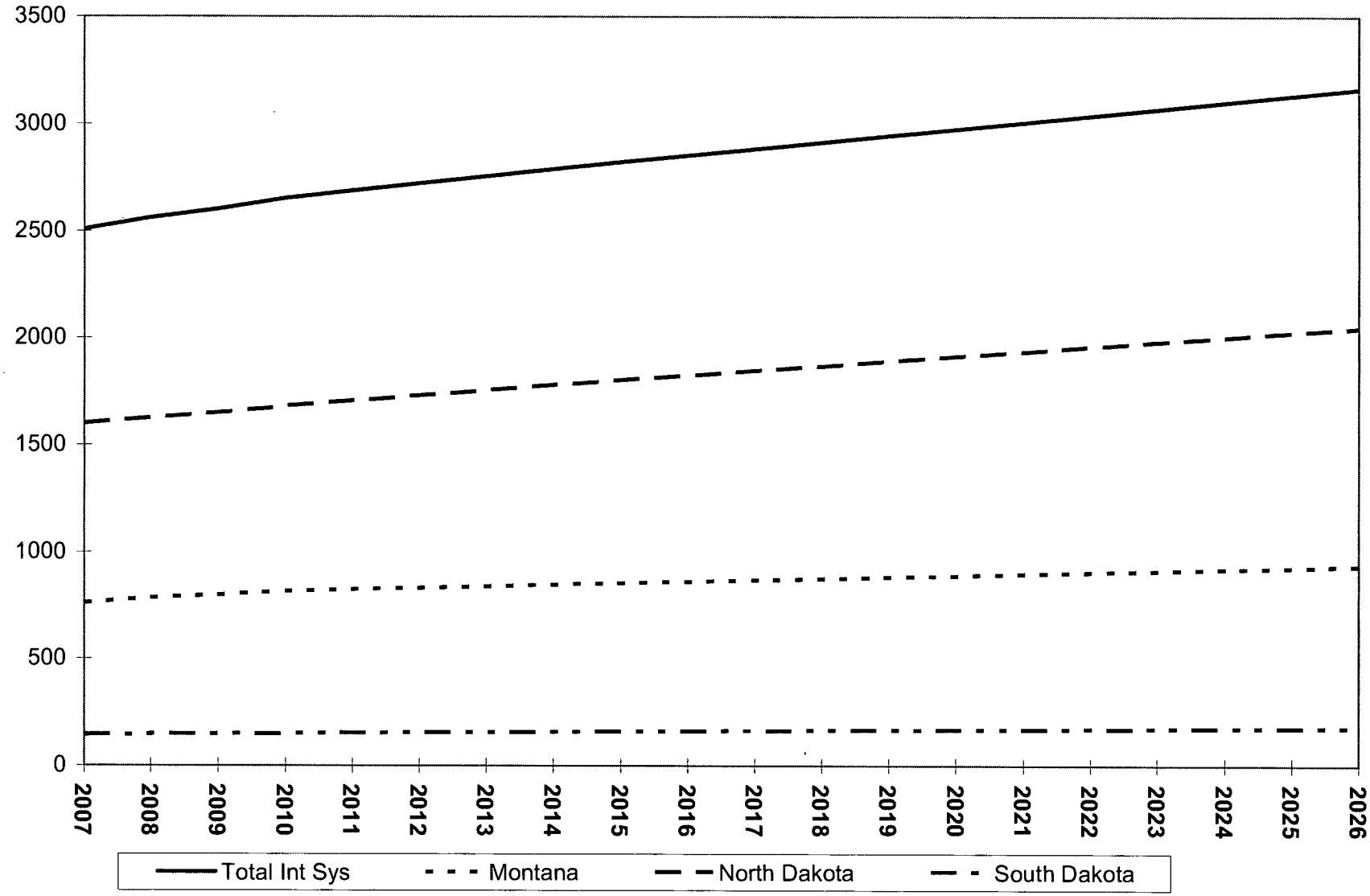
MONTANA-DAKOTA UTILITIES CO.
FORECASTED ENERGY (GWh) AND SEASONAL DEMANDS (MW)
INTEGRATED SYSTEM

YEAR	SUMMER PEAK (MW)	% CHG	SUMMER PEAK NET OF INT LOADS (MW)	% CHG	WINTER PEAK (MW)	% CHG	ANNUAL ENERGY REQUIREMENTS (GWh)	% CHG	LOAD FACTOR (%) 1/
2007	480.8		475.3		390.8		2,509.5		60.27%
2008	487.4	1.37%	481.9	1.39%	396.2	1.38%	2,562.1	2.10%	60.53%
2009	493.4	1.23%	487.9	1.25%	400.9	1.19%	2,602.9	1.59%	60.90%
2010	499.2	1.18%	493.7	1.19%	405.3	1.10%	2,652.7	1.91%	61.34%
2011	504.7	1.10%	499.2	1.11%	409.8	1.11%	2,688.4	1.35%	61.48%
2012	510.2	1.09%	504.7	1.10%	414.2	1.07%	2,721.9	1.25%	61.40%
2013	515.6	1.06%	510.1	1.07%	418.7	1.09%	2,755.4	1.23%	61.66%
2014	521.1	1.07%	515.6	1.08%	423.2	1.07%	2,789.3	1.23%	61.76%
2015	526.6	1.06%	521.1	1.07%	427.6	1.04%	2,822.5	1.19%	61.83%
2016	532.1	1.04%	526.6	1.06%	432.1	1.05%	2,852.9	1.08%	61.68%
2017	537.6	1.03%	532.1	1.04%	436.6	1.04%	2,883.5	1.07%	61.86%
2018	543.0	1.00%	537.5	1.01%	441.0	1.01%	2,914.1	1.06%	61.89%
2019	548.5	1.01%	543.0	1.02%	445.4	1.00%	2,944.7	1.05%	61.91%
2020	553.9	0.98%	548.4	0.99%	450.0	1.03%	2,975.5	1.05%	61.77%
2021	559.5	1.01%	554.0	1.02%	454.3	0.96%	3,006.4	1.04%	61.95%
2022	564.9	0.97%	559.4	0.97%	458.9	1.01%	3,037.4	1.03%	61.98%
2023	570.4	0.97%	564.9	0.98%	463.2	0.94%	3,068.6	1.03%	62.01%
2024	575.9	0.96%	570.4	0.97%	467.7	0.97%	3,099.7	1.01%	61.87%
2025	581.4	0.96%	575.9	0.96%	472.2	0.96%	3,131.1	1.01%	62.06%
2026	586.9	0.95%	581.4	0.96%	476.7	0.95%	3,162.6	1.01%	62.10%

1/ Load Factor is calculated using demand net of interruptible loads.

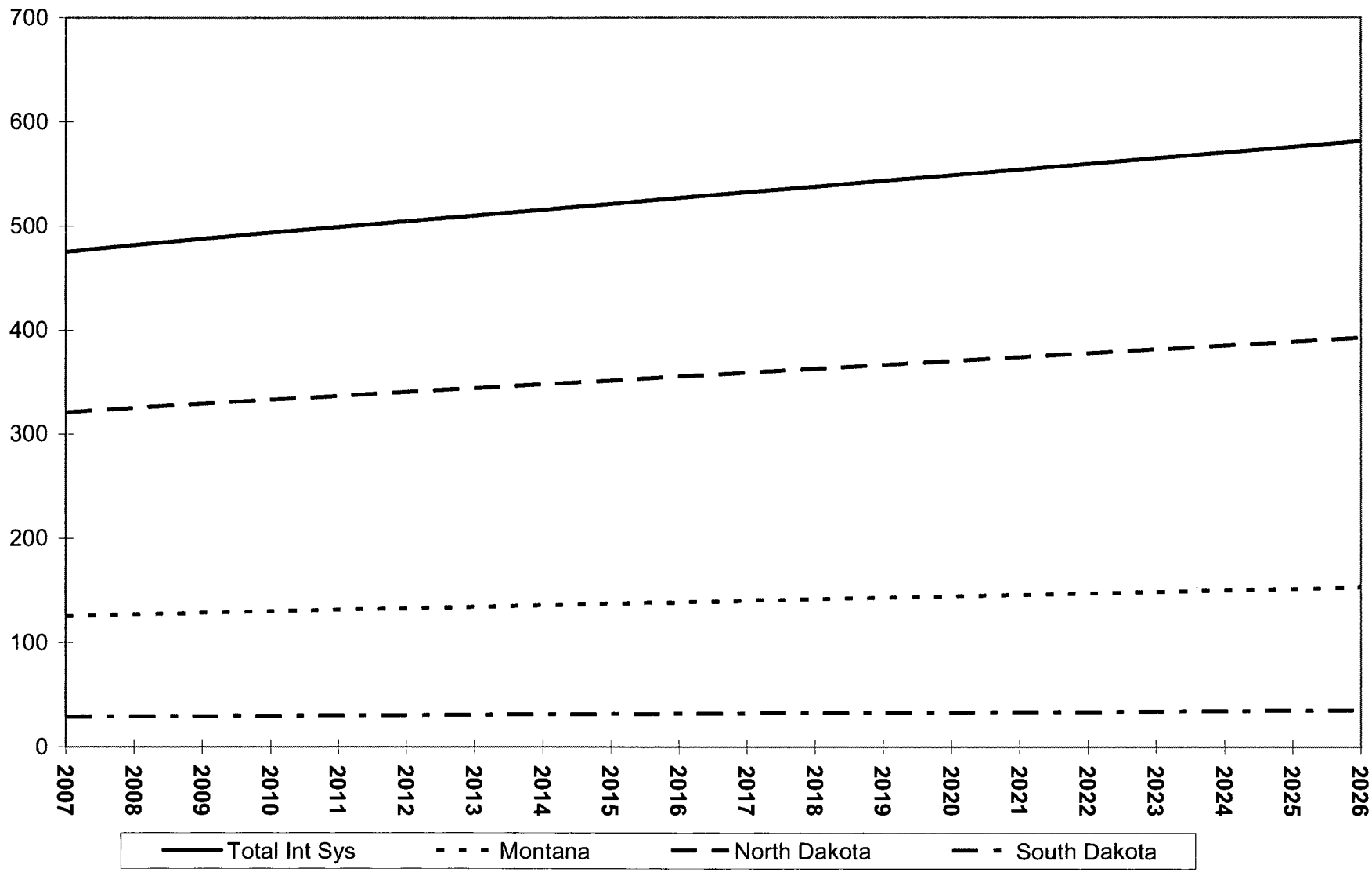
Montana-Dakota Integrated System

Forecast of Annual Energy by State



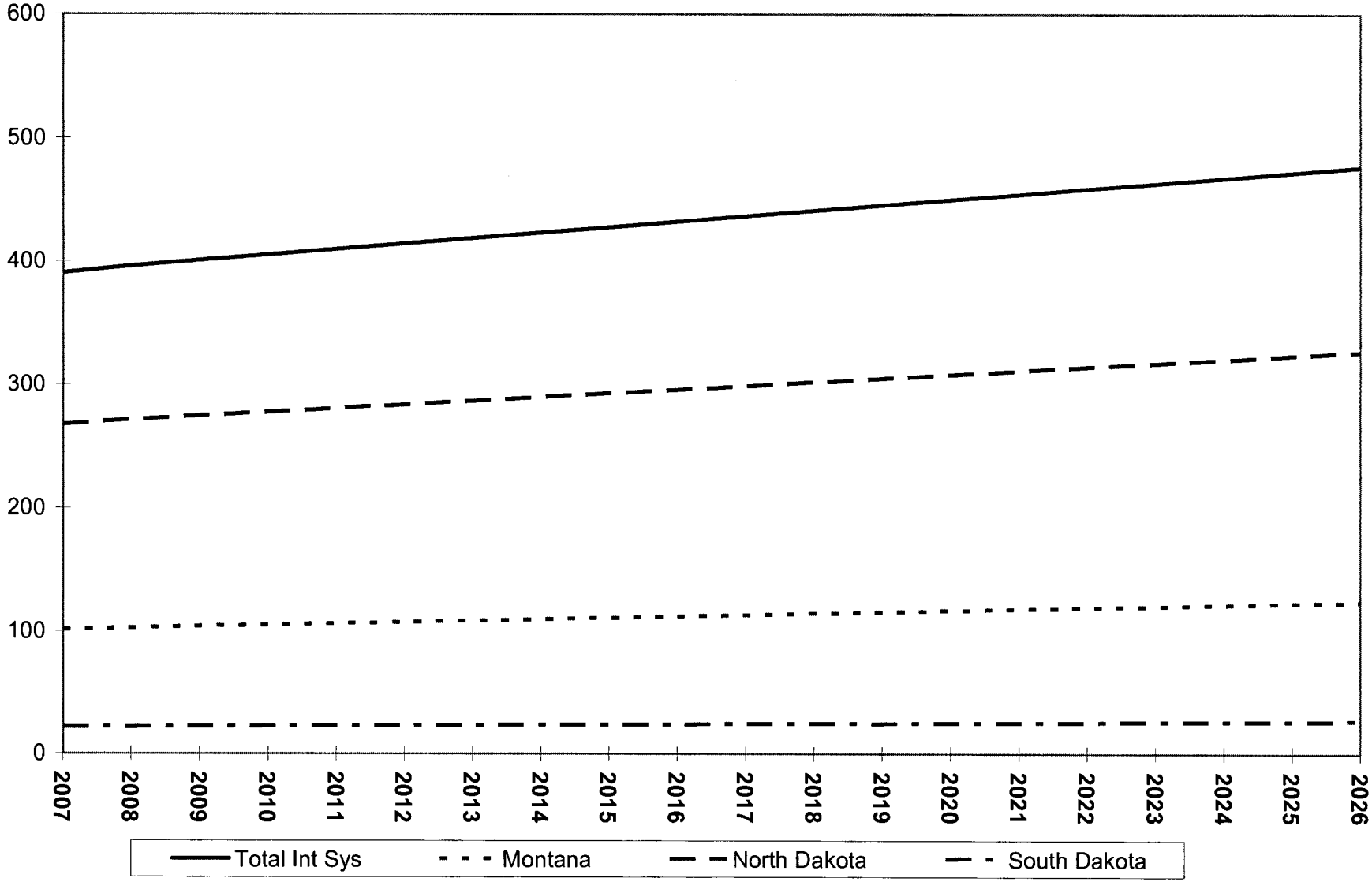
Montana-Dakota Integrated System

Forecast of Summer Peak Demand (Net of Interruptible Load)
by State



Montana-Dakota Integrated System

Forecast of Winter Peak Demand by State



APPENDIX D

Monthly Forecasts - Montana
(2007-2016)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2007

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	811.9	702.5	677.5	595.2	588.3	601.2	810.8	756.1	614.0	614.6	695.0	809.4	8,277.4
# of Residential Customers	18,670	18,665	18,643	18,590	18,595	18,601	18,617	18,626	18,633	18,646	18,670	18,672	18,636
Total Residential Sales - MWh	15,158	13,112	12,630	11,065	10,939	11,183	15,095	14,083	11,441	11,460	12,975	15,114	154,255
Use per Small Comm & Ind Customer - kWh	1,978.5	1,821.2	1,790.2	1,618.2	1,705.5	1,681.9	2,100.7	1,980.1	1,718.0	1,673.5	1,774.2	1,948.9	21,792.2
# of Small Comm & Ind Customers	4,610	4,608	4,614	4,662	4,727	4,753	4,766	4,771	4,756	4,702	4,673	4,661	4,692
Total Small Comm & Ind Sales - MWh	9,121	8,392	8,260	7,544	8,062	7,994	10,012	9,447	8,171	7,869	8,291	9,084	102,247
General Large Comm & Ind Sales	16,237	16,423	15,308	15,994	15,293	15,109	15,901	16,083	16,155	17,373	17,998	20,126	198,000
Encore Oil Sales	17,882	18,466	18,647	18,951	18,980	18,343	19,200	18,901	18,991	20,682	20,965	22,098	232,106
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	58,622	56,622	55,047	53,743	53,437	52,763	60,333	58,636	54,887	57,544	60,441	66,672	688,747
Other Public Sales	475	442	452	449	542	598	756	719	607	487	446	470	6,443
Street & Highway Lighting Sales	617	568	622	585	633	570	587	617	585	632	600	620	7,236
Interdepartmental Sales	19	17	17	15	15	13	16	15	14	15	17	21	194
Total Billed Sales - MWh	59,733	57,649	56,138	54,792	54,627	53,944	61,692	59,987	56,093	58,678	61,504	67,783	702,620
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	59,783	57,695	56,180	54,828	54,660	53,975	61,730	60,022	56,123	58,709	61,542	67,826	703,073
Total Requirements (Energy + Losses)	64,876	62,610	60,966	59,499	59,316	58,573	66,989	65,135	60,904	63,710	66,785	73,604	762,967
# of Large Comm & Ind Customers	248	248	249	251	256	258	259	259	257	254	252	251	254
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	98.3	95.9	80.6	75.3	82.0	106.5	125.4	119.6	97.7	82.5	89.5	101.4	125.4
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	98.3	95.9	80.6	75.3	82.0	106.5	125.4	119.6	97.7	82.5	89.5	101.4	125.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2008

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	817.5	707.3	682.1	599.3	592.1	604.9	815.5	760.8	618.0	618.8	699.7	814.1	8,331.0
# of Residential Customers	18,708	18,704	18,682	18,628	18,633	18,639	18,655	18,664	18,671	18,684	18,709	18,710	18,674
Total Residential Sales - MWh	15,294	13,229	12,743	11,163	11,032	11,274	15,213	14,200	11,539	11,562	13,091	15,232	155,572
Use per Small Comm & Ind Customer - kWh	1,975.2	1,817.8	1,787.2	1,615.3	1,702.4	1,678.7	2,097.1	1,976.7	1,715.0	1,670.6	1,771.2	1,948.7	21,756.9
# of Small Comm & Ind Customers	4,643	4,642	4,647	4,695	4,761	4,787	4,800	4,805	4,790	4,736	4,707	4,695	4,726
Total Small Comm & Ind Sales - MWh	9,171	8,438	8,305	7,584	8,105	8,036	10,066	9,498	8,215	7,912	8,337	9,149	102,816
General Large Comm & Ind Sales	16,579	16,770	15,631	16,331	15,615	15,427	16,237	16,423	16,497	17,741	18,378	20,517	202,146
Encore Oil Sales	19,142	19,767	19,961	20,285	20,317	19,635	20,552	20,233	20,328	22,138	22,441	23,369	248,168
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	60,410	58,433	56,842	55,552	55,232	54,506	62,193	60,476	56,708	59,513	62,459	68,517	710,841
Other Public Sales	474	441	451	448	541	597	755	718	605	487	446	469	6,432
Street & Highway Lighting Sales	617	568	623	585	633	570	587	617	585	632	600	620	7,237
Interdepartmental Sales	19	17	17	15	15	13	16	15	14	15	17	20	193
Total Billed Sales - MWh	61,520	59,459	57,933	56,600	56,421	55,686	63,551	61,826	57,912	60,647	63,522	69,626	724,703
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	61,570	59,505	57,975	56,636	56,454	55,717	63,589	61,861	57,942	60,678	63,560	69,669	725,156
Total Requirements (Energy + Losses)	66,815	64,574	62,914	61,461	61,263	60,464	69,006	67,131	62,878	65,847	68,975	75,604	786,932
# of Large Comm & Ind Customers	251	252	253	254	259	261	262	263	261	258	256	255	257
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	100.4	98.0	82.4	76.8	83.2	108.1	127.1	121.2	99.1	83.6	90.7	102.8	127.1
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	100.4	98.0	82.4	76.8	83.2	108.1	127.1	121.2	99.1	83.6	90.7	102.8	127.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	821.6	711.0	685.6	602.3	595.1	608.0	819.6	764.8	621.2	622.0	703.3	821.4	8,377.0
# of Residential Customers	18,743	18,738	18,716	18,663	18,667	18,673	18,690	18,698	18,705	18,719	18,743	18,745	18,708
Total Residential Sales - MWh	15,400	13,322	12,832	11,241	11,109	11,353	15,319	14,300	11,620	11,643	13,182	15,398	156,719
Use per Small Comm & Ind Customer - kWh	1,978.6	1,820.7	1,790.1	1,617.8	1,705.3	1,681.2	2,101.0	1,980.4	1,717.7	1,673.3	1,774.2	1,950.9	21,792.1
# of Small Comm & Ind Customers	4,675	4,674	4,679	4,728	4,794	4,821	4,833	4,838	4,824	4,769	4,739	4,727	4,758
Total Small Comm & Ind Sales - MWh	9,250	8,510	8,376	7,649	8,175	8,105	10,154	9,581	8,286	7,980	8,408	9,222	103,696
General Large Comm & Ind Sales	16,849	17,043	15,884	16,597	15,870	15,678	16,500	16,690	16,766	18,031	18,678	20,851	205,437
Encore Oil Sales	19,852	20,499	20,700	21,038	21,071	20,363	21,314	20,983	21,082	22,960	23,273	24,224	257,359
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	61,575	59,603	57,994	56,714	56,388	55,633	63,412	61,676	57,883	60,774	63,753	69,945	725,350
Other Public Sales	473	440	450	447	540	596	754	717	604	486	445	469	6,421
Street & Highway Lighting Sales	618	569	623	585	633	570	587	617	585	632	600	620	7,239
Interdepartmental Sales	19	17	17	15	15	13	16	15	14	15	17	20	193
Total Billed Sales - MWh	62,685	60,629	59,084	57,761	57,576	56,812	64,769	63,025	59,086	61,907	64,815	71,054	739,203
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	62,735	60,675	59,126	57,797	57,609	56,843	64,807	63,060	59,116	61,938	64,853	71,097	739,656
Total Requirements (Energy + Losses)	68,079	65,844	64,163	62,721	62,517	61,685	70,328	68,432	64,152	67,214	70,378	77,154	802,667
# of Large Comm & Ind Customers	254	255	256	258	262	264	266	266	264	261	259	258	260
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	101.8	99.2	83.4	77.8	84.1	109.4	128.7	122.7	100.3	84.6	91.7	104.0	128.7
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	101.8	99.2	83.4	77.8	84.1	109.4	128.7	122.7	100.3	84.6	91.7	104.0	128.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	831.6	719.5	693.9	609.6	602.3	615.3	829.6	774.0	628.7	629.5	711.8	829.7	8,476.4
# of Residential Customers	18,774	18,769	18,747	18,694	18,698	18,705	18,721	18,730	18,737	18,750	18,774	18,776	18,740
Total Residential Sales - MWh	15,612	13,505	13,009	11,396	11,262	11,509	15,531	14,497	11,780	11,803	13,363	15,578	158,845
Use per Small Comm & Ind Customer - kWh	1,979.8	1,821.7	1,791.1	1,618.9	1,706.2	1,682.3	2,101.9	1,981.7	1,718.6	1,674.4	1,775.1	1,951.9	21,804.9
# of Small Comm & Ind Customers	4,707	4,706	4,711	4,760	4,827	4,854	4,867	4,871	4,857	4,801	4,772	4,760	4,791
Total Small Comm & Ind Sales - MWh	9,319	8,573	8,438	7,706	8,236	8,166	10,230	9,653	8,347	8,039	8,471	9,291	104,469
General Large Comm & Ind Sales	17,117	17,314	16,136	16,860	16,121	15,927	16,763	16,956	17,031	18,318	18,976	21,182	208,701
Encore Oil Sales	20,562	21,233	21,442	21,790	21,824	21,092	22,077	21,734	21,837	23,781	24,107	24,813	266,292
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	62,834	60,854	59,227	57,941	57,606	56,828	64,726	62,962	59,124	62,101	65,129	71,114	740,446
Other Public Sales	473	440	450	447	540	595	753	716	604	485	444	468	6,415
Street & Highway Lighting Sales	618	569	623	585	633	570	587	617	585	632	601	621	7,241
Interdepartmental Sales	19	17	17	15	15	13	16	15	14	15	17	20	193
Total Billed Sales - MWh	63,944	61,880	60,317	58,988	58,794	58,006	66,082	64,310	60,327	63,233	66,191	72,223	754,295
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	63,994	61,926	60,359	59,024	58,827	58,037	66,120	64,345	60,357	63,264	66,229	72,266	754,748
Total Requirements (Energy + Losses)	69,446	67,201	65,501	64,052	63,838	62,981	71,753	69,827	65,499	68,653	71,871	78,422	819,044
# of Large Comm & Ind Customers	258	258	259	261	266	268	269	269	267	265	262	261	264
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	103.0	100.4	84.4	78.7	85.0	110.6	130.2	124.1	101.4	85.4	92.7	105.1	130.2
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	103.0	100.4	84.4	78.7	85.0	110.6	130.2	124.1	101.4	85.4	92.7	105.1	130.2

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	838.6	725.6	699.7	614.8	607.4	620.5	836.7	780.6	634.0	634.8	717.8	835.0	8,546.5
# of Residential Customers	18,806	18,801	18,780	18,726	18,730	18,737	18,753	18,762	18,769	18,782	18,806	18,808	18,772
Total Residential Sales - MWh	15,771	13,642	13,141	11,512	11,377	11,627	15,690	14,645	11,900	11,923	13,499	15,705	160,432
Use per Small Comm & Ind Customer - kWh	1,981.9	1,823.9	1,793.0	1,620.6	1,707.8	1,684.2	2,104.5	1,983.5	1,720.4	1,675.8	1,776.9	1,954.7	21,828.2
# of Small Comm & Ind Customers	4,739	4,737	4,743	4,792	4,860	4,886	4,899	4,904	4,889	4,834	4,804	4,792	4,823
Total Small Comm & Ind Sales - MWh	9,392	8,640	8,504	7,766	8,300	8,229	10,310	9,727	8,411	8,101	8,536	9,367	105,283
General Large Comm & Ind Sales	17,393	17,594	16,397	17,133	16,382	16,184	17,034	17,229	17,307	18,614	19,283	21,522	212,072
Encore Oil Sales	20,676	21,350	21,560	21,911	21,945	21,209	22,199	21,853	21,957	23,912	24,239	24,951	267,762
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	63,456	61,455	59,804	58,511	58,167	57,383	65,358	63,576	59,704	62,710	65,769	71,795	747,688
Other Public Sales	472	439	449	446	539	594	752	715	603	485	444	467	6,405
Street & Highway Lighting Sales	618	569	623	585	633	570	587	617	585	632	601	621	7,241
Interdepartmental Sales	18	16	17	15	14	13	16	14	13	14	16	20	186
Total Billed Sales - MWh	64,564	62,479	60,893	59,557	59,353	58,560	66,713	64,922	60,905	63,841	66,830	72,903	761,520
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	64,614	62,525	60,935	59,593	59,386	58,591	66,751	64,957	60,935	63,872	66,868	72,946	761,973
Total Requirements (Energy + Losses)	70,118	67,852	66,126	64,670	64,445	63,582	72,438	70,491	66,126	69,313	72,564	79,160	826,885
# of Large Comm & Ind Customers	261	261	262	264	269	271	272	273	271	268	265	264	267
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	104.4	101.8	85.6	79.8	85.9	111.8	131.6	125.4	102.5	86.4	93.7	106.3	131.6
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	104.4	101.8	85.6	79.8	85.9	111.8	131.6	125.4	102.5	86.4	93.7	106.3	131.6

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	842.8	729.3	703.3	617.9	610.5	623.7	840.9	784.5	637.2	638.0	721.4	839.2	8,589.6
# of Residential Customers	18,838	18,833	18,811	18,757	18,762	18,768	18,785	18,793	18,801	18,814	18,838	18,840	18,803
Total Residential Sales - MWh	15,877	13,734	13,230	11,590	11,454	11,705	15,796	14,744	11,980	12,003	13,590	15,810	161,513
Use per Small Comm & Ind Customer - kWh	1,985.7	1,827.6	1,796.6	1,623.9	1,711.3	1,687.5	2,108.7	1,987.6	1,723.7	1,679.5	1,780.2	1,958.9	21,872.4
# of Small Comm & Ind Customers	4,770	4,768	4,774	4,823	4,891	4,918	4,931	4,936	4,922	4,865	4,836	4,823	4,855
Total Small Comm & Ind Sales - MWh	9,472	8,714	8,577	7,832	8,370	8,299	10,398	9,811	8,484	8,171	8,609	9,448	106,185
General Large Comm & Ind Sales	17,670	17,873	16,657	17,405	16,641	16,441	17,304	17,503	17,582	18,909	19,589	21,861	215,435
Encore Oil Sales	20,791	21,468	21,679	22,033	22,067	21,326	22,322	21,975	22,079	24,045	24,374	25,089	269,248
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	64,034	62,018	60,345	59,049	58,695	57,905	65,945	64,155	60,254	63,288	66,374	72,458	754,520
Other Public Sales	472	439	449	445	538	593	751	714	602	484	443	467	6,397
Street & Highway Lighting Sales	618	569	623	585	633	570	587	617	585	632	601	621	7,241
Interdepartmental Sales	18	16	16	14	14	13	15	14	13	14	16	20	183
Total Billed Sales - MWh	65,142	63,042	61,433	60,093	59,880	59,081	67,298	65,500	61,454	64,418	67,434	73,566	768,341
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	65,192	63,088	61,475	60,129	59,913	59,112	67,336	65,535	61,484	64,449	67,472	73,609	768,794
Total Requirements (Energy + Losses)	70,746	68,462	66,712	65,251	65,017	64,148	73,072	71,118	66,722	69,939	73,220	79,880	834,287
# of Large Comm & Ind Customers	264	265	265	267	272	274	276	276	274	271	269	268	270
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	105.5	102.9	86.5	80.6	86.9	113.0	133.1	126.8	103.7	87.3	94.8	107.4	133.1
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	105.5	102.9	86.5	80.6	86.9	113.0	133.1	126.8	103.7	87.3	94.8	107.4	133.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	847.0	732.8	706.7	620.9	613.5	626.8	845.1	788.4	640.4	641.1	725.0	843.4	8,632.2
# of Residential Customers	18,870	18,865	18,843	18,789	18,794	18,800	18,816	18,825	18,832	18,846	18,870	18,872	18,835
Total Residential Sales - MWh	15,983	13,825	13,317	11,667	11,530	11,783	15,902	14,842	12,060	12,083	13,680	15,916	162,588
Use per Small Comm & Ind Customer - kWh	1,990.6	1,831.6	1,801.0	1,627.7	1,715.2	1,691.3	2,113.4	1,991.9	1,727.8	1,683.4	1,784.8	1,964.2	21,924.2
# of Small Comm & Ind Customers	4,800	4,799	4,804	4,854	4,923	4,950	4,963	4,968	4,953	4,896	4,866	4,854	4,886
Total Small Comm & Ind Sales - MWh	9,555	8,790	8,652	7,901	8,444	8,372	10,489	9,896	8,558	8,242	8,685	9,534	107,118
General Large Comm & Ind Sales	17,945	18,152	16,918	17,677	16,901	16,697	17,574	17,776	17,856	19,204	19,895	22,200	218,795
Encore Oil Sales	20,907	21,588	21,801	22,156	22,190	21,445	22,447	22,097	22,202	24,179	24,510	25,230	270,752
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	64,614	62,584	60,890	59,590	59,228	58,431	66,537	64,733	60,805	63,868	66,982	73,130	761,392
Other Public Sales	471	438	448	445	538	593	750	714	602	483	443	466	6,391
Street & Highway Lighting Sales	618	569	623	585	633	570	587	617	585	632	601	621	7,241
Interdepartmental Sales	18	16	16	14	14	13	15	14	13	14	16	19	182
Total Billed Sales - MWh	65,721	63,607	61,977	60,634	60,413	59,607	67,889	66,078	62,005	64,997	68,042	74,236	775,206
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	65,771	63,653	62,019	60,670	60,446	59,638	67,927	66,113	62,035	65,028	68,080	74,279	775,659
Total Requirements (Energy + Losses)	71,374	69,076	67,302	65,838	65,595	64,719	73,714	71,745	67,320	70,568	73,880	80,607	841,738
# of Large Comm & Ind Customers	267	268	269	271	276	278	279	279	277	274	272	271	273
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	106.7	104.0	87.4	81.5	87.8	114.2	134.5	128.2	104.8	88.3	95.8	108.6	134.5
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	106.7	104.0	87.4	81.5	87.8	114.2	134.5	128.2	104.8	88.3	95.8	108.6	134.5

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	851.8	737.1	710.8	624.5	617.0	630.4	849.9	792.9	644.0	644.8	729.1	848.1	8,681.2
# of Residential Customers	18,891	18,886	18,864	18,810	18,815	18,821	18,838	18,846	18,854	18,867	18,891	18,893	18,856
Total Residential Sales - MWh	16,091	13,920	13,408	11,746	11,608	11,864	16,010	14,943	12,142	12,165	13,774	16,024	163,695
Use per Small Comm & Ind Customer - kWh	1,996.7	1,837.5	1,806.2	1,632.4	1,720.6	1,696.5	2,120.1	1,998.4	1,733.2	1,688.7	1,790.1	1,970.5	21,992.1
# of Small Comm & Ind Customers	4,831	4,830	4,836	4,886	4,954	4,982	4,995	5,000	4,985	4,928	4,898	4,885	4,918
Total Small Comm & Ind Sales - MWh	9,646	8,875	8,735	7,976	8,524	8,452	10,590	9,992	8,640	8,322	8,768	9,626	108,146
General Large Comm & Ind Sales	18,218	18,428	17,174	17,945	17,158	16,951	17,841	18,046	18,127	19,496	20,197	22,535	222,116
Encore Oil Sales	21,024	21,710	21,924	22,280	22,315	21,566	22,573	22,222	22,327	24,316	24,648	25,372	272,277
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	65,203	63,162	61,443	60,136	59,768	58,967	67,139	65,325	61,365	64,459	67,599	73,807	768,373
Other Public Sales	471	437	447	444	537	592	749	713	601	483	442	465	6,381
Street & Highway Lighting Sales	618	569	623	585	633	571	588	617	585	632	601	621	7,243
Interdepartmental Sales	18	16	16	14	14	12	15	14	13	14	16	19	181
Total Billed Sales - MWh	66,310	64,184	62,529	61,179	60,952	60,142	68,491	66,669	62,564	65,588	68,658	74,912	782,178
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	66,360	64,230	62,571	61,215	60,985	60,173	68,529	66,704	62,594	65,619	68,696	74,955	782,631
Total Requirements (Energy + Losses)	72,013	69,702	67,901	66,430	66,180	65,299	74,367	72,387	67,926	71,209	74,548	81,340	849,302
# of Large Comm & Ind Customers	270	271	272	274	279	281	283	283	281	278	275	274	277
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	107.8	105.2	88.4	82.4	88.7	115.4	135.9	129.5	105.9	89.2	96.8	109.8	135.9
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	107.8	105.2	88.4	82.4	88.7	115.4	135.9	129.5	105.9	89.2	96.8	109.8	135.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	856.4	741.0	714.6	627.9	620.3	633.7	854.5	797.2	647.5	648.2	733.0	852.7	8,728.1
# of Residential Customers	18,915	18,910	18,888	18,834	18,839	18,845	18,861	18,870	18,878	18,891	18,915	18,917	18,880
Total Residential Sales - MWh	16,199	14,012	13,497	11,825	11,686	11,943	16,117	15,043	12,224	12,246	13,865	16,131	164,788
Use per Small Comm & Ind Customer - kWh	2,003.1	1,843.2	1,812.0	1,637.9	1,726.2	1,702.0	2,126.7	2,004.6	1,738.6	1,693.7	1,795.9	1,970.7	22,055.6
# of Small Comm & Ind Customers	4,861	4,860	4,866	4,916	4,985	5,013	5,026	5,031	5,016	4,959	4,928	4,916	4,948
Total Small Comm & Ind Sales - MWh	9,737	8,958	8,817	8,052	8,605	8,532	10,689	10,085	8,721	8,399	8,850	9,688	109,133
General Large Comm & Ind Sales	18,491	18,704	17,433	18,215	17,416	17,206	18,109	18,317	18,399	19,788	20,500	22,870	225,448
Encore Oil Sales	21,143	21,833	22,047	22,406	22,441	21,688	22,700	22,348	22,453	24,453	24,788	25,516	273,816
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	65,794	63,736	61,996	60,687	60,311	59,503	67,740	65,915	61,926	65,046	68,215	74,455	775,324
Other Public Sales	470	437	447	444	536	591	748	712	600	482	441	464	6,372
Street & Highway Lighting Sales	618	569	623	586	634	571	588	618	586	633	601	621	7,248
Interdepartmental Sales	18	16	16	14	14	12	15	14	13	14	16	19	181
Total Billed Sales - MWh	66,900	64,758	63,082	61,731	61,495	60,677	69,091	67,259	63,125	66,175	69,273	75,559	789,125
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	66,950	64,804	63,124	61,767	61,528	60,708	69,129	67,294	63,155	66,206	69,311	75,602	789,578
Total Requirements (Energy + Losses)	72,653	70,325	68,502	67,029	66,770	65,880	75,018	73,027	68,535	71,846	75,216	82,043	856,844
# of Large Comm & Ind Customers	273	274	275	277	282	284	286	286	284	281	278	277	280
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	109.0	106.3	89.3	83.3	89.7	116.6	137.4	130.9	107.0	90.2	97.8	110.9	137.4
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	109.0	106.3	89.3	83.3	89.7	116.6	137.4	130.9	107.0	90.2	97.8	110.9	137.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	861.4	745.3	718.8	631.5	624.0	637.5	859.5	801.8	651.3	652.1	737.3	857.7	8,779.1
# of Residential Customers	18,932	18,927	18,905	18,851	18,855	18,862	18,878	18,887	18,894	18,908	18,932	18,934	18,897
Total Residential Sales - MWh	16,308	14,107	13,589	11,904	11,765	12,024	16,226	15,144	12,306	12,329	13,959	16,239	165,900
Use per Small Comm & Ind Customer - kWh	1,999.0	1,839.5	1,808.4	1,634.7	1,722.7	1,698.5	2,122.4	2,000.6	1,735.1	1,690.5	1,792.1	1,967.0	22,011.5
# of Small Comm & Ind Customers	4,891	4,890	4,896	4,946	5,016	5,044	5,057	5,062	5,047	4,989	4,959	4,946	4,979
Total Small Comm & Ind Sales - MWh	9,777	8,995	8,854	8,085	8,641	8,567	10,733	10,127	8,757	8,434	8,887	9,729	109,586
General Large Comm & Ind Sales	18,763	18,979	17,688	18,483	17,672	17,459	18,375	18,586	18,670	20,079	20,801	23,204	228,759
Encore Oil Sales	21,263	21,957	22,173	22,534	22,569	21,811	22,830	22,475	22,581	24,592	24,929	25,661	275,375
Westmoreland Coal - MT Sales	224	229	202	189	163	134	125	122	129	160	212	250	2,139
Total Sales (Residential, SC&I and LC&I)	66,335	64,267	62,506	61,195	60,810	59,995	68,289	66,454	62,443	65,594	68,788	75,083	781,759
Other Public Sales	469	436	446	443	535	590	747	711	599	481	441	464	6,362
Street & Highway Lighting Sales	618	569	623	586	634	571	588	618	586	633	601	621	7,248
Interdepartmental Sales	18	16	16	14	14	12	15	14	13	14	16	19	181
Total Billed Sales - MWh	67,440	65,288	63,591	62,238	61,993	61,168	69,639	67,797	63,641	66,722	69,846	76,187	795,550
Company Use	50	46	42	36	33	31	38	35	30	31	38	43	453
Total Energy	67,490	65,334	63,633	62,274	62,026	61,199	69,677	67,832	63,671	66,753	69,884	76,230	796,003
Total Requirements (Energy + Losses)	73,239	70,900	69,054	67,579	67,310	66,413	75,613	73,611	69,095	72,440	75,837	82,724	863,815
# of Large Comm & Ind Customers	277	277	278	280	285	287	289	289	287	284	282	281	283
# of Other Public Customers	100	99	100	103	106	107	107	107	105	103	101	100	103
# of Street & Highway Lighting Customers	90	93	91	91	91	91	81	81	82	82	82	82	86
Peak Demand	110.1	107.4	90.3	84.2	90.6	117.9	138.8	132.3	108.1	91.1	98.8	112.1	138.8
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	110.1	107.4	90.3	84.2	90.6	117.9	138.8	132.3	108.1	91.1	98.8	112.1	138.8

APPENDIX E

Monthly Forecasts - North Dakota
(2007-2016)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2007

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	873.6	779.8	726.3	639.4	621.5	639.1	820.4	777.3	654.8	647.1	755.0	864.8	8,799.3
# of Residential Customers	60,923	60,932	60,946	60,959	61,001	61,093	61,130	61,169	61,189	61,195	61,217	61,210	61,080
Total Residential Sales - MWh	53,223	47,517	44,268	38,980	37,910	39,044	50,149	47,548	40,069	39,602	46,216	52,936	537,462
Use per Small Comm & Ind Customer - kWh	2,379.2	2,178.9	2,257.5	1,997.9	2,015.4	2,010.6	2,413.2	2,366.1	2,077.0	2,048.8	2,228.0	2,325.9	26,297.3
# of Small Comm & Ind Customers	9,403	9,389	9,390	9,457	9,547	9,602	9,608	9,635	9,621	9,554	9,526	9,531	9,522
Total Small Comm & Ind Sales - MWh	22,372	20,458	21,198	18,894	19,241	19,306	23,186	22,797	19,983	19,574	21,224	22,168	250,401
General Large Comm & Ind Sales	43,438	43,517	42,499	42,160	43,136	43,275	48,732	49,167	44,989	44,149	44,197	45,321	534,580
Sabin Metals Sales	1,014	1,050	1,095	1,088	1,110	1,041	1,127	1,113	1,058	1,109	871	821	12,497
Tesoro Refinery Sales	3,787	3,881	4,252	4,276	4,514	4,699	4,934	4,985	4,658	4,604	4,550	4,272	53,412
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	126,427	118,877	115,627	107,598	107,884	109,093	129,856	127,444	112,688	111,241	119,404	128,073	1,414,212
Other Public Sales	2,662	2,562	2,646	2,462	2,834	3,028	3,452	3,413	2,865	2,558	2,514	2,603	33,599
Street & Highway Lighting Sales	1,815	1,718	1,738	1,658	1,665	1,535	1,618	1,643	1,664	1,761	1,847	1,830	20,492
Interdepartmental Sales	23	22	21	20	20	18	20	18	18	21	22	24	247
Total Billed Sales - MWh	130,927	123,179	120,032	111,738	112,403	113,674	134,946	132,518	117,235	115,581	123,787	132,530	1,468,550
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	131,364	123,602	120,444	112,157	112,832	114,117	135,434	133,016	117,668	116,003	124,231	132,972	1,473,840
Total Requirements (Energy + Losses)	142,555	134,132	130,705	121,712	122,444	123,839	146,972	144,348	127,692	125,885	134,814	144,300	1,599,398
# of Large Comm & Ind Customers	735	738	740	743	745	744	745	745	745	747	748	747	744
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	247.4	235.5	224.9	213.0	239.2	298.6	326.3	315.9	272.6	220.8	239.2	267.4	326.3
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	247.4	235.5	224.9	213.0	239.2	298.6	320.8	315.9	272.6	220.8	239.2	267.4	320.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2008

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	879.6	785.2	731.3	643.8	625.4	643.0	825.1	782.2	659.1	651.6	760.2	869.9	8,856.2
# of Residential Customers	61,049	61,057	61,072	61,084	61,127	61,219	61,256	61,295	61,315	61,321	61,343	61,336	61,206
Total Residential Sales - MWh	53,698	47,942	44,665	39,324	38,231	39,362	50,540	47,942	40,413	39,955	46,630	53,355	542,057
Use per Small Comm & Ind Customer - kWh	2,375.1	2,174.8	2,253.4	1,994.1	2,011.4	2,006.8	2,408.8	2,361.7	2,073.2	2,045.1	2,224.0	2,325.5	26,252.6
# of Small Comm & Ind Customers	9,470	9,457	9,457	9,525	9,616	9,671	9,677	9,704	9,690	9,622	9,594	9,599	9,590
Total Small Comm & Ind Sales - MWh	22,492	20,567	21,310	18,994	19,342	19,408	23,310	22,918	20,089	19,678	21,337	22,322	251,767
General Large Comm & Ind Sales	44,835	44,916	43,865	43,514	44,522	44,666	50,303	50,752	46,438	45,570	45,619	46,616	551,616
Sabin Metals Sales	1,014	1,050	1,095	1,088	1,110	1,041	1,127	1,113	1,058	1,109	871	821	12,497
Tesoro Refinery Sales	3,908	4,005	4,387	4,413	4,659	4,850	5,092	5,144	4,807	4,750	4,695	4,406	55,116
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	128,540	120,934	117,637	109,533	109,837	111,055	132,100	129,703	114,736	113,265	121,498	130,075	1,438,913
Other Public Sales	2,658	2,558	2,642	2,458	2,830	3,023	3,447	3,408	2,861	2,554	2,511	2,600	33,550
Street & Highway Lighting Sales	1,815	1,718	1,738	1,658	1,665	1,536	1,619	1,643	1,664	1,761	1,848	1,831	20,496
Interdepartmental Sales	23	22	21	20	20	17	20	18	18	21	22	24	246
Total Billed Sales - MWh	133,036	125,232	122,038	113,669	114,352	115,631	137,186	134,772	119,279	117,601	125,879	134,530	1,493,205
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	133,473	125,655	122,450	114,088	114,781	116,074	137,674	135,270	119,712	118,023	126,323	134,972	1,498,495
Total Requirements (Energy + Losses)	144,844	136,360	132,882	123,807	124,559	125,962	149,402	146,794	129,910	128,077	137,084	146,470	1,626,151
# of Large Comm & Ind Customers	745	748	749	753	754	754	755	755	755	757	757	757	753
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	252.8	240.5	229.7	217.3	242.3	302.6	330.8	320.3	276.3	223.8	242.5	271.1	330.8
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	252.8	240.5	229.7	217.3	242.3	302.6	325.3	320.3	276.3	223.8	242.5	271.1	325.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	884.1	789.2	735.1	647.1	628.7	646.3	829.3	786.2	662.5	654.9	764.1	877.4	8,904.9
# of Residential Customers	61,161	61,170	61,184	61,197	61,239	61,331	61,368	61,407	61,427	61,434	61,455	61,449	61,319
Total Residential Sales - MWh	54,074	48,277	44,976	39,599	38,498	39,638	50,894	48,277	40,695	40,234	46,955	53,918	546,035
Use per Small Comm & Ind Customer - kWh	2,378.7	2,178.1	2,257.0	1,997.0	2,014.6	2,009.8	2,412.7	2,365.6	2,076.3	2,048.0	2,227.4	2,327.5	26,291.3
# of Small Comm & Ind Customers	9,536	9,522	9,522	9,591	9,682	9,738	9,744	9,771	9,757	9,689	9,660	9,666	9,657
Total Small Comm & Ind Sales - MWh	22,683	20,740	21,491	19,153	19,505	19,571	23,509	23,114	20,258	19,843	21,517	22,498	253,882
General Large Comm & Ind Sales	45,941	46,024	44,946	44,587	45,621	45,768	51,546	52,007	47,583	46,694	46,744	47,751	565,212
Sabin Metals Sales	1,014	1,050	1,095	1,088	1,110	1,041	1,127	1,113	1,058	1,109	871	1,003	12,679
Tesoro Refinery Sales	4,029	4,129	4,523	4,549	4,802	5,000	5,250	5,303	4,956	4,897	4,840	4,540	56,818
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	130,334	122,674	119,346	111,176	111,509	112,746	134,054	131,648	116,481	114,980	123,273	132,265	1,460,486
Other Public Sales	2,654	2,554	2,638	2,455	2,826	3,019	3,443	3,403	2,857	2,551	2,507	2,596	33,503
Street & Highway Lighting Sales	1,816	1,718	1,739	1,658	1,665	1,536	1,619	1,644	1,664	1,762	1,848	1,831	20,500
Interdepartmental Sales	23	22	21	20	19	17	19	18	18	20	21	24	242
Total Billed Sales - MWh	134,827	126,968	123,744	115,309	116,019	117,318	139,135	136,713	121,020	119,313	127,649	136,716	1,514,731
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	135,264	127,391	124,156	115,728	116,448	117,761	139,623	137,211	121,453	119,735	128,093	137,158	1,520,021
Total Requirements (Energy + Losses)	146,787	138,243	134,733	125,587	126,368	127,793	151,517	148,900	131,800	129,935	139,005	148,842	1,649,510
# of Large Comm & Ind Customers	754	758	759	762	764	764	765	765	765	767	767	767	763
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	256.3	243.8	232.7	220.2	245.1	306.4	334.9	324.3	279.6	226.2	245.2	274.4	334.9
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	256.3	243.8	232.7	220.2	245.1	306.4	329.4	324.3	279.6	226.2	245.2	274.4	329.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	894.8	798.7	744.0	654.9	636.3	654.1	839.3	795.7	670.5	662.8	773.3	886.4	9,010.7
# of Residential Customers	61,263	61,272	61,286	61,299	61,342	61,434	61,471	61,510	61,530	61,536	61,558	61,552	61,421
Total Residential Sales - MWh	54,817	48,940	45,595	40,143	39,029	40,184	51,595	48,942	41,255	40,787	47,601	54,557	553,445
Use per Small Comm & Ind Customer - kWh	2,379.5	2,178.8	2,257.6	1,997.6	2,015.1	2,010.4	2,413.5	2,366.5	2,077.0	2,048.6	2,228.1	2,328.4	26,299.9
# of Small Comm & Ind Customers	9,602	9,588	9,588	9,657	9,749	9,805	9,811	9,838	9,824	9,756	9,727	9,732	9,723
Total Small Comm & Ind Sales - MWh	22,848	20,890	21,646	19,291	19,645	19,712	23,679	23,282	20,404	19,986	21,673	22,660	255,716
General Large Comm & Ind Sales	47,041	47,126	46,022	45,653	46,712	46,864	52,784	53,256	48,723	47,812	47,864	48,880	578,737
Sabin Metals Sales	1,387	1,437	1,498	1,488	1,518	1,424	1,542	1,523	1,447	1,517	1,192	1,160	17,133
Tesoro Refinery Sales	4,150	4,252	4,659	4,685	4,947	5,150	5,407	5,462	5,104	5,044	4,985	4,674	58,519
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	132,836	125,099	121,735	113,460	113,824	115,062	136,735	134,299	118,864	117,349	125,661	134,486	1,489,410
Other Public Sales	2,650	2,551	2,635	2,452	2,822	3,015	3,437	3,398	2,854	2,548	2,504	2,593	33,459
Street & Highway Lighting Sales	1,816	1,719	1,739	1,659	1,665	1,536	1,619	1,644	1,665	1,762	1,848	1,831	20,503
Interdepartmental Sales	23	22	21	20	19	17	19	18	18	20	21	24	242
Total Billed Sales - MWh	137,325	129,391	126,130	117,591	118,330	119,630	141,810	139,359	123,401	121,679	130,034	138,934	1,543,614
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	137,762	129,814	126,542	118,010	118,759	120,073	142,298	139,857	123,834	122,101	130,478	139,376	1,548,904
Total Requirements (Energy + Losses)	149,498	140,873	137,322	128,063	128,876	130,302	154,420	151,771	134,383	132,503	141,593	151,249	1,680,853
# of Large Comm & Ind Customers	764	767	769	772	774	773	774	775	775	777	777	776	773
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	259.4	246.7	235.5	222.7	247.7	309.9	338.8	327.9	282.7	228.7	248.0	277.4	338.8
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	259.4	246.7	235.5	222.7	247.7	309.9	333.3	327.9	282.7	228.7	248.0	277.4	333.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	902.3	805.5	750.3	660.4	641.6	659.6	846.5	802.4	676.2	668.4	779.8	892.2	9,085.3
# of Residential Customers	61,368	61,377	61,391	61,404	61,447	61,539	61,576	61,615	61,635	61,642	61,664	61,657	61,526
Total Residential Sales - MWh	55,375	49,438	46,059	40,552	39,426	40,594	52,122	49,441	41,675	41,202	48,085	55,013	558,982
Use per Small Comm & Ind Customer - kWh	2,382.1	2,181.2	2,260.2	1,999.7	2,017.2	2,012.5	2,416.1	2,368.8	2,079.2	2,050.9	2,230.5	2,331.6	26,328.7
# of Small Comm & Ind Customers	9,666	9,652	9,652	9,722	9,814	9,871	9,877	9,905	9,890	9,821	9,792	9,798	9,788
Total Small Comm & Ind Sales - MWh	23,025	21,053	21,815	19,441	19,797	19,865	23,864	23,463	20,563	20,142	21,841	22,845	257,714
General Large Comm & Ind Sales	48,168	48,255	47,125	46,748	47,832	47,987	54,049	54,532	49,891	48,958	49,011	50,038	592,594
Sabin Metals Sales	1,462	1,514	1,579	1,568	1,600	1,501	1,624	1,605	1,525	1,598	1,256	1,220	18,052
Tesoro Refinery Sales	4,270	4,376	4,794	4,822	5,090	5,299	5,564	5,621	5,253	5,191	5,130	4,809	60,219
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	134,893	127,090	123,687	115,331	115,718	116,974	138,951	136,496	120,838	119,294	127,669	136,480	1,513,421
Other Public Sales	2,648	2,548	2,631	2,449	2,819	3,011	3,433	3,394	2,849	2,544	2,500	2,589	33,415
Street & Highway Lighting Sales	1,816	1,719	1,739	1,659	1,666	1,537	1,620	1,644	1,665	1,762	1,849	1,832	20,508
Interdepartmental Sales	22	21	20	19	19	17	19	18	18	20	21	23	237
Total Billed Sales - MWh	139,379	131,378	128,077	119,458	120,222	121,539	144,023	141,552	125,370	123,620	132,039	140,924	1,567,581
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	139,816	131,801	128,489	119,877	120,651	121,982	144,511	142,050	125,803	124,042	132,483	141,366	1,572,871
Total Requirements (Energy + Losses)	151,727	143,029	139,435	130,089	130,929	132,374	156,822	154,151	136,520	134,609	143,769	153,409	1,706,863
# of Large Comm & Ind Customers	773	776	778	781	783	782	783	784	784	786	786	786	782
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	263.0	250.2	238.8	225.8	250.4	313.3	342.5	331.6	285.8	231.2	250.7	280.4	342.5
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	263.0	250.2	238.8	225.8	250.4	313.3	337.0	331.6	285.8	231.2	250.7	280.4	337.0

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	906.9	809.5	754.0	663.7	644.9	663.0	850.7	806.4	679.6	671.8	783.7	896.7	9,131.0
# of Residential Customers	61,472	61,481	61,495	61,508	61,551	61,643	61,680	61,720	61,739	61,746	61,768	61,761	61,630
Total Residential Sales - MWh	55,747	49,771	46,368	40,825	39,692	40,867	52,474	49,774	41,956	41,480	48,409	55,381	562,744
Use per Small Comm & Ind Customer - kWh	2,387.0	2,185.6	2,264.5	2,003.6	2,021.2	2,016.4	2,420.8	2,373.8	2,083.3	2,054.8	2,235.0	2,336.5	26,381.2
# of Small Comm & Ind Customers	9,729	9,715	9,716	9,786	9,879	9,936	9,942	9,969	9,955	9,886	9,856	9,862	9,853
Total Small Comm & Ind Sales - MWh	23,223	21,233	22,002	19,607	19,967	20,035	24,068	23,664	20,739	20,314	22,028	23,043	259,923
General Large Comm & Ind Sales	49,294	49,384	48,227	47,841	48,950	49,108	55,311	55,806	51,057	50,103	50,157	51,195	606,433
Sabin Metals Sales	1,536	1,592	1,660	1,648	1,682	1,577	1,707	1,687	1,603	1,680	1,321	1,281	18,974
Tesoro Refinery Sales	4,391	4,500	4,930	4,958	5,234	5,449	5,722	5,780	5,401	5,338	5,275	4,943	61,921
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	136,784	128,934	125,502	117,079	117,498	118,764	141,010	138,545	122,687	121,118	129,536	138,398	1,535,855
Other Public Sales	2,644	2,544	2,628	2,445	2,815	3,007	3,428	3,389	2,846	2,540	2,497	2,586	33,369
Street & Highway Lighting Sales	1,817	1,719	1,740	1,659	1,666	1,537	1,620	1,644	1,665	1,763	1,849	1,832	20,511
Interdepartmental Sales	22	21	20	19	19	17	19	18	18	20	21	23	237
Total Billed Sales - MWh	141,267	133,218	129,890	121,202	121,998	123,325	146,077	143,596	127,216	125,441	133,903	142,839	1,589,972
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	141,704	133,641	130,302	121,621	122,427	123,768	146,565	144,094	127,649	125,863	134,347	143,281	1,595,262
Total Requirements (Energy + Losses)	153,776	145,026	141,402	131,982	132,857	134,312	159,051	156,369	138,523	136,585	145,792	155,487	1,731,162
# of Large Comm & Ind Customers	782	786	787	791	793	792	793	793	794	796	796	795	792
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	265.9	252.9	241.4	228.3	253.2	316.7	346.2	335.2	288.9	233.7	253.4	283.5	346.2
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	265.9	252.9	241.4	228.3	253.2	316.7	340.7	335.2	288.9	233.7	253.4	283.5	340.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	911.4	813.6	757.8	667.0	648.1	666.3	855.0	810.5	682.9	675.1	787.6	901.2	9,176.5
# of Residential Customers	61,576	61,584	61,598	61,611	61,654	61,747	61,784	61,824	61,844	61,850	61,872	61,866	61,734
Total Residential Sales - MWh	56,119	50,103	46,677	41,097	39,957	41,140	52,825	50,107	42,236	41,756	48,731	55,754	566,502
Use per Small Comm & Ind Customer - kWh	2,392.4	2,190.8	2,269.8	2,008.4	2,026.0	2,021.3	2,426.7	2,379.2	2,088.3	2,059.7	2,240.2	2,343.1	26,444.7
# of Small Comm & Ind Customers	9,792	9,777	9,778	9,848	9,942	9,999	10,005	10,033	10,018	9,949	9,919	9,925	9,915
Total Small Comm & Ind Sales - MWh	23,426	21,419	22,194	19,779	20,142	20,211	24,279	23,871	20,921	20,492	22,221	23,255	262,210
General Large Comm & Ind Sales	50,419	50,511	49,328	48,933	50,067	50,229	56,574	57,080	52,223	51,246	51,302	52,344	620,256
Sabin Metals Sales	1,611	1,669	1,740	1,728	1,764	1,654	1,791	1,769	1,681	1,762	1,385	1,341	19,895
Tesoro Refinery Sales	4,512	4,624	5,066	5,094	5,378	5,600	5,880	5,939	5,550	5,484	5,420	5,078	63,625
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	138,680	130,780	127,320	118,831	119,281	120,562	143,077	140,600	124,542	122,943	131,405	140,327	1,558,348
Other Public Sales	2,640	2,541	2,624	2,441	2,811	3,003	3,424	3,385	2,842	2,537	2,494	2,582	33,324
Street & Highway Lighting Sales	1,817	1,720	1,740	1,659	1,666	1,537	1,620	1,645	1,666	1,763	1,849	1,832	20,514
Interdepartmental Sales	22	21	20	19	19	17	18	17	17	20	21	23	234
Total Billed Sales - MWh	143,159	135,062	131,704	122,950	123,777	125,119	148,139	145,647	129,067	127,263	135,769	144,764	1,612,420
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	143,596	135,485	132,116	123,369	124,206	125,562	148,627	146,145	129,500	127,685	136,213	145,206	1,617,710
Total Requirements (Energy + Losses)	155,829	147,027	143,371	133,879	134,787	136,259	161,289	158,595	140,532	138,562	147,817	157,576	1,755,523
# of Large Comm & Ind Customers	792	796	797	801	803	802	803	803	803	806	806	805	801
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	268.8	255.7	244.1	230.8	255.9	320.1	349.9	338.7	292.0	236.2	256.1	286.5	349.9
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	268.8	255.7	244.1	230.8	255.9	320.1	344.4	338.7	292.0	236.2	256.1	286.5	344.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	916.5	818.2	762.1	670.8	651.8	670.1	859.9	815.1	686.8	678.9	792.1	906.3	9,228.5
# of Residential Customers	61,645	61,654	61,668	61,681	61,724	61,817	61,854	61,894	61,914	61,920	61,942	61,936	61,804
Total Residential Sales - MWh	56,500	50,443	46,995	41,377	40,229	41,421	53,186	50,448	42,524	42,040	49,063	56,130	570,356
Use per Small Comm & Ind Customer - kWh	2,400.0	2,197.4	2,277.0	2,014.6	2,032.3	2,027.5	2,434.2	2,386.7	2,094.8	2,066.2	2,247.3	2,350.2	26,527.1
# of Small Comm & Ind Customers	9,855	9,841	9,841	9,912	10,006	10,064	10,070	10,098	10,083	10,013	9,983	9,989	9,980
Total Small Comm & Ind Sales - MWh	23,652	21,625	22,408	19,969	20,335	20,405	24,512	24,101	21,122	20,689	22,435	23,476	264,729
General Large Comm & Ind Sales	51,531	51,625	50,415	50,012	51,172	51,337	57,821	58,338	53,374	52,376	52,432	53,488	633,921
Sabin Metals Sales	1,685	1,746	1,821	1,808	1,845	1,731	1,874	1,851	1,759	1,844	1,449	1,384	20,797
Tesoro Refinery Sales	4,633	4,747	5,201	5,231	5,523	5,749	6,037	6,098	5,699	5,632	5,566	5,212	65,328
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	140,594	132,640	129,155	120,597	121,077	122,371	145,158	142,670	126,409	124,784	133,291	142,245	1,580,991
Other Public Sales	2,636	2,537	2,621	2,438	2,807	2,999	3,419	3,380	2,838	2,533	2,490	2,578	33,276
Street & Highway Lighting Sales	1,817	1,720	1,740	1,660	1,667	1,537	1,620	1,645	1,666	1,763	1,850	1,833	20,518
Interdepartmental Sales	22	21	20	19	19	16	18	17	17	19	20	23	231
Total Billed Sales - MWh	145,069	136,918	133,536	124,714	125,570	126,923	150,215	147,712	130,930	129,099	137,651	146,679	1,635,016
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	145,506	137,341	133,948	125,133	125,999	127,366	150,703	148,210	131,363	129,521	138,095	147,121	1,640,306
Total Requirements (Energy + Losses)	157,902	149,041	145,359	135,793	136,733	138,216	163,541	160,836	142,554	140,555	149,859	159,654	1,780,043
# of Large Comm & Ind Customers	802	805	807	810	812	812	813	813	813	815	816	815	811
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	271.7	258.4	246.7	233.2	258.6	323.5	353.6	342.3	295.1	238.7	258.9	289.6	353.6
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	271.7	258.4	246.7	233.2	258.6	323.5	348.1	342.3	295.1	238.7	258.9	289.6	348.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	921.5	822.6	766.2	674.4	655.3	673.7	864.5	819.5	690.5	682.6	796.4	911.2	9,278.4
# of Residential Customers	61,724	61,732	61,747	61,759	61,803	61,896	61,933	61,972	61,992	61,999	62,021	62,014	61,883
Total Residential Sales - MWh	56,878	50,780	47,309	41,653	40,498	41,698	53,542	50,786	42,808	42,321	49,391	56,506	574,170
Use per Small Comm & Ind Customer - kWh	2,407.6	2,204.4	2,284.2	2,021.0	2,038.6	2,033.9	2,441.7	2,394.2	2,101.4	2,072.6	2,254.2	2,351.4	26,604.0
# of Small Comm & Ind Customers	9,916	9,902	9,902	9,974	10,069	10,127	10,133	10,161	10,146	10,076	10,046	10,051	10,042
Total Small Comm & Ind Sales - MWh	23,874	21,828	22,618	20,157	20,527	20,597	24,742	24,327	21,321	20,884	22,646	23,634	267,155
General Large Comm & Ind Sales	52,645	52,741	51,506	51,093	52,278	52,447	59,071	59,599	54,528	53,508	53,566	54,629	647,611
Sabin Metals Sales	1,723	1,785	1,862	1,848	1,886	1,769	1,915	1,892	1,797	1,884	1,481	1,396	21,238
Tesoro Refinery Sales	4,753	4,871	5,337	5,367	5,666	5,899	6,194	6,258	5,847	5,778	5,711	5,347	67,028
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	142,466	134,459	130,947	122,318	122,828	124,138	147,192	144,696	128,232	126,578	135,141	144,067	1,603,062
Other Public Sales	2,633	2,534	2,617	2,435	2,803	2,995	3,415	3,375	2,834	2,530	2,487	2,574	33,232
Street & Highway Lighting Sales	1,818	1,720	1,741	1,660	1,667	1,538	1,621	1,645	1,666	1,763	1,850	1,833	20,522
Interdepartmental Sales	22	21	20	19	18	16	18	17	17	19	20	23	230
Total Billed Sales - MWh	146,939	138,734	135,325	126,432	127,316	128,687	152,246	149,733	132,749	130,890	139,498	148,497	1,657,046
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	147,376	139,157	135,737	126,851	127,745	129,130	152,734	150,231	133,182	131,312	139,942	148,939	1,662,336
Total Requirements (Energy + Losses)	159,931	151,012	147,300	137,657	138,628	140,131	165,745	163,029	144,528	142,498	151,864	161,627	1,803,950
# of Large Comm & Ind Customers	811	814	816	820	821	821	822	822	822	825	825	824	820
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	274.6	261.2	249.3	235.8	261.4	326.9	357.3	345.9	298.2	241.3	261.6	292.6	357.3
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	274.6	261.2	249.3	235.8	261.4	326.9	351.8	345.9	298.2	241.3	261.6	292.6	351.8

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

NORTH DAKOTA YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	926.9	827.4	770.7	678.4	659.1	677.6	869.6	824.3	694.6	686.6	801.0	916.5	9,332.6
# of Residential Customers	61,778	61,787	61,801	61,814	61,857	61,950	61,987	62,027	62,047	62,053	62,075	62,069	61,937
Total Residential Sales - MWh	57,260	51,122	47,627	41,933	40,771	41,979	53,903	51,128	43,096	42,606	49,723	56,886	578,034
Use per Small Comm & Ind Customer - kWh	2,402.7	2,199.9	2,279.6	2,016.9	2,034.6	2,029.8	2,437.0	2,389.5	2,097.2	2,068.5	2,249.8	2,346.8	26,551.2
# of Small Comm & Ind Customers	9,977	9,963	9,963	10,035	10,130	10,189	10,195	10,223	10,208	10,138	10,107	10,113	10,103
Total Small Comm & Ind Sales - MWh	23,972	21,918	22,712	20,240	20,611	20,682	24,845	24,428	21,408	20,970	22,739	23,733	268,258
General Large Comm & Ind Sales	53,752	53,849	52,588	52,167	53,376	53,549	60,312	60,851	55,674	54,633	54,692	55,764	661,207
Sabin Metals Sales	1,723	1,785	1,862	1,848	1,886	1,769	1,915	1,892	1,797	1,884	1,481	1,396	21,238
Tesoro Refinery Sales	4,875	4,995	5,473	5,504	5,810	6,049	6,352	6,417	5,996	5,926	5,856	5,481	68,734
Westmoreland Coal - ND Sales	2,593	2,454	2,315	2,200	1,973	1,728	1,728	1,834	1,931	2,203	2,346	2,555	25,860
Total Sales (Residential, SC&I and LC&I)	144,175	136,123	132,577	123,892	124,427	125,756	149,055	146,550	129,902	128,222	136,837	145,815	1,623,331
Other Public Sales	2,629	2,530	2,613	2,432	2,799	2,990	3,410	3,371	2,830	2,527	2,484	2,571	33,186
Street & Highway Lighting Sales	1,818	1,721	1,741	1,660	1,667	1,538	1,621	1,646	1,667	1,764	1,850	1,833	20,526
Interdepartmental Sales	22	20	19	18	18	16	18	17	17	19	20	22	226
Total Billed Sales - MWh	148,644	140,394	136,950	128,002	128,911	130,300	154,104	151,584	134,416	132,532	141,191	150,241	1,677,269
Company Use	437	423	412	419	429	443	488	498	433	422	444	442	5,290
Total Energy	149,081	140,817	137,362	128,421	129,340	130,743	154,592	152,082	134,849	132,954	141,635	150,683	1,682,559
Total Requirements (Energy + Losses)	161,781	152,813	149,064	139,361	140,358	141,881	167,762	165,038	146,337	144,280	153,701	163,520	1,825,896
# of Large Comm & Ind Customers	820	824	826	829	831	831	832	832	832	834	834	834	830
# of Other Public Customers	731	731	732	737	743	743	743	741	739	734	731	726	736
# of Street & Highway Lighting Customers	423	429	430	432	433	433	412	413	413	415	415	417	422
Peak Demand	277.4	263.9	251.9	238.2	264.1	330.3	361.1	349.6	301.3	243.8	264.3	295.7	361.1
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	277.4	263.9	251.9	238.2	264.1	330.3	355.6	349.6	301.3	243.8	264.3	295.7	355.6

APPENDIX F

Monthly Forecasts – South Dakota
(2007-2016)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2007

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	971.1	837.7	813.5	696.8	665.5	670.2	840.8	788.0	678.2	685.2	792.0	928.4	9,365.0
# of Residential Customers	6,671	6,667	6,666	6,675	6,699	6,716	6,745	6,740	6,728	6,709	6,678	6,658	6,696
Total Residential Sales - MWh	6,478	5,585	5,423	4,651	4,458	4,501	5,671	5,311	4,563	4,597	5,289	6,181	62,708
Use per Small Comm & Ind Customer - kWh	1,770.6	1,618.0	1,548.5	1,393.6	1,384.2	1,403.0	1,825.8	1,721.4	1,520.2	1,524.9	1,590.2	1,705.7	19,002.3
# of Small Comm & Ind Customers	1,783	1,780	1,785	1,814	1,853	1,871	1,871	1,870	1,861	1,827	1,813	1,811	1,828
Total Small Comm & Ind Sales - MWh	3,157	2,880	2,764	2,528	2,565	2,625	3,416	3,219	2,829	2,786	2,883	3,089	34,741
General Large Comm & Ind Sales	2,780	2,636	2,631	2,498	2,617	2,363	3,052	2,712	2,778	2,912	2,744	2,871	32,594
Total Sales (Residential, SC&I and LC&I)	12,415	11,101	10,818	9,677	9,640	9,489	12,139	11,242	10,170	10,295	10,916	12,141	130,043
Other Public Sales	191	193	183	175	218	218	294	245	222	193	185	202	2,519
Street & Highway Lighting Sales	225	215	226	223	226	218	221	225	219	228	222	214	2,662
Interdepartmental Sales	2	1	1	1	1	-	-	-	1	1	1	1	10
Total Billed Sales - MWh	12,833	11,510	11,228	10,076	10,085	9,925	12,654	11,712	10,612	10,717	11,324	12,558	135,234
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	12,885	11,551	11,262	10,097	10,103	9,935	12,665	11,726	10,624	10,735	11,353	12,602	135,538
Total Requirements (Energy + Losses)	13,983	12,535	12,221	10,957	10,964	10,781	13,744	12,725	11,529	11,650	12,320	13,676	147,085
# of Large Comm & Ind Customers	70	70	70	70	70	70	70	70	70	70	70	70	70
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	21.0	21.2	19.9	18.6	20.8	26.9	29.1	29.5	22.5	17.1	20.5	22.0	29.5
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	21.0	21.2	19.9	18.6	20.8	26.9	29.1	29.5	22.5	17.1	20.5	22.0	29.5

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2008

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	977.9	843.4	819.2	701.6	669.7	674.1	845.7	793.0	682.7	689.8	797.5	933.8	9,426.2
# of Residential Customers	6,685	6,681	6,680	6,688	6,713	6,730	6,759	6,754	6,742	6,722	6,692	6,672	6,710
Total Residential Sales - MWh	6,537	5,635	5,472	4,692	4,496	4,537	5,716	5,356	4,603	4,637	5,337	6,230	63,248
Use per Small Comm & Ind Customer - kWh	1,767.3	1,615.2	1,545.6	1,391.9	1,382.1	1,400.5	1,823.2	1,719.1	1,517.6	1,522.3	1,587.6	1,705.6	18,974.3
# of Small Comm & Ind Customers	1,796	1,793	1,798	1,827	1,866	1,885	1,884	1,883	1,874	1,840	1,826	1,824	1,841
Total Small Comm & Ind Sales - MWh	3,174	2,896	2,779	2,543	2,579	2,640	3,435	3,237	2,844	2,801	2,899	3,111	34,938
General Large Comm & Ind Sales	2,868	2,720	2,715	2,577	2,700	2,437	3,149	2,798	2,866	3,005	2,832	2,949	33,616
Total Sales (Residential, SC&I and LC&I)	12,579	11,251	10,966	9,812	9,775	9,614	12,300	11,391	10,313	10,443	11,068	12,290	131,802
Other Public Sales	190	193	183	175	218	218	294	245	222	193	185	202	2,518
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	228	222	214	2,663
Interdepartmental Sales	2	1	1	1	1	-	-	-	1	1	1	1	10
Total Billed Sales - MWh	12,996	11,660	11,376	10,211	10,220	10,051	12,815	11,861	10,755	10,865	11,476	12,707	136,993
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,048	11,701	11,410	10,232	10,238	10,061	12,826	11,875	10,767	10,883	11,505	12,751	137,297
Total Requirements (Energy + Losses)	14,160	12,698	12,382	11,104	11,110	10,918	13,919	12,887	11,684	11,810	12,485	13,837	148,994
# of Large Comm & Ind Customers	71	71	71	71	71	71	71	71	71	71	71	71	71
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	21.4	21.6	20.3	19.0	21.1	27.2	29.5	29.7	22.8	17.3	20.7	22.3	29.7
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	21.4	21.6	20.3	19.0	21.1	27.2	29.5	29.7	22.8	17.3	20.7	22.3	29.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	982.8	847.8	823.4	705.0	673.2	677.5	850.0	797.1	686.2	693.2	801.5	942.0	9,477.2
# of Residential Customers	6,697	6,693	6,692	6,701	6,725	6,742	6,772	6,766	6,755	6,735	6,704	6,684	6,722
Total Residential Sales - MWh	6,582	5,674	5,510	4,724	4,527	4,568	5,756	5,393	4,635	4,669	5,373	6,296	63,707
Use per Small Comm & Ind Customer - kWh	1,770.5	1,616.8	1,548.1	1,393.7	1,384.2	1,402.5	1,826.0	1,721.5	1,519.3	1,524.6	1,590.0	1,708.1	19,001.6
# of Small Comm & Ind Customers	1,808	1,806	1,810	1,839	1,879	1,898	1,897	1,896	1,887	1,853	1,839	1,836	1,854
Total Small Comm & Ind Sales - MWh	3,201	2,920	2,802	2,563	2,601	2,662	3,464	3,264	2,867	2,825	2,924	3,136	35,229
General Large Comm & Ind Sales	2,937	2,785	2,780	2,638	2,765	2,495	3,225	2,865	2,935	3,077	2,899	3,019	34,420
Total Sales (Residential, SC&I and LC&I)	12,720	11,379	11,092	9,925	9,893	9,725	12,445	11,522	10,437	10,571	11,196	12,451	133,356
Other Public Sales	190	192	183	175	217	218	293	244	222	193	184	202	2,513
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	228	222	214	2,663
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,136	11,787	11,502	10,324	10,337	10,162	12,959	11,991	10,879	10,993	11,603	12,868	138,541
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,188	11,828	11,536	10,345	10,355	10,172	12,970	12,005	10,891	11,011	11,632	12,912	138,845
Total Requirements (Energy + Losses)	14,311	12,836	12,519	11,226	11,237	11,039	14,075	13,028	11,819	11,949	12,623	14,012	150,674
# of Large Comm & Ind Customers	72	72	72	72	72	72	72	72	72	72	72	72	72
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	21.7	21.9	20.5	19.2	21.3	27.5	29.8	30.1	23.0	17.6	21.0	22.5	30.1
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	21.7	21.9	20.5	19.2	21.3	27.5	29.8	30.1	23.0	17.6	21.0	22.5	30.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	994.8	858.1	833.4	713.5	681.2	685.8	860.2	806.7	694.5	701.7	811.3	951.5	9,590.4
# of Residential Customers	6,708	6,704	6,703	6,712	6,737	6,754	6,783	6,778	6,766	6,746	6,715	6,695	6,733
Total Residential Sales - MWh	6,673	5,753	5,586	4,789	4,589	4,632	5,835	5,468	4,699	4,734	5,448	6,370	64,576
Use per Small Comm & Ind Customer - kWh	1,771.0	1,618.3	1,549.4	1,394.7	1,384.8	1,402.9	1,827.2	1,722.4	1,520.5	1,526.0	1,591.0	1,708.5	19,013.0
# of Small Comm & Ind Customers	1,821	1,818	1,822	1,852	1,892	1,911	1,910	1,909	1,900	1,865	1,851	1,849	1,867
Total Small Comm & Ind Sales - MWh	3,225	2,942	2,823	2,583	2,620	2,681	3,490	3,288	2,889	2,846	2,945	3,159	35,491
General Large Comm & Ind Sales	3,006	2,851	2,845	2,701	2,830	2,554	3,302	2,933	3,004	3,150	2,968	3,088	35,232
Total Sales (Residential, SC&I and LC&I)	12,904	11,546	11,254	10,073	10,039	9,867	12,627	11,689	10,592	10,730	11,361	12,617	135,299
Other Public Sales	190	192	183	175	217	217	293	244	222	193	184	202	2,512
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	228	222	214	2,663
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,320	11,954	11,664	10,472	10,483	10,303	13,141	12,158	11,034	11,152	11,768	13,034	140,483
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,372	11,995	11,698	10,493	10,501	10,313	13,152	12,172	11,046	11,170	11,797	13,078	140,787
Total Requirements (Energy + Losses)	14,511	13,017	12,695	11,387	11,396	11,192	14,272	13,209	11,987	12,122	12,802	14,192	152,782
# of Large Comm & Ind Customers	72	72	72	73	73	73	72	72	73	73	73	73	73
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	22.0	22.2	20.8	19.5	21.6	27.8	30.2	30.4	23.3	17.7	21.2	22.8	30.4
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	22.0	22.2	20.8	19.5	21.6	27.8	30.2	30.4	23.3	17.7	21.2	22.8	30.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,003.0	865.2	840.4	719.6	687.2	691.6	867.7	813.5	700.5	707.6	818.2	957.7	9,669.8
# of Residential Customers	6,720	6,716	6,715	6,723	6,748	6,765	6,794	6,789	6,777	6,758	6,727	6,707	6,745
Total Residential Sales - MWh	6,740	5,811	5,643	4,838	4,637	4,679	5,895	5,523	4,747	4,782	5,504	6,423	65,222
Use per Small Comm & Ind Customer - kWh	1,773.0	1,620.2	1,551.0	1,395.7	1,385.8	1,404.4	1,828.9	1,724.2	1,522.2	1,527.2	1,592.3	1,711.4	19,032.5
# of Small Comm & Ind Customers	1,833	1,830	1,835	1,865	1,905	1,924	1,923	1,922	1,913	1,878	1,864	1,861	1,879
Total Small Comm & Ind Sales - MWh	3,250	2,965	2,846	2,603	2,640	2,702	3,517	3,314	2,912	2,868	2,968	3,185	35,770
General Large Comm & Ind Sales	3,078	2,919	2,913	2,765	2,898	2,616	3,381	3,003	3,076	3,225	3,039	3,162	36,075
Total Sales (Residential, SC&I and LC&I)	13,068	11,695	11,402	10,206	10,175	9,997	12,793	11,840	10,735	10,875	11,511	12,770	137,067
Other Public Sales	190	192	182	174	217	217	293	244	221	192	184	201	2,507
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	228	222	214	2,663
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,484	12,103	11,811	10,604	10,619	10,433	13,307	12,309	11,176	11,296	11,918	13,186	142,246
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,536	12,144	11,845	10,625	10,637	10,443	13,318	12,323	11,188	11,314	11,947	13,230	142,550
Total Requirements (Energy + Losses)	14,689	13,179	12,854	11,530	11,543	11,333	14,453	13,373	12,141	12,278	12,965	14,357	154,695
# of Large Comm & Ind Customers	73	73	73	73	74	74	73	73	74	74	74	74	74
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	22.3	22.5	21.1	19.7	21.8	28.1	30.6	30.7	23.6	17.9	21.5	23.1	30.7
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	22.3	22.5	21.1	19.7	21.8	28.1	30.6	30.7	23.6	17.9	21.5	23.1	30.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,008.2	869.6	844.5	723.1	690.4	695.0	872.0	817.7	703.8	711.2	822.2	962.5	9,717.7
# of Residential Customers	6,731	6,727	6,726	6,735	6,760	6,777	6,806	6,801	6,789	6,769	6,738	6,718	6,756
Total Residential Sales - MWh	6,786	5,850	5,680	4,870	4,667	4,710	5,935	5,561	4,778	4,814	5,540	6,466	65,657
Use per Small Comm & Ind Customer - kWh	1,776.7	1,623.2	1,553.9	1,398.5	1,389.1	1,407.5	1,832.6	1,727.6	1,525.7	1,530.2	1,595.4	1,714.9	19,071.9
# of Small Comm & Ind Customers	1,845	1,842	1,847	1,877	1,917	1,936	1,936	1,935	1,925	1,890	1,876	1,873	1,892
Total Small Comm & Ind Sales - MWh	3,278	2,990	2,870	2,625	2,663	2,725	3,548	3,343	2,937	2,892	2,993	3,212	36,076
General Large Comm & Ind Sales	3,151	2,988	2,982	2,830	2,966	2,677	3,460	3,074	3,149	3,301	3,110	3,235	36,923
Total Sales (Residential, SC&I and LC&I)	13,215	11,828	11,532	10,325	10,296	10,112	12,943	11,978	10,864	11,007	11,643	12,913	138,656
Other Public Sales	189	192	182	174	217	217	292	243	221	192	184	201	2,504
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	229	222	214	2,664
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,630	12,236	11,941	10,723	10,740	10,548	13,456	12,446	11,305	11,429	12,050	13,329	143,833
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,682	12,277	11,975	10,744	10,758	10,558	13,467	12,460	11,317	11,447	12,079	13,373	144,137
Total Requirements (Energy + Losses)	14,848	13,323	12,995	11,659	11,674	11,457	14,614	13,521	12,281	12,422	13,108	14,512	156,414
# of Large Comm & Ind Customers	74	74	74	74	74	74	74	74	74	74	75	74	74
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	22.6	22.8	21.3	20.0	22.1	28.4	30.9	31.1	23.8	18.1	21.7	23.3	31.1
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	22.6	22.8	21.3	20.0	22.1	28.4	30.9	31.1	23.8	18.1	21.7	23.3	31.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,013.1	874.0	848.9	726.8	693.8	698.4	876.3	821.8	707.5	714.7	826.2	967.5	9,766.7
# of Residential Customers	6,743	6,738	6,737	6,746	6,771	6,788	6,817	6,812	6,800	6,780	6,750	6,729	6,768
Total Residential Sales - MWh	6,831	5,889	5,719	4,903	4,698	4,741	5,974	5,598	4,811	4,846	5,577	6,510	66,097
Use per Small Comm & Ind Customer - kWh	1,780.8	1,626.8	1,557.3	1,401.8	1,391.7	1,410.5	1,836.8	1,731.4	1,528.4	1,533.6	1,599.0	1,719.9	19,114.1
# of Small Comm & Ind Customers	1,857	1,854	1,859	1,889	1,930	1,949	1,948	1,947	1,938	1,902	1,888	1,885	1,904
Total Small Comm & Ind Sales - MWh	3,307	3,016	2,895	2,648	2,686	2,749	3,578	3,371	2,962	2,917	3,019	3,242	36,390
General Large Comm & Ind Sales	3,222	3,056	3,050	2,895	3,033	2,738	3,539	3,144	3,221	3,377	3,181	3,307	37,763
Total Sales (Residential, SC&I and LC&I)	13,360	11,961	11,664	10,446	10,417	10,228	13,091	12,113	10,994	11,140	11,777	13,059	140,250
Other Public Sales	189	191	182	174	216	216	292	243	221	192	183	201	2,500
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	229	222	214	2,664
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,775	12,368	12,073	10,844	10,860	10,663	13,604	12,581	11,435	11,562	12,183	13,475	145,423
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,827	12,409	12,107	10,865	10,878	10,673	13,615	12,595	11,447	11,580	12,212	13,519	145,727
Total Requirements (Energy + Losses)	15,005	13,466	13,138	11,791	11,805	11,582	14,775	13,668	12,422	12,567	13,252	14,671	158,142
# of Large Comm & Ind Customers	75	75	75	75	75	75	75	75	75	75	75	75	75
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	22.8	23.0	21.6	20.2	22.3	28.7	31.2	31.4	24.1	18.3	21.9	23.6	31.4
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	22.8	23.0	21.6	20.2	22.3	28.7	31.2	31.4	24.1	18.3	21.9	23.6	31.4

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,019.0	878.9	853.5	730.8	697.9	702.5	881.3	826.4	711.4	718.8	831.0	972.8	9,821.8
# of Residential Customers	6,750	6,746	6,745	6,754	6,779	6,796	6,825	6,820	6,808	6,788	6,757	6,737	6,775
Total Residential Sales - MWh	6,878	5,929	5,757	4,936	4,731	4,774	6,015	5,636	4,843	4,879	5,615	6,554	66,547
Use per Small Comm & Ind Customer - kWh	1,786.0	1,631.8	1,562.3	1,406.1	1,396.5	1,415.6	1,842.4	1,737.6	1,533.3	1,539.2	1,604.7	1,724.4	19,176.4
# of Small Comm & Ind Customers	1,869	1,866	1,871	1,901	1,942	1,961	1,961	1,959	1,950	1,914	1,900	1,898	1,916
Total Small Comm & Ind Sales - MWh	3,338	3,045	2,923	2,673	2,712	2,776	3,613	3,404	2,990	2,946	3,049	3,273	36,742
General Large Comm & Ind Sales	3,294	3,123	3,118	2,959	3,101	2,799	3,618	3,214	3,292	3,451	3,252	3,379	38,600
Total Sales (Residential, SC&I and LC&I)	13,510	12,097	11,798	10,568	10,544	10,349	13,246	12,254	11,125	11,276	11,916	13,206	141,889
Other Public Sales	189	191	182	174	216	216	292	243	220	192	183	200	2,498
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	229	222	214	2,664
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	13,925	12,504	12,207	10,966	10,987	10,784	13,759	12,722	11,565	11,698	12,322	13,621	147,060
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	13,977	12,545	12,241	10,987	11,005	10,794	13,770	12,736	11,577	11,716	12,351	13,665	147,364
Total Requirements (Energy + Losses)	15,168	13,614	13,284	11,923	11,943	11,714	14,943	13,821	12,563	12,714	13,403	14,829	159,919
# of Large Comm & Ind Customers	76	76	76	76	76	76	76	76	76	76	76	76	76
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	23.0	23.2	21.8	20.4	22.5	29.0	31.6	31.7	24.3	18.5	22.2	23.8	31.7
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	23.0	23.2	21.8	20.4	22.5	29.0	31.6	31.7	24.3	18.5	22.2	23.8	31.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,024.3	883.6	858.2	734.8	701.6	706.3	886.0	830.9	715.3	722.7	835.4	978.2	9,874.9
# of Residential Customers	6,759	6,755	6,754	6,762	6,787	6,804	6,834	6,829	6,817	6,797	6,766	6,745	6,784
Total Residential Sales - MWh	6,923	5,969	5,796	4,969	4,762	4,806	6,055	5,674	4,876	4,912	5,652	6,598	66,992
Use per Small Comm & Ind Customer - kWh	1,791.6	1,636.8	1,567.5	1,410.9	1,401.2	1,420.2	1,848.5	1,742.4	1,538.7	1,544.1	1,609.8	1,726.0	19,234.2
# of Small Comm & Ind Customers	1,881	1,878	1,882	1,913	1,954	1,973	1,973	1,972	1,962	1,926	1,912	1,909	1,928
Total Small Comm & Ind Sales - MWh	3,370	3,074	2,950	2,699	2,738	2,802	3,647	3,436	3,019	2,974	3,078	3,295	37,082
General Large Comm & Ind Sales	3,365	3,191	3,185	3,023	3,168	2,859	3,696	3,283	3,363	3,526	3,322	3,451	39,432
Total Sales (Residential, SC&I and LC&I)	13,658	12,234	11,931	10,691	10,668	10,467	13,398	12,393	11,258	11,412	12,052	13,344	143,506
Other Public Sales	188	191	181	174	216	216	291	242	220	191	183	200	2,493
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	229	223	215	2,666
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	14,072	12,641	12,339	11,089	11,111	10,902	13,910	12,860	11,698	11,833	12,459	13,760	148,674
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	14,124	12,682	12,373	11,110	11,129	10,912	13,921	12,874	11,710	11,851	12,488	13,804	148,978
Total Requirements (Energy + Losses)	15,327	13,762	13,427	12,056	12,077	11,842	15,107	13,971	12,708	12,861	13,552	14,980	161,670
# of Large Comm & Ind Customers	77	77	77	77	77	77	77	77	77	77	77	77	77
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	23.3	23.5	22.0	20.6	22.8	29.4	31.9	32.1	24.6	18.7	22.4	24.1	32.1
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	23.3	23.5	22.0	20.6	22.8	29.4	31.9	32.1	24.6	18.7	22.4	24.1	32.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

SOUTH DAKOTA YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	1,030.3	888.8	863.2	739.2	705.9	710.4	891.2	835.6	719.3	726.9	840.4	983.9	9,932.6
# of Residential Customers	6,765	6,761	6,760	6,768	6,793	6,810	6,840	6,835	6,823	6,803	6,772	6,751	6,790
Total Residential Sales - MWh	6,970	6,009	5,835	5,003	4,795	4,838	6,096	5,711	4,908	4,945	5,691	6,642	67,443
Use per Small Comm & Ind Customer - kWh	1,788.6	1,633.7	1,563.9	1,407.8	1,398.3	1,416.4	1,844.8	1,738.9	1,535.5	1,540.8	1,606.0	1,722.0	19,192.9
# of Small Comm & Ind Customers	1,892	1,889	1,894	1,925	1,966	1,986	1,985	1,984	1,974	1,938	1,924	1,921	1,940
Total Small Comm & Ind Sales - MWh	3,384	3,086	2,962	2,710	2,749	2,813	3,662	3,450	3,031	2,986	3,090	3,308	37,231
General Large Comm & Ind Sales	3,436	3,258	3,253	3,087	3,235	2,919	3,774	3,353	3,434	3,600	3,393	3,523	40,265
Total Sales (Residential, SC&I and LC&I)	13,790	12,353	12,050	10,800	10,779	10,570	13,532	12,514	11,373	11,531	12,174	13,473	144,939
Other Public Sales	188	191	181	173	215	215	291	242	220	191	183	200	2,490
Street & Highway Lighting Sales	225	215	226	223	226	219	221	225	219	229	223	215	2,666
Interdepartmental Sales	1	1	1	1	1	-	-	-	1	1	1	1	9
Total Billed Sales - MWh	14,204	12,760	12,458	11,197	11,221	11,004	14,044	12,981	11,813	11,952	12,581	13,889	150,104
Company Use	52	41	34	21	18	10	11	14	12	18	29	44	304
Total Energy	14,256	12,801	12,492	11,218	11,239	11,014	14,055	12,995	11,825	11,970	12,610	13,933	150,408
Total Requirements (Energy + Losses)	15,470	13,892	13,556	12,174	12,196	11,952	15,252	14,102	12,832	12,990	13,684	15,120	163,220
# of Large Comm & Ind Customers	78	78	78	78	78	78	78	78	78	78	78	78	78
# of Other Public Customers	55	55	55	57	61	62	63	62	61	57	55	54	58
# of Street & Highway Lighting Customers	36	36	36	36	37	37	35	35	35	35	35	35	36
Peak Demand	23.5	23.7	22.3	20.8	23.0	29.7	32.2	32.4	24.8	18.9	22.6	24.3	32.4
Interruptible Demand	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Demand Net of Interruptible Load	23.5	23.7	22.3	20.8	23.0	29.7	32.2	32.4	24.8	18.9	22.6	24.3	32.4

APPENDIX G

Monthly Forecasts – Integrated System (2007-2016)

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2007

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	867.8	767.6	722.5	634.3	617.7	633.4	819.9	773.6	647.9	643.1	744.9	857.8	8,730.6
# of Residential Customers	86,264	86,264	86,255	86,224	86,295	86,410	86,492	86,535	86,550	86,550	86,565	86,540	86,412
Total Residential Sales - MWh	74,859	66,214	62,321	54,696	53,307	54,728	70,915	66,942	56,073	55,659	64,480	74,231	754,425
Use per Small Comm & Ind Customer - kWh	2,193.6	2,011.2	2,040.8	1,818.0	1,852.0	1,844.3	2,253.9	2,178.9	1,908.1	1,879.6	2,023.4	2,145.9	24,148.3
# of Small Comm & Ind Customers	15,796	15,777	15,789	15,933	16,127	16,226	16,245	16,276	16,238	16,083	16,012	16,003	16,042
Total Small Comm & Ind Sales - MWh	34,650	31,730	32,222	28,966	29,868	29,925	36,614	35,463	30,983	30,229	32,398	34,341	387,389
General Large Comm & Ind Sales	62,455	62,576	60,438	60,652	61,046	60,747	67,685	67,962	63,922	64,434	64,939	68,318	765,174
Sabin Metals Sales	1,014	1,050	1,095	1,088	1,110	1,041	1,127	1,113	1,058	1,109	871	821	12,497
Encore Oil Sales	17,882	18,466	18,647	18,951	18,980	18,343	19,200	18,901	18,991	20,682	20,965	22,098	232,106
Tesoro Refinery Sales	3,787	3,881	4,252	4,276	4,514	4,699	4,934	4,985	4,658	4,604	4,550	4,272	53,412
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	197,464	186,600	181,492	171,018	170,961	171,345	202,328	197,322	177,745	179,080	190,761	206,886	2,233,002
Other Public Sales	3,328	3,197	3,281	3,086	3,594	3,844	4,502	4,377	3,694	3,238	3,145	3,275	42,561
Street & Highway Lighting Sales	2,657	2,501	2,586	2,466	2,524	2,323	2,426	2,485	2,468	2,621	2,669	2,664	30,390
Interdepartmental Sales	44	40	39	36	36	31	36	33	33	37	40	46	451
Total Billed Sales - MWh	203,493	192,338	187,398	176,606	177,115	177,543	209,292	204,217	183,940	184,976	196,615	212,871	2,306,404
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	204,032	192,848	187,886	177,082	177,595	178,027	209,829	204,764	184,415	185,447	197,126	213,400	2,312,451
Total Requirements (Energy + Losses)	221,414	209,277	203,892	192,168	192,724	193,193	227,705	222,208	200,125	201,245	213,919	231,580	2,509,450
# of Large Comm & Ind Customers	1,053	1,056	1,059	1,064	1,071	1,072	1,074	1,074	1,072	1,071	1,070	1,068	1,067
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	366.7	352.6	325.4	306.9	342.0	432.0	480.8	465.0	392.8	320.4	349.2	390.8	480.8
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	366.7	352.6	325.4	306.9	342.0	432.0	475.3	465.0	392.8	320.4	349.2	390.8	475.3

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2011

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	DCT	NDV	DEC	ANNUAL
Use per Residential Customer - kWh	896.3	792.8	746.3	655.2	637.8	653.7	846.0	798.6	669.0	664.2	769.4	884.9	9,014.4
# of Residential Customers	86,894	86,894	86,886	86,853	86,925	87,041	87,123	87,166	87,181	87,182	87,197	87,172	87,043
Total Residential Sales - MWh	77,886	68,891	64,843	56,902	55,440	56,900	73,707	69,609	58,322	57,907	67,088	77,141	784,636
Use per Small Comm & Ind Customer - kWh	2,196.5	2,013.6	2,043.4	1,820.0	1,854.0	1,846.2	2,257.1	2,181.8	1,910.3	1,881.8	2,025.8	2,151.7	24,180.9
# of Small Comm & Ind Customers	16,238	16,219	16,230	16,379	16,579	16,681	16,699	16,731	16,692	16,533	16,460	16,451	16,491
Total Small Comm & Ind Sales - MWh	35,667	32,658	33,165	29,810	30,737	30,796	37,691	36,504	31,886	31,111	33,345	35,397	398,767
General Large Comm & Ind Sales	68,639	68,768	66,435	66,646	67,112	66,787	74,464	74,764	70,274	70,797	71,333	74,722	840,741
Sabin Metals Sales	1,462	1,514	1,579	1,568	1,600	1,501	1,624	1,605	1,525	1,598	1,256	1,220	18,052
Encore Oil Sales	20,676	21,350	21,560	21,911	21,945	21,209	22,199	21,853	21,957	23,912	24,239	24,951	267,762
Tesoro Refinery Sales	4,270	4,376	4,794	4,822	5,090	5,299	5,564	5,621	5,253	5,191	5,130	4,809	60,219
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	211,417	200,240	194,893	184,048	184,060	184,354	217,102	211,912	191,277	192,879	204,949	221,045	2,398,176
Other Public Sales	3,310	3,179	3,262	3,069	3,575	3,822	4,478	4,353	3,673	3,221	3,128	3,257	42,327
Street & Highway Lighting Sales	2,659	2,503	2,588	2,467	2,525	2,326	2,428	2,486	2,469	2,622	2,672	2,667	30,412
Interdepartmental Sales	41	38	38	35	34	30	35	32	32	35	38	44	432
Total Billed Sales - MWh	217,427	205,960	200,781	189,619	190,194	190,532	224,043	218,783	197,451	198,757	210,787	227,013	2,471,347
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	217,966	206,470	201,269	190,095	190,674	191,016	224,580	219,330	197,926	199,228	211,298	227,542	2,477,394
Total Requirements (Energy + Losses)	236,534	224,060	218,415	206,289	206,917	207,289	243,713	238,015	214,787	216,200	229,298	246,926	2,688,443
# of Large Comm & Ind Customers	1,107	1,110	1,113	1,118	1,126	1,127	1,128	1,130	1,129	1,128	1,125	1,124	1,122
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	389.7	374.5	345.5	325.3	358.1	453.2	504.7	487.7	411.9	335.5	365.9	409.8	504.7
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	389.7	374.5	345.5	325.3	358.1	453.2	499.2	487.7	411.9	335.5	365.9	409.8	499.2

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2008

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	873.8	772.8	727.5	638.6	621.7	637.2	824.6	778.4	652.1	647.5	750.0	862.8	8,787.1
# of Residential Customers	86,442	86,442	86,434	86,400	86,473	86,588	86,670	86,713	86,728	86,727	86,744	86,718	86,590
Total Residential Sales - MWh	75,529	66,806	62,880	55,179	53,759	55,173	71,469	67,498	56,555	56,154	65,058	74,817	760,877
Use per Small Comm & Ind Customer - kWh	2,189.8	2,007.4	2,037.1	1,814.7	1,848.6	1,840.8	2,249.9	2,175.0	1,904.6	1,876.2	2,019.8	2,145.6	24,108.2
# of Small Comm & Ind Customers	15,909	15,892	15,902	16,047	16,243	16,343	16,361	16,392	16,354	16,198	16,127	16,118	16,157
Total Small Comm & Ind Sales - MWh	34,837	31,901	32,394	29,121	30,026	30,084	36,811	35,653	31,148	30,391	32,573	34,582	389,521
General Large Comm & Ind Sales	64,282	64,406	62,211	62,422	62,837	62,530	69,689	69,973	65,801	66,316	66,829	70,082	787,378
Sabin Metals Sales	1,014	1,050	1,095	1,088	1,110	1,041	1,127	1,113	1,058	1,109	871	821	12,497
Encore Oil Sales	19,142	19,767	19,961	20,285	20,317	19,635	20,552	20,233	20,328	22,138	22,441	23,369	248,168
Tesoro Refinery Sales	3,908	4,005	4,387	4,413	4,659	4,850	5,092	5,144	4,807	4,750	4,695	4,406	55,116
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	201,529	190,618	185,445	174,897	174,844	175,175	206,593	201,570	181,757	183,221	195,025	210,882	2,281,556
Other Public Sales	3,322	3,192	3,276	3,081	3,589	3,838	4,496	4,371	3,688	3,234	3,142	3,271	42,500
Street & Highway Lighting Sales	2,657	2,501	2,587	2,466	2,524	2,325	2,427	2,485	2,468	2,621	2,670	2,665	30,396
Interdepartmental Sales	44	40	39	36	36	30	36	33	33	37	40	45	449
Total Billed Sales - MWh	207,552	196,351	191,347	180,480	180,993	181,368	213,552	208,459	187,946	189,113	200,877	216,863	2,354,901
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	208,091	196,861	191,835	180,956	181,473	181,852	214,089	209,006	188,421	189,584	201,388	217,392	2,360,948
Total Requirements (Energy + Losses)	225,819	213,632	208,178	196,372	196,932	197,344	232,327	226,812	204,472	205,734	218,544	235,911	2,562,077
# of Large Comm & Ind Customers	1,067	1,071	1,073	1,078	1,084	1,086	1,088	1,089	1,087	1,086	1,084	1,083	1,081
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	374.6	360.1	332.4	313.1	346.6	437.9	487.4	471.2	398.2	324.7	353.9	396.2	487.4
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	374.6	360.1	332.4	313.1	346.6	437.9	481.9	471.2	398.2	324.7	353.9	396.2	481.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2009

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	878.2	776.8	731.2	641.9	624.9	640.5	828.8	782.4	655.4	650.8	753.8	870.3	8,835.4
# of Residential Customers	86,601	86,601	86,592	86,561	86,631	86,746	86,830	86,871	86,887	86,888	86,902	86,878	86,749
Total Residential Sales - MWh	76,056	67,273	63,318	55,564	54,134	55,559	71,969	67,970	56,950	56,546	65,510	75,612	766,461
Use per Small Comm & Ind Customer - kWh	2,193.3	2,010.4	2,040.4	1,817.4	1,851.5	1,843.5	2,253.7	2,178.7	1,907.4	1,879.0	2,023.0	2,147.8	24,144.6
# of Small Comm & Ind Customers	16,019	16,002	16,011	16,158	16,355	16,457	16,474	16,505	16,468	16,311	16,238	16,229	16,269
Total Small Comm & Ind Sales - MWh	35,134	32,170	32,669	29,365	30,281	30,338	37,127	35,959	31,411	30,648	32,849	34,856	392,807
General Large Comm & Ind Sales	65,727	65,852	63,610	63,822	64,256	63,941	71,271	71,562	67,284	67,802	68,321	71,621	805,069
Sabin Metals Sales	1,014	1,050	1,095	1,088	1,110	1,041	1,127	1,113	1,058	1,109	871	1,003	12,679
Encore Oil Sales	19,852	20,499	20,700	21,038	21,071	20,363	21,314	20,983	21,082	22,960	23,273	24,224	257,359
Tesoro Refinery Sales	4,029	4,129	4,523	4,549	4,802	5,000	5,250	5,303	4,956	4,897	4,840	4,540	56,818
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	204,629	193,656	188,432	177,815	177,790	178,104	209,911	204,846	184,801	186,325	198,222	214,661	2,319,192
Other Public Sales	3,317	3,186	3,271	3,077	3,583	3,833	4,490	4,364	3,683	3,230	3,136	3,267	42,437
Street & Highway Lighting Sales	2,659	2,502	2,588	2,466	2,524	2,325	2,427	2,486	2,468	2,622	2,670	2,665	30,402
Interdepartmental Sales	43	40	39	36	35	30	35	33	33	36	39	45	444
Total Billed Sales - MWh	210,648	199,384	194,330	183,394	183,932	184,292	216,863	211,729	190,985	192,213	204,067	220,638	2,392,475
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	211,187	199,894	194,818	183,870	184,412	184,776	217,400	212,276	191,460	192,684	204,578	221,167	2,398,522
Total Requirements (Energy + Losses)	229,177	216,923	211,415	199,534	200,122	200,517	235,920	230,360	207,771	209,098	222,006	240,008	2,602,851
# of Large Comm & Ind Customers	1,080	1,085	1,087	1,092	1,098	1,100	1,103	1,103	1,101	1,100	1,098	1,097	1,095
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	379.8	364.9	336.6	317.2	350.5	443.3	493.4	477.1	402.9	328.4	357.9	400.9	493.4
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	379.8	364.9	336.6	317.2	350.5	443.3	487.9	477.1	402.9	328.4	357.9	400.9	487.9

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	888.8	786.2	740.1	649.7	632.4	648.2	838.9	791.9	663.4	658.7	762.9	879.1	8,940.4
# of Residential Customers	86,745	86,745	86,736	86,705	86,777	86,893	86,975	87,018	87,033	87,032	87,047	87,023	86,894
Total Residential Sales - MWh	77,102	68,198	64,190	56,328	54,880	56,325	72,961	68,907	57,734	57,324	66,412	76,505	776,866
Use per Small Comm & Ind Customer - kWh	2,194.2	2,011.2	2,041.3	1,818.2	1,852.1	1,844.2	2,254.6	2,179.7	1,908.2	1,879.9	2,023.8	2,148.6	24,154.8
# of Small Comm & Ind Customers	16,130	16,112	16,121	16,269	16,468	16,570	16,588	16,618	16,581	16,422	16,350	16,341	16,381
Total Small Comm & Ind Sales - MWh	35,392	32,405	32,907	29,580	30,501	30,559	37,399	36,223	31,640	30,871	33,089	35,110	395,676
General Large Comm & Ind Sales	67,164	67,291	65,003	65,214	65,663	65,345	72,849	73,145	68,758	69,280	69,808	73,150	822,670
Sabin Metals Sales	1,387	1,437	1,498	1,488	1,518	1,424	1,542	1,523	1,447	1,517	1,192	1,160	17,133
Encore Oil Sales	20,562	21,233	21,442	21,790	21,824	21,092	22,077	21,734	21,837	23,781	24,107	24,813	266,292
Tesoro Refinery Sales	4,150	4,252	4,659	4,685	4,947	5,150	5,407	5,462	5,104	5,044	4,985	4,674	58,519
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	208,574	197,499	192,216	181,474	181,469	181,757	214,088	208,950	188,580	190,180	202,151	218,217	2,365,155
Other Public Sales	3,313	3,183	3,268	3,074	3,579	3,827	4,483	4,358	3,680	3,226	3,132	3,263	42,386
Street & Highway Lighting Sales	2,659	2,503	2,588	2,467	2,524	2,325	2,427	2,486	2,469	2,622	2,671	2,666	30,407
Interdepartmental Sales	43	40	39	36	35	30	35	33	33	36	39	45	444
Total Billed Sales - MWh	214,589	203,225	198,111	187,051	187,607	187,939	221,033	215,827	194,762	196,064	207,993	224,191	2,438,392
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	215,128	203,735	198,599	187,527	188,087	188,423	221,570	216,374	195,237	196,535	208,504	224,720	2,444,439
Total Requirements (Energy + Losses)	233,455	221,091	215,518	203,502	204,110	204,475	240,445	234,807	211,869	213,278	226,266	243,863	2,652,679
# of Large Comm & Ind Customers	1,094	1,097	1,100	1,106	1,113	1,114	1,115	1,116	1,115	1,115	1,112	1,110	1,109
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	384.4	369.3	340.7	320.9	354.3	448.3	499.2	482.4	407.4	331.8	361.9	405.3	499.2
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	384.4	369.3	340.7	320.9	354.3	448.3	493.7	482.4	407.4	331.8	361.9	405.3	493.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2012

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	900.8	796.8	750.0	658.4	641.0	657.0	850.3	802.6	672.3	667.6	773.3	889.3	9,059.7
# of Residential Customers	87,041	87,041	87,032	87,000	87,073	87,188	87,271	87,314	87,329	87,329	87,344	87,319	87,190
Total Residential Sales - MWh	78,410	69,355	65,278	57,285	55,813	57,282	74,205	70,079	58,714	58,297	67,539	77,657	789,914
Use per Small Comm & Ind Customer - kWh	2,201.0	2,017.6	2,047.4	1,823.6	1,857.7	1,849.9	2,261.5	2,186.3	1,914.1	1,885.5	2,029.8	2,156.2	24,229.5
# of Small Comm & Ind Customers	16,344	16,325	16,337	16,486	16,687	16,790	16,809	16,840	16,802	16,641	16,568	16,558	16,599
Total Small Comm & Ind Sales - MWh	35,973	32,937	33,449	30,064	31,000	31,059	38,014	36,818	32,160	31,377	33,630	35,703	402,184
General Large Comm & Ind Sales	70,115	70,245	67,866	68,076	68,557	68,226	76,075	76,383	71,788	72,313	72,856	76,291	858,791
Sabin Metals Sales	1,536	1,592	1,660	1,648	1,682	1,577	1,707	1,687	1,603	1,680	1,321	1,281	18,974
Encore Oil Sales	20,791	21,468	21,679	22,033	22,067	21,326	22,322	21,975	22,079	24,045	24,374	25,089	269,248
Tesoro Refinery Sales	4,391	4,500	4,930	4,958	5,234	5,449	5,722	5,780	5,401	5,338	5,275	4,943	61,921
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	214,033	202,780	197,379	186,453	186,489	186,781	219,898	214,678	193,805	195,413	207,553	223,769	2,429,031
Other Public Sales	3,305	3,175	3,259	3,064	3,570	3,817	4,471	4,346	3,669	3,216	3,124	3,254	42,270
Street & Highway Lighting Sales	2,660	2,503	2,589	2,467	2,525	2,326	2,428	2,486	2,469	2,624	2,672	2,667	30,416
Interdepartmental Sales	41	38	37	34	34	30	34	32	32	35	38	44	429
Total Billed Sales - MWh	220,039	208,496	203,264	192,018	192,618	192,954	226,831	221,542	199,975	201,288	213,387	229,734	2,502,146
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	220,578	209,006	203,752	192,494	193,098	193,438	227,368	222,089	200,450	201,759	213,898	230,263	2,508,193
Total Requirements (Energy + Losses)	239,370	226,811	221,109	208,892	209,548	209,917	246,737	241,008	217,526	218,946	232,120	249,879	2,721,863
# of Large Comm & Ind Customers	1,120	1,125	1,126	1,132	1,139	1,140	1,143	1,143	1,142	1,141	1,140	1,137	1,136
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	394.0	378.6	349.2	328.9	362.2	458.1	510.2	493.1	416.4	339.1	369.9	414.2	510.2
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	394.0	378.6	349.2	328.9	362.2	458.1	504.7	493.1	416.4	339.1	369.9	414.2	504.7

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2013

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	905.3	800.8	753.8	661.7	644.2	660.3	854.5	806.6	675.7	670.9	777.1	893.8	9,104.8
# of Residential Customers	87,189	87,187	87,178	87,146	87,219	87,335	87,417	87,461	87,476	87,476	87,492	87,467	87,337
Total Residential Sales - MWh	78,933	69,817	65,713	57,667	56,185	57,664	74,701	70,547	59,107	58,685	67,988	78,180	795,187
Use per Small Comm & Ind Customer - kWh	2,206.1	2,022.2	2,052.2	1,828.0	1,862.0	1,854.2	2,266.8	2,191.3	1,918.6	1,890.0	2,034.7	2,162.2	24,287.1
# of Small Comm & Ind Customers	16,449	16,430	16,441	16,591	16,795	16,898	16,916	16,948	16,909	16,747	16,673	16,664	16,705
Total Small Comm & Ind Sales - MWh	36,288	33,225	33,741	30,328	31,272	31,332	38,346	37,138	32,441	31,651	33,925	36,031	405,718
General Large Comm & Ind Sales	71,586	71,719	69,296	69,505	70,001	69,664	77,687	78,000	73,300	73,827	74,378	77,851	876,814
Sabin Metals Sales	1,611	1,669	1,740	1,728	1,764	1,654	1,791	1,769	1,681	1,762	1,385	1,341	19,895
Encore Oil Sales	20,907	21,588	21,801	22,156	22,190	21,445	22,447	22,097	22,202	24,179	24,510	25,230	270,752
Tesoro Refinery Sales	4,512	4,624	5,066	5,094	5,378	5,600	5,880	5,939	5,550	5,484	5,420	5,078	63,625
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	216,654	205,325	199,874	188,867	188,926	189,221	222,705	217,446	196,341	197,951	210,164	226,516	2,459,990
Other Public Sales	3,300	3,170	3,254	3,060	3,565	3,812	4,466	4,342	3,665	3,212	3,120	3,249	42,215
Street & Highway Lighting Sales	2,660	2,504	2,589	2,467	2,525	2,326	2,428	2,487	2,470	2,624	2,672	2,667	30,419
Interdepartmental Sales	41	38	37	34	34	30	33	31	31	35	38	43	425
Total Billed Sales - MWh	222,655	211,037	205,754	194,428	195,050	195,389	229,632	224,306	202,507	203,822	215,994	232,475	2,533,049
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	223,194	211,547	206,242	194,904	195,530	195,873	230,169	224,853	202,982	204,293	216,505	233,004	2,539,096
Total Requirements (Energy + Losses)	242,208	229,569	223,811	211,508	212,187	212,560	249,778	244,008	220,274	221,697	234,949	252,854	2,755,403
# of Large Comm & Ind Customers	1,134	1,139	1,141	1,147	1,154	1,155	1,157	1,157	1,155	1,155	1,153	1,151	1,150
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	398.3	382.7	353.1	332.5	366.0	463.0	515.6	498.3	420.9	342.8	373.8	418.7	515.6
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	398.3	382.7	353.1	332.5	366.0	463.0	510.1	498.3	420.9	342.8	373.8	418.7	510.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2014

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	910.4	805.3	758.0	665.5	647.8	664.0	859.4	811.2	679.5	674.7	781.5	898.8	9,156.4
# of Residential Customers	87,286	87,286	87,277	87,245	87,318	87,434	87,517	87,560	87,576	87,575	87,590	87,566	87,436
Total Residential Sales - MWh	79,469	70,292	66,160	58,059	56,568	58,059	75,211	71,027	59,509	59,084	68,452	78,708	800,598
Use per Small Comm & Ind Customer - kWh	2,213.0	2,028.5	2,058.6	1,833.5	1,867.9	1,860.0	2,273.9	2,198.3	1,924.6	1,896.0	2,041.1	2,168.8	24,363.0
# of Small Comm & Ind Customers	16,555	16,537	16,548	16,699	16,902	17,007	17,026	17,057	17,018	16,855	16,781	16,772	16,813
Total Small Comm & Ind Sales - MWh	36,636	33,545	34,066	30,618	31,571	31,633	38,715	37,497	32,752	31,957	34,252	36,375	409,617
General Large Comm & Ind Sales	73,043	73,176	70,707	70,916	71,431	71,087	79,280	79,598	74,793	75,323	75,881	79,402	894,637
Sabin Metals Sales	1,685	1,746	1,821	1,808	1,845	1,731	1,874	1,851	1,759	1,844	1,449	1,384	20,797
Encore Oil Sales	21,024	21,710	21,924	22,280	22,315	21,566	22,573	22,222	22,327	24,316	24,648	25,372	272,277
Tesoro Refinery Sales	4,633	4,747	5,201	5,231	5,523	5,749	6,037	6,098	5,699	5,632	5,566	5,212	65,328
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	219,307	207,899	202,396	191,301	191,389	191,687	225,543	220,249	198,899	200,519	212,806	229,258	2,491,253
Other Public Sales	3,296	3,165	3,250	3,056	3,560	3,807	4,460	4,336	3,659	3,208	3,115	3,243	42,155
Street & Highway Lighting Sales	2,660	2,504	2,589	2,468	2,526	2,327	2,429	2,487	2,470	2,624	2,673	2,668	30,425
Interdepartmental Sales	41	38	37	34	34	28	33	31	31	34	37	43	421
Total Billed Sales - MWh	225,304	213,606	208,272	196,859	197,509	197,849	232,465	227,103	205,059	206,385	218,631	235,212	2,564,254
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	225,843	214,116	208,760	197,335	197,989	198,333	233,002	227,650	205,534	206,856	219,142	235,741	2,570,301
Total Requirements (Energy + Losses)	245,083	232,357	226,544	214,146	214,856	215,229	252,851	247,044	223,043	224,478	237,810	255,823	2,789,264
# of Large Comm & Ind Customers	1,148	1,152	1,155	1,160	1,167	1,169	1,172	1,172	1,170	1,169	1,167	1,165	1,164
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	402.5	386.8	356.9	336.0	369.8	467.9	521.1	503.5	425.3	346.4	377.9	423.2	521.1
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	402.5	386.8	356.9	336.0	369.8	467.9	515.6	503.5	425.3	346.4	377.9	423.2	515.6

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	915.4	809.7	762.1	669.1	651.3	667.6	864.0	815.6	683.2	678.3	785.7	903.7	9,205.9
# of Residential Customers	87,398	87,397	87,389	87,355	87,429	87,545	87,628	87,671	87,687	87,687	87,702	87,676	87,547
Total Residential Sales - MWh	80,000	70,761	66,602	58,447	56,946	58,447	75,714	71,503	59,908	59,479	68,908	79,235	805,950
Use per Small Comm & Ind Customer - kWh	2,220.0	2,034.9	2,065.2	1,839.4	1,873.8	1,865.9	2,281.0	2,205.1	1,930.7	1,901.8	2,047.5	2,169.8	24,433.9
# of Small Comm & Ind Customers	16,658	16,640	16,650	16,803	17,008	17,113	17,132	17,164	17,124	16,961	16,886	16,876	16,918
Total Small Comm & Ind Sales - MWh	36,981	33,860	34,385	30,908	31,870	31,931	39,078	37,848	33,061	32,257	34,574	36,617	413,370
General Large Comm & Ind Sales	74,501	74,636	72,124	72,331	72,862	72,512	80,876	81,199	76,290	76,822	77,388	80,950	912,491
Sabin Metals Sales	1,723	1,785	1,862	1,848	1,886	1,769	1,915	1,892	1,797	1,884	1,481	1,396	21,238
Encore Oil Sales	21,143	21,833	22,047	22,406	22,441	21,688	22,700	22,348	22,453	24,453	24,788	25,516	273,816
Tesoro Refinery Sales	4,753	4,871	5,337	5,367	5,666	5,899	6,194	6,258	5,847	5,778	5,711	5,347	67,028
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	221,918	210,429	204,874	193,696	193,807	194,108	228,330	223,004	201,416	203,036	215,408	231,866	2,521,892
Other Public Sales	3,291	3,162	3,245	3,053	3,555	3,802	4,454	4,329	3,654	3,203	3,111	3,238	42,097
Street & Highway Lighting Sales	2,661	2,504	2,590	2,469	2,527	2,328	2,430	2,488	2,471	2,625	2,674	2,669	30,436
Interdepartmental Sales	41	38	37	34	33	28	33	31	31	34	37	43	420
Total Billed Sales - MWh	227,911	216,133	210,746	199,252	199,922	200,266	235,247	229,852	207,572	208,898	221,230	237,816	2,594,845
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	228,450	216,643	211,234	199,728	200,402	200,750	235,784	230,399	208,047	209,369	221,741	238,345	2,600,892
Total Requirements (Energy + Losses)	247,911	235,099	229,229	216,742	217,475	217,853	255,870	250,027	225,771	227,205	240,632	258,650	2,822,464
# of Large Comm & Ind Customers	1,161	1,165	1,168	1,174	1,180	1,182	1,185	1,185	1,183	1,183	1,180	1,178	1,177
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	406.9	391.0	360.6	339.7	373.9	472.9	526.6	508.9	429.8	350.2	381.8	427.6	526.6
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	406.9	391.0	360.6	339.7	373.9	472.9	521.1	508.9	429.8	350.2	381.8	427.6	521.1

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

INTEGRATED SYSTEM YEAR 2016

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	920.7	814.4	766.6	673.0	655.2	671.5	869.1	820.3	687.2	682.3	790.3	909.0	9,259.7
# of Residential Customers	87,475	87,475	87,466	87,433	87,505	87,622	87,705	87,749	87,764	87,764	87,779	87,754	87,624
Total Residential Sales - MWh	80,538	71,238	67,051	58,840	57,331	58,841	76,225	71,983	60,310	59,880	69,373	79,767	811,377
Use per Small Comm & Ind Customer - kWh	2,215.6	2,030.8	2,061.0	1,835.7	1,870.1	1,862.0	2,276.5	2,200.8	1,926.8	1,898.0	2,043.3	2,165.5	24,384.9
# of Small Comm & Ind Customers	16,760	16,742	16,753	16,906	17,112	17,219	17,237	17,269	17,229	17,065	16,990	16,980	17,022
Total Small Comm & Ind Sales - MWh	37,133	33,999	34,528	31,035	32,001	32,062	39,240	38,005	33,196	32,390	34,716	36,770	415,075
General Large Comm & Ind Sales	75,951	76,086	73,529	73,737	74,283	73,927	82,461	82,790	77,778	78,312	78,886	82,491	930,231
Sabin Metals Sales	1,723	1,785	1,862	1,848	1,886	1,769	1,915	1,892	1,797	1,884	1,481	1,396	21,238
Encore Oil Sales	21,263	21,957	22,173	22,534	22,569	21,811	22,830	22,475	22,581	24,592	24,929	25,661	275,375
Tesoro Refinery Sales	4,875	4,995	5,473	5,504	5,810	6,049	6,352	6,417	5,996	5,926	5,856	5,481	68,734
Westmoreland Coal Sales	2,817	2,683	2,517	2,389	2,136	1,862	1,853	1,956	2,060	2,363	2,558	2,805	27,999
Total Sales (Residential, SC&I and LC&I)	224,300	212,743	207,133	195,887	196,016	196,321	230,876	225,518	203,718	205,347	217,799	234,371	2,550,029
Other Public Sales	3,286	3,157	3,240	3,048	3,549	3,795	4,448	4,324	3,649	3,199	3,108	3,235	42,038
Street & Highway Lighting Sales	2,661	2,505	2,590	2,469	2,527	2,328	2,430	2,489	2,472	2,626	2,674	2,669	30,440
Interdepartmental Sales	41	37	36	33	33	28	33	31	31	34	37	42	416
Total Billed Sales - MWh	230,288	218,442	212,999	201,437	202,125	202,472	237,787	232,362	209,870	211,206	223,618	240,317	2,622,923
Company Use	539	510	488	476	480	484	537	547	475	471	511	529	6,047
Total Energy	230,827	218,952	213,487	201,913	202,605	202,956	238,324	232,909	210,345	211,677	224,129	240,846	2,628,970
Total Requirements (Energy + Losses)	250,490	237,605	231,674	219,114	219,864	220,246	258,627	252,751	228,264	229,710	243,222	261,364	2,852,931
# of Large Comm & Ind Customers	1,175	1,179	1,182	1,187	1,194	1,196	1,199	1,199	1,197	1,196	1,194	1,193	1,191
# of Other Public Customers	886	885	887	897	910	912	913	910	905	894	887	880	897
# of Street & Highway Lighting Customers	549	558	557	559	561	561	528	529	530	532	532	534	544
Peak Demand	411.0	395.0	364.5	343.2	377.7	477.9	532.1	514.3	434.2	353.8	385.7	432.1	532.1
Interruptible Demand	-	-	-	-	-	-	5.5	-	-	-	-	-	5.5
Peak Demand Net of Interruptible Load	411.0	395.0	364.5	343.2	377.7	477.9	526.6	514.3	434.2	353.8	385.7	432.1	526.6

ATTACHMENT B

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DEMAND-SIDE DOCUMENTATION

ATTACHMENT B

DEMAND-SIDE DOCUMENTATION

Overview

With the demand for electricity growing Montana-Dakota recognizes the value DSM can play in meeting future energy requirements. Montana-Dakota reviewed a list of potential DSM programs that would be best suited to the Company's load shape in order to get the results when needed. These potential programs were selected through a joint effort between Montana-Dakota and the IRP Public Advisory Group (PAG). However, the implementation of DSM programs cannot be done without cost consideration to the utility, its customers/ratepayers and its shareholders. All interests need to be balanced to achieve the results at an affordable cost to both the utility and its customers.

Contained in this Attachment is a detailed discussion of the methodology used in evaluation of the DSM programs, program analysis work papers and DSM Model spreadsheets. The DSM program analysis and DSM Model spreadsheets are included for a base case and sensitivity analysis based on high and low participation rates.

Potential DSM Programs

Montana-Dakota explored the feasibility of offering 14 DSM programs to its customer base. Programs that are being implemented currently were also included. Also included in the DSM programs is a program that uses rate design as a tool to promote DSM. The following programs were evaluated:

Residential Programs:

1. Promote ENERGY STAR® Clothes Washer to electric water heating customers through the use of a $25 cash incentive for replacement of customer's clothes washer with the purchase of a new ENERGY STAR® Clothes Washer.

2. Promote ENERGY STAR® Dishwashers to electric water heating customers through the use of a $10 cash incentive for replacement of customer's dishwasher with the purchase of a new ENERGY STAR® dishwasher.

3. Promote ENERGY STAR® Refrigerators through the use of a $15 cash incentive for replacement of customer's refrigerator with the purchase of a new ENERGY STAR® refrigerator.

4. Promote ENERGY STAR® Freezers through the use of a $15 cash incentive for replacement of customer's freezer with the purchase of a new ENERGY STAR® freezer.

5. Promote ENERGY STAR® Central Air Conditioners through the use of a $200/ton cash incentive for replacement of a customer's central air conditioner with the purchase of a new ENERGY STAR® central air conditioner with a Seasonal Energy Efficiency Ratio (SEER) of 15 or greater.

6. Promote a Central Air Conditioning Cycling Program through the use of a controllable thermostat.

7. Promote a Refrigerator Round-Up Program, whereby customers are offered a $35 cash incentive in exchange for the Company removing the customer's second refrigerator.

8. Promote high efficient Ground Source Heat Pumps through the use of a $1,100 cash incentive for the replacement of a customer's existing heating and cooling system with a Ground Source Heat Pump (available to customer's in Montana-Dakota's electric-only service territories)

Commercial Programs Evaluated:

9. Promote Interruptible Demand Response Rate in North Dakota and expand this rate to the other states. Rate design can be an effective DSM tool and this rate provides participating customers a reduced rate in return for the ability to interrupt service at the Company's request.

10. Promote high efficient motors, whereby customers are offered an incentive of $0.15/kWh saved by replacing existing motors with high efficient motors.

11. Promote ENERGY STAR® Central Air Conditioner through the use of a $100/ton cash incentive for replacement of a customer's central air conditioner with the purchase of a new ENERGY STAR® central air conditioner with a SEER of 12 or greater.

12. Promote a Central Air Conditioning Cycling Program through the use of a controllable thermostat.

13. Promote a high-efficiency lighting program through the use of an $8 per fixture ($0.20 per watt) cash incentive for replacement of a customer's lights with the purchase of new high efficiency lights.

14. Promote LED (Light Emitting Diode) Exit Sign Lighting Program through the use of a $5 per fixture cash incentive for replacement of a customer's lights with the purchase of new high efficiency lights.

DSM Methodology

In order to balance all interests and achieve cost-effective DSM for the utility and its customers/ratepayers, a cost-benefit analysis from different perspectives was performed on potential DSM measures. Each of the perspectives or "tests" is not intended to be used individually or in isolation and they must be compared to each other. This multi-perspective approach will allow consideration for tradeoffs between various tests, however the impacts measured from the Ratepayer Test will determine if a program is feasible. Once a program is determined feasible all test results are considered to determine if a program is implemented. Therefore even if a program is feasible it may not be implemented due to tradeoffs with other tests and other identified factors.

Benefit/Cost Analysis

Montana-Dakota used a Microsoft Excel spreadsheet-based model (Montana-Dakota DSM Model) to run a benefit/cost analysis for each considered DSM program. The basic function of this evaluation tool is to calculate each DSM program's benefits over the projected life of the measure on a discounted cash flows basis to determine the cost effectiveness of each respective program on a stand alone basis. The programs were evaluated using four different cost-effectiveness tests:

- *Participant Test* considers the economic impact of a program on the participating customers.
- *Utility Test* considers the impact on the utility.
- Societal *Cost Test* considers the impact on both the participating and non-participating customers as well as including environmental externalities.
- *Ratepayer Test* includes all quantifiable benefits and costs of a given program and its impact on all ratepayers.

The following section explains the process of evaluating the programs from each of the four perspectives:

Participant Test

The Participant Test is a measure of the quantifiable benefits and costs brought about by a customer's participation in a DSM program. For purposes of evaluating the merits of a particular DSM program, quantifiable benefits include any incentives received by a participant and the reduction in a participant's electric bill through reduced energy and/or demand. Quantifiable costs include any costs the customer incurs in order to participate in a DSM program, such as increased appliance costs or the availability of a back up fuel source. The merits of the DSM program are evaluated on the net present value of the annual benefits and costs over the years in the analysis horizon. The present value uses the customer discount rate and assumes the cash flows occur at the end of the year.

The following represents a simplified look at the equations used to evaluate the participant net benefit:

Net Benefit = Total Annual Benefits – Total Annual Costs,

where:

Total Annual Benefits = Energy Savings (kWh) + Demand Savings (kW) + Incentive + Other Savings

Total Annual Costs = Direct Costs + Other Costs

A benefit/cost ratio greater than one for the participant test indicates the DSM program will result in savings to the participant over the life of the program.

Utility Test

The Utility Test is a measure of the quantifiable benefits and costs the utility incurs as a result of customer participation in a DSM program. For purposes of evaluating the merits of a particular DSM program, quantifiable benefits include any reduction in purchased power costs due to decreased customer energy and demand, along with a reduction in variable operation and maintenance costs. Quantifiable costs to the utility include incentive and administrative costs, along

with the loss of electric margin due to reduced sales. The merits of the DSM program are evaluated on the net present value of the annual benefits and costs over the years in the analysis horizon, assuming the cash flows occur at the end of the year. The annual costs are discounted at the utility discount rate. The following represents a simplified look at the equations used to evaluate the utility net benefit:

Net Benefit = Annual Cost of Energy Saved – Annual Project Costs

where:

Annual Cost of Energy Saved = Energy Savings (kWh)* + Peak Demand Savings (kW)* + O&M Savings

**kWh & kW savings include losses and reserve requirement savings*

Annual Project Costs = Total Project Costs + Lost Margin

A benefit/cost ratio greater than one for the utility test indicates the cost of energy saved is greater than the cost of saving the energy.

Societal Cost Test

The Societal Cost Test measures the net costs of a DSM program as resource option based on the total costs of the program (both the participants' costs and the utility's costs). This test also includes a factor for environmental externalities. This test is a summation of the benefit and cost terms in the Participant Test and the Ratepayer Test. The merits of the DSM program are evaluated on the net present value of the annual benefits and costs over the years in the analysis horizon, assuming cash flows occur at the end of the year. The annual costs are discounted at the utility discount rate. The following represents a simplified look at the equations used to evaluate the total cost net benefit:

Net Benefit = Annual Cost of Energy Saved – Annual Project Costs

where:

Annual Cost of Energy Saved = Energy Savings (kWh) * + Demand Savings (kW) * + O&M Savings + Avoided Environmental Damage

**kWh & kW savings include losses and reserve requirement savings*

Annual Project Costs = Total Project Costs

A benefit/cost ratio greater than one for the societal cost test indicates the DSM program is beneficial to both the utility and its ratepayers on a societal cost basis.

Ratepayer Test

The Ratepayer Test is a measure of the quantifiable benefits and costs placed on ratepayers due to changes in the utility's revenues and operating costs as a result of the DSM program. The Ratepayer test includes the same benefits and costs as the utility test, except the quantifiable costs exclude lost margin. The merits of the DSM program are evaluated on the net present value of the annual benefits and costs over the years in the analysis horizon, assuming the cash flows occur at the end of the year. The annual costs are discounted at the utility discount rate. The following represents a simplified look at the equations used to evaluate the ratepayer net benefit:

Net Benefit = Annual Cost of Energy Saved – Annual Project Costs

where:

Annual Cost of Energy Saved = Energy Savings (kWh) * + Demand Savings (kW) * + O&M Savings

**kWh & kW savings include losses and reserve requirement savings*

Annual Project Costs = Total Project Costs

A benefit/cost ratio greater than one for the ratepayer test indicates the DSM program will result will reduce overall rates.

Montana-Dakota evaluated each program's feasibility based on the results of the Ratepayer Test. If the benefit/cost ratio for the tests were greater than one, the DSM program(s) are considered feasible and will be further evaluated.

DSM Model Input Data

Montana-Dakota's DSM Model is dependent on the input data to determine the cost-benefit of each program. Recent Company operational and financial data is used for the general model data inputs and estimated supply cost avoidance is used based on marginal energy costs and capacity costs of adding the next supply resource including reserve requirements and losses. In addition program specific data is used for each program being evaluated. The operational, financial, and program data

inputs are shown for each program model run in Appendix A and the sources of this data are summarized below in Table B-1.

2007 Input Data Summary

Demand-Side Management Model

Table - B-1

Input Data Description	Information Source
Retail Rate	System Average retail rate for customer class that DSM is applicable to.
System Marginal Energy Costs	System Marginal energy costs are based on ND & SD Cogeneration filings July 2006-June 2007
Retail Demand Cost	Seasonal demand cost for customer class that DSM is applicable - ND Rate 30
System Peak Shaving Demand Costs	Demand Cost is based on estimated levelized cost of Combustion turbine
System Conservation Demand Costs	Demand cost is based on estimated levelized costs of Big Stone II - Base Load
MRO Reserve Margin	Current required capacity reserve margin
Variable O&M	Based on Montana-Dakota's historical information
Environmental Damage Factor	Based on MT PSC 1993 IRP order
Total Sales By Class	2006 total sales for customer class that DSM program is applicable.
Total Customers	2006 total customers for customer class that DSM program is applicable
Growth and Escalation Factors	Projected based on consumer indexes and forecasted escalation rates
Utility Discount Rate	MDU's capital structure of incremental WACC 2006
Societal Discount Rate	Equal to the 30 year T-Bill rate average of 52 weeks ending January 24, 2007
General Input Data Year	Year data was input
Project Analysis Year	Year program will be implemented
Effective Tax Rate	Avg of MDU's current state and local tax rate for integrated system
System Demand Line Loss Factor	Historical demand line loss factor for integrated electric system
System Energy Line Loss Factor	Historical energy line loss factor for integrated electric system
Direct Utility Project Costs	Total direct cost to the utility caused by implementing the DSM program
Administrative Costs	Total projected administrative costs including general admin and marketing costs of the DSM program
Direct Operating Costs	Direct operating cost estimated for the specific DSM program
Incentive Costs	Total annual cost of the incentive paid to the program participant
Direct Participant Project Costs	Direct costs that the participant would have to pay to participate in the DSM program
Other Participant Project Costs	Other costs or savings (neg) to the participant for participating in the DSM program
Project Life	Based on the estimated useful life of the energy saving equipment
Avg. Energy Reduction	Avg energy reduction (kWh) caused by the DSM program
Avg. Demand Reduction	Avg energy reduction (kW) caused by the DSM program
Number of Participants	Total projected participation by customers or kW load target, or equipment saturation

As shown in the table there is inputs for avoided system energy costs and capacity costs due to the specific DSM measure. Avoided energy costs based on system marginal energy cost as filed in the 2206 cogeneration filings in North Dakota and South Dakota. The System Marginal Energy cost avoided is the same regardless of the strategic focus of the DSM measure. However, there are two different system demand costs called "Peak Shaving Demand Costs" and "Conservation Demand Costs". These costs are significantly different and are applied to specific DSM programs depending on their strategic focus. For example the System Peak Shaving Demand Cost would apply to programs that are primarily peak shaving in nature. As shown above the demand cost avoidance for this measure would be the current installed cost of a combustion turbine or the "System Peak Shaving Demand Cost. The System Conservation Demand Cost is based on the cost avoidance of additional base load capacity which is based on the base case cost for Big Stone II used in the supply cost analysis and would apply to all DSM programs that have a strategic conservation focus.

DSM Program Analysis Data

The underlying demand-side resource program designs and evaluation criteria, cost information and other assumptions that are particular to the studied programs are given for each program in Appendix A. A summary list of sources for energy savings calculation, program cost, participant cost, and participation rate estimates for each DSM program is contained below in Table B-2.

DSM Program Analysis Sources

Table B-2

DSM #	DSM Program	Energy Calculation Data	Program Cost Data	Customer Cost Data	Participation Rate Estimate
1	Interruptible Rate - Demand Response	500 kW Model	Operating, Admin & Mkting Estimate	Industry Data	Potential Customers - Customer Reps
2	Commercial High Efficiency Motors	Motor Master - DOE & AEE for LF	Operating, Admin & Mkting Estimate	Motor Master - DOE	Estimate
3	Energy Star Washers	Energy Star	Operating, Admin & Mkting Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
4	Energy Star Dishwashers	Energy Star	Operating, Admin & Mkting Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
5	Energy Star Refrigerators	Energy Star, AHAM, WAPA	Operating, Admin & Mkting Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
6	Energy Star Freezers	Energy Star, AHAM	Operating, Admin & Mkting Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
7	High Efficiency A/C Residential	Energy Star, Industry Data, EPRI	Operating, Admin & Mkting Estimate	Industry Data	End Use Survey, Estimate
8	High Efficiency A/C Commercial	Energy Star, Industry Data, EPRI	Operating, Admin & Mkting Estimate	Industry Data	Estimate
9	Residential A/C Cycling (T-Stat)	Industry Data, EPRI	Operating, Admin & Mkting Estimate	NA	End Use Survey, Vendor Data
10	Commercial A/C Cycling (T-Stat)	Industry Data, EPRI	Operating, Admin & Mkting Estimate	NA	End Use Survey, Vendor Data
11	Refrigerator Round-Up	WAPA	Operating, Admin & Mkting Estimate	NA	End Use Survey, Industry Data
12	Ground Source Heat Pumps	Industry Data, DOE	Operating, Admin & Mkting Estimate	Industry Data	End Use Survey, Estimate
13	Commercial Lighting	Industry Data, IES	Operating, Admin & Mkting Estimate	Industry Data	Xenergy Survey, Estimate
14	LED Exit Signs	Industry Data, IES	Operating, Admin & Mkting Estimate	Industry Data	Xenergy Survey, Estimate

AHAM - Association of Home Appliance Manufacturers
EPRI - Electric Power Research Institute
IES - Illumination Engineering Society

WAPA - Western Area Power Association 1992 DSM Guide
DOE - Department of Energy
AEE - Associtation onf Energy Engineers

DSM Model Results

Based on the methodology and data inputs discussed above a base case scenario was developed for all DSM programs. The complete DSM Model runs for each program are contained in Appendix B and a summary of the cost-benefit ratios are contained below on Table B-3:

DSM Program Cost-Benefit Summary

Table B-3

DSM#	DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Interruptible Rate - Demand Response Only	CI	PC	6.37	6.45	4.56	2.46
2	Commercial High Efficiency Motors	CI	SC	3.05	5.26	1.76	1.14
3	Energy Star Washers with electric heat	R	SC	1.12	3.22	1.84	3.12
4	Energy Star Dishwashers with electric heat	R	SC	0.20	0.31	0.28	2.59
5	Energy Star Refrigerators	R	SC	3.86	7.73	6.25	2.91
6	Energy Star Freezers	R	SC	3.43	5.61	4.45	2.04
7	High Efficiency A/C Residential	R	SC	1.61	2.06	1.44	1.20
8	High Efficiency A/C Commercial	CI	SC	2.20	2.47	1.85	1.63
9	Residential A/C Cycling (T-Stat)	R	PC	2.66	3.09	4.72	INF
10	Commercial A/C Cycling (T-Stat)	CI	PC	2.90	3.10	4.73	INF
11	Refrigerator Round-Up	R	SC	2.64	4.93	7.28	INF
12	Ground Source Heat Pumps	R	SLG/SC	5.84	6.24	2.23	1.86
13	Commercial Lighting	CI	SC	6.05	12.33	3.68	1.58
14	LED Exit Signs	CI	SC	2.14	4.24	1.97	2.18

INF= Infinity as partcipant has no cost participation amount

PC = Peak Clipping
C= Commercial

SLG = Strategic Load Growth
R= Residential

SC = Strategic Conservation
I = Industrial

Sensitivity Analysis

Montana-Dakota has identified that one of the most significant variables affecting the viability of the programs are the participation rate estimates. In order to quantify reduced or increased participation in the programs over the base case a sensitivity analysis was performed for all programs based on high and low participation.

Sensitivity A is an analysis assuming the participation rate in all DSM programs doubles over the base case. The DSM Model inputs and results of this analysis are contained in Appendices C and D respectively. A summary of the cost-benefit ratios are contained below in Table B-4.

DSM Program Cost-Benefit Summary
Table B-4

DSM #	DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Interruptible Rate - Demand Response Only	CI	PC	6.65	6.74	4.67	2.46
2	Commercial High Efficiency Motors	CI	SC	3.46	6.63	1.87	1.14
3	Energy Star Washers with electric heat	R	SC	1.23	4.22	2.07	3.12
4	Energy Star Dishwashers with electric heat	R	SC	0.28	0.52	0.39	2.59
5	Energy Star Refrigerators	R	SC	4.39	10.16	7.42	2.91
6	Energy Star Freezers	R	SC	4.11	7.70	5.40	2.04
7	High Efficiency A/C Residential	R	SC	1.67	2.16	1.49	1.20
8	High Efficiency A/C Commercial	CI	SC	2.61	3.00	2.07	1.63
9	Residential A/C Cycling (T-Stat)	R	PC	2.78	3.26	5.05	INF
10	Commercial A/C Cycling (T-Stat)	CI	PC	5.66	6.44	13.87	INF
11	Refrigerator Round-Up	R	SC	2.93	6.03	9.44	INF
12	Ground Source Heat Pumps	R	SLG /SC	6.02	6.47	2.25	1.86
13	Commercial Lighting	CI	SC	6.43	14.02	3.80	1.58
14	LED Exit Signs	CI	SC	2.70	7.20	2.34	2.18

INF= Infinity as partcipant has no cost participation amount

PC = Peak Clipping
C= Commercial

SLG = Strategic Load Growth
R= Residential

SC = Strategic Conservation
I = Industrial

Sensitivity B is an analysis assuming the participation rate in all DSM programs is reduced by fifty percent over the base case. The DSM Model results of this analysis are contained in Appendices E and F respectively. A summary of the cost-benefit ratios are contained below in Table B-5:

DSM Program Cost-Benefit Summary
Table B-5

DSM #	DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Interruptible Rate - Demand Response Only	CI	PC	5.87	5.94	4.34	2.46
2	Commercial High Efficiency Motors	CI	SC	2.46	3.72	1.58	1.14
3	Energy Star Washers with electric heat	R	SC	0.96	2.18	1.50	3.12
4	Energy Star Dishwashers with electric heat	R	SC	0.14	0.18	0.18	2.59
5	Energy Star Refrigerators	R	SC	3.11	5.22	4.75	2.91
6	Energy Star Freezers	R	SC	2.58	3.64	3.30	2.04
7	High Efficiency A/C Residential	R	SC	1.49	1.87	1.37	1.20
8	High Efficiency A/C Commercial	CI	SC	1.67	1.82	1.52	1.63
9	Residential A/C Cycling (T-Stat)	R	PC	2.44	2.80	4.18	INF
10	Commercial A/C Cycling (T-Stat)	CI	PC	3.61	3.91	6.42	INF
11	Refrigerator Round-Up	R	SC	2.21	3.61	5.00	INF
12	Ground Source Heat Pumps	R	SLG /SC	5.52	5.83	2.18	1.86
13	Commercial Lighting	CI	SC	5.42	9.95	3.48	1.58
14	LED Exit Signs	CI	SC	1.51	2.32	1.50	2.18

INF= Infinity as partcipant has no cost participation amount

PC = Peak Clipping
C= Commercial

SLG = Strategic Load Growth
R= Residential

SC = Strategic Conservation
I = Industrial

As indicated by the sensitivity analysis there were not significant changes in the feasibility of any of the programs in Sensitivity A – High Participation. However under Sensitivity B – Low Participation, ENERGY STAR Clothes Washer did not pass from the Utility Test perspective. This program is still considered feasible as it did pass the Rate Payer and Societal Test.

Feasible DSM Programs

Based on the Ratepayer Test, the following programs have been identified as feasible DSM programs:

1. ENERGY STAR® Clothes Washers
2. ENERGY STAR® Refrigerators
3. ENERGY STAR® Freezers
4. ENERGY STAR® Residential Central Air Conditioners
5. Residential Air Conditioner Cycling
6. Refrigerator Round-Up
7. Ground Source Heat Pumps
8. Interruptible Demand Response Rate
9. High Efficiency Motors
10. ENERGY STAR® Commercial Central Air Conditioners
11. Commercial Air Conditioner Cycling
12. High Efficiency Lighting
13. LED Exit Sign Lighting

Current DSM Program Activity

As a result of the 2005 IRP, Montana-Dakota implemented the following DSM programs that continue today:

ENERGY STAR® Partnership

This program is an indirect program with no quantifiable benefits; however it is used to promote conservation, education, and consumer awareness. Montana-Dakota applied to become an ENERGY STAR partner in January of 2006 and received partnership status in May of 2006. Montana-Dakota continues to use the ENERGY STAR® Partnership to promote conservation in its marketing efforts and is also continuing to explore additional partnerships with ENEGRY STAR on national campaigns such as the 'Change a Light' program.

ENERGY STAR® Residential Central Air Conditioning

This program offers a $60 per ton incentive to participants for installing a Central Air Conditioner with a 14 SEER or higher and was implemented June 1, 2006. Participation in this program has been lower than expected, however Montana-Dakota feels this was due to excess inventories of 10 SEER Air Conditioners because of the Federal Standards change to a 12 SEER Minimum in June 2006. Therefore this program will continue for 2007 unchanged. Future plans are to change to a $200 per ton incentive and a 15 SEER minimum in 2008. This change is to better align with forecasted future ENERGY STAR Program changes and Federal Tax Credits.

Energy (kWh) and Demand (kW) reductions forecasted for this program are included in the load forecast contained in this IRP. Therefore this program will not be included in the integration analysis.

Commercial Lighting

This program offers a $0.20 per watt incentive for replacing existing T-12 Lighting with new higher efficiency lighting. The average rebate is about $8.00 for the most common type of fixture and was implemented September 1, 2006. Participation in this program is on track to meet forecasted levels. This program will continue unchanged for the foreseeable future.

Energy (kWh) and Demand (kW) reductions forecasted for this program are included in the load forecast contained in this IRP. Therefore this program will not be included in the integration analysis.

Other DSM Activity

Montana-Dakota currently offers in North Dakota an Interruptible Rate Tariff and very recently added a Demand Response Rate Tariff for large commercial customers that is similar to the current DSM program that is modeled in this IRP. Since this rate is currently in place, 5.5 MW of interruptible load is available and has been included as a peak demand reduction in the load forecast. Therefore, only the forecasted incremental 4.5 MW of Demand Response, is included in the integration analysis.

Integration of DSM Programs

Montana-Dakota has not included the following programs for implementation:

- ENERGY STAR® Clothes Washers – This program was not selected for implementation because it is limited to customers who have electric water heating, since a majority of the energy savings are realized through reduced water heating load. Montana-Dakota's saturation of electric water heating is very low and therefore the marketing efforts would be to small market segment.
- Ground Source Heat Pumps – This program was not selected for implementation because there is a very high cost to the customer to participate in this program and there is a very small market of potential customers for the program in Montana-Dakota's electric only service territory.

Of the 13 feasible programs two programs are currently being implemented and included in the load forecast, two other programs were eliminated after further evaluation, and the nine programs shown below were selected to be included in the integration analysis:

1. ENERGY STAR® Refrigerators
2. ENERGY STAR® Freezers
3. Residential Air Conditioner Cycling
4. Refrigerator Round-Up
5. Interruptible Demand Response Rate (4.5 MW)
6. High Efficiency Motors
7. ENERGY STAR® Commercial Central Air Conditioners
8. Commercial Air Conditioner Cycling
9. LED Exit Sign Lighting

The nine selected demand side programs were placed into four separate groups generally representing similar characteristics for purposes of integration. The grouping allowed Strategist® to find the programs more attractive to select since they would represent a larger amount of potential savings. The program groupings are as follows:

DSM Integration Packages
Table B-6

Conservation 1	Available Date	Annual kWh Savings	Peak kW Savings	Installed Cost/kWh	Installed Cost/kW
Energy Star Refrigerators		312,191	195	$0.027	$636
Energy Star Freezers		175,574	127	$0.042	$867
Refrigerator Round-Up		473,999	503	$0.034	$324
LED Exit Signs		86,944	124	$0.014	$971
Total Conservation 1	**2008**	**1,048,708**	**949**	**$0.025**	**$545**
Conservation 2					
Residential A/C Cycling		238,782	7,151	$0.126	$419
Commercial A/C Cycling		29,157	873	$0.126	$421
Total Conservation 2	**2009**	**267,939**	**8,024**	**$0.126**	**$420**
Conservation 3					
Commercial High Efficiency A/C		203,689	199	$0.054	$835
High Efficiency Motors		567,063	138	$0.017	$1045
Total Conservation 3	**2008**	**770,752**	**337**	**$0.027**	**$ 921**
Conservation 4					
IT Rate - Demand Response		340,025	4,500	$0.163	$123
Total Conservation 4	**2008**	**340,025**	**4,500**	**$0.163**	**$123**

Implementing the nine additional DSM programs above will provide the Company an estimated demand reduction of 13.8 MW once implementation is complete. The DSM program cost is approximately $344/kW or $0.076/kWh. The first year program costs are estimated to be approximately $1,988,179, with a total estimated cost of approximately $4,747,576 over the implementation period. The portfolio of DSM programs will benefit all customers as shown by the Ratepayer Test results included in this attachment.

Response to Interruptible rates for customer less than 500 kW
ND Commission order PU-05-504

The IT Rate – Demand Response measure that was evaluated and integrated into this IRP was modeled for a customer that would have a average demand load of 500 kW or greater. The 500 kW or greater model was selected based on a similar rate that is currently effective in North Dakota. A sensitivity analysis was performed to determine the cost benefit of offering this type of rate to customers with an average demand under 500 kW.

The sensitivity analysis performed used the same assumptions as the base model for the larger customers including load factor, administrative expense, operating expense, and participant expense for primary service and interconnection costs. As shown by the cost benefit model included in this attachment the smallest load that is still beneficial from all four perspectives is 150 kW. However, customers that are below 500 kW typically will not have an alternate power supply such as assumed for the larger customers. If the cost of the alternate power supply is considered as a participant expense the program will fail the participant test.

Therefore, Montana-Dakota has determined that demand response opportunities for customers below 500 kW can be better achieved through the use of demand response programs that will utilize technology that significantly reduces the initial cost for customers below 500 kW.

As indicated in this report, Montana-Dakota is expecting to implement demand response through the Air Conditioning Cycling program(s) for Commercial and Residential customers in 2009. These programs are modeled using costs assuming the use of controllable thermostats; however as part of the initial implementation process for these programs Montana-Dakota will issue a Request for Proposal for all types of Demand Response technologies. Depending on the costs and benefits of other technologies additional demand response opportunities may be available for small commercial customers in the future.

Appendix A

Base Case Inputs

Interruptible Rate - Demand Response
Quantitative DSM # 1

Customer Class:	Commercial and Industrial	

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ 3,600		$ 194	$ 3,600	$ 3,600	$ 3,600	$ 10,800
Incentive Costs	$ 15,000		$ 15,000	$ 93,000	$ 186,000	$ 279,000	$ 558,000
Admin & Advertising	$ 19,829		$ 3,198	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 18,392**	**$ 116,429**	**$ 209,429**	**$ 302,429**	**$ 628,287**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 2.50	per kW/month

Participant Costs (Incremental Cost Basis)

Estimated Average cost of inteconnection	$ 50,000	Average interconnection costs - Estimated
Estimated cost of Primary Service	$ 40,000	Cost for Transformer, Primary Metering, Switch Fuse
Total Cost	**$ 90,000**	
Other Partcipant Costs (Diesel @ 100 hrs of curtailment)	$ 6,499	

Participation Rate Calc

	% of Cust	Cust	
C& I Customers over 500 kW	100.00%	93	RA provided Query of CIS

Total Customer Available for program	93			
Total Estimated Saturation Percentage	20.0%	**Total MW**		
Total Participantion Rate	**19**	9.3	20.00%	Of total Customer Base
Participation Year 1	6	3.1		
Participation Year 2	6	3.1		
Participation Year 3	6	3.1		

Energy Savings Calculation

IT Rate	Total conn kW	kW/Customer	Avg kW per event	Coincident Rate
Rate 38 - DR	500	500.0	500	100.0%

Avg Customer KWh Avoided @ 100 hrs **26,986** 75% Customer LF
Primary Service Rate Savings per year **$ 20,264** Included in other particapant savings

	Per Part
Summer Demand Reduction	166.7
Winter Demand Reduction	333.3
Total Demand Reduction	**500**
Summer Energy Reduction	26,986
Winter Energy Reduction	0

Proposed IT DR Rate	
Summer kW	$ 8.254
Winter kW	$ 5.254
Energy kWh	$ 0.03255
Demand Credit kW	$ 2.50

Note:
MW of IT is the target not Customers
Incentive is equal to our lost Margin between ND Rate 30 Secondary and IT Rate

Commercial High Efficiency Motors
Quantitative DSM # 2

Customer Class:	Commercial & Industrial

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$0	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$264	$ 264	$ 28,167	$ 28,167	$ 28,167	$ 84,502
Admin & Advertising	$19,829	$ 186	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 451**	**$ 47,996**	**$ 47,996**	**$ 47,996**	**$ 143,989**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 0.150	Per kWh Saved

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Motor	$ 3,320	50HP 3600 rpm - Motor Master
Avg Cost of High Efficiency Motor	$ 4,787	50 HP 3600 rpm - Motor Master
Increased cost of Higher Eff Model	**$ 1,467**	

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	17,042	
Customer with Standard Motors		75.00%	12,782	
Estimated Motors per Customer			5	
Total Motors Available for Program	63,908			
Total Estimated Saturation Percentage	0.5%			
Total Motors	**320**		1.88%	Of total Customer Base
Participation Year 1	107			
Participation Year 2	107			
Participation Year 3	107			

Energy Savings Calculation

Electric Motor Data	kw Conn	Annual kWh	Utilization Factor
Standard Motor (50hp)	37.3	106,860	100%
High Efficiency Motor(50hp)	36.9	105,097	100%
Energy Savings	**0.4**	**1,763**	

4380 hrs per year operation @ 60 % Load Factor
4380 hrs per year operation @ 60% Load Factor
Energy Calculation based on Motor Master - DOE
Example is based on 50 hp - 3600 rpm - 460 v TEFC

	Per Part	
Summer Demand Reduction	0.133	Levelized for 4 months
Winter Demand Reduction	0.267	Levelized for 8 Months
Total Demand Reduction	**0.400**	**Total demand Reduction for Measure**
Summer Energy Reduction	588	
Winter Energy Reduction	1175	

Notes:
TEFC = Total Enclosed Fan Cooled

Energy Star Clothes Washer Program
Quantitative DSM # 3

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	Per year	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 25	Per Particpant	$ 25	$ 21,837	$ 21,837	$ 21,837	$ 65,511
Admin & Advertising	$ 19,829	Per year	$ 23	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 48**	**$ 41,666**	**$ 41,666**	**$ 41,666**	**$ 124,998**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 750	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 300**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers with Electric Water heating	32.83%	28,283	Per 2004 Customer Survey
Customer with Clothes Washers	92.65%	26,205	Per 2004 Customer Survey

Total Customers Available for program	26,205	
Total Estimated Saturation Percentage	10.0%	
Total Particapants	**2,620**	3.04% Of total Customer Base
Participation Year 1	873	
Participation Year 2	873	
Participation Year 3	873	

Energy Savings Calculation

Clothes Washer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.469	531	10%	Savings is Due to reduceed Water Consumption
Energy Star	0.192	234	10%	Savings is based on Energy Star Calculator
Energy Savings	**0.277**	**297**		

	Per Part	
Summer Demand Reduction	0.009	Levelized for 4 months
Winter Demand Reduction	0.018	Levelized for 8 Months
Total Demand Reduction	**0.028**	**Total demand Reduction for Measure**
Summer Energy Reduction	99	
Winter Energy Reduction	198	
Other Particpants Costs / Savings	$ (35.00)	

***** Note water & detergent savings is estimated at $35 per year (7,000 gallons) entered as Other Part Costs (neg)***

Energy Star Dishwasher Program
Quantitative DSM # 4

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10	$ 10	$ 5,314	$ 5,314	$ 5,314	$ 15,943
Admin & Advertising	$ 19,829	$ 37	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 47**	**$ 25,143**	**$ 25,143**	**$ 25,143**	**$ 75,430**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 500	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 50**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers with electric water heating	32.83%	28,283	
Customer with Automatic Dishwashers	56.37%	15,943	Per 2004 Customer Survey

Total Customers Available for program	15,943		
Total Estimated Saturation Percentage	10.0%		
Total Participants	**1,594**	1.85%	Of total Customer Base
Participation Year 1	531		
Participation Year 2	531		
Participation Year 2	531		

Energy Savings Calculation

Dishwasher Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0	413	20%	Savings is Driven by Reduce Water Consumption
Energy Star	0	341	20%	Savings is based on Energy Star Calculator
Energy Savings	**0**	**72**		

	Per Part		
Summer Demand Reduction	0.000	Levelized for 4 months	
Winter Demand Reduction	0.000	Levelized for 8 Months	
Total Demand Reduction	**0.000**	**Total demand Reduction for Measure**	
Summer Energy Reduction	24		
Winter Energy Reduction	48		
Other Participants Cost / Savings	$ (3.00)		

**** Water savings is estimated at 830 gallons per year! Not used in model as savings insignificant at $3.00/yr/part

Energy Star Refrigerators Program
Quantitative DSM # 5

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 15		$ 15	$ 21,538	$ 21,538	$ 21,538	$ 64,613
Admin & Advertising	$ 19,829		$ 14	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 29**	**$ 41,367**	**$ 41,367**	**$ 41,367**	**$ 124,100**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 1,070	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 1,100	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 30**	Partial automatic defrost

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151

Total Customers Available for program	86,151	
Total Estimated Saturation Percentage	5.0%	
Total Participants	**4,308**	5.00% Of total Customer Base
Participation Year 1	1,436	
Participation Year 2	1,436	
Participation Year 2	1,436	

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.8	479	35%	18 Cu Ft Top Freezer ice maker
Energy Star	0.68	407	35%	As per survey results 88% for FF
Energy Savings	**0.12**	**72**		Energy Star - DOE 2004

	Per Part	
Summer Demand Reduction	0.014	Levelized for 4 months
Winter Demand Reduction	0.028	Levelized for 8 Months
Total Demand Reduction	**0.042**	**Total demand Reduction for Measure**
Summer Energy Reduction	24	
Winter Energy Reduction	48	

Energy Star Freezers Program
Quantitative DSM # 6

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 15		$ 15	$ 16,771	$ 16,771	$ 16,771	$ 50,314
Admin & Advertising	$ 19,829		$ 18	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 33**	**$ 36,600**	**$ 36,600**	**$ 36,600**	**$ 109,801**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 329	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 362	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 33**	23 Cu ft Chest Manual DF

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Customer with Freezers	77.87%	67,086	Per 2004 Customer Survey

Total Customers Available for program	67,086		
Total Estimated Saturation Percentage	5.0%		
Total Participants	**3,354**	3.89%	Of total Customer Base
Participation Year 1	1,118		
Participation Year 2	1,118		
Participation Year 3	1,118		

Energy Savings Calculation

Freezer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional Freezer	0.9	520	35%	22 Cu ft Chest Manual DF
Energy Star Freezer	0.8	468	35%	Energy Star -DOE 2004
Energy Savings	**0.1**	**52**		

	Per Part		
Summer Demand Reduction	0.012	Levelized for 4 months	
Winter Demand Reduction	0.023	Levelized for 8 Months	
Total Demand Reduction	**0.035**	**Total demand Reduction for Measure**	
Summer Energy Reduction	17		
Winter Energy Reduction	35		

Residential High Efficiency A/C (Energy Star Rated)
Quantitative DSM # 7

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 600	$ 600	$ 177,281	$ 177,281	$ 177,281	$ 531,843
Admin & Advertising	$ 19,829	$ 67	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 667**	**$ 197,110**	**$ 197,110**	**$ 197,110**	**$ 591,330**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 200	Per Ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (13 SEER)	$ 1,200	Market Reasearch with local HVAC Dealers
Cost of High Efficiency Model (15 SEER)	$ 2,300	Market Reasearch with local HVAC Dealers
Increased cost of Higher Eff Model	**$ 1,100**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers With Central AC	50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers	0.81%	698	Per 2004 Customer Survey

Total Available for program	44,325		
Total Estimated Saturation Percentage	2.0%		
Total Participants	**886**	1.03%	Of total Customer Base
Participation Year 1	295		
Participation Year 2	295		
Participation Year 3	295		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
10 SEER Unit	3.8	2,160	67%
15 SEER Unit	2.9	1,440	
Energy Reduction	**0.92**	**720**	

EPRI for Utilization Factor
BismarckWeather Data used for cooling hrs

	Per Part
Summer Demand Reduction	0.6
Winter Demand Reduction	0.0
Summer Energy Reduction	720
Winter Energy Reduction	0

Commercial High Efficiency A/C
Quantitative DSM # 8

Customer Class:	Commercial

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 500	$ 500	$ 35,501	$ 35,501	$ 35,501	$ 106,502
Admin & Advertising	$ 19,829	$ 279	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 779**	**$ 55,330**	**$ 55,330**	**$ 55,330**	**$ 165,989**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 100.00	per ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (10 SEER)	$ 2,000	Trane 5 Ton Packaged Unit ($400 per ton Mike S)
Cost of High Efficiency Model (12 SEER)	$ 3,000	Trane 5 Ton Packaged Unit ($600 per ton Mike S)
Increased cost of Higher Eff Model	**$ 1,000**	

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	17,042	
Total Customers With Central AC		50.00%	8,521	Estimated no survey data
Total Customers with Evap or Swamp Coolers		0.00%	-	
Total Available for program	8,521			
Total Estimated Saturation Percentage	2.5%			
Total Participants	**213**		1.25%	Of total Customer Base
Participation Year 1	71			
Participation Year 2	71			
Participation Year 3	71			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	6.86	5,700	67%	Trane 5 ton Unit
12 Seer Unit	5.56	4,750		Trane 5 ton Unit
Energy Reduction	**1.3**	**950**		

	Per Part
Summer Demand Reduction	0.9
Winter Demand Reduction	0.0
Summer Energy Reduction	950
Winter Energy Reduction	0

Residential A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 9

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 45,421	$ 308	$ 1,169,321	$ 557,371	$ 557,371	$ 2,284,064
Incentive Costs ($89 t-Stat)	$ 93	$ 97	$ 322,462	$ 161,231	$ 161,231	$ 644,924
Admin & Advertising (MDU)	$ 23,429	$ 10.57	$ 23,429	$ 23,429	$ 23,429	$ 70,287
Total Cost		**$ 416**	**$ 1,515,212**	**$ 742,031**	**$ 742,031**	**$ 2,999,275**

Notes
Increased 2005 numbers by 4% inflation per year
MDU operational cost is less field operations

Participant Costs

None / Comfort Issues	$ -

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	86,151	
Total Customers With Central AC		50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers		0.81%	698	
Total Available for program	44,325			
Total Estimated Saturation Percentage	15.0%			
Total Participants	**6,649**		7.72%	Of total Customer Base
Participation Year 1	3,324			
Participation Year 2	1,662			
Participation Year 3	1,662			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
3 Ton 10 SEER Unit	3.6	2,340	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**1.00**		

Av is 1 kW per particpant (Honeywell)
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized kW redcction per partcipant

	Per Part
Summer Demand Reduction	1.00
Winter Demand Reduction	0.000
Summer Energy Reduction	360
Winter Energy Reduction	0

Commercial A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 10

Customer Class:	Small Comm

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 45,421	$ 282	$ 98,658	$ 60,439	$ 60,439	$ 219,536
Incentive Costs ($337 t-Stat)	$ 365	$ 365	$ 38,877	$ 19,439	$ 19,439	$ 77,754
Admin & Advertising (MDU)	$ 23,429	$ 330	$ 23,429	$ 23,429	$ 23,429	$ 70,287
Total Cost		**$ 977**	**$ 160,964**	**$ 103,307**	**$ 103,307**	**$ 367,577**

Notes
Increased 2005 numbers by 4% inflation per year
MDU operational cost is less field operations

Participant Costs

None / Comfort Issues	$ -

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	17,042	
Total Customers in class available for program		50.00%	8,521	Estimate
Total Customer with A/C		50.00%	4,261	Estimate
Total Available for program	4,261			
Total Estimated Saturation Percentage	5.0%			
Total Participants	**213**		1.25%	Of total Customer Base
Participation Year 1	107			
Participation Year 2	53			
Participation Year 3	53			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
(2) 5 Ton Unit 11.8 SEER	13.72	10800	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**3.80**		

Per Trane
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized kW redcction per partcipant

	Per Part
Summer Demand Reduction	3.8
Winter Demand Reduction	0.000
Summer Energy Reduction	1,372
Winter Energy Reduction	0

Refrigerator Round-Up Program
Quantitative DSM # 11

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Transport & Recycling (Operating)	$ -	$ 25	$ 23,558	$ 23,558	$ 23,558	$ 70,674
Incentive Costs	$ 35	$ 35	$ 10,994	$ 10,994	$ 10,994	$ 32,981
Admin & Advertising	$ 19,829	$ 63	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 123**	**$ 54,381**	**$ 54,381**	**$ 54,381**	**$ 163,142**

Notes

Operating Costs Calculated

Pick up and Recycling is estimated at loaded rate for 1.5 hr plus mileage & $20 recycling fee at Porter Bros $ 75

Participant Costs

None $ -

Participation Rate Calc

		% of Cust	Cust
Total Customers is Class		100.00%	86,151
Total Customers with 2 Refrigerators		34.03%	29,317
Total Customers with 3 or more Refrigerators		2.43%	2,093
Total Available for program	31,411		
Total Estimated Saturation Percentage	3.0%		
Total Partcipation	**942**	1.09%	Of total Customer Base
Participation Year 1	314		
Participation Year 2	314		
Participation Year 2	314		

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor
Frost Free	1.5	1200	35%
Standard	1	1000	35%
Avg (WAC)	**1.415**	**1166**	

As per WAPA DSM Pocket Guide 1992
Assumes 1987 vintage 17.3 cu ft
As per survey results 88% for FF
UPA 1992 Study - Older Fridges

	Per Part	
Summer Demand Reduction	0.165	Levelized for 4 months
Winter Demand Reduction	0.330	Levelized for 8 Months
Total Demand Reduction	**0.495**	**Total demand Reduction for Measure**
Summer Energy Reduction	389	
Winter Energy Reduction	777	

Residential GSHP
Quantitative DSM # 12

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 1,100	$ 1,100	$ 65,723	$ 65,723	$ 65,723	$ 197,170
Admin & Advertising	$ 19,829	$ 84	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost		**$ 1,184**	**$ 70,723**	**$ 70,723**	**$ 70,723**	**$ 212,170**

Notes

Program is based in straight electric areas only

Participant Costs (Incremental Cost Basis)

Furnace & Central Air (STD Eff)	$ 6,000	3 Ton A/C & 75,000 BTU Furnace 80%
GS Heat pump	$ 10,000	3 Ton Unit 17 SEER 14.5 EER
Increased cost of GSHP	**$ 4,000**	

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	86,151	
Combination Customers		58.39%	50,302	Per 2004 Customer Survey
Total Electric Only Customers		41.61%	35,849	Per 2004 Customer Survey
Total Available for program	35,849			
Total Estimated Saturation Percentage	0.50%			
Total Participants	**179**		0.21%	Of total Customer Base
Participation Year 1	60			
Participation Year 2	60			
Participation Year 3	60			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
Std A/C Cooling (10 SEER)	3.6	2,160	67%
Heat pump Cooling	2.5	1,271	
Cooling Energy Reduction	**1.1**	**889**	
Heating Energy Add	**2.5**	**6,638**	

COP of 3

	Per Part
Peak Demand Reduction	0.7
Winter Demand Reduction	-2.5
Summer Energy Reduction	889
Winter Energy Reduction	(6,638)
Savings Electric vs Propane	$ 577
Electric Heat after tax margin per cooling kwh reduction	$ 0.0911

**Heat Pump vs. propane at 80% AFUE & 5 yr avg price of $0.89 per gal ($827 annual cost for 930 Gallons)
** Annaul cost of electric heat $250

T-8 Lighting Retrofit (4 Lamp fixture model)
Quantitative DSM # 13

Customer Class:	Comm & Ind

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 184	$ 184	$ 62,715	$ 62,715	$ 62,715	$ 62,715	$ 62,715	$ 313,573
Admin & Advertising	$ 19,829	$ 58	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 99,145
Total Cost		**$ 242**	**$ 82,544**	**$ 82,544**	**$ 82,544**	**$ 82,544**	**$ 82,544**	**$ 412,718**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
	$ 8.00	per fix

Participant Costs

Avg Cost per Fixture	$ 40.00	4 Lamp Fixture with Ballast per ESG Avg Pricing plus labor
Fixtures per Participant	23	
Total Direct Cost per Part	**$ 920**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated fixtures per Customer	23	Derived from xenergy survey
Estimated fixtures on System	**391,966**	

Total fixtures Available for program	391,966
Estimated Conversion Percentage	10.0%
Part Rate of Light fixtures	39,197
Total Partcipants	**1,704**
Participation Year 1	341
Participation Year 2	341
Participation Year 3	341
Participation Year 4	341
Participation Year 5	341

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	hrs/yr	
Existing T-12 4 lamp Fixture	144	360	100%	2500	34 w bulbs energy saving magnetic ballast
T-8 4 Lamp Fixture	107	267	100%	2500	electronic ballast
Reduction Per fixture	**37**	**93**	**100%**		

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.0373	0.29	Levelized for 4 months
Winter Demand Reduction	0.0373	0.57	Levelized for 8 Months
Total Demand Reduction		**0.86**	**Total demand Reduction for Measure**
Summer Energy Reduction	31	715	
Winter Energy Reduction	62	1,430	

***** kWh calculation assumes 2,500 hrs per year of operation as is typically for M-F 8-5pm operation**

****** Actual Lighting program with be more comprehensive and include CFL & MH, however incentive will follow the same $ per watt of savings**

LED Exits Signs (Incandescent Model)
Quantitative DSM # 14

Customer Class:	Comm & Ind

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 25.00	$ 25	$ 4,261	$ 4,261	$ 4,261	$ 4,261	$ 4,261	$ 21,303
Admin & Advertising	$ 19,829	$ 116	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 99,145
Total Cost		**$ 141**	**$ 24,090**	**$ 24,090**	**$ 24,090**	**$ 24,090**	**$ 24,090**	**$ 120,448**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
Incentive	$ 5.00	per Fixture

Participant Costs

Cost Per Exit Light	$ 50.00	*Replacement cost as per ESG Todd Kaduan (Retrofit cost is $20/fix)*
Exit Signs per Part	5	
Total Direct Cost per Part	**$ 250**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated Exit Signs per Customer	5	derived Per Xenergy Study
Estimated Exit Signs on System	**85,210**	

Total Exit Lights Available for program	85,210
Estimated Conversion Percentage	5.0%
Part Rate of Exit Lights	4,261
Total Partcipants	**852**
Participation Year 1	170
Participation Year 2	170
Participation Year 3	170
Participation Year 4	170
Participation Year 5	170

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	kW Redc	kWh Reduc
Existing Incandescent	32	280	100%	0.032	280
Existing CFL	10	88	100%	0.01	88
LED (Replace the others)	5	44	100%	0.005	44

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.027	0.05	Levelized for 4 months
Winter Demand Reduction	0.027	0.09	Levelized for 8 Months
Total Demand Reduction		**0.14**	**Total demand Reduction for Measure**
Summer Energy Reduction	79	394	
Winter Energy Reduction	158	788	

***** Note For Program development that if CFL's are replaced incentive is reduced to 1/4 of incentive for incandescent**
******* LED Signs Must be energy star rated which is 5 watts or less (1 Watt is the best available)**
Fixture life is 10 years

Appendix B

Base Case Runs

DSM Base Case - Societal Test Perspective

Current DSM Programs

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Particpants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Part Cost Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
1	IT Rate - Demand Response	2007	3	10	19	4,178,534	5,530	$329,727	$10,919	$1,985	$ 342,631	$ 3,781,677	$684	$0.905
7	**Residential High Efficiency A/C	2006	3	15	886	9,636,358	586	$325,015	$19,829	$0	$ 344,844	$ 1,034,533	$1,766	$0.107
13	Commercial Lighting	2006	5	10	1,704	31,536,056	1,577	$313,573	$19,829	$0	$ 333,402	$ 1,667,009	$1,057	$0.053
	Totals					**45,350,948**	**7,693**	**$968,315**	**$50,577**	**$1,985**	**$ 1,020,877**	**$ 6,483,219**		

** Current Program for 2007 - Higher SEER Requirement & Incentive for 2008

Net Cost per kW	**$ 843**
Net Cost per kWh	**$ 0.143**

Conservation 1

5	Energy Star Refridgerators	2008	3	15	4,308	4,682,858	195	$43,076	$19,829	$0	$ 62,905	$ 188,714	$967	$0.040
6	Energy Star Freezers	2008	3	15	3,354	2,633,613	127	$36,897	$19,829	$0	$ 56,726	$ 56,726	$448	$0.022
11	Refridgerator Round-Up	2008	3	10	942	4,739,985	503	$0	$19,829	$23,558	$ 43,387	$ 130,161	$259	$0.027
14	Led Exit Signs	2008	5	10	852	8,694,379	124	$42,605	$19,829	$0	$ 62,434	$ 312,170	$2,516	$0.036
	Totals					**20,750,835**	**949**	**$122,578**	**$79,316**	**$23,558**	**$ 225,452**	**$ 687,771**		

Net Cost per kW	**$ 725**
Net Cost per kWh	**$ 0.033**

Consevation 2

9	Residential A/C Cycling	2009	3	10	6,649	23,878,187	7,151	$0	$23,429	$1,169,321	$1,192,750	$2,354,351	$329	$0.099
10	Commercial A/C Cycling	2009	3	10	213	2,915,725	873	$0	$23,429	$98,658	$122,087	$289,823	$332	$0.099
	Total Increase 2010					**26,793,912**	**8,024**	**$0**	**$46,858**	**$1,267,979**	**$1,314,837**	**$2,644,174**		

Net Cost per kW	**$ 330**
Net Cost per kWh	**$ 0.099**

Conservation 3

8	Commercial High Efficiency A/C	2008	3	15	213	3,055,336	199	$71,001	$19,829	$0	$ 90,830	$272,491	$1,370	$0.089
2	High Efficiency Motors	2008	3	15	320	8,505,940	138	$156,254	$19,829	$0	$176,083	$528,249	$3,832	$0.062
	Totals					**11,561,276**	**337**	**$227,255**	**$39,658**	**$0**	**$ 266,913**	**$800,739**		

Net Cost per kW	**$ 2,378**
Net Cost per kWh	**$ 0.069**

Conservation 4

1	IT Rate - Demand Response	2008	3	10	9	3,400,252	4,500	$269,777	$8,910	$1,615	$ 280,302	$ 3,094,099	***$688***	**$0.910**

Includes Admin at full amount per program

Cumulative Cost per kW	**$ 624**
Cumulative Cost per kWh	**$ 0.102**

DSM Base Case - Program Cost Only

Current DSM Programs

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Particpants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Incentive Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
1	IT Rate - Demand Response	2007	3	10	19	4,178,534	5,530	$51,285	$10,919	$1,985	$ 64,189	$ 679,890	$123	$0.163
7	**Residential High Efficiency A/C	2006	3	15	886	9,636,358	586	$177,281	$19,829	$0	$ 197,110	$ 591,330	$1,010	$0.061
13	Commercial Lighting	2006	5	10	1,704	31,536,056	1,577	$62,715	$19,829	$0	$ 82,544	$ 412,718	$262	$0.013
	Totals					**45,350,948**	**7,693**	**$291,281**	**$50,577**	**$1,985**	**$ 343,843**	**$ 1,683,938**		

** Current Program for 2007 - Higher SEER Requirement & Incentive for 2008

Net Cost per kW	**$ 219**
Net Cost per kWh	**$ 0.037**

Conservation 1

5	Energy Star Refridgerators	2008	3	15	4,308	4,682,858	195	$21,538	$19,829	$0	$ 41,367	$ 124,100	$636	$0.027
6	Energy Star Freezers	2008	3	15	3,354	2,633,613	127	$16,771	$19,829	$0	$ 36,600	$ 109,801	$867	$0.042
11	Refridgerator Round-Up	2008	3	10	942	4,739,985	503	$10,994	$19,829	$23,558	$ 54,381	$ 163,142	$324	$0.034
14	Led Exit Signs	2008	5	10	852	8,694,379	124	$4,261	$19,829	$0	$ 24,090	$ 120,448	$971	$0.014
	Totals					**20,750,835**	**949**	**$53,563**	**$79,316**	**$23,558**	**$ 156,437**	**$ 517,491**		

Net Cost per kW	**$ 545**
Net Cost per kWh	**$ 0.025**

Conservation 2

9	Residential A/C Cycling	2009	3	10	6,649	23,878,187	7,151	$322,462	$23,429	$1,169,321	$1,515,212	$2,999,275	$419	$0.126
10	Commercial A/C Cycling	2009	3	10	213	2,915,725	873	$38,877	$23,429	$98,658	$160,964	$367,577	$421	$0.126
	Total Increase 2010					**26,793,912**	**8,024**	**$361,339**	**$46,858**	**$1,267,979**	**$1,676,176**	**$3,366,852**		

Net Cost per kW	**$ 420**
Net Cost per kWh	**$ 0.126**

Conservation 3

8	Commercial High Efficiency A/C	2008	3	15	213	3,055,336	199	$35,501	$19,829	$0	$ 55,330	$165,989	$835	$0.054
2	High Efficiency Motors	2008	3	15	320	8,505,940	138	$28,167	$19,829	$0	$47,996	$143,989	$1,045	$0.017
	Totals					**11,561,276**	**337**	**$63,668**	**$39,658**	**$0**	**$ 103,326**	**$309,978**		

Includes Admin at full amount per program

Net Cost per kW	**$ 921**
Net Cost per kWh	**$ 0.027**

Conservation 4

1	IT Rate - Demand Response	2008	3	10	9	3,400,252	4,500	$41,715	$8,910	$1,615	$ 52,240	$ 553,255	***$123***	**$0.163**

$ 4,747,576

Cumulative Cost per kW	**$ 299**
Cumulative Cost per kWh	**$ 0.056**

Conservation 1,2,3,4,only Cost per kW	**$ 344**
Conservation 1,2,3,4,only Cost per kWh	**$ 0.076**

DSM Program Summary

All Programs

DSM #	DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Interruptible Rate - Demand Response Only	CI	PC	6.37	6.45	4.56	2.46
2	Commercial High Efficiency Motors	CI	SC	3.05	5.26	1.76	1.14
3	Energy Star Washers with electric heat	R	SC	1.12	3.22	1.84	3.12
4	Energy Star Dishwashers with electric heat	R	SC	0.20	0.31	0.28	2.59
5	Energy Star Refrigerators	R	SC	3.86	7.73	6.25	2.91
6	Energy Star Freezers	R	SC	3.43	5.61	4.45	2.04
7	High Efficiency A/C Residential	R	SC	1.61	2.06	1.44	1.20
8	High Efficiency A/C Commercial	CI	SC	2.20	2.47	1.85	1.63
9	Residential A/C Cycling (T-Stat)	R	PC	2.66	3.09	4.72	INF
10	Commercial A/C Cycling (T-Stat)	CI	PC	2.90	3.10	4.73	INF
11	Refrigerator Round-Up	R	SC	2.64	4.93	7.28	INF
12	Ground Source Heat Pumps	R	SLG /SC	5.84	6.24	2.23	1.86
13	Commercial Lighting	CI	SC	6.05	12.33	3.68	1.58
14	LED Exit Signs	CI	SC	2.14	4.24	1.97	2.18

INF= Infinity as partcipant has no cost participation amount

PC = Peak Clipping
C= Commercial

SLG = Strategic Load Growth
R= Residential

SC = Strategic Conservation
I = Industrial

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03255
1a) Retail Rate Winter ($/kWh) =	$0.03255
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$10.00
3a) Retail Winter Demand Rate ($/kW/season) =	$20.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	93
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$93,000
Total Utility Project Costs Year 1 =	**$116,429**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$186,000
Total Utility Project Costs Year 2 =	**$209,429**
15b) Total Utilty Cost Year 3 =	**$302,429**
15c) Total Utilty Cost Year 4 =	**$302,429**
15d) Total Utility Cost Year 5 =	**$302,429**
15e) Total Utility Operating Cost (Program Life) =	**$302,429**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$90,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 6,499
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 20,264
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	166.7
20a) Avg Winter kW/part Saved =	333.3
21) Avg. Summer kWh/Part. Saved =	26,986
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	6
22a) Number of Participants (Second Year) =	6
22a) Number of Participants (Third Year) =	6
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15,000

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Interruptible Rate - Demand Response**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$1,233,145
Total Program Participants	19
Utility Cost per Participant (First Year) =	$18,778.87
Utility Cost per Participant (Program) =	$66,298.12
Total kW Reduction	10,030
Total Energy Reduction (kWh)	7,578,786
Societal Cost per kwh	$0.57

Test Results

	NPV	B/C
Utility Test	$13,547,980	6.37
Ratepayer Test	$13,580,681	6.45
Societal Cost Test	$15,429,879	4.56
Participant Test	$3,639,909	2.46

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	180,447	$0.0190	$0	3,343	$140.17	$472,071	$116,429	1,784	$118,213	$353,858
2	2009	360,895	$0.0195	0	6,687	$147.02	990,143	$209,429	3,443	212,872	777,271
3	2010	541,342	$0.0201	0	10,030	$154.25	1,558,058	$302,429	4,971	307,400	1,250,658
4	2011	541,342	$0.0207	0	10,030	$161.89	1,634,957	$302,429	4,772	307,201	1,327,757
5	2012	541,342	$0.0213	0	10,030	$169.95	1,716,139	$302,429	4,567	306,996	1,409,144
6	2013	541,342	$0.0220	0	10,030	$178.46	1,801,843	$302,429	4,355	306,784	1,495,058
7	2014	541,342	$0.0226	0	10,030	$187.44	1,892,319	$302,429	4,138	306,567	1,585,753
8	2015	541,342	$0.0233	0	10,030	$196.93	1,987,835	$302,429	3,914	306,343	1,681,493
9	2016	541,342	$0.0240	0	10,030	$206.95	2,088,672	$302,429	3,683	306,112	1,782,560
10	2017	541,342	$0.0247	0	10,030	$217.52	2,195,125	$302,429	3,445	305,874	1,889,251
11	2018	541,342	$0.0255	0	10,030	$228.68	2,307,508	$302,429	3,200	305,629	2,001,879
12	2019	541,342	$0.0262	0	10,030	$240.47	2,426,152	$302,429	2,948	305,377	2,120,775
13	2020	541,342	$0.0270	0	10,030	$252.92	2,551,405	$302,429	2,688	305,117	2,246,289
14	2021	541,342	$0.0278	0	10,030	$266.06	2,683,637	$302,429	2,420	304,849	2,378,788
15	2022	541,342	$0.0287	0	10,030	$279.93	2,823,236	$302,429	2,144	304,573	2,518,663
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		7,578,786			140,421		$29,129,102	$4,257,435	$52,470	$4,309,905	$24,819,197
NPV =							16,071,596	2,490,915	32,701	2,523,616	13,547,980

Total NPV = $13,547,980
Benefit/Cost Ratio = 6.37

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Interruptible Rate - Demand Response**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$3,420	$0	$468,652	$472,071	$116,429	$116,429	$355,642
2009	7,045	0	983,098	990,143	$209,429	209,429	780,714
2010	10,884	0	1,547,174	1,558,058	$302,429	302,429	1,255,629
2011	11,211	0	1,623,747	1,634,957	$302,429	302,429	1,332,528
2012	11,547	0	1,704,592	1,716,139	$302,429	302,429	1,413,710
2013	11,894	0	1,789,949	1,801,843	$302,429	302,429	1,499,414
2014	12,250	0	1,880,069	1,892,319	$302,429	302,429	1,589,890
2015	12,618	0	1,975,217	1,987,835	$302,429	302,429	1,685,406
2016	12,996	0	2,075,675	2,088,672	$302,429	302,429	1,786,243
2017	13,386	0	2,181,738	2,195,125	$302,429	302,429	1,892,696
2018	13,788	0	2,293,720	2,307,508	$302,429	302,429	2,005,079
2019	14,202	0	2,411,950	2,426,152	$302,429	302,429	2,123,723
2020	14,628	0	2,536,778	2,551,405	$302,429	302,429	2,248,976
2021	15,066	0	2,668,571	2,683,637	$302,429	302,429	2,381,208
2022	15,518	0	2,807,718	2,823,236	$302,429	302,429	2,520,807
2023	0	0	0	0	0	0	0
Total =	$180,454	$0	$28,948,648	$29,129,102	$4,257,435	$4,257,435	$24,871,667
NPV =	101,812	0	15,969,784	16,071,596	2,490,915	2,490,915	13,580,681

Total NPV = $13,580,681

Benefit/Cost Ratio = 6.45

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$3,420	$0	$468,652	$72,935	$545,006	$116,429	$599,504	$93,000	$622,933	($77,926)
2009	$7,045	$0	$983,098	$157,566	1,147,710	$209,429	643,497	$186,000	666,926	480,783
2010	$10,884	$0	$1,547,174	$255,380	1,813,438	$302,429	646,062	$279,000	669,491	1,143,946
2011	$11,211	$0	$1,623,747	$276,024	1,910,981	$302,429	90,704	$0	393,133	1,517,848
2012	$11,547	$0	$1,704,592	$298,421	2,014,561	$302,429	93,425	$0	395,854	1,618,706
2013	$11,894	$0	$1,789,949	$322,724	2,124,567	$302,429	96,228	$0	398,657	1,725,910
2014	$12,250	$0	$1,880,069	$349,097	2,241,416	$302,429	99,115	$0	401,544	1,839,872
2015	$12,618	$0	$1,975,217	$377,720	2,365,555	$302,429	102,088	$0	404,517	1,961,037
2016	$12,996	$0	$2,075,675	$408,786	2,497,458	$302,429	105,151	$0	407,580	2,089,878
2017	$13,386	$0	$2,181,738	$442,510	2,637,634	$302,429	108,306	$0	410,735	2,226,900
2018	$13,788	$0	$2,293,720	$479,120	2,786,628	$302,429	111,555	$0	413,984	2,372,644
2019	$14,202	$0	$2,411,950	$518,867	2,945,019	$302,429	114,901	$0	417,330	2,527,688
2020	$14,628	$0	$2,536,778	$562,024	3,113,429	$302,429	118,349	$0	420,778	2,692,652
2021	$15,066	$0	$2,668,571	$608,886	3,292,523	$302,429	121,899	$0	424,328	2,868,195
2022	$15,518	$0	$2,807,718	$659,776	3,483,012	$302,429	125,556	$0	427,985	3,055,027
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$180,454	$0	$28,948,648	$5,789,836	$34,918,938	$4,257,435	$3,176,341	$558,000	$6,875,776	$28,043,161
NPV =	101,812	0	15,969,784	3,697,147	19,768,743	2,490,915	2,324,561	476,611	4,338,864	15,429,879

Total NPV = $15,429,879
Benefit/Cost Ratio = 4.56

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0662	$93,000	167,313	0	$0.040	$0.040	1,033	2,067	$10.56	$21.12	$279,885	$558,000	$41,504	$599,504	($319,619)
2009	0.1315	$186,000	334,626	0	$0.042	$0.042	2,067	4,133	$11.15	$22.29	$566,605	558,000	$85,497	643,497	(76,892)
2010	0.1306	$279,000	501,940	0	$0.045	$0.045	3,100	6,200	$11.77	$23.54	$860,733	558,000	$88,062	646,062	214,671
2011	0.1297	$0	501,940	0	$0.047	$0.047	3,100	6,200	$12.43	$24.85	$593,162	0	$90,704	90,704	502,458
2012	0.1288	$0	501,940	0	$0.050	$0.050	3,100	6,200	$13.12	$26.24	$605,229	0	$93,425	93,425	511,804
2013	0.1279	$0	501,940	0	$0.053	$0.053	3,100	6,200	$13.85	$27.70	$617,969	0	$96,228	96,228	521,741
2014	0.1270	$0	501,940	0	$0.055	$0.055	3,100	6,200	$14.62	$29.25	$631,420	0	$99,115	99,115	532,305
2015	0.1261	$0	501,940	0	$0.059	$0.059	3,100	6,200	$15.44	$30.88	$645,622	0	$102,088	102,088	543,533
2016	0.1252	$0	501,940	0	$0.062	$0.062	3,100	6,200	$16.30	$32.60	$660,616	0	$105,151	105,151	555,465
2017	0.1243	$0	501,940	0	$0.065	$0.065	3,100	6,200	$17.21	$34.42	$676,447	0	$108,306	108,306	568,141
2018	0.1235	$0	501,940	0	$0.069	$0.069	3,100	6,200	$18.17	$36.34	$693,161	0	$111,555	111,555	581,606
2019	0.1226	$0	501,940	0	$0.073	$0.073	3,100	6,200	$19.19	$38.37	$710,808	0	$114,901	114,901	595,906
2020	0.1218	$0	501,940	0	$0.077	$0.077	3,100	6,200	$20.26	$40.51	$729,439	0	$118,349	118,349	611,091
2021	0.1209	$0	501,940	0	$0.081	$0.081	3,100	6,200	$21.39	$42.77	$749,110	0	$121,899	121,899	627,211
2022	0.1201	$0	501,940	0	$0.086	$0.086	3,100	6,200	$22.58	$45.16	$769,879	0	$125,556	125,556	644,323
2023	0.1193	0	0	0	$0.090	$0.090	0	0	$23.84	$47.68	$0	0	$0	0	0
			7,027,154	0							$9,790,085	$1,674,000	$1,502,341	$3,176,341	$6,613,744
											$6,128,351	1,566,175	922,267	2,488,442	3,639,909

Total NPV = $3,639,909
Benefit/Cost Ratio = 2.46

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$28,167
Total Utility Project Costs Year 1 =	**$47,996**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$28,167
Total Utility Project Costs Year 2 =	**$47,996**
15b) Total Utilty Cost Year 3 =	**$47,996**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,467.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.13
20a) Avg Winter kW/part Saved =	0.27
21) Avg. Summer kWh/Part. Saved =	588
21a) Avg. Winter kWh/Part. Saved =	1,175
22) Number of Participants (First Year) =	107
22a) Number of Participants (Second Year) =	107
22a) Number of Participants (Third Year) =	107
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 264

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$143,989
Total Program Participants	320
Utility Cost per Participant (First Year) =	$450.62
Utility Cost per Participant (Program) =	$450.62
Total kW Reduction	138
Total Energy Reduction (kWh)	8,505,940
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$444,699	3.05
Ratepayer Test	$536,100	5.26
Societal Cost Test	$352,127	1.76
Participant Test	$60,368	1.14

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

		Cost of Energy Saved						Project Cost			Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	202,522	$0.0190	$0	46	$349.78	$19,910	$47,996	2,706	$50,702	($30,792)
2	2009	405,045	$0.0195	0	92	$366.87	41,622	47,996	5,653	53,649	(12,028)
3	2010	607,567	$0.0201	0	138	$384.91	65,275	47,996	8,868	56,864	8,411
4	2011	607,567	$0.0207	0	138	$403.96	68,268	0	9,283	9,283	58,984
5	2012	607,567	$0.0213	0	138	$424.07	71,418	0	9,728	9,728	61,690
6	2013	607,567	$0.0220	0	138	$445.31	74,734	0	10,203	10,203	64,531
7	2014	607,567	$0.0226	0	138	$467.73	78,225	0	10,711	10,711	67,514
8	2015	607,567	$0.0233	0	138	$491.40	81,900	0	11,254	11,254	70,647
9	2016	607,567	$0.0240	0	138	$516.39	85,770	0	11,833	11,833	73,938
10	2017	607,567	$0.0247	0	138	$542.78	89,845	0	12,451	12,451	77,394
11	2018	607,567	$0.0255	0	138	$570.64	94,137	0	13,111	13,111	81,026
12	2019	607,567	$0.0262	0	138	$600.05	98,655	0	13,815	13,815	84,841
13	2020	607,567	$0.0270	0	138	$631.11	103,414	0	14,565	14,565	88,850
14	2021	607,567	$0.0278	0	138	$663.90	108,427	0	15,364	15,364	93,062
15	2022	607,567	$0.0287	0	138	$698.51	113,706	0	16,216	16,216	97,490
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		8,505,940			1,930		$1,195,307	$143,989	$165,761	$309,750	$885,557
NPV =							661,942	125,842	91,401	217,243	444,699

Total NPV = $444,699
Benefit/Cost Ratio = 3.05

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial High Efficiency Motors**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$3,838	$0	$16,072	$19,910	$47,996	$47,996	($28,086)
2009	7,907	0	33,715	41,622	47,996	47,996	(6,375)
2010	12,216	0	53,059	65,275	47,996	47,996	17,279
2011	12,582	0	55,685	68,268	0	0	68,268
2012	12,960	0	58,458	71,418	0	0	71,418
2013	13,349	0	61,385	74,734	0	0	74,734
2014	13,749	0	64,476	78,225	0	0	78,225
2015	14,162	0	67,739	81,900	0	0	81,900
2016	14,586	0	71,184	85,770	0	0	85,770
2017	15,024	0	74,821	89,845	0	0	89,845
2018	15,475	0	78,662	94,137	0	0	94,137
2019	15,939	0	82,716	98,655	0	0	98,655
2020	16,417	0	86,997	103,414	0	0	103,414
2021	16,910	0	91,517	108,427	0	0	108,427
2022	17,417	0	96,289	113,706	0	0	113,706
2023	0	0	0	0	0	0	0
Total =	$202,530	$0	$992,778	$1,195,307	$143,989	$143,989	$1,051,318
NPV =	114,267	0	547,675	661,942	125,842	125,842	536,100

Total NPV = $536,100

Benefit/Cost Ratio = 5.26

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$3,838	$0	$16,072	$3,076	$22,986	$47,996	$156,254	$28,167	$176,083	($153,096)
2009	$7,907	$0	$33,715	$6,623	48,245	47,996	156,254	$28,167	176,083	(127,838)
2010	$12,216	$0	$53,059	$10,699	75,975	47996.231	156,254	$28,167	176,083	(100,108)
2011	$12,582	$0	$55,685	$11,525	79,793	0	0	$0	0	79,793
2012	$12,960	$0	$58,458	$12,419	83,837	0	0	$0	0	83,837
2013	$13,349	$0	$61,385	$13,385	88,119	0	0	$0	0	88,119
2014	$13,749	$0	$64,476	$14,431	92,656	0	0	$0	0	92,656
2015	$14,162	$0	$67,739	$15,562	97,463	0	0	$0	0	97,463
2016	$14,586	$0	$71,184	$16,787	102,557	0	0	$0	0	102,557
2017	$15,024	$0	$74,821	$18,112	107,957	0	0	$0	0	107,957
2018	$15,475	$0	$78,662	$19,546	113,683	0	0	$0	0	113,683
2019	$15,939	$0	$82,716	$21,099	119,754	0	0	$0	0	119,754
2020	$16,417	$0	$86,997	$22,780	126,195	0	0	$0	0	126,195
2021	$16,910	$0	$91,517	$24,601	133,028	0	0	$0	0	133,028
2022	$17,417	$0	$96,289	$26,573	140,279	0	0	$0	0	140,279
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$202,530	$0	$992,778	$237,219	$1,432,526	$143,989	$468,762	$84,502	$528,249	$904,277
NPV =	114,267	0	547,675	151,861	813,803	125,842	409,685	73,852	461,675	352,127

Total NPV = $352,127
Benefit/Cost Ratio = 1.76

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0062	$28,167	62,594	125,188	$0.045	$0.045	14	28	$47.41	$69.46	$39,235	$156,254	$0	$156,254	($117,018)
2009	0.0123	$28,167	125,188	250,375	$0.047	$0.047	28	57	$50.05	$73.34	$51,539	156,254	$0	156,254	(104,715)
2010	0.0122	$28,167	187,782	375,563	$0.050	$0.050	43	85	$52.84	$77.43	$65,181	156,254	$0	156,254	(91,073)
2011	0.0122	$0	187,782	375,563	$0.053	$0.053	43	85	$55.79	$81.75	$39,079	0	$0	0	39,079
2012	0.0121	$0	187,782	375,563	$0.056	$0.056	43	85	$58.91	$86.31	$41,260	0	$0	0	41,260
2013	0.0120	0	187,782	375,563	$0.059	$0.059	43	85	$62.19	$91.13	$43,562	0	$0	0	43,562
2014	0.0119	0	187,782	375,563	$0.062	$0.062	43	85	$65.66	$96.21	$45,993	0	$0	0	45,993
2015	0.0118	0	187,782	375,563	$0.066	$0.066	43	85	$69.33	$101.58	$48,559	0	$0	0	48,559
2016	0.0117	0	187,782	375,563	$0.069	$0.069	43	85	$73.19	$107.25	$51,269	0	$0	0	51,269
2017	0.0117	0	187,782	375,563	$0.073	$0.073	43	85	$77.28	$113.23	$54,130	0	$0	0	54,130
2018	0.0116	0	187,782	375,563	$0.077	$0.077	43	85	$81.59	$119.55	$57,150	0	$0	0	57,150
2019	0.0115	0	187,782	375,563	$0.082	$0.082	43	85	$86.14	$126.22	$60,339	0	$0	0	60,339
2020	0.0114	0	187,782	375,563	$0.086	$0.086	43	85	$90.95	$133.27	$63,706	0	$0	0	63,706
2021	0.0113	0	187,782	375,563	$0.091	$0.091	43	85	$96.03	$140.70	$67,261	0	$0	0	67,261
2022	0.0113	0	187,782	375,563	$0.096	$0.096	43	85	$101.38	$148.55	$71,014	0	$0	0	71,014
2023	0.0112	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			2,628,942	5,257,883							$799,276	$468,762	$0	$468,762	$330,514
											$498,936	438,568	0	438,568	60,368

Total NPV = $60,368
Benefit/Cost Ratio = 1.14

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$21,837
Total Utility Project Costs Year 1 =	**$41,666**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$21,837
Total Utility Project Costs Year 2 =	**$41,666**
15b) Total Utilty Cost Year 3 =	**$41,666**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$300.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$ (35.00)
Escalation Rate =	3.00%
18) Project Life (Years) =	11
20) Avg Summer kW/part. Saved =	0.01
20a) Avg Winter kW/part Saved =	0.02
21) Avg. Summer kWh/Part. Saved =	99
21a) Avg. Winter kWh/Part. Saved =	198
22) Number of Participants (First Year) =	873
22a) Number of Participants (Second Year) =	873
22a) Number of Participants (Third Year) =	873
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 25.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Res E-STAR Clothes Washers w/ Elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	11
Total Progam Cost (Utility)	$124,998
Total Program Participants	2,620
Utility Cost per Participant (First Year) =	$47.70
Utility Cost per Participant (Program) =	$47.70
Total kW Reduction	78
Total Energy Reduction (kWh)	8,393,696
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$38,811	1.12
Ratepayer Test	$242,082	3.22
Societal Cost Test	$193,195	1.84
Participant Test	$406,781	3.12

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

		Cost of Energy Saved					Project Cost				
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	Cost of Energy Saved Less Project Cost (J)
1	2008	279,790	$0.0190	$0	26	$349.78	$14,430	$41,666	8,324	$49,990	($35,560)
2	2009	559,580	$0.0195	0	52	$366.87	30,070	41,666	17,329	58,995	(28,925)
3	2010	839,370	$0.0201	0	78	$384.91	47,009	41666.12	27,080	68,746	(21,737)
4	2011	839,370	$0.0207	0	78	$403.96	49,007	0	28,235	28,235	20,772
5	2012	839,370	$0.0213	0	78	$424.07	51,103	0	29,462	29,462	21,641
6	2013	839,370	$0.0220	0	78	$445.31	53,302	0	30,766	30,766	22,536
7	2014	839,370	$0.0226	0	78	$467.73	55,611	0	32,151	32,151	23,459
8	2015	839,370	$0.0233	0	78	$491.40	58,034	0	33,622	33,622	24,411
9	2016	839,370	$0.0240	0	78	$516.39	60,577	0	35,185	35,185	25,393
10	2017	839,370	$0.0247	0	78	$542.78	63,247	0	36,843	36,843	26,404
11	2018	839,370	$0.0255	0	78	$570.64	66,051	0	38,604	38,604	27,447
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		8,393,696			783		$548,441	$124,998	$317,602	$442,600	$105,841
NPV =							351,327	109,245	203,271	312,516	38,811

Total NPV = $38,811
Benefit/Cost Ratio = 1.12

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$5,303	$0	$9,127	$14,430	$41,666	$41,666	($27,236)
2009	10,923	0	19,147	30,070	41,666	41,666	(11,596)
2010	16,877	0	30,133	47,009	41,666	41,666	5,343
2011	17,383	0	31,624	49,007	0	0	49,007
2012	17,904	0	33,199	51,103	0	0	51,103
2013	18,441	0	34,861	53,302	0	0	53,302
2014	18,995	0	36,616	55,611	0	0	55,611
2015	19,565	0	38,469	58,034	0	0	58,034
2016	20,151	0	40,426	60,577	0	0	60,577
2017	20,756	0	42,491	63,247	0	0	63,247
2018	21,379	0	44,672	66,051	0	0	66,051
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$187,676	$0	$360,765	$548,441	$124,998	$124,998	$423,443
NPV =	121,125	0	230,202	351,327	109,245	109,245	242,082

Total NPV =	$242,082
Benefit/Cost Ratio =	3.22

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$5,303	$0	$9,127	$2,229	$16,659	$41,666	$230,556	$21,837	$250,385	($233,726)
2009	$10,923	$0	$19,147	$4,785	34,855	41,666	197,178	$21,837	217,007	(182,152)
2010	$16,877	$0	$30,133	$7,705	54,714	41666.121	195,232	$21,837	215,061	(160,346)
2011	$17,383	$0	$31,624	$8,274	57,280	0	(68,818)	$0	(68,818)	126,098
2012	$17,904	$0	$33,199	$8,886	59,989	0	(70,883)	$0	(70,883)	130,872
2013	$18,441	$0	$34,861	$9,547	62,849	0	(73,009)	$0	(73,009)	135,858
2014	$18,995	$0	$36,616	$10,259	65,870	0	(75,199)	$0	(75,199)	141,069
2015	$19,565	$0	$38,469	$11,027	69,061	0	(77,455)	$0	(77,455)	146,516
2016	$20,151	$0	$40,426	$11,856	72,433	0	(79,779)	$0	(79,779)	152,212
2017	$20,756	$0	$42,491	$12,750	75,997	0	(82,172)	$0	(82,172)	158,170
2018	$21,379	$0	$44,672	$13,715	79,766	0	(84,638)	$0	(84,638)	164,403
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$187,676	$0	$360,765	$101,033	$649,475	$124,998	$11,013	$65,511	$70,500	$578,975
NPV =	121,125	0	230,202	72,717	424,044	109,245	178,859	57,255	230,849	193,195

Total NPV = $193,195

Benefit/Cost Ratio = 1.84

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0100	$21,837	86,475	172,950	$0.074	$0.074	8	16	$0.00	$0.00	$41,125	$262,045	($31,489)	$230,556	($189,431)
2009	0.0196	$21,837	172,950	345,900	$0.078	$0.078	16	32	$0.00	$0.00	$62,566	262,045	($64,868)	197,178	(134,612)
2010	0.0193	$21,837	259,425	518,850	$0.083	$0.083	24	48	$0.00	$0.00	$86,339	262,045	($66,814)	195,232	(108,893)
2011	0.0190	$0	259,425	518,850	$0.088	$0.088	24	48	$0.00	$0.00	$68,101	0	($68,818)	(68,818)	136,919
2012	0.0187	$0	259,425	518,850	$0.092	$0.092	24	48	$0.00	$0.00	$71,901	0	($70,883)	(70,883)	142,784
2013	0.0184	0	259,425	518,850	$0.098	$0.098	24	48	$0.00	$0.00	$75,914	0	($73,009)	(73,009)	148,923
2014	0.0181	0	259,425	518,850	$0.103	$0.103	24	48	$0.00	$0.00	$80,149	0	($75,199)	(75,199)	155,349
2015	0.0179	0	259,425	518,850	$0.109	$0.109	24	48	$0.00	$0.00	$84,622	0	($77,455)	(77,455)	162,077
2016	0.0176	0	259,425	518,850	$0.115	$0.115	24	48	$0.00	$0.00	$89,344	0	($79,779)	(79,779)	169,123
2017	0.0173	0	259,425	518,850	$0.121	$0.121	24	48	$0.00	$0.00	$94,329	0	($82,172)	(82,172)	176,501
2018	0.0170	0	259,425	518,850	$0.128	$0.128	24	48	$0.00	$0.00	$99,593	0	($84,638)	(84,638)	184,230
2019	0.0168	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0165	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0162	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0160	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0157	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			2,594,250	5,188,500							$853,983	$786,136	($775,124)	$11,013	$842,971
											$598,249	735,500	(544,032)	191,468	406,781

Total NPV = $406,781
Benefit/Cost Ratio = 3.12

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$5,314
Total Utility Project Costs Year 1 =	**$25,143**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$5,314
Total Utility Project Costs Year 2 =	**$25,143**
15b) Total Utilty Cost Year 3 =	**$25,143**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$50.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	($3.00)
Escalation Rate =	3.00%
18) Project Life (Years) =	13
20) Avg Summer kW/part. Saved =	0.00
20a) Avg Winter kW/part Saved =	0.00
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	531
22a) Number of Participants (Second Year) =	531
22a) Number of Participants (Third Year) =	531
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 10.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Res E-STAR Dishwashers w/ Elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	13
Total Progam Cost (Utility)	$75,430
Total Program Participants	1,594
Utility Cost per Participant (First Year) =	$47.31
Utility Cost per Participant (Program) =	$47.31
Total kW Reduction	0
Total Energy Reduction (kWh)	1,485,638
Societal Cost per kwh	$0.06

Test Results

	NPV	B/C
Utility Test	($80,445)	0.20
Ratepayer Test	($45,245)	0.31
Societal Cost Test	($66,075)	0.28
Participant Test	$66,681	2.59

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	41,268	$0.0190	$0	0	$349.78	$782	$25,143	1,228	$26,371	($25,589)
2	2009	82,535	$0.0195	0	0	$366.87	1,611	25,143	2,556	27,699	(26,088)
3	2010	123,803	$0.0201	0	0	$384.91	2,489	25143.45	3,994	29,138	(26,648)
4	2011	123,803	$0.0207	0	0	$403.96	2,564	0	4,165	4,165	(1,601)
5	2012	123,803	$0.0213	0	0	$424.07	2,641	0	4,346	4,346	(1,705)
6	2013	123,803	$0.0220	0	0	$445.31	2,720	0	4,538	4,538	(1,818)
7	2014	123,803	$0.0226	0	0	$467.73	2,802	0	4,742	4,742	(1,941)
8	2015	123,803	$0.0233	0	0	$491.40	2,886	0	4,959	4,959	(2,073)
9	2016	123,803	$0.0240	0	0	$516.39	2,972	0	5,190	5,190	(2,217)
10	2017	123,803	$0.0247	0	0	$542.78	3,061	0	5,434	5,434	(2,373)
11	2018	123,803	$0.0255	0	0	$570.64	3,153	0	5,694	5,694	(2,541)
12	2019	123,803	$0.0262	0	0	$600.05	3,248	0	5,970	5,970	(2,722)
13	2020	123,803	$0.0270	0	0	$631.11	3,345	0	6,262	6,262	(2,917)
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		1,485,638			0		$34,275	$75,430	$59,076	$134,507	($100,232)
NPV =							20,679	65,924	35,200	101,124	(80,445)

Total NPV = ($80,445)

Benefit/Cost Ratio = 0.20

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$782	$0	$0	$782	$25,143	$25,143	($24,361)
2009	1,611	0	0	1,611	25,143	25,143	(23,532)
2010	2,489	0	0	2,489	25,143	25,143	(22,654)
2011	2,564	0	0	2,564	0	0	2,564
2012	2,641	0	0	2,641	0	0	2,641
2013	2,720	0	0	2,720	0	0	2,720
2014	2,802	0	0	2,802	0	0	2,802
2015	2,886	0	0	2,886	0	0	2,886
2016	2,972	0	0	2,972	0	0	2,972
2017	3,061	0	0	3,061	0	0	3,061
2018	3,153	0	0	3,153	0	0	3,153
2019	3,248	0	0	3,248	0	0	3,248
2020	3,345	0	0	3,345	0	0	3,345
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$34,275	$0	$0	$34,275	$75,430	$75,430	($41,156)
NPV =	20,679	0	0	20,679	65,924	65,924	(45,245)

Total NPV =	($45,245)
Benefit/Cost Ratio =	0.31

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$782	$0	$0	$121	$903	$25,143	$24,930	$5,314	$44,759	($43,856)
2009	$1,611	$0	$0	$256	1,868	25,143	23,189	$5,314	43,018	(41,151)
2010	$2,489	$0	$0	$408	2,897	25143.446	23,088	$5,314	42,917	(40,020)
2011	$2,564	$0	$0	$433	2,997	0	(3,589)	$0	(3,589)	6,586
2012	$2,641	$0	$0	$459	3,100	0	(3,697)	$0	(3,697)	6,797
2013	$2,720	$0	$0	$487	3,207	0	(3,807)	$0	(3,807)	7,015
2014	$2,802	$0	$0	$517	3,318	0	(3,922)	$0	(3,922)	7,240
2015	$2,886	$0	$0	$548	3,434	0	(4,039)	$0	(4,039)	7,473
2016	$2,972	$0	$0	$582	3,554	0	(4,160)	$0	(4,160)	7,714
2017	$3,061	$0	$0	$617	3,679	0	(4,285)	$0	(4,285)	7,964
2018	$3,153	$0	$0	$655	3,808	0	(4,414)	$0	(4,414)	8,222
2019	$3,248	$0	$0	$695	3,942	0	(4,546)	$0	(4,546)	8,489
2020	$3,345	$0	$0	$737	4,082	0	(4,683)	$0	(4,683)	8,765
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$34,275	$0	$0	$6,515	$40,789	$75,430	$30,065	$15,943	$89,552	($48,763)
NPV =	20,679	0	0	4,464	25,144	65,924	39,229	13,934	91,219	(66,075)

Total NPV = ($66,075)

Benefit/Cost Ratio = 0.28

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0061	$5,314	12,755	25,509	$0.074	$0.074	0	0	$0.00	$0.00	$8,159	$26,572	($1,642)	$24,930	($16,771)
2009	0.0120	$5,314	25,509	51,019	$0.078	$0.078	0	0	$0.00	$0.00	$11,322	26,572	($3,383)	23,189	(11,868)
2010	0.0118	$5,314	38,264	76,528	$0.083	$0.083	0	0	$0.00	$0.00	$14,828	26,572	($3,484)	23,088	(8,260)
2011	0.0116	$0	38,264	76,528	$0.088	$0.088	0	0	$0.00	$0.00	$10,045	0	($3,589)	(3,589)	13,634
2012	0.0114	$0	38,264	76,528	$0.092	$0.092	0	0	$0.00	$0.00	$10,605	0	($3,697)	(3,697)	14,302
2013	0.0112	0	38,264	76,528	$0.098	$0.098	0	0	$0.00	$0.00	$11,197	0	($3,807)	(3,807)	15,004
2014	0.0110	0	38,264	76,528	$0.103	$0.103	0	0	$0.00	$0.00	$11,822	0	($3,922)	(3,922)	15,743
2015	0.0109	0	38,264	76,528	$0.109	$0.109	0	0	$0.00	$0.00	$12,481	0	($4,039)	(4,039)	16,521
2016	0.0107	0	38,264	76,528	$0.115	$0.115	0	0	$0.00	$0.00	$13,178	0	($4,160)	(4,160)	17,338
2017	0.0105	0	38,264	76,528	$0.121	$0.121	0	0	$0.00	$0.00	$13,913	0	($4,285)	(4,285)	18,198
2018	0.0104	0	38,264	76,528	$0.128	$0.128	0	0	$0.00	$0.00	$14,689	0	($4,414)	(4,414)	19,103
2019	0.0102	0	38,264	76,528	$0.135	$0.135	0	0	$0.00	$0.00	$15,509	0	($4,546)	(4,546)	20,055
2020	0.0100	0	38,264	76,528	$0.143	$0.143	0	0	$0.00	$0.00	$16,375	0	($4,683)	(4,683)	21,057
2021	0.0099	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0097	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0096	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			459,168	918,336							$164,123	$79,717	($49,652)	$30,065	$134,058
											$108,676	74,582	(32,588)	41,994	66,681

Total NPV = $66,681
Benefit/Cost Ratio = 2.59

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$21,538
Total Utility Project Costs Year 1 =	**$41,367**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$21,538
Total Utility Project Costs Year 2 =	**$41,367**
15b) Total Utilty Cost Year 3 =	**$41,367**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$30.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.014
20a) Avg Winter kW/part Saved =	0.028
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	1,436
22a) Number of Participants (Second Year) =	1,436
22a) Number of Participants (Third Year) =	1,436
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$124,100
Total Program Participants	4,308
Utility Cost per Participant (First Year) =	$28.81
Utility Cost per Participant (Program) =	$28.81
Total kW Reduction	195
Total Energy Reduction (kWh)	4,682,858
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$621,004	3.86
Ratepayer Test	$729,660	7.73
Societal Cost Test	$865,777	6.25
Participant Test	$231,132	2.91

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential ENERGY STAR Refridgerators**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	111,497	$0.0190	$0	65	$349.78	$24,863	$41,367	3,317	$44,684	($19,821)
2	2009	222,993	$0.0195	0	130	$366.87	52,075	41,367	6,906	48,272	3,803
3	2010	334,490	$0.0201	0	195	$384.91	81,829	41366.75	10,791	52,158	29,671
4	2011	334,490	$0.0207	0	195	$403.96	85,748	0	11,252	11,252	74,496
5	2012	334,490	$0.0213	0	195	$424.07	89,880	0	11,741	11,741	78,139
6	2013	334,490	$0.0220	0	195	$445.31	94,237	0	12,260	12,260	81,977
7	2014	334,490	$0.0226	0	195	$467.73	98,833	0	12,812	12,812	86,020
8	2015	334,490	$0.0233	0	195	$491.40	103,678	0	13,399	13,399	90,280
9	2016	334,490	$0.0240	0	195	$516.39	108,789	0	14,021	14,021	94,768
10	2017	334,490	$0.0247	0	195	$542.78	114,178	0	14,682	14,682	99,496
11	2018	334,490	$0.0255	0	195	$570.64	119,862	0	15,384	15,384	104,478
12	2019	334,490	$0.0262	0	195	$600.05	125,857	0	16,128	16,128	109,729
13	2020	334,490	$0.0270	0	195	$631.11	132,180	0	16,919	16,919	115,261
14	2021	334,490	$0.0278	0	195	$663.90	138,848	0	17,757	17,757	121,091
15	2022	334,490	$0.0287	0	195	$698.51	145,882	0	18,647	18,647	127,235
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		4,682,858			2,732		$1,516,738	$124,100	$196,016	$320,116	$1,196,622
NPV =							838,121	108,460	108,656	217,116	621,004

Total NPV = $621,004

Benefit/Cost Ratio = 3.86

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential ENERGY STAR Refridgerators**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,113	$0	$22,749	$24,863	$41,367	$41,367	($16,504)
2009	4,353	0	47,722	52,075	41,367	41,367	10,708
2010	6,725	0	75,104	81,829	41,367	41,367	40,462
2011	6,927	0	78,821	85,748	0	0	85,748
2012	7,135	0	82,745	89,880	0	0	89,880
2013	7,349	0	86,888	94,237	0	0	94,237
2014	7,569	0	91,263	98,833	0	0	98,833
2015	7,796	0	95,882	103,678	0	0	103,678
2016	8,030	0	100,758	108,789	0	0	108,789
2017	8,271	0	105,907	114,178	0	0	114,178
2018	8,519	0	111,343	119,862	0	0	119,862
2019	8,775	0	117,082	125,857	0	0	125,857
2020	9,038	0	123,141	132,180	0	0	132,180
2021	9,309	0	129,539	138,848	0	0	138,848
2022	9,589	0	136,293	145,882	0	0	145,882
2023	0	0	0	0	0	0	0
Total =	$111,501	$0	$1,405,238	$1,516,738	$124,100	$124,100	$1,392,638
NPV =	62,909	0	775,212	838,121	108,460	108,460	729,660

Total NPV =	$729,660
Benefit/Cost Ratio =	7.73

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential ENERGY STAR Refridgerators**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,113	$0	$22,749	$3,841	$28,704	$41,367	$43,076	$21,538	$62,905	($34,201)
2009	$4,353	$0	$47,722	$8,287	60,362	41,367	43,076	$21,538	62,905	(2,543)
2010	$6,725	$0	$75,104	$13,412	95,241	41366.75	43,076	$21,538	62,905	32,337
2011	$6,927	$0	$78,821	$14,476	100,224	0	0	$0	0	100,224
2012	$7,135	$0	$82,745	$15,629	105,509	0	0	$0	0	105,509
2013	$7,349	$0	$86,888	$16,879	111,116	0	0	$0	0	111,116
2014	$7,569	$0	$91,263	$18,233	117,065	0	0	$0	0	117,065
2015	$7,796	$0	$95,882	$19,700	123,379	0	0	$0	0	123,379
2016	$8,030	$0	$100,758	$21,292	130,080	0	0	$0	0	130,080
2017	$8,271	$0	$105,907	$23,017	137,195	0	0	$0	0	137,195
2018	$8,519	$0	$111,343	$24,888	144,750	0	0	$0	0	144,750
2019	$8,775	$0	$117,082	$26,916	152,773	0	0	$0	0	152,773
2020	$9,038	$0	$123,141	$29,117	161,296	0	0	$0	0	161,296
2021	$9,309	$0	$129,539	$31,503	170,351	0	0	$0	0	170,351
2022	$9,589	$0	$136,293	$34,092	179,974	0	0	$0	0	179,974
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$111,501	$0	$1,405,238	$301,282	$1,818,021	$124,100	$129,227	$64,613	$188,714	$1,629,307
NPV =	62,909	0	775,212	192,587	1,030,707	108,460	112,941	56,470	164,931	865,777

Total NPV = $865,777

Benefit/Cost Ratio = 6.25

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0164	$21,538	34,460	68,921	$0.074	$0.074	20	40	$0.00	$0.00	$29,224	$43,076	$0	$43,076	($13,851)
2009	0.0323	$21,538	68,921	137,842	$0.078	$0.078	40	80	$0.00	$0.00	$37,768	43,076	$0	43,076	(5,307)
2010	0.0318	$21,538	103,381	206,762	$0.083	$0.083	60	121	$0.00	$0.00	$47,242	43,076	$0	43,076	4,166
2011	0.0313	$0	103,381	206,762	$0.088	$0.088	60	121	$0.00	$0.00	$27,138	0	$0	0	27,138
2012	0.0308	$0	103,381	206,762	$0.092	$0.092	60	121	$0.00	$0.00	$28,653	0	$0	0	28,653
2013	0.0303	0	103,381	206,762	$0.098	$0.098	60	121	$0.00	$0.00	$30,252	0	$0	0	30,252
2014	0.0298	0	103,381	206,762	$0.103	$0.103	60	121	$0.00	$0.00	$31,940	0	$0	0	31,940
2015	0.0294	0	103,381	206,762	$0.109	$0.109	60	121	$0.00	$0.00	$33,722	0	$0	0	33,722
2016	0.0289	0	103,381	206,762	$0.115	$0.115	60	121	$0.00	$0.00	$35,604	0	$0	0	35,604
2017	0.0284	0	103,381	206,762	$0.121	$0.121	60	121	$0.00	$0.00	$37,590	0	$0	0	37,590
2018	0.0280	0	103,381	206,762	$0.128	$0.128	60	121	$0.00	$0.00	$39,688	0	$0	0	39,688
2019	0.0276	0	103,381	206,762	$0.135	$0.135	60	121	$0.00	$0.00	$41,902	0	$0	0	41,902
2020	0.0271	0	103,381	206,762	$0.143	$0.143	60	121	$0.00	$0.00	$44,241	0	$0	0	44,241
2021	0.0267	0	103,381	206,762	$0.151	$0.151	60	121	$0.00	$0.00	$46,709	0	$0	0	46,709
2022	0.0263	0	103,381	206,762	$0.159	$0.159	60	121	$0.00	$0.00	$49,316	0	$0	0	49,316
2023	0.0259	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			1,447,337	2,894,674							$560,988	$129,227	$0	$129,227	$431,761
											$352,035	120,903	0	120,903	231,132

Total NPV = $231,132
Benefit/Cost Ratio = 2.91

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$16,771
Total Utility Project Costs Year 1 =	**$36,600**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$16,771
Total Utility Project Costs Year 2 =	**$36,600**
15b) Total Utilty Cost Year 3 =	**$36,600**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$33.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.012
20a) Avg Winter kW/part Saved =	0.023
21) Avg. Summer kWh/Part. Saved =	17
21a) Avg. Winter kWh/Part. Saved =	35
22) Number of Participants (First Year) =	1,118
22a) Number of Participants (Second Year) =	1,118
22a) Number of Participants (Third Year) =	1,118
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential ENERGY STAR Freezers**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$109,801
Total Program Participants	3,354
Utility Cost per Participant (First Year) =	$32.73
Utility Cost per Participant (Program) =	$32.73
Total kW Reduction	127
Total Energy Reduction (kWh)	2,633,613
Societal Cost per kwh	$0.06

Test Results

	NPV	B/C
Utility Test	$381,356	3.43
Ratepayer Test	$442,464	5.61
Societal Cost Test	$513,437	4.45
Participant Test	$107,497	2.04

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	62,705	$0.0190	$0	42	$349.78	$15,951	$36,600	1,866	$38,466	($22,515)
2	2009	125,410	$0.0195	0	84	$366.87	33,416	36,600	3,884	40,484	(7,068)
3	2010	188,115	$0.0201	0	127	$384.91	52,518	36600.45	6,069	42,670	9,849
4	2011	188,115	$0.0207	0	127	$403.96	55,044	0	6,328	6,328	48,716
5	2012	188,115	$0.0213	0	127	$424.07	57,707	0	6,603	6,603	51,104
6	2013	188,115	$0.0220	0	127	$445.31	60,516	0	6,895	6,895	53,621
7	2014	188,115	$0.0226	0	127	$467.73	63,479	0	7,206	7,206	56,274
8	2015	188,115	$0.0233	0	127	$491.40	66,604	0	7,535	7,535	59,069
9	2016	188,115	$0.0240	0	127	$516.39	69,900	0	7,885	7,885	62,015
10	2017	188,115	$0.0247	0	127	$542.78	73,376	0	8,257	8,257	65,119
11	2018	188,115	$0.0255	0	127	$570.64	77,043	0	8,652	8,652	68,392
12	2019	188,115	$0.0262	0	127	$600.05	80,911	0	9,071	9,071	71,841
13	2020	188,115	$0.0270	0	127	$631.11	84,992	0	9,515	9,515	75,477
14	2021	188,115	$0.0278	0	127	$663.90	89,296	0	9,987	9,987	79,309
15	2022	188,115	$0.0287	0	127	$698.51	93,836	0	10,487	10,487	83,349
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		2,633,613			1,773		$974,589	$109,801	$110,238	$220,040	$754,550
NPV =							538,428	95,963	61,108	157,071	381,356

Total NPV = $381,356
Benefit/Cost Ratio = 3.43

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test *This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.*

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,188	$0	$14,763	$15,951	$36,600	$36,600	($20,650)
2009	2,448	0	30,968	33,416	36,600	36,600	(3,185)
2010	3,782	0	48,736	52,518	36,600	36,600	15,918
2011	3,896	0	51,148	55,044	0	0	55,044
2012	4,013	0	53,695	57,707	0	0	57,707
2013	4,133	0	56,383	60,516	0	0	60,516
2014	4,257	0	59,222	63,479	0	0	63,479
2015	4,385	0	62,219	66,604	0	0	66,604
2016	4,516	0	65,384	69,900	0	0	69,900
2017	4,652	0	68,725	73,376	0	0	73,376
2018	4,791	0	72,252	77,043	0	0	77,043
2019	4,935	0	75,976	80,911	0	0	80,911
2020	5,083	0	79,908	84,992	0	0	84,992
2021	5,236	0	84,060	89,296	0	0	89,296
2022	5,393	0	88,443	93,836	0	0	93,836
2023	0	0	0	0	0	0	0
Total =	$62,707	$0	$911,882	$974,589	$109,801	$109,801	$864,788
NPV =	35,379	0	503,048	538,428	95,963	95,963	442,464

Total NPV = $442,464
Benefit/Cost Ratio = 5.61

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,188	$0	$14,763	$2,464	$18,415	$36,600	$36,897	$16,771	$56,726	($38,311)
2009	$2,448	$0	$30,968	$5,318	38,733	36,600	36,897	$16,771	56,726	(17,993)
2010	$3,782	$0	$48,736	$8,608	61,126	36600.446	36,897	$16,771	56,726	4,400
2011	$3,896	$0	$51,148	$9,293	64,337	0	0	$0	0	64,337
2012	$4,013	$0	$53,695	$10,035	67,742	0	0	$0	0	67,742
2013	$4,133	$0	$56,383	$10,839	71,355	0	0	$0	0	71,355
2014	$4,257	$0	$59,222	$11,711	75,190	0	0	$0	0	75,190
2015	$4,385	$0	$62,219	$12,656	79,260	0	0	$0	0	79,260
2016	$4,516	$0	$65,384	$13,681	83,581	0	0	$0	0	83,581
2017	$4,652	$0	$68,725	$14,792	88,168	0	0	$0	0	88,168
2018	$4,791	$0	$72,252	$15,997	93,040	0	0	$0	0	93,040
2019	$4,935	$0	$75,976	$17,304	98,215	0	0	$0	0	98,215
2020	$5,083	$0	$79,908	$18,722	103,713	0	0	$0	0	103,713
2021	$5,236	$0	$84,060	$20,260	109,556	0	0	$0	0	109,556
2022	$5,393	$0	$88,443	$21,929	115,765	0	0	$0	0	115,765
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$62,707	$0	$911,882	$193,608	$1,168,197	$109,801	$110,692	$50,314	$170,179	$998,018
NPV =	35,379	0	503,048	123,741	662,168	95,963	96,741	43,973	148,732	513,437

Total NPV = $513,437
Benefit/Cost Ratio = 4.45

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0128	$16,771	19,380	38,761	$0.074	$0.074	13	26	$0.00	$0.00	$21,094	$36,897	$0	$36,897	($15,803)
2009	0.0251	$16,771	38,761	77,521	$0.078	$0.078	26	52	$0.00	$0.00	$25,899	36,897	$0	36,897	(10,998)
2010	0.0247	$16,771	58,141	116,282	$0.083	$0.083	39	78	$0.00	$0.00	$31,227	36,897	$0	36,897	(5,670)
2011	0.0244	$0	58,141	116,282	$0.088	$0.088	39	78	$0.00	$0.00	$15,263	0	$0	0	15,263
2012	0.0240	$0	58,141	116,282	$0.092	$0.092	39	78	$0.00	$0.00	$16,114	0	$0	0	16,114
2013	0.0236	0	58,141	116,282	$0.098	$0.098	39	78	$0.00	$0.00	$17,013	0	$0	0	17,013
2014	0.0232	0	58,141	116,282	$0.103	$0.103	39	78	$0.00	$0.00	$17,963	0	$0	0	17,963
2015	0.0229	0	58,141	116,282	$0.109	$0.109	39	78	$0.00	$0.00	$18,965	0	$0	0	18,965
2016	0.0225	0	58,141	116,282	$0.115	$0.115	39	78	$0.00	$0.00	$20,023	0	$0	0	20,023
2017	0.0221	0	58,141	116,282	$0.121	$0.121	39	78	$0.00	$0.00	$21,141	0	$0	0	21,141
2018	0.0218	0	58,141	116,282	$0.128	$0.128	39	78	$0.00	$0.00	$22,320	0	$0	0	22,320
2019	0.0215	0	58,141	116,282	$0.135	$0.135	39	78	$0.00	$0.00	$23,566	0	$0	0	23,566
2020	0.0211	0	58,141	116,282	$0.143	$0.143	39	78	$0.00	$0.00	$24,881	0	$0	0	24,881
2021	0.0208	0	58,141	116,282	$0.151	$0.151	39	78	$0.00	$0.00	$26,269	0	$0	0	26,269
2022	0.0205	0	58,141	116,282	$0.159	$0.159	39	78	$0.00	$0.00	$27,735	0	$0	0	27,735
2023	0.0201	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			813,974	1,627,948							$329,473	$110,692	$0	$110,692	$218,781
											$211,058	103,562	0	103,562	107,497

Total NPV = $107,497
Benefit/Cost Ratio = 2.04

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$177,281
Total Utility Project Costs Year 1 =	**$197,110**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$177,281
Total Utility Project Costs Year 2 =	**$197,110**
15b) Total Utilty Cost Year 3 =	**$197,110**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,100.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.61
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	720
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	295
22a) Number of Participants (Second Year) =	295
22a) Number of Participants (Third Year) =	295
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 600.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$591,330
Total Program Participants	886
Utility Cost per Participant (First Year) =	$667.11
Utility Cost per Participant (Program) =	$667.11
Total kW Reduction	586
Total Energy Reduction (kWh)	9,636,358
Societal Cost per kwh	$0.09

Test Results

	NPV	B/C
Utility Test	$400,384	1.61
Ratepayer Test	$545,278	2.06
Societal Cost Test	$401,794	1.44
Participant Test	$185,363	1.20

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	229,437	$0.0190	$0	195	$140.17	$31,717	$197,110	6,486	$203,596	($171,879)
2	2009	458,874	$0.0195	0	391	$147.02	66,370	197,110	12,813	209,923	(143,552)
3	2010	688,311	$0.0201	0	586	$154.25	104,194	197110.0281	18,973	216,083	(111,889)
4	2011	688,311	$0.0207	0	586	$161.89	109,081	0	18,720	18,720	90,361
5	2012	688,311	$0.0213	0	586	$169.95	114,230	0	18,459	18,459	95,771
6	2013	688,311	$0.0220	0	586	$178.46	119,655	0	18,190	18,190	101,465
7	2014	688,311	$0.0226	0	586	$187.44	125,372	0	17,914	17,914	107,458
8	2015	688,311	$0.0233	0	586	$196.93	131,396	0	17,629	17,629	113,767
9	2016	688,311	$0.0240	0	586	$206.95	137,744	0	17,335	17,335	120,409
10	2017	688,311	$0.0247	0	586	$217.52	144,434	0	17,033	17,033	127,401
11	2018	688,311	$0.0255	0	586	$228.68	151,484	0	16,721	16,721	134,763
12	2019	688,311	$0.0262	0	586	$240.47	158,915	0	16,400	16,400	142,514
13	2020	688,311	$0.0270	0	586	$252.92	166,746	0	16,070	16,070	150,676
14	2021	688,311	$0.0278	0	586	$266.06	175,001	0	15,729	15,729	159,271
15	2022	688,311	$0.0287	0	586	$279.93	183,702	0	15,379	15,379	168,323
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		9,636,358			8,201		$1,920,041	$591,330	$243,851	$835,181	$1,084,860
NPV =							1,062,085	516,807	144,894	661,701	400,384

Total NPV = $400,384
Benefit/Cost Ratio = 1.61

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential High Efficiency Air Conditioning**

	Decreases			Increases			
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$4,348	$0	$27,369	$31,717	$197,110	$197,110	($165,393)
2009	8,957	0	57,413	66,370	197,110	197,110	(130,740)
2010	13,839	0	90,355	104,194	197,110	197,110	(92,916)
2011	14,254	0	94,826	109,081	0	0	109,081
2012	14,682	0	99,548	114,230	0	0	114,230
2013	15,123	0	104,533	119,655	0	0	119,655
2014	15,576	0	109,796	125,372	0	0	125,372
2015	16,044	0	115,352	131,396	0	0	131,396
2016	16,525	0	121,219	137,744	0	0	137,744
2017	17,021	0	127,413	144,434	0	0	144,434
2018	17,531	0	133,953	151,484	0	0	151,484
2019	18,057	0	140,857	158,915	0	0	158,915
2020	18,599	0	148,147	166,746	0	0	166,746
2021	19,157	0	155,844	175,001	0	0	175,001
2022	19,732	0	163,970	183,702	0	0	183,702
2023	0	0	0	0	0	0	0
Total =	$229,445	$0	$1,690,595	$1,920,041	$591,330	$591,330	$1,328,710
NPV =	129,453	0	932,632	1,062,085	516,807	516,807	545,278

Total NPV =	$545,278
Benefit/Cost Ratio =	2.06

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$4,348	$0	$27,369	$4,900	$36,618	$197,110	$325,015	$177,281	$344,844	($308,226)
2009	$8,957	$0	$57,413	$10,562	76,932	197,110	325,015	$177,281	344,844	(267,912)
2010	$13,839	$0	$90,355	$17,078	121,272	197110.03	325,015	$177,281	344,844	(223,572)
2011	$14,254	$0	$94,826	$18,416	127,497	0	0	$0	0	127,497
2012	$14,682	$0	$99,548	$19,864	134,094	0	0	$0	0	134,094
2013	$15,123	$0	$104,533	$21,431	141,086	0	0	$0	0	141,086
2014	$15,576	$0	$109,796	$23,129	148,501	0	0	$0	0	148,501
2015	$16,044	$0	$115,352	$24,967	156,363	0	0	$0	0	156,363
2016	$16,525	$0	$121,219	$26,959	164,703	0	0	$0	0	164,703
2017	$17,021	$0	$127,413	$29,116	173,550	0	0	$0	0	173,550
2018	$17,531	$0	$133,953	$31,453	182,937	0	0	$0	0	182,937
2019	$18,057	$0	$140,857	$33,986	192,901	0	0	$0	0	192,901
2020	$18,599	$0	$148,147	$36,731	203,477	0	0	$0	0	203,477
2021	$19,157	$0	$155,844	$39,706	214,707	0	0	$0	0	214,707
2022	$19,732	$0	$163,970	$42,930	226,632	0	0	$0	0	226,632
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$229,445	$0	$1,690,595	$381,228	$2,301,268	$591,330	$975,046	$531,843	$1,034,533	$1,266,736
NPV =	129,453	0	932,632	243,863	1,305,948	516,807	852,164	464,817	904,154	401,794

Total NPV = $401,794
Benefit/Cost Ratio = 1.44

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0034	$177,281	212,737	0	$0.074	$0.074	181	0	$0.00	$0.00	$193,098	$325,015	$0	$325,015	($131,917)
2009	0.0066	$177,281	425,474	0	$0.078	$0.078	362	0	$0.00	$0.00	$210,680	325,015	$0	325,015	(114,335)
2010	0.0065	$177,281	638,212	0	$0.083	$0.083	543	0	$0.00	$0.00	$230,175	325,015	$0	325,015	(94,840)
2011	0.0064	$0	638,212	0	$0.088	$0.088	543	0	$0.00	$0.00	$55,845	0	$0	0	55,845
2012	0.0063	$0	638,212	0	$0.092	$0.092	543	0	$0.00	$0.00	$58,962	0	$0	0	58,962
2013	0.0062	0	638,212	0	$0.098	$0.098	543	0	$0.00	$0.00	$62,252	0	$0	0	62,252
2014	0.0061	0	638,212	0	$0.103	$0.103	543	0	$0.00	$0.00	$65,725	0	$0	0	65,725
2015	0.0060	0	638,212	0	$0.109	$0.109	543	0	$0.00	$0.00	$69,393	0	$0	0	69,393
2016	0.0059	0	638,212	0	$0.115	$0.115	543	0	$0.00	$0.00	$73,265	0	$0	0	73,265
2017	0.0059	0	638,212	0	$0.121	$0.121	543	0	$0.00	$0.00	$77,353	0	$0	0	77,353
2018	0.0058	0	638,212	0	$0.128	$0.128	543	0	$0.00	$0.00	$81,669	0	$0	0	81,669
2019	0.0057	0	638,212	0	$0.135	$0.135	543	0	$0.00	$0.00	$86,226	0	$0	0	86,226
2020	0.0056	0	638,212	0	$0.143	$0.143	543	0	$0.00	$0.00	$91,038	0	$0	0	91,038
2021	0.0055	0	638,212	0	$0.151	$0.151	543	0	$0.00	$0.00	$96,118	0	$0	0	96,118
2022	0.0054	0	638,212	0	$0.159	$0.159	543	0	$0.00	$0.00	$101,481	0	$0	0	101,481
2023	0.0053	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			8,934,964	0							$1,553,280	$975,046	$0	$975,046	$578,234
											$1,097,605	912,242	0	912,242	185,363

Total NPV = $185,363
Benefit/Cost Ratio = 1.20

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$35,501
Total Utility Project Costs Year 1 =	**$55,330**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$35,501
Total Utility Project Costs Year 2 =	**$55,330**
15b) Total Utilty Cost Year 3 =	**$55,330**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,000.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.87
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	950
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	71
22a) Number of Participants (Second Year) =	71
22a) Number of Participants (Third Year) =	71
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 500.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial High Efficiency A/C**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$165,989
Total Program Participants	213
Utility Cost per Participant (First Year) =	$779.28
Utility Cost per Participant (Program) =	$779.28
Total kW Reduction	199
Total Energy Reduction (kWh)	3,055,336
Societal Cost per kwh	$0.08

Test Results

	NPV	B/C
Utility Test	$194,876	2.20
Ratepayer Test	$212,655	2.47
Societal Cost Test	$201,721	1.85
Participant Test	$125,669	1.63

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	72,746	$0.0190	$0	66	$140.17	$10,672	$55,330	907	$56,236	($45,564)
2	2009	145,492	$0.0195	0	133	$147.02	22,335	55,330	1,763	57,093	(34,758)
3	2010	218,238	$0.0201	0	199	$154.25	35,068	55329.62	2,567	57,897	(22,828)
4	2011	218,238	$0.0207	0	199	$161.89	36,718	0	2,487	2,487	34,232
5	2012	218,238	$0.0213	0	199	$169.95	38,457	0	2,404	2,404	36,053
6	2013	218,238	$0.0220	0	199	$178.46	40,289	0	2,319	2,319	37,971
7	2014	218,238	$0.0226	0	199	$187.44	42,220	0	2,231	2,231	39,989
8	2015	218,238	$0.0233	0	199	$196.93	44,255	0	2,141	2,141	42,115
9	2016	218,238	$0.0240	0	199	$206.95	46,400	0	2,047	2,047	44,352
10	2017	218,238	$0.0247	0	199	$217.52	48,660	0	1,952	1,952	46,709
11	2018	218,238	$0.0255	0	199	$228.68	51,043	0	1,853	1,853	49,190
12	2019	218,238	$0.0262	0	199	$240.47	53,554	0	1,751	1,751	51,803
13	2020	218,238	$0.0270	0	199	$252.92	56,201	0	1,646	1,646	54,555
14	2021	218,238	$0.0278	0	199	$266.06	58,992	0	1,538	1,538	57,453
15	2022	218,238	$0.0287	0	199	$279.93	61,933	0	1,427	1,427	60,506
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		3,055,336			2,785		$646,799	$165,989	$29,033	$195,022	$451,777
NPV =							357,725	145,070	17,779	162,849	194,876

Total NPV = $194,876
Benefit/Cost Ratio = 2.20

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial High Efficiency A/C**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,379	$0	$9,293	$10,672	$55,330	$55,330	($44,658)
2009	2,840	0	19,495	22,335	55,330	55,330	(32,995)
2010	4,388	0	30,680	35,068	55,330	55,330	(20,261)
2011	4,520	0	32,199	36,718	0	0	36,718
2012	4,655	0	33,802	38,457	0	0	38,457
2013	4,795	0	35,495	40,289	0	0	40,289
2014	4,939	0	37,282	42,220	0	0	42,220
2015	5,087	0	39,168	44,255	0	0	44,255
2016	5,239	0	41,161	46,400	0	0	46,400
2017	5,397	0	43,264	48,660	0	0	48,660
2018	5,559	0	45,484	51,043	0	0	51,043
2019	5,725	0	47,829	53,554	0	0	53,554
2020	5,897	0	50,304	56,201	0	0	56,201
2021	6,074	0	52,918	58,992	0	0	58,992
2022	6,256	0	55,677	61,933	0	0	61,933
2023	0	0	0	0	0	0	0
Total =	$72,749	$0	$574,050	$646,799	$165,989	$165,989	$480,810
NPV =	41,045	0	316,680	357,725	145,070	145,070	212,655

Total NPV =	$212,655
Benefit/Cost Ratio =	2.47

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,379	$0	$9,293	$1,649	$12,321	$55,330	$71,001	$35,501	$90,830	($78,509)
2009	$2,840	$0	$19,495	$3,554	25,889	55,330	71,001	$35,501	90,830	(64,941)
2010	$4,388	$0	$30,680	$5,748	40,816	55329.616	71,001	$35,501	90,830	(50,014)
2011	$4,520	$0	$32,199	$6,199	42,917	0	0	$0	0	42,917
2012	$4,655	$0	$33,802	$6,687	45,145	0	0	$0	0	45,145
2013	$4,795	$0	$35,495	$7,216	47,506	0	0	$0	0	47,506
2014	$4,939	$0	$37,282	$7,789	50,009	0	0	$0	0	50,009
2015	$5,087	$0	$39,168	$8,409	52,664	0	0	$0	0	52,664
2016	$5,239	$0	$41,161	$9,081	55,481	0	0	$0	0	55,481
2017	$5,397	$0	$43,264	$9,809	58,470	0	0	$0	0	58,470
2018	$5,559	$0	$45,484	$10,598	61,641	0	0	$0	0	61,641
2019	$5,725	$0	$47,829	$11,453	65,007	0	0	$0	0	65,007
2020	$5,897	$0	$50,304	$12,380	68,581	0	0	$0	0	68,581
2021	$6,074	$0	$52,918	$13,385	72,376	0	0	$0	0	72,376
2022	$6,256	$0	$55,677	$14,473	76,407	0	0	$0	0	76,407
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$72,749	$0	$574,050	$128,432	$775,231	$165,989	$213,004	$106,502	$272,491	$502,740
NPV =	41,045	0	316,680	82,146	439,871	145,070	186,160	93,080	238,150	201,721

Total NPV = $201,721
Benefit/Cost Ratio = 1.85

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0041	$35,501	67,451	0	$0.045	$0.045	61	0	$47.41	$69.46	$41,440	$71,001	$0	$71,001	($29,561)
2009	0.0082	$35,501	134,902	0	$0.047	$0.047	123	0	$50.05	$73.34	$48,042	71,001	$0	71,001	(22,959)
2010	0.0082	$35,501	202,354	0	$0.050	$0.050	184	0	$52.84	$77.43	$55,363	71,001	$0	71,001	(15,639)
2011	0.0081	$0	202,354	0	$0.053	$0.053	184	0	$55.79	$81.75	$20,970	0	$0	0	20,970
2012	0.0080	$0	202,354	0	$0.056	$0.056	184	0	$58.91	$86.31	$22,140	0	$0	0	22,140
2013	0.0080	0	202,354	0	$0.059	$0.059	184	0	$62.19	$91.13	$23,376	0	$0	0	23,376
2014	0.0079	0	202,354	0	$0.062	$0.062	184	0	$65.66	$96.21	$24,680	0	$0	0	24,680
2015	0.0079	0	202,354	0	$0.066	$0.066	184	0	$69.33	$101.58	$26,057	0	$0	0	26,057
2016	0.0078	0	202,354	0	$0.069	$0.069	184	0	$73.19	$107.25	$27,511	0	$0	0	27,511
2017	0.0078	0	202,354	0	$0.073	$0.073	184	0	$77.28	$113.23	$29,047	0	$0	0	29,047
2018	0.0077	0	202,354	0	$0.077	$0.077	184	0	$81.59	$119.55	$30,667	0	$0	0	30,667
2019	0.0077	0	202,354	0	$0.082	$0.082	184	0	$86.14	$126.22	$32,379	0	$0	0	32,379
2020	0.0076	0	202,354	0	$0.086	$0.086	184	0	$90.95	$133.27	$34,185	0	$0	0	34,185
2021	0.0076	0	202,354	0	$0.091	$0.091	184	0	$96.03	$140.70	$36,093	0	$0	0	36,093
2022	0.0075	0	202,354	0	$0.096	$0.096	184	0	$101.38	$148.55	$38,107	0	$0	0	38,107
2023	0.0075	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			2,832,949	0							$490,059	$213,004	$0	$213,004	$277,055
											$324,953	199,284	0	199,284	125,669

Total NPV = $125,669
Benefit/Cost Ratio = 1.63

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$1,169,321
Incentive Costs =	$322,462
Total Utility Project Costs Year 1 =	**$1,515,212**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$557,371
Incentive Costs =	$161,231
Total Utility Project Costs Year 2 =	**$742,031**
15b) Total Utilty Cost Year 3 =	**$742,031**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$0.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	1.00
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	360
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	3,324
22a) Number of Participants (Second Year) =	1,662
22a) Number of Participants (Third Year) =	1,662
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 97.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Air Conditioning Cycling T-Stat**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$2,999,275
Total Program Participants	6,649
Utility Cost per Participant (First Year) =	$455.79
Utility Cost per Participant (Program) =	$451.11
Total kW Reduction	7,151
Total Energy Reduction (kWh)	23,878,187
Societal Cost per kwh	$0.09

Test Results

	NPV	B/C
Utility Test	$5,136,144	2.66
Ratepayer Test	$5,571,012	3.09
Societal Cost Test	$7,800,551	4.72
Participant Test	$2,154,455	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	1,290,713	$0.0190	$0	3,575	$140.17	$525,623	$1,515,212	36,487	$1,551,699	($1,026,076)
2	2009	1,936,069	$0.0195	0	5,363	$147.02	826,264	742,031	54,059	796,090	30,174
3	2010	2,581,426	$0.0201	0	7,151	$154.25	1,154,902	742031.2218	71,157	813,188	341,714
4	2011	2,581,426	$0.0207	0	7,151	$161.89	1,211,049	0	70,207	70,207	1,140,842
5	2012	2,581,426	$0.0213	0	7,151	$169.95	1,270,289	0	69,228	69,228	1,201,060
6	2013	2,581,426	$0.0220	0	7,151	$178.46	1,332,793	0	68,221	68,221	1,264,572
7	2014	2,581,426	$0.0226	0	7,151	$187.44	1,398,742	0	67,183	67,183	1,331,559
8	2015	2,581,426	$0.0233	0	7,151	$196.93	1,468,327	0	66,114	66,114	1,402,213
9	2016	2,581,426	$0.0240	0	7,151	$206.95	1,541,749	0	65,013	65,013	1,476,737
10	2017	2,581,426	$0.0247	0	7,151	$217.52	1,619,222	0	63,879	63,879	1,555,344
11	2018	0	$0.0255	0	0	$228.68	0	0	0	0	0
12	2019	0	$0.0262	0	0	$240.47	0	0	0	0	0
13	2020	0	$0.0270	0	0	$252.92	0	0	0	0	0
14	2021	0	$0.0278	0	0	$266.06	0	0	0	0	0
15	2022	0	$0.0287	0	0	$279.93	0	0	0	0	0
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		23,878,187			66,143		$12,348,960	$2,999,275	$631,546	$3,630,821	$8,718,139
NPV =							8,238,820	2,667,809	434,868	3,102,677	5,136,144

Total NPV = $5,136,144
Benefit/Cost Ratio = 2.66

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Air Conditioning Cycling T-Stat**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$24,462	$0	$501,161	$525,623	$1,515,212	$1,515,212	($989,589)
2009	37,793	0	788,471	826,264	742,031	742,031	84,233
2010	51,903	0	1,103,000	1,154,902	742,031	742,031	412,871
2011	53,460	0	1,157,589	1,211,049	0	0	1,211,049
2012	55,063	0	1,215,225	1,270,289	0	0	1,270,289
2013	56,715	0	1,276,077	1,332,793	0	0	1,332,793
2014	58,417	0	1,340,325	1,398,742	0	0	1,398,742
2015	60,169	0	1,408,157	1,468,327	0	0	1,468,327
2016	61,974	0	1,479,775	1,541,749	0	0	1,541,749
2017	63,834	0	1,555,389	1,619,222	0	0	1,619,222
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$523,790	$0	$11,825,170	$12,348,960	$2,999,275	$2,999,275	$9,349,685
NPV =	352,716	0	7,886,104	8,238,820	2,667,809	2,667,809	5,571,012

Total NPV = $5,571,012

Benefit/Cost Ratio = 3.09

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential Air Conditioning Cycling T-Stat**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$24,462	$0	$501,161	$81,209	$606,832	$1,515,212	$0	$322,462	$1,192,750	($585,919)
2009	$37,793	$0	$788,471	$131,488	957,752	742,031	0	$161,231	580,800	376,952
2010	$51,903	$0	$1,103,000	$189,299	1,344,201	742031.22	0	$161,231	580,800	763,401
2011	$53,460	$0	$1,157,589	$204,457	1,415,506	0	0	$0	0	1,415,506
2012	$55,063	$0	$1,215,225	$220,892	1,491,181	0	0	$0	0	1,491,181
2013	$56,715	$0	$1,276,077	$238,714	1,571,506	0	0	$0	0	1,571,506
2014	$58,417	$0	$1,340,325	$258,041	1,656,783	0	0	$0	0	1,656,783
2015	$60,169	$0	$1,408,157	$279,005	1,747,332	0	0	$0	0	1,747,332
2016	$61,974	$0	$1,479,775	$301,745	1,843,494	0	0	$0	0	1,843,494
2017	$63,834	$0	$1,555,389	$326,415	1,945,637	0	0	$0	0	1,945,637
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$523,790	$0	$11,825,170	$2,231,264	$14,580,224	$2,999,275	$0	$644,924	$2,354,351	$12,225,873
NPV =	352,716	0	7,886,104	1,656,192	9,895,012	2,667,809	0	573,348	2,094,461	7,800,551

Total NPV = $7,800,551

Benefit/Cost Ratio = 4.72

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0380	$322,462	1,196,767	0	$0.074	$0.074	3,315	0	$0.00	$0.00	$411,441	$0	$0	$0	$411,441
2009	0.0561	$161,231	1,795,150	0	$0.078	$0.078	4,973	0	$0.00	$0.00	$302,147	0	$0	0	302,147
2010	0.0552	$161,231	2,393,533	0	$0.083	$0.083	6,630	0	$0.00	$0.00	$359,603	0	$0	0	359,603
2011	0.0543	$0	2,393,533	0	$0.088	$0.088	6,630	0	$0.00	$0.00	$209,441	0	$0	0	209,441
2012	0.0535	$0	2,393,533	0	$0.092	$0.092	6,630	0	$0.00	$0.00	$221,128	0	$0	0	221,128
2013	0.0526	0	2,393,533	0	$0.098	$0.098	6,630	0	$0.00	$0.00	$233,467	0	$0	0	233,467
2014	0.0518	0	2,393,533	0	$0.103	$0.103	6,630	0	$0.00	$0.00	$246,494	0	$0	0	246,494
2015	0.0510	0	2,393,533	0	$0.109	$0.109	6,630	0	$0.00	$0.00	$260,249	0	$0	0	260,249
2016	0.0502	0	2,393,533	0	$0.115	$0.115	6,630	0	$0.00	$0.00	$274,771	0	$0	0	274,771
2017	0.0494	0	2,393,533	0	$0.121	$0.121	6,630	0	$0.00	$0.00	$290,103	0	$0	0	290,103
2018	0.0486	0	0	0	$0.128	$0.128	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0478	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0471	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0463	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0456	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0449	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			22,140,182	0							$2,808,844	$0	$0	$0	$2,808,844
											$2,154,455	0	0	0	2,154,455

Total NPV = $2,154,455
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$98,658
Incentive Costs =	$38,877
Total Utility Project Costs Year 1 =	**$160,964**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$60,439
Incentive Costs =	$19,439
Total Utility Project Costs Year 2 =	**$103,307**
15b) Total Utilty Cost Year 3 =	**$103,307**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$ -
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	3.80
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	1,372
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	107
22a) Number of Participants (Second Year) =	53
22a) Number of Participants (Third Year) =	53
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 365.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial Air Conditioning Cycling T-Stat**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$367,577
Total Program Participants	213
Utility Cost per Participant (First Year) =	$1,511.22
Utility Cost per Participant (Program) =	$1,725.51
Total kW Reduction	873
Total Energy Reduction (kWh)	2,915,725
Societal Cost per kwh	$0.09

Test Results

	NPV	B/C
Utility Test	$659,698	2.90
Ratepayer Test	$681,307	3.10
Societal Cost Test	$952,666	4.73
Participant Test	$519,754	#DIV/0!

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	157,607	$0.0190	$0	437	$140.17	$64,183	$160,964	1,965	$162,928	($98,745)
2	2009	236,410	$0.0195	0	655	$147.02	100,894	103,307	2,865	106,172	(5,278)
3	2010	315,214	$0.0201	0	873	$154.25	141,023	103306.8	3,708	107,014	34,009
4	2011	315,214	$0.0207	0	873	$161.89	147,879	0	3,592	3,592	144,288
5	2012	315,214	$0.0213	0	873	$169.95	155,113	0	3,472	3,472	151,641
6	2013	315,214	$0.0220	0	873	$178.46	162,745	0	3,349	3,349	159,396
7	2014	315,214	$0.0226	0	873	$187.44	170,798	0	3,222	3,222	167,576
8	2015	315,214	$0.0233	0	873	$196.93	179,295	0	3,092	3,092	176,203
9	2016	315,214	$0.0240	0	873	$206.95	188,260	0	2,957	2,957	185,303
10	2017	315,214	$0.0247	0	873	$217.52	197,721	0	2,819	2,819	194,902
11	2018	0	$0.0255	0	0	$228.68	0	0	0	0	0
12	2019	0	$0.0262	0	0	$240.47	0	0	0	0	0
13	2020	0	$0.0270	0	0	$252.92	0	0	0	0	0
14	2021	0	$0.0278	0	0	$266.06	0	0	0	0	0
15	2022	0	$0.0287	0	0	$279.93	0	0	0	0	0
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		2,915,725			8,077		$1,507,911	$367,577	$31,040	$398,617	$1,109,293
NPV =							1,006,028	324,722	21,609	346,331	659,698

Total NPV = $659,698
Benefit/Cost Ratio = 2.90

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)
(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilitles Co.**

Project: **Commercial Air Conditioning Cycling T-Stat**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,987	$0	$61,196	$64,183	$160,964	$160,964	($96,781)
2009	4,615	0	96,279	100,894	103,307	103,307	(2,413)
2010	6,338	0	134,685	141,023	103,307	103,307	37,716
2011	6,528	0	141,351	147,879	0	0	147,879
2012	6,724	0	148,389	155,113	0	0	155,113
2013	6,925	0	155,820	162,745	0	0	162,745
2014	7,133	0	163,665	170,798	0	0	170,798
2015	7,347	0	171,948	179,295	0	0	179,295
2016	7,568	0	180,693	188,260	0	0	188,260
2017	7,795	0	189,926	197,721	0	0	197,721
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$63,959	$0	$1,443,952	$1,507,911	$367,577	$367,577	$1,140,333
NPV =	43,070	0	962,959	1,006,028	324,722	324,722	681,307

Total NPV = $681,307

Benefit/Cost Ratio = 3.10

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Commercial Air Conditioning Cycling T-Stat**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,987	$0	$61,196	$9,916	$74,099	$160,964	$0	$38,877	$122,087	($47,987)
2009	$4,615	$0	$96,279	$16,056	116,949	103,307	0	$19,439	83,868	33,081
2010	$6,338	$0	$134,685	$23,115	164,138	103306.79	0	$19,439	83,868	80,270
2011	$6,528	$0	$141,351	$24,966	172,845	0	0	$0	0	172,845
2012	$6,724	$0	$148,389	$26,973	182,086	0	0	$0	0	182,086
2013	$6,925	$0	$155,820	$29,149	191,894	0	0	$0	0	191,894
2014	$7,133	$0	$163,665	$31,509	202,307	0	0	$0	0	202,307
2015	$7,347	$0	$171,948	$34,069	213,364	0	0	$0	0	213,364
2016	$7,568	$0	$180,693	$36,846	225,106	0	0	$0	0	225,106
2017	$7,795	$0	$189,926	$39,858	237,578	0	0	$0	0	237,578
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$63,959	$0	$1,443,952	$272,456	$1,780,367	$367,577	$0	$77,754	$289,823	$1,490,543
NPV =	43,070	0	962,959	202,235	1,208,263	324,722	0	69,125	255,597	952,666

Total NPV = $952,666

Benefit/Cost Ratio = 4.73

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0062	$38,877	146,135	0	$0.045	$0.045	405	0	$47.41	$69.46	$64,621	$0	$0	$0	$64,621
2009	0.0092	$19,439	219,203	0	$0.047	$0.047	607	0	$50.05	$73.34	$60,209	0	$0	0	60,209
2010	0.0092	$19,439	292,270	0	$0.050	$0.050	810	0	$52.84	$77.43	$76,832	0	$0	0	76,832
2011	0.0091	$0	292,270	0	$0.053	$0.053	810	0	$55.79	$81.75	$60,596	0	$0	0	60,596
2012	0.0091	$0	292,270	0	$0.056	$0.056	810	0	$58.91	$86.31	$63,977	0	$0	0	63,977
2013	0.0090	0	292,270	0	$0.059	$0.059	810	0	$62.19	$91.13	$67,547	0	$0	0	67,547
2014	0.0089	0	292,270	0	$0.062	$0.062	810	0	$65.66	$96.21	$71,317	0	$0	0	71,317
2015	0.0089	0	292,270	0	$0.066	$0.066	810	0	$69.33	$101.58	$75,296	0	$0	0	75,296
2016	0.0088	0	292,270	0	$0.069	$0.069	810	0	$73.19	$107.25	$79,498	0	$0	0	79,498
2017	0.0087	0	292,270	0	$0.073	$0.073	810	0	$77.28	$113.23	$83,933	0	$0	0	83,933
2018	0.0087	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0086	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0086	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0085	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0084	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0084	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			2,703,500	0							$703,826	$0	$0	$0	$703,826
											$519,754	0	0	0	519,754

Total NPV = $519,754
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$23,558
Incentive Costs =	$10,994
Total Utility Project Costs Year 1 =	**$54,381**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$23,558
Incentive Costs =	$10,994
Total Utility Project Costs Year 2 =	**$54,381**
15b) Total Utilty Cost Year 3 =	**$54,381**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$ -
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	5
20) Avg Summer kW/part. Saved =	0.165
20a) Avg Winter kW/part Saved =	0.330
21) Avg. Summer kWh/Part. Saved =	389
21a) Avg. Winter kWh/Part. Saved =	777
22) Number of Participants (First Year) =	314
22a) Number of Participants (Second Year) =	314
22a) Number of Participants (Third Year) =	314
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 35.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Refridgerator Round Up**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	5
Total Progam Cost (Utility)	$163,142
Total Program Participants	942
Utility Cost per Participant (First Year) =	$173.13
Utility Cost per Participant (Program) =	$173.13
Total kW Reduction	503
Total Energy Reduction (kWh)	4,739,985
Societal Cost per kwh	$0.02

Test Results

	NPV	B/C
Utility Test	$437,340	2.64
Ratepayer Test	$560,769	4.93
Societal Cost Test	$714,715	7.28
Participant Test	$346,930	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	394,999	$0.0190	$0	168	$349.78	$66,169	$54,381	11,751	$66,132	$37
2	2009	789,997	$0.0195	0	336	$366.87	138,522	54,381	24,465	78,845	59,677
3	2010	1,184,996	$0.0201	0	503	$384.91	217,559	54380.72	38,231	92,612	124,947
4	2011	1,184,996	$0.0207	0	503	$403.96	227,862	0	39,861	39,861	188,001
5	2012	1,184,996	$0.0213	0	503	$424.07	238,721	0	41,594	41,594	197,127
6	2013	0	$0.0220	0	0	$445.31	0	0	0	0	0
7	2014	0	$0.0226	0	0	$467.73	0	0	0	0	0
8	2015	0	$0.0233	0	0	$491.40	0	0	0	0	0
9	2016	0	$0.0240	0	0	$516.39	0	0	0	0	0
10	2017	0	$0.0247	0	0	$542.78	0	0	0	0	0
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		4,739,985			2,013		$888,833	$163,142	$155,902	$319,044	$569,789
NPV =							703,351	142,582	123,430	266,012	437,340

Total NPV = $437,340
Benefit/Cost Ratio = 2.64

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Refridgerator Round Up**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$7,486	$0	$58,683	$66,169	$54,381	$54,381	$11,789
2009	15,421	0	123,101	138,522	54,381	54,381	84,141
2010	23,826	0	193,733	217,559	54,381	54,381	163,178
2011	24,541	0	203,321	227,862	0	0	227,862
2012	25,277	0	213,445	238,721	0	0	238,721
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$96,550	$0	$792,283	$888,833	$163,142	$163,142	$725,691
NPV =	76,538	0	626,813	703,351	142,582	142,582	560,769

Total NPV = $560,769

Benefit/Cost Ratio = 4.93

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$7,486	$0	$58,683	$10,223	$76,392	$54,381	$0	$10,994	$43,387	$33,006
2009	$15,421	$0	$123,101	$22,044	160,566	54,381	0	$10,994	43,387	117,179
2010	$23,826	$0	$193,733	$35,660	253,219	54380.72	0	$10,994	43,387	209,832
2011	$24,541	$0	$203,321	$38,469	266,331	0	0	$0	0	266,331
2012	$25,277	$0	$213,445	$41,512	280,233	0	0	$0	0	280,233
2013	$0	$0	$0	$0	0	0	0	$0	0	0
2014	$0	$0	$0	$0	0	0	0	$0	0	0
2015	$0	$0	$0	$0	0	0	0	$0	0	0
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$96,550	$0	$792,283	$147,907	$1,036,741	$163,142	$0	$32,981	$130,161	$906,580
NPV =	76,538	0	626,813	125,121	828,472	142,582	0	28,825	113,757	714,715

Total NPV = $714,715
Benefit/Cost Ratio = 7.28

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0036	$10,994	122,083	244,165	$0.074	$0.074	52	104	$0.00	$0.00	$38,224	$0	$0	$0	$38,224
2009	0.0071	$10,994	244,165	488,331	$0.078	$0.078	104	207	$0.00	$0.00	$68,493	0	$0	0	68,493
2010	0.0070	$10,994	366,248	732,496	$0.083	$0.083	156	311	$0.00	$0.00	$102,056	0	$0	0	102,056
2011	0.0068	$0	366,248	732,496	$0.088	$0.088	156	311	$0.00	$0.00	$96,143	0	$0	0	96,143
2012	0.0067	$0	366,248	732,496	$0.092	$0.092	156	311	$0.00	$0.00	$101,508	0	$0	0	101,508
2013	0.0066	0	0	0	$0.098	$0.098	0	0	$0.00	$0.00	$0	0	$0	0	0
2014	0.0065	0	0	0	$0.103	$0.103	0	0	$0.00	$0.00	$0	0	$0	0	0
2015	0.0064	0	0	0	$0.109	$0.109	0	0	$0.00	$0.00	$0	0	$0	0	0
2016	0.0063	0	0	0	$0.115	$0.115	0	0	$0.00	$0.00	$0	0	$0	0	0
2017	0.0062	0	0	0	$0.121	$0.121	0	0	$0.00	$0.00	$0	0	$0	0	0
2018	0.0061	0	0	0	$0.128	$0.128	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0060	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0059	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0058	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0057	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0057	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			1,464,993	2,929,986							$406,425	$0	$0	$0	$406,425
											$346,930	0	0	0	346,930

Total NPV = $346,930
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06987
1a) Retail Rate Winter ($/kWh) =	$0.03431
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5)Heating margin increase per cooling reduc ($/kW	$0.09
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System Demand Line loss factor	7.85%
14b) System Energy Line Loss Factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$65,723
Total Utility Project Costs Year 1 =	**$70,723**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$65,723
Total Utility Project Costs Year 2 =	**$70,723**
15b) Total Utilty Cost Year 3 =	**$70,723**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$4,000.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
17a) Other Participant Savings vs propane (Annual $/ Part)	$577.00
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.73
20a) Avg Winter kW/part Saved =	0.73
21) Avg. Summer kWh/Part. Saved =	889
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	60
22a) Number of Participants (Second Year) =	60
22a) Number of Participants (Third Year) =	60
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 1,100.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$212,170
Total Program Participants	179
Utility Cost per Participant (First Year) =	$1,183.68
Utility Cost per Participant (Program) =	$1,183.68
Total Summer kW Reduction	131
Total Winter kW Reduction	131
Total Summer Energy Reduction (kWh)	2,230,883
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.27

Test Results

	NPV	B/C
Utility Test	$1,092,084	5.84
Ratepayer Test	$972,234	6.24
Societal Cost Test	$784,151	2.23
Participant Test	$577,797	1.86

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	After Tax Added Margin Heating Load (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	57,286	$0.0190	$5,369	94	$349.78	$39,480	$70,723	1,776	$72,499	($33,019)
2	2009	114,572	$0.0195	11,061	189	$366.87	82,573	70,723	3,511	74,235	8,339
3	2010	171,858	$0.0201	17,089	283	$384.91	129,569	70,723	5,206	75,929	53,640
4	2011	171,858	$0.0207	17,602	283	$403.96	135,582	0	5,143	5,143	130,439
5	2012	171,858	$0.0213	18,130	283	$424.07	141,913	0	5,077	5,077	136,836
6	2013	171,858	$0.0220	18,674	283	$445.31	148,582	0	5,010	5,010	143,572
7	2014	171,858	$0.0226	19,234	283	$467.73	155,606	0	4,941	4,941	150,665
8	2015	171,858	$0.0233	19,811	283	$491.40	163,004	0	4,870	4,870	158,134
9	2016	171,858	$0.0240	20,405	283	$516.39	170,798	0	4,797	4,797	166,001
10	2017	171,858	$0.0247	21,018	283	$542.78	179,008	0	4,721	4,721	174,287
11	2018	171,858	$0.0255	21,648	283	$570.64	187,657	0	4,643	4,643	183,013
12	2019	171,858	$0.0262	22,298	283	$600.05	196,769	0	4,563	4,563	192,206
13	2020	171,858	$0.0270	22,966	283	$631.11	206,369	0	4,481	4,481	201,889
14	2021	171,858	$0.0278	23,655	283	$663.90	216,485	0	4,396	4,396	212,089
15	2022	171,858	$0.0287	24,365	283	$698.51	227,143	0	4,308	4,308	222,835
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		2,406,008			3,965		$2,380,539	$212,170	$67,444	$279,613	$2,100,925
NPV =							1,317,517	185,431	40,003	225,433	1,092,084

Total NPV = $1,092,084
Benefit/Cost Ratio = 5.84

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilitles Co.**

Project: **Residential Ground Source Heat Pump**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,086	$0	$33,024	$34,110	$70,723	$70,723	($36,613)
2009	2,237	0	69,276	71,513	70,723	70,723	789
2010	3,455	0	109,025	112,480	70,723	70,723	41,757
2011	3,559	0	114,421	117,980	0	0	117,980
2012	3,666	0	120,118	123,783	0	0	123,783
2013	3,776	0	126,132	129,908	0	0	129,908
2014	3,889	0	132,483	136,372	0	0	136,372
2015	4,006	0	139,188	143,193	0	0	143,193
2016	4,126	0	146,267	150,393	0	0	150,393
2017	4,250	0	153,741	157,990	0	0	157,990
2018	4,377	0	161,632	166,009	0	0	166,009
2019	4,509	0	169,963	174,471	0	0	174,471
2020	4,644	0	178,759	183,403	0	0	183,403
2021	4,783	0	188,046	192,829	0	0	192,829
2022	4,927	0	197,851	202,778	0	0	202,778
2023	0	0	0	0	0	0	0
Total =	$57,288	$0	$2,039,925	$2,097,213	$212,170	$212,170	$1,885,043
NPV =	32,322	0	1,125,343	1,157,665	185,431	185,431	972,234

Total NPV = $972,234

Benefit/Cost Ratio = 6.24

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential Ground Source Heat Pump**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,086	$0	$33,024	$5,270	$39,380	$70,723	$238,993	$65,723	$243,993	($204,613)
2009	$2,237	$0	$69,276	$11,380	82,893	70,723	238,993	$65,723	243,993	(161,101)
2010	$3,455	$0	$109,025	$18,437	130,917	70,723	238,993	$65,723	243,993	(113,077)
2011	$3,559	$0	$114,421	$19,918	137,898	0	0	$0	0	137,898
2012	$3,666	$0	$120,118	$21,525	145,308	0	0	$0	0	145,308
2013	$3,776	$0	$126,132	$23,268	153,176	0	0	$0	0	153,176
2014	$3,889	$0	$132,483	$25,158	161,530	0	0	$0	0	161,530
2015	$4,006	$0	$139,188	$27,209	170,402	0	0	$0	0	170,402
2016	$4,126	$0	$146,267	$29,434	179,827	0	0	$0	0	179,827
2017	$4,250	$0	$153,741	$31,849	189,839	0	0	$0	0	189,839
2018	$4,377	$0	$161,632	$34,469	200,478	0	0	$0	0	200,478
2019	$4,509	$0	$169,963	$37,313	211,785	0	0	$0	0	211,785
2020	$4,644	$0	$178,759	$40,400	223,803	0	0	$0	0	223,803
2021	$4,783	$0	$188,046	$43,751	236,580	0	0	$0	0	236,580
2022	$4,927	$0	$197,851	$47,388	250,166	0	0	$0	0	250,166
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$57,288	$0	$2,039,925	$416,769	$2,513,981	$212,170	$716,980	$197,170	$731,980	$1,782,001
NPV =	32,322	0	1,125,343	266,218	1,423,883	185,431	626,622	172,321	639,731	784,151

Total NPV = $784,151

Benefit/Cost Ratio = 2.23

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0007	$65,723	53,116	0	$0.079	$0.042	44	44	$0.00	$0.00	$104,417	$238,993	$0	$238,993	($134,576)
2009	0.0013	$65,723	106,233	0	$0.084	$0.044	88	88	$0.00	$0.00	$143,583	238,993	$0	238,993	(95,411)
2010	0.0013	$65,723	159,349	0	$0.089	$0.047	131	131	$0.00	$0.00	$183,258	238,993	$0	238,993	(55,735)
2011	0.0013	$0	159,349	0	$0.093	$0.049	131	131	$0.00	$0.00	$118,322	0	$0	0	118,322
2012	0.0013	$0	159,349	0	$0.099	$0.052	131	131	$0.00	$0.00	$119,154	0	$0	0	119,154
2013	0.0013	0	159,349	0	$0.104	$0.055	131	131	$0.00	$0.00	$120,031	0	$0	0	120,031
2014	0.0012	0	159,349	0	$0.110	$0.058	131	131	$0.00	$0.00	$120,958	0	$0	0	120,958
2015	0.0012	0	159,349	0	$0.116	$0.061	131	131	$0.00	$0.00	$121,936	0	$0	0	121,936
2016	0.0012	0	159,349	0	$0.123	$0.065	131	131	$0.00	$0.00	$122,969	0	$0	0	122,969
2017	0.0012	0	159,349	0	$0.129	$0.068	131	131	$0.00	$0.00	$124,060	0	$0	0	124,060
2018	0.0012	0	159,349	0	$0.137	$0.072	131	131	$0.00	$0.00	$125,211	0	$0	0	125,211
2019	0.0011	0	159,349	0	$0.144	$0.076	131	131	$0.00	$0.00	$126,427	0	$0	0	126,427
2020	0.0011	0	159,349	0	$0.152	$0.080	131	131	$0.00	$0.00	$127,711	0	$0	0	127,711
2021	0.0011	0	159,349	0	$0.161	$0.085	131	131	$0.00	$0.00	$129,066	0	$0	0	129,066
2022	0.0011	0	159,349	0	$0.170	$0.090	131	131	$0.00	$0.00	$130,496	0	$0	0	130,496
2023	0.0011	0	0	0	$0.179	$0.095	0	0	$0.00	$0.00	$0	0	$0	0	0
			2,230,883	0							$1,917,599	$716,980	$0	$716,980	$1,200,619
											$1,248,595	670,798	0	670,798	577,797

Total NPV = $577,797
Benefit/Cost Ratio = 1.86

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$62,715
Total Utility Project Costs Year 1 =	**$82,544**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$62,715
Total Utility Project Costs Year 2 =	**$82,544**
15b) Total Utilty Cost Year 3 =	**$82,544**
15c) Total Utilty Cost Year 4 =	**$82,544**
15d) Total Utility Cost Year 5 =	**$82,544**
16) Direct Participant Costs ($/Part.) =	$ 920.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0.29
20a) Avg Winter kW/part Saved =	0.57
21) Avg. Summer kWh/Part. Saved =	715
21a) Avg. Winter kWh/Part. Saved =	1,430
22) Number of Participants (First Year) =	341
22a) Number of Participants (Second Year) =	341
22a) Number of Participants (Third Year) =	341
22a) Number of Participants (Fourth Year) =	341
22a) Number of Participants (Fifth Year) =	341
23) Incentive/Participant (All) =	$ 184.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$412,718
Total Program Participants	1,704
Utility Cost per Participant (First Year) =	$242.18
Utility Cost per Participant (Program) =	$242.18
Total kW Reduction	1,577
Total Energy Reduction (kWh)	31,536,056
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$3,480,430	6.05
Ratepayer Test	$3,831,127	12.33
Societal Cost Test	$3,664,192	3.68
Participant Test	$793,455	1.58

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	788,401	$0.0190	$0	315	$349.78	$125,248	$82,544	10,533	$93,076	$32,172
2	2009	1,576,803	$0.0195	0	631	$366.87	262,172	82,544	22,007	104,550	157,621
3	2010	2,365,204	$0.0201	0	946	$384.91	411,713	82543.56	34,522	117,065	294,647
4	2011	3,153,606	$0.0207	0	1,261	$403.96	574,883	82543.56	48,186	130,730	444,154
5	2012	3,942,007	$0.0213	0	1,577	$424.07	752,768	82543.56	63,117	145,660	607,107
6	2013	3,942,007	$0.0220	0	1,577	$445.31	788,774	0	66,200	66,200	722,574
7	2014	3,942,007	$0.0226	0	1,577	$467.73	826,725	0	69,496	69,496	757,229
8	2015	3,942,007	$0.0233	0	1,577	$491.40	866,726	0	73,016	73,016	793,710
9	2016	3,942,007	$0.0240	0	1,577	$516.39	908,890	0	76,774	76,774	832,116
10	2017	3,942,007	$0.0247	0	1,577	$542.78	953,336	0	80,786	80,786	872,550
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		31,536,056			12,614		$6,471,235	$412,718	$544,637	$957,355	$5,513,880
NPV =							4,169,119	337,992	350,697	688,689	3,480,430

Total NPV = $3,480,430
Benefit/Cost Ratio = 6.05

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$14,942	$0	$110,306	$125,248	$82,544	$82,544	$42,705
2009	30,780	0	231,391	262,172	82,544	82,544	179,628
2010	47,555	0	364,158	411,713	82,544	82,544	329,169
2011	65,309	0	509,574	574,883	82543.56	82,544	492,340
2012	84,086	0	668,682	752,768	82543.56	82,544	670,224
2013	86,608	0	702,166	788,774	0	0	788,774
2014	89,206	0	737,518	826,725	0	0	826,725
2015	91,883	0	774,844	866,726	0	0	866,726
2016	94,639	0	814,251	908,890	0	0	908,890
2017	97,478	0	855,858	953,336	0	0	953,336
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$702,486	$0	$5,768,749	$6,471,235	$412,718	$412,718	$6,058,517
NPV =	455,906	0	3,713,213	4,169,119	337,992	337,992	3,831,127

Total NPV = $3,831,127

Benefit/Cost Ratio = 12.33

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$14,942	$0	$110,306	$19,351	$144,599	$82,544	$313,573	$62,715	$333,402	($188,803)
2009	$30,780	$0	$231,391	$41,721	303,892	82,544	313,573	$62,715	333,402	(29,510)
2010	$47,555	$0	$364,158	$67,483	479,196	82543.56	313,573	$62,715	333,402	145,794
2011	$65,309	$0	$509,574	$97,055	671,939	82543.56	313,573	$62,715	333,402	338,537
2012	$84,086	$0	$668,682	$130,900	883,667	82543.56	313,573	$62,715	333,402	550,265
2013	$86,608	$0	$702,166	$141,276	930,050	0	0	$0	0	930,050
2014	$89,206	$0	$737,518	$152,515	979,240	0	0	$0	0	979,240
2015	$91,883	$0	$774,844	$164,691	1,031,417	0	0	$0	0	1,031,417
2016	$94,639	$0	$814,251	$177,884	1,086,775	0	0	$0	0	1,086,775
2017	$97,478	$0	$855,858	$192,181	1,145,517	0	0	$0	0	1,145,517
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$702,486	$0	$5,768,749	$1,185,057	$7,656,292	$412,718	$1,567,864	$313,573	$1,667,009	$5,989,283
NPV =	455,906	0	3,713,213	860,258	5,029,377	337,992	1,283,991	256,798	1,365,185	3,664,192

Total NPV = $3,664,192

Benefit/Cost Ratio = 3.68

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0199	$62,715	243,672	487,344	$0.045	$0.045	97	195	$47.41	$69.46	$113,662	$313,573	$0	$313,573	($199,911)
2009	0.0394	$62,715	487,344	974,689	$0.047	$0.047	195	390	$50.05	$73.34	$170,295	313,573	$0	313,573	(143,277)
2010	0.0392	$62,715	731,017	1,462,033	$0.050	$0.050	292	585	$52.84	$77.43	$233,090	313,573	$0	313,573	(80,483)
2011	0.0389	$62,715	974,689	1,949,378	$0.053	$0.053	390	780	$55.79	$81.75	$302,558	313,573	$0	313,573	(11,015)
2012	0.0386	$62,715	1,218,361	2,436,722	$0.056	$0.056	487	975	$58.91	$86.31	$379,248	313,573	$0	313,573	65,675
2013	0.0384	0	1,218,361	2,436,722	$0.059	$0.059	487	975	$62.19	$91.13	$334,196	0	$0	0	334,196
2014	0.0381	0	1,218,361	2,436,722	$0.062	$0.062	487	975	$65.66	$96.21	$352,844	0	$0	0	352,844
2015	0.0378	0	1,218,361	2,436,722	$0.066	$0.066	487	975	$69.33	$101.58	$372,533	0	$0	0	372,533
2016	0.0376	0	1,218,361	2,436,722	$0.069	$0.069	487	975	$73.19	$107.25	$393,320	0	$0	0	393,320
2017	0.0373	0	1,218,361	2,436,722	$0.073	$0.073	487	975	$77.28	$113.23	$415,267	0	$0	0	415,267
2018	0.0370	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0368	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0365	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0363	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0360	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0358	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			9,746,888	19,493,776							$3,067,015	$1,567,864	$0	$1,567,864	$1,499,151
											$2,167,968	1,374,512	0	1,374,512	793,455

Total NPV = $793,455
Benefit/Cost Ratio = 1.58

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$4,261
Total Utility Project Costs Year 1 =	**$24,090**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$4,261
Total Utility Project Costs Year 2 =	**$24,090**
15b) Total Utilty Cost Year 3 =	**$24,090**
15c) Total Utilty Cost Year 4 =	**$24,090**
15d) Total Utility Cost Year 5 =	**$24,090**
16) Direct Participant Costs ($/Part.) =	$ 250.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0.05
20a) Avg Winter kW/part Saved =	0.09
21) Avg. Summer kWh/Part. Saved =	394
21a) Avg. Winter kWh/Part. Saved =	788
22) Number of Participants (First Year) =	170
22a) Number of Participants (Second Year) =	170
22a) Number of Participants (Third Year) =	170
22a) Number of Participants (Fourth Year) =	170
22a) Number of Participants (Fifth Year) =	170
23) Incentive/Participant (All) =	$ 25.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$120,448
Total Program Participants	852
Utility Cost per Participant (First Year) =	$141.35
Utility Cost per Participant (Program) =	$141.35
Total kW Reduction	124
Total Energy Reduction (kWh)	8,694,379
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$222,524	2.14
Ratepayer Test	$319,210	4.24
Societal Cost Test	$248,319	1.97
Participant Test	$220,883	2.18

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **LED Exit Signs (Incandescent Model)**

		Cost of Energy Saved				Project Cost					Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	217,359	$0.0190	$0	25	$349.78	$12,798	$24,090	2,904	$26,993	($14,195)
2	2009	434,719	$0.0195	0	50	$366.87	26,692	24,090	6,067	30,157	(3,465)
3	2010	652,078	$0.0201	0	74	$384.91	41,763	24089.5	9,518	33,607	8,156
4	2011	869,438	$0.0207	0	99	$403.96	58,099	24089.5	13,285	37,374	20,725
5	2012	1,086,797	$0.0213	0	124	$424.07	75,794	24089.5	17,401	41,491	34,304
6	2013	1,086,797	$0.0220	0	124	$445.31	79,124	0	18,251	18,251	60,873
7	2014	1,086,797	$0.0226	0	124	$467.73	82,622	0	19,160	19,160	63,462
8	2015	1,086,797	$0.0233	0	124	$491.40	86,297	0	20,130	20,130	66,167
9	2016	1,086,797	$0.0240	0	124	$516.39	90,157	0	21,166	21,166	68,991
10	2017	1,086,797	$0.0247	0	124	$542.78	94,214	0	22,272	22,272	71,941
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		8,694,379			993		$647,561	$120,448	$150,155	$270,602	$376,959
NPV =							417,849	98,640	96,686	195,325	222,524

Total NPV = $222,524

Benefit/Cost Ratio = 2.14

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **LED Exit Signs (Incandescent Model)**

		Decreases				Increases		
	Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
	2008	$4,119	$0	$8,679	$12,798	$24,090	$24,090	($11,291)
	2009	8,486	0	18,206	26,692	24,090	24,090	2,602
	2010	13,111	0	28,652	41,763	24,090	24,090	17,673
	2011	18,006	0	40,094	58,099	24089.5	24,090	34,010
	2012	23,182	0	52,612	75,794	24089.5	24,090	51,705
	2013	23,878	0	55,247	79,124	0	0	79,124
	2014	24,594	0	58,028	82,622	0	0	82,622
	2015	25,332	0	60,965	86,297	0	0	86,297
	2016	26,092	0	64,066	90,157	0	0	90,157
	2017	26,874	0	67,339	94,214	0	0	94,214
	2018	0	0	0	0	0	0	0
	2019	0	0	0	0	0	0	0
	2020	0	0	0	0	0	0	0
	2021	0	0	0	0	0	0	0
	2022	0	0	0	0	0	0	0
	2023	0	0	0	0	0	0	0
Total =		$193,673	$0	$453,888	$647,561	$120,448	$120,448	$527,113
NPV =		125,692	0	292,157	417,849	98,640	98,640	319,210

Total NPV =	$319,210
Benefit/Cost Ratio =	4.24

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **LED Exit Signs (Incandescent Model)**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$4,119	$0	$8,679	$1,977	$14,776	$24,090	$42,605	$4,261	$62,434	($47,658)
2009	$8,486	$0	$18,206	$4,248	30,940	24,090	42,605	$4,261	62,434	(31,494)
2010	$13,111	$0	$28,652	$6,845	48,608	24089.5	42,605	$4,261	62,434	(13,826)
2011	$18,006	$0	$40,094	$9,809	67,908	24089.5	42,605	$4,261	62,434	5,474
2012	$23,182	$0	$52,612	$13,180	88,974	24089.5	42,605	$4,261	62,434	26,540
2013	$23,878	$0	$55,247	$14,172	93,296	0	0	$0	0	93,296
2014	$24,594	$0	$58,028	$15,242	97,864	0	0	$0	0	97,864
2015	$25,332	$0	$60,965	$16,398	102,694	0	0	$0	0	102,694
2016	$26,092	$0	$64,066	$17,645	107,803	0	0	$0	0	107,803
2017	$26,874	$0	$67,339	$18,992	113,206	0	0	$0	0	113,206
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$193,673	$0	$453,888	$118,508	$766,069	$120,448	$213,025	$21,303	$312,170	$453,899
NPV =	125,692	0	292,157	86,120	503,969	98,640	174,455	17,446	255,649	248,319

Total NPV = $248,319

Benefit/Cost Ratio = 1.97

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0099	$4,261	67,180	134,359	$0.045	$0.045	8	15	$47.41	$69.46	$14,729	$42,605	$0	$42,605	($27,876)
2009	0.0197	$4,261	134,359	268,718	$0.047	$0.047	15	31	$50.05	$73.34	$26,365	42,605	$0	42,605	(16,240)
2010	0.0196	$4,261	201,539	403,077	$0.050	$0.050	23	46	$52.84	$77.43	$39,267	42,605	$0	42,605	(3,338)
2011	0.0194	$4,261	268,718	537,437	$0.053	$0.053	31	61	$55.79	$81.75	$53,540	42,605	$0	42,605	10,935
2012	0.0193	$4,261	335,898	671,796	$0.056	$0.056	38	77	$58.91	$86.31	$69,298	42,605	$0	42,605	26,693
2013	0.0192	0	335,898	671,796	$0.059	$0.059	38	77	$62.19	$91.13	$68,666	0	$0	0	68,666
2014	0.0190	0	335,898	671,796	$0.062	$0.062	38	77	$65.66	$96.21	$72,498	0	$0	0	72,498
2015	0.0189	0	335,898	671,796	$0.066	$0.066	38	77	$69.33	$101.58	$76,543	0	$0	0	76,543
2016	0.0188	0	335,898	671,796	$0.069	$0.069	38	77	$73.19	$107.25	$80,814	0	$0	0	80,814
2017	0.0187	0	335,898	671,796	$0.073	$0.073	38	77	$77.28	$113.23	$85,324	0	$0	0	85,324
2018	0.0185	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0184	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0183	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0181	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0180	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0179	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			2,687,183	5,374,365							$587,043	$213,025	$0	$213,025	$374,018
											$407,637	186,754	0	186,754	220,883

Total NPV = $220,883
Benefit/Cost Ratio = 2.18

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Appendix C

Scenario A Inputs

Program Data Key Assumption Sources

Table XXXXX

DSM #	DSM Program	Energy Calculation Data	Program Cost Data	Customer Cost Data	Participation Rate Estimate
1	Interruptible Rate - Demand Response Only	500 kW Model	Operationg, Admin & Mkting Cost Estimate	Industry Data	Potential Customers - Customer Reps
2	Interruptible Rate - Energy & Demand Response	500 kW Model	Operationg, Admin & Mkting Cost Estimate	Industry Data	Potential Customers - Customer Reps
3	Commercial High Efficiency Motors	Motor Master Program - DOE & AEE for LF	Operationg, Admin & Mkting Cost Estimate	Motor Master - DOE	Estimate
4	Energy Star Washers with electric heat	Energy Star	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
5	Energy Star Dishwashers with electric heat	Energy Star	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
6	Energy Star Refrigerators	Energy Star, AHAM, WAPA DSM Guide	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
7	Energy Star Freezers	Energy Star, AHAM	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
8	High Efficiency A/C Residential	Energy Star, Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	Industry Data	Customer End Use Survey, Estimate
9	High Efficiency A/C Commercial	Energy Star, Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	Industry Data	Estimate
10	Residential A/C Cycling (T-Stat)	Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	NA	End Use Survey, Vendor Data
11	Commercial A/C Cycling (T-Stat)	Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	NA	End Use Survey, Vendor Data
12	Refrigerator Round-Up	WAPA DSM Guide	Operationg, Admin & Mkting Cost Estimate	NA	End Use Survey, Industry Data
13	Ground Source Heat Pumps	Industry Data, DOE	Operationg, Admin & Mkting Cost Estimate	Industry Data	Customer End Use Survey, Estimate
14	Commercial Lighting	Industry Data, IES	Operationg, Admin & Mkting Cost Estimate	Industry Data	Xenergy Survey, Estimate
15	LED Exit Signs	Industry Data, IES	Operationg, Admin & Mkting Cost Estimate	Industry Data	Xenergy Survey, Estimate

AHAM - Association of Home Appliance Manufacturers
EPRI - Electric Power Research Institute
IES - Illumination Engineering Society

WAPA - Western Area Power Association 1992 DSM Guide
DOE - Department of Energy
AEE - Associtation onf Energy Engineers

Interruptible Rate - Demand Response
Quantitative DSM # 1

Customer Class:	Commercial and Industrial	

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ 3,600		$ 97	$ 3,600	$ 3,600	$ 3,600	$ 10,800
Incentive Costs	$ 15,000		$ 15,000	$ 186,000	$ 372,000	$ 558,000	$ 1,116,000
Admin & Advertising	$ 19,829		$ 1,599	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 16,696**	**$ 209,429**	**$ 395,429**	**$ 581,429**	**$ 1,186,287**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 2.50	per kW/month

Participant Costs (Incremental Cost Basis)

Estimated Average cost of inteconnection	$ 50,000	Average interconnection costs - Estimated
Estimated cost of Primary Service	$ 40,000	Cost for Transformer, Primary Metering, Switch Fuse
Total Cost	**$ 90,000**	
Other Partcipant Costs (Diesel @ 100 hrs of curtailment)	$ 6,499	

Participation Rate Calc

	% of Cust	Cust	
C& I Customers over 500 kW	100.00%	93	RA provided Query of CIS

Total Customer Available for program	93			
Total Estimated Saturation Percentage	40.0%	**Total MW**		
Total Participantion Rate	**37**	18.6	40.00%	Of total Customer Base
Participation Year 1	12	6.2		
Participation Year 2	12	6.2		
Participation Year 3	12	6.2		

Energy Savings Calculation

IT Rate	Total conn kW	kW/Customer	Avg kW per event	Coincident Rate
Rate 38 - DR	500	500.0	500	100.0%

Avg Customer KWh Avoided @ 100 hrs	**26,986**	75% Customer LF	
Primary Service Rate Savings per year	**$ 20,264**	Included in other particapant savings	

	Per Part
Summer Demand Reduction	166.7
Winter Demand Reduction	333.3
Total Demand Reduction	**500**
Summer Energy Reduction	26,986
Winter Energy Reduction	0

Proposed IT DR Rate	
Summer kW	$ 8.254
Winter kW	$ 5.254
Energy kWh	$ 0.03255
Demand Credit kW	$ 2.50

Note:
MW of IT is the target not Customers
Incentive is equal to our lost Margin between ND Rate 30 Secondary and IT Rate

Commercial High Efficiency Motors
Quantitative DSM # 2

Customer Class:	Commercial & Industrial

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$0	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$264	$ 264	$ 56,334	$ 56,334	$ 56,334	$ 169,003
Admin & Advertising	$19,829	$ 93	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 358**	**$ 76,163**	**$ 76,163**	**$ 76,163**	**$ 228,490**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 0.150	Per kWh Saved

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Motor	$ 3,320	50HP 3600 rpm - Motor Master
Avg Cost of High Efficiency Motor	$ 4,787	50 HP 3600 rpm - Motor Master
Increased cost of Higher Eff Model	**$ 1,467**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	17,042	
Customer with Standard Motors	75.00%	12,782	
Estimated Motors per Customer		5	
Total Motors Available for Program	63,908		
Total Estimated Saturation Percentage	1.0%		
Total Motors	**639**		3.75% Of total Customer Base
Participation Year 1	213		
Participation Year 2	213		
Participation Year 3	213		

Energy Savings Calculation

Electric Motor Data	kw Conn	Annual kWh	Utilization Factor
Standard Motor (50hp)	37.3	106,860	100%
High Efficiency Motor(50hp)	36.9	105,097	100%
Energy Savings	**0.4**	**1,763**	

4380 hrs per year operation @ 60 % Load Factor
4380 hrs per year operation @ 60% Load Factor
Energy Calculation based on Motor Master - DOE
Example is based on 50 hp - 3600 rpm - 460 v TEFC

	Per Part	
Summer Demand Reduction	0.133	Levelized for 4 months
Winter Demand Reduction	0.267	Levelized for 8 Months
Total Demand Reduction	**0.400**	**Total demand Reduction for Measure**
Summer Energy Reduction	588	
Winter Energy Reduction	1175	

Notes:
TEFC = Total Enclosed Fan Cooled

Energy Star Clothes Washer Program
Quantitative DSM # 3

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	Per year	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 25	Per Particpant	$ 25	$ 43,674	$ 43,674	$ 43,674	$ 131,023
Admin & Advertising	$ 19,829	Per year	$ 11	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 36**	**$ 63,503**	**$ 63,503**	**$ 63,503**	**$ 190,510**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 750	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 300**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers with Electric Water heating	32.83%	28,283	Per 2004 Customer Survey
Customer with Clothes Washers	92.65%	26,205	Per 2004 Customer Survey

Total Customers Available for program	26,205	
Total Estimated Saturation Percentage	20.0%	
Total Particapants	**5,241**	6.08% Of total Customer Base
Participation Year 1	1,747	
Participation Year 2	1,747	
Participation Year 3	1,747	

Energy Savings Calculation

Clothes Washer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.469	531	10%	Savings is Due to reduceed Water Consumption
Energy Star	0.192	234	10%	Savings is based on Energy Star Calculator
Energy Savings	**0.277**	**297**		

	Per Part	
Summer Demand Reduction	0.009	Levelized for 4 months
Winter Demand Reduction	0.018	Levelized for 8 Months
Total Demand Reduction	**0.028**	**Total demand Reduction for Measure**
Summer Energy Reduction	99	
Winter Energy Reduction	198	
Other Particpants Costs / Savings	$ (35.00)	

**** Note water & detergent savings is estimated at $35 per year (7,000 gallons) entered as Other Part Costs (neg***

Energy Star Dishwasher Program
Quantitative DSM # 4

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10	$ 10	$ 10,629	$ 10,629	$ 10,629	$ 31,887
Admin & Advertising	$ 19,829	$ 19	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 29**	**$ 30,458**	**$ 30,458**	**$ 30,458**	**$ 91,374**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 500	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 50**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers with electric water heating	32.83%	28,283	
Customer with Automatic Dishwashers	56.37%	15,943	Per 2004 Customer Survey

Total Customers Available for program	15,943		
Total Estimated Saturation Percentage	20.0%		
Total Participants	**3,189**	3.70%	Of total Customer Base
Participation Year 1	1,063		
Participation Year 2	1,063		
Participation Year 2	1,063		

Energy Savings Calculation

Dishwasher Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0	413	20%	Savings is Driven by Reduce Water Consumption
Energy Star	0	341	20%	Savings is based on Energy Star Calculator
Energy Savings	**0**	**72**		

	Per Part	
Summer Demand Reduction	0.000	Levelized for 4 months
Winter Demand Reduction	0.000	Levelized for 8 Months
Total Demand Reduction	**0.000**	**Total demand Reduction for Measure**
Summer Energy Reduction	24	
Winter Energy Reduction	48	
Other Participants Cost / Savings	$ (3.00)	

**** Water savings is estimated at 830 gallons per year! Not used in model as savings insignificant at $3.00/yr/part

Energy Star Refrigerators Program
Quantitative DSM # 5

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$	-	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$	15	$ 15	$ 43,076	$ 43,076	$ 43,076	$ 129,227
Admin & Advertising	$	19,829	$ 7	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 22**	**$ 62,905**	**$ 62,905**	**$ 62,905**	**$ 188,714**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 1,070		Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 1,100		Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 30**		Partial automatic defrost

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151

Total Customers Available for program	86,151		
Total Estimated Saturation Percentage	10.0%		
Total Participants	**8,615**	10.00%	Of total Customer Base
Participation Year 1	2,872		
Participation Year 2	2,872		
Participation Year 2	2,872		

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.8	479	35%	18 Cu Ft Top Freezer ice maker
Energy Star	0.68	407	35%	As per survey results 88% for FF
Energy Savings	**0.12**	**72**		Energy Star - DOE 2004

	Per Part	
Summer Demand Reduction	0.014	Levelized for 4 months
Winter Demand Reduction	0.028	Levelized for 8 Months
Total Demand Reduction	**0.042**	**Total demand Reduction for Measure**
Summer Energy Reduction	24	
Winter Energy Reduction	48	

Energy Star Freezers Program
Quantitative DSM # 6

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 15	$ 15	$ 33,543	$ 33,543	$ 33,543	$ 100,629
Admin & Advertising	$ 19,829	$ 9	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 24**	**$ 53,372**	**$ 53,372**	**$ 53,372**	**$ 160,116**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 329	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 362	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 33**	23 Cu ft Chest Manual DF

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Customer with Freezers	77.87%	67,086	Per 2004 Customer Survey

Total Customers Available for program	67,086		
Total Estimated Saturation Percentage	10.0%		
Total Participants	**6,709**	7.79%	Of total Customer Base
Participation Year 1	2,236		
Participation Year 2	2,236		
Participation Year 3	2,236		

Energy Savings Calculation

Freezer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional Freezer	0.9	520	35%	22 Cu ft Chest Manual DF
Energy Star Freezer	0.8	468	35%	Energy Star -DOE 2004
Energy Savings	**0.1**	**52**		

	Per Part	
Summer Demand Reduction	0.012	Levelized for 4 months
Winter Demand Reduction	0.023	Levelized for 8 Months
Total Demand Reduction	**0.035**	**Total demand Reduction for Measure**
Summer Energy Reduction	17	
Winter Energy Reduction	35	

Residential High Efficiency A/C (Energy Star Rated)
Quantitative DSM # 7

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 600		$ 600	$ 354,562	$ 354,562	$ 354,562	$ 1,063,686
Admin & Advertising	$ 19,829		$ 34	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 634**	**$ 374,391**	**$ 374,391**	**$ 374,391**	**$ 1,123,173**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 200	Per Ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (13 SEER)	$ 1,200	Market Reasearch with local HVAC Dealers
Cost of High Efficiency Model (15 SEER)	$ 2,300	Market Reasearch with local HVAC Dealers
Increased cost of Higher Eff Model	**$ 1,100**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers With Central AC	50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers	0.81%	698	Per 2004 Customer Survey

Total Available for program	44,325		
Total Estimated Saturation Percentage	4.0%		
Total Participants	**1,773**	2.06%	Of total Customer Base
Participation Year 1	591		
Participation Year 2	591		
Participation Year 3	591		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
10 SEER Unit	3.8	2,160	67%
15 SEER Unit	2.9	1,440	
Energy Reduction	**0.92**	**720**	

EPRI for Utilization Factor
BismarckWeather Data used for cooling hrs

	Per Part
Summer Demand Reduction	0.6
Winter Demand Reduction	0.0
Summer Energy Reduction	720
Winter Energy Reduction	0

Commercial High Efficiency A/C
Quantitative DSM # 8

Customer Class:	Commercial

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 500		$ 500	$ 71,001	$ 71,001	$ 71,001	$ 213,004
Admin & Advertising	$ 19,829		$ 140	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 640**	**$ 90,830**	**$ 90,830**	**$ 90,830**	**$ 272,491**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 100.00	per ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (10 SEER)	$ 2,000	Trane 5 Ton Packaged Unit ($400 per ton Mike S)
Cost of High Efficiency Model (12 SEER)	$ 3,000	Trane 5 Ton Packaged Unit ($600 per ton Mike S)
Increased cost of Higher Eff Model	**$ 1,000**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	17,042	
Total Customers With Central AC	50.00%	8,521	Estimated no survey data
Total Customers with Evap or Swamp Coolers	0.00%	-	

Total Available for program	8,521		
Total Estimated Saturation Percentage	5.0%		
Total Participants	**426**	2.50%	Of total Customer Base
Participation Year 1	142		
Participation Year 2	142		
Participation Year 3	142		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	6.86	5,700	67%	Trane 5 ton Unit
12 Seer Unit	5.56	4,750		Trane 5 ton Unit
Energy Reduction	**1.3**	**950**		

	Per Part
Summer Demand Reduction	0.9
Winter Demand Reduction	0.0
Summer Energy Reduction	950
Winter Energy Reduction	0

Residential A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 9

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 45,421	$ 308	$ 2,193,222	$ 1,069,321	$ 1,069,321	$ 4,331,864
Incentive Costs ($89 t-Stat)	$ 93	$ 97	$ 644,924	$ 322,462	$ 322,462	$ 1,289,848
Admin & Advertising (MDU)	$ 23,429	$ 5.29	$ 23,429	$ 23,429	$ 23,429	$ 70,287
Total Cost		**$ 410**	**$ 2,861,575**	**$ 1,415,212**	**$ 1,415,212**	**$ 5,692,000**

Notes
Increased 2005 numbers by 4% inflation per year
MDU operational cost is less field operations

Participant Costs
None / Comfort Issues $ -

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers With Central AC	50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers	0.81%	698	

Total Available for program	44,325
Total Estimated Saturation Percentage	30.0%
Total Participants	**13,297**
Participation Year 1	6,649
Participation Year 2	3,324
Participation Year 3	3,324

15.44% Of total Customer Base

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
3 Ton 10 SEER Unit	3.6	2,340	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**1.00**		

Av is 1 kW per particpant (Honeywell)
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized
kW redcction per partcipant

	Per Part
Summer Demand Reduction	1.00
Winter Demand Reduction	0.000
Summer Energy Reduction	360
Winter Energy Reduction	0

Commercial A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 10

Customer Class:	Small Comm

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 45,421	$ 282	$ 248,840	$ 135,531	$ 135,531	$ 519,901
Incentive Costs ($337 t-Stat)	$ 365	$ 365	$ 233,262	$ 116,631	$ 116,631	$ 466,525
Admin & Advertising (MDU)	$ 23,429	$ 55	$ 23,429	$ 23,429	$ 23,429	$ 70,287
Total Cost		**$ 702**	**$ 505,532**	**$ 275,591**	**$ 275,591**	**$ 1,056,713**

Notes
Increased 2005 numbers by 4% inflation per year
MDU operational cost is less field operations

Participant Costs

None / Comfort Issues	$ -

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	17,042	
Total Customers in class available for program	50.00%	8,521	Estimate
Total Customer with A/C	50.00%	4,261	Estimate

Total Available for program	4,261		
Total Estimated Saturation Percentage	30.0%		
Total Participants	**1,278**	7.50%	Of total Customer Base
Participation Year 1	639		
Participation Year 2	320		
Participation Year 3	320		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
(2) 5 Ton Unit 11.8 SEER	13.72	10800	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**3.80**		

Per Trane
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized kW redcction per partcipant

	Per Part
Summer Demand Reduction	3.8
Winter Demand Reduction	0.000
Summer Energy Reduction	1,372
Winter Energy Reduction	0

Refrigerator Round-Up Program
Quantitative DSM # 11

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Transport & Recycling (Operating)	$ -	$ 25	$ 47,116	$ 47,116	$ 47,116	$ 141,348
Incentive Costs	$ 35	$ 35	$ 21,987	$ 21,987	$ 21,987	$ 65,962
Admin & Advertising	$ 19,829	$ 32	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 92**	**$ 88,932**	**$ 88,932**	**$ 88,932**	**$ 266,797**

Notes

Operating Costs Calculated

Pick up and Recycling is estimated at loaded rate for 1.5 hr plus mileage & $20 recycling fee at Porter Bros $ 75

Participant Costs

None $ -

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151
Total Customers with 2 Refrigerators	34.03%	29,317
Total Customers with 3 or more Refrigerators	2.43%	2,093

Total Available for program	31,411	
Total Estimated Saturation Percentage	6.0%	
Total Partcipation	**1,885**	2.19% Of total Customer Base
Participation Year 1	628	
Participation Year 2	628	
Participation Year 2	628	

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor
Frost Free	1.5	1200	35%
Standard	1	1000	35%
Avg (WAC)	**1.415**	**1166**	

As per WAPA DSM Pocket Guide 1992
Assumes 1987 vintage 17.3 cu ft
As per survey results 88% for FF
UPA 1992 Study - Older Fridges

	Per Part	
Summer Demand Reduction	0.165	Levelized for 4 months
Winter Demand Reduction	0.330	Levelized for 8 Months
Total Demand Reduction	**0.495**	**Total demand Reduction for Measure**
Summer Energy Reduction	389	
Winter Energy Reduction	777	

Residential GSHP
Quantitative DSM # 12

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 1,100	$ 1,100	$ 131,446	$ 131,446	$ 131,446	$ 394,339
Admin & Advertising	$ 19,829	$ 42	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost		**$ 1,142**	**$ 136,446**	**$ 136,446**	**$ 136,446**	**$ 409,339**

Notes

Program is based in straight electric areas only

Participant Costs (Incremental Cost Basis)

Furnace & Central Air (STD Eff)	$ 6,000	3 Ton A/C & 75,000 BTU Furnace 80%
GS Heat pump	$ 10,000	3 Ton Unit 17 SEER 14.5 EER
Increased cost of GSHP	**$ 4,000**	

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	86,151	
Combination Customers		58.39%	50,302	Per 2004 Customer Survey
Total Electric Only Customers		41.61%	35,849	Per 2004 Customer Survey
Total Available for program	35,849			
Total Estimated Saturation Percentage	1.00%			
Total Participants	**358**		0.42%	Of total Customer Base
Participation Year 1	119			
Participation Year 2	119			
Participation Year 3	119			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
Std A/C Cooling (10 SEER)	3.6	2,160	67%	
Heat pump Cooling	2.5	1,271		
Cooling Energy Reduction	**1.1**	**889**		
Heating Energy Add	**2.5**	**6,638**		COP of 3

	Per Part
Peak Demand Reduction	0.7
Winter Demand Reduction	-2.5
Summer Energy Reduction	889
Winter Energy Reduction	(6,638)
Savings Electric vs Propane	$ 577
Electric Heat after tax margin per cooling kwh reduction	$ 0.0911

**Heat Pump vs. propane at 80% AFUE & 5 yr avg price of $0.89 per gal ($827 annual cost for 930 Gallons)
** Annaul cost of electric heat $250

T-8 Lighting Retrofit (4 Lamp fixture model)
Quantitative DSM # 13

Customer Class:	Comm & Ind

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 184	$ 184	$ 125,429	$ 125,429	$ 125,429	$ 125,429	$ 125,429	$ 627,146
Admin & Advertising	$ 19,829	$ 29	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 99,145
Total Cost		**$ 213**	**$ 145,258**	**$ 145,258**	**$ 145,258**	**$ 145,258**	**$ 145,258**	**$ 726,291**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
	$ 8.00	per fix

Participant Costs

Avg Cost per Fixture	$ 40.00	4 Lamp Fixture with Ballast per ESG Avg Pricing plus labor
Fixtures per Participant	23	
Total Direct Cost per Part	**$ 920**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated fixtures per Customer	23	Derived from xenergy survey
Estimated fixtures on System	**391,966**	

Total fixtures Available for program	391,966
Estimated Conversion Percentage	20.0%
Part Rate of Light fixtures	78,393
Total Partcipants	**3,408**
Participation Year 1	682
Participation Year 2	682
Participation Year 3	682
Participation Year 4	682
Participation Year 5	682

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	hrs/yr	
Existing T-12 4 lamp Fixture	144	360	100%	2500	34 w bulbs energy saving magnetic ballast
T-8 4 Lamp Fixture	107	267	100%	2500	electronic ballast
Reduction Per fixture	**37**	**93**	**100%**		

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.0373	0.29	Levelized for 4 months
Winter Demand Reduction	0.0373	0.57	Levelized for 8 Months
Total Demand Reduction		**0.86**	**Total demand Reduction for Measure**
Summer Energy Reduction	31	715	
Winter Energy Reduction	62	1,430	

***** kWh calculation assumes 2,500 hrs per year of operation as is typically for M-F 8-5pm operation**

****** Actual Lighting program with be more comprehensive and include CFL & MH, however incentive will follow the same $ per watt of savings**

LED Exits Signs (Incandescent Model)
Quantitative DSM # 14

Customer Class:	Comm & Ind

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 25.00		$ 25	$ 8,521	$ 8,521	$ 8,521	$ 8,521	$ 8,521	$ 42,605
Admin & Advertising	$ 19,829		$ 58	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 99,145
Total Cost			**$ 83**	**$ 28,350**	**$ 28,350**	**$ 28,350**	**$ 28,350**	**$ 28,350**	**$ 141,750**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
Incentive	$ 5.00	per Fixture

Participant Costs

Cost Per Exit Light	$ 50.00	*Replacement cost as per ESG Todd Kaduan (Retrofit cost is $20/fix)*
Exit Signs per Part	5	
Total Direct Cost per Part	**$ 250**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated Exit Signs per Customer	5	derived Per Xenergy Study
Estimated Exit Signs on System	**85,210**	

Total Exit Lights Available for program	85,210
Estimated Conversion Percentage	10.0%
Part Rate of Exit Lights	8,521
Total Partcipants	**1,704**
Participation Year 1	341
Participation Year 2	341
Participation Year 3	341
Participation Year 4	341
Participation Year 5	341

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	kW Redc	kWh Reduc
Existing Incandescent	32	280	100%	0.032	280
Existing CFL	10	88	100%	0.01	88
LED (Replace the others)	5	44	100%	0.005	44

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.027	0.05	Levelized for 4 months
Winter Demand Reduction	0.027	0.09	Levelized for 8 Months
Total Demand Reduction		**0.14**	**Totai demand Reduction for Measure**
Summer Energy Reduction	79	394	
Winter Energy Reduction	158	788	

***** Note For Program development that if CFL's are replaced incentive is reduced to 1/4 of incentive for incandescent**
******* LED Signs Must be energy star rated which is 5 watts or less (1 Watt is the best available)**
Fixture life is 10 years

Appendix D

Scenario A Runs

2007 Input Data Summary
Demand-Side Management Model

Sensitivity A

Input Data Description	Information Source
Retail Rate	System Average retail rate for customer class that DSM is applicable to.
System Marginal Energy Costs	System Marginal energy costs are based on ND & SD Cogeneration filings July 2006 - June 2007
Retail Demand Cost	Seasonal demand cost for customer class that DSM is applicable - ND Rate 30
System Peak Shaving Demand Costs	Demand Cost is based on estimated levelized cost of Combustion turbine
System Conservation Demand Costs	Demand cost is based on estimated levelized costs of Big Stone II - Base Load
MRO Reserve Margin	Current required capacity reserve margin
Variable O&M	Based on Montana-Dakota's historical information
Environmental Damage Factor	Based on MT PSC 1993 IRP order
Total Sales By Class	2006 total sales for customer class that DSM program is applicable.
Total Customers	2006 total customers for customer class that DSM program is applicable
Growth and Escalation Factors	Projected based on consumer indexes and forecasted escalation rates
Utility Discount Rate	MDU's capital structure of incremental WACC 2006
Societal Discount Rate	Equal to the 30 year T-Bill rate average of 52 weeks ending January 24, 2007
General Input Data Year	Year data was input
Project Analysis Year	Year program will be implemented
Effective Tax Rate	Avg of MDU's current state and local tax rate for integrated system
System Demand Line Loss Factor	Historical demand line loss factor for integrated electric system
System Energy Line Loss Factor	Historical energy line loss factor for integrated electric system
Direct Utility Project Costs	Total direct cost to the utility caused by implementing the DSM program
Administrative Costs	Total projected administrative costs including general admin and marketing costs of the DSM program
Direct Operating Costs	Direct operating cost estimated for the specific DSM program
Incentive Costs	Total annual cost of the incentive paid to the program participant
Direct Participant Project Costs	Direct costs that the participant would have to pay to participate in the DSM program
Other Participant Project Costs	Other costs or savings (neg) to the participant for participating in the DSM program
Project Life	Based on the estimated useful life of the energy saving equipment
Avg. Energy Reduction	Avg energy reduction (kWh) caused by the DSM program
Avg. Demand Reduction	Avg energy reduction (kW) caused by the DSM program
Number of Participants	Total projected participation by customers or kW load target, or equipment saturation

Potential DSM Phases - Sensitivey A - High Participation

Current DSM Programs

Sensitivity A

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Particpants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Incentive Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
1	IT Rate - Demand Response	2007	3	10	37	15,157,572	20,060	$186,000	$19,829	$3,600	$ 209,429	$ 2,349,145	$117	$0.155
7	**Residential High Efficiency A/C	2006	3	15	1,773	19,272,717	1,172	$354,562	$19,829	$0	$ 374,391	$ 1,123,173	$959	$0.058
13	Commercial Lighting	2006	5	10	3,408	63,072,111	3,154	$125,429	$19,829	$0	$ 145,258	$ 726,291	$230	$0.012
	Totals					**97,502,400**	**24,385**	**$665,991**	**$59,487**	**$3,600**	**$ 729,078**	**$ 4,198,609**		

** Current Program for 2007 - Higher SEER Requirement & Incentive for 2008

Net Cost per kW	$ 172
Net Cost per kWh	$ 0.043

Conservation 1

5	Energy Star Refridgerators	2008	3	15	8,615	9,365,716	390	$43,076	$19,829	$0	$ 62,905	$ 188,714	$484	$0.020
6	Energy Star Freezers	2008	3	15	6,709	5,267,227	253	$33,543	$19,829	$0	$ 53,372	$ 160,116	$632	$0.030
11	Refridgerator Round-Up	2008	3	10	1,885	9,479,969	1,007	$21,987	$19,829	$47,116	$ 88,932	$ 266,797	$265	$0.028
14	Led Exit Signs	2008	5	10	1,704	17,388,758	248	$8,521	$19,829	$0	$ 28,350	$ 141,750	$571	$0.008
	Totals					**41,501,671**	**1,898**	**$107,127**	**$79,316**	**$47,116**	**$ 233,559**	**$ 757,376**		

Net Cost per kW	$ 399
Net Cost per kWh	$ 0.018

Conservation 2

9	Residential A/C Cycling	2009	3	10	13,297	47,756,373	14,301	$644,924	$23,429	$2,193,222	$2,861,575	$5,692,000	$398	$0.119
10	Commercial A/C Cycling	2009	3	10	1,278	17,494,350	5,239	$233,262	$23,429	$248,840	$505,532	$1,056,713	$202	$0.060
	Total Increase 2010					**65,250,724**	**19,540**	**$878,187**	**$46,858**	**$2,442,062**	**$3,367,106**	**$6,748,713**		

Net Cost per kW	$ 345
Net Cost per kWh	$ 0.103

Conservation 3

8	Commercial High Efficiency A/C	2008	3	15	426	6,110,671	398	$71,001	$19,829	$0	$ 90,830	$272,491	$685	$0.045
2	High Efficiency Motors	2008	3	15	639	17,011,881	276	$56,334	$19,829	$0	$76,163	$228,490	$829	$0.013
	Totals					**23,122,552**	**673**	**$127,336**	**$39,658**	**$0**	**$ 166,994**	**$500,981**	**$1,514**	

Includes Admin at full amount per program

Net Cost per kW	$ 744
Net Cost per kWh	$ 0.022

Cumulative Cost per kW	$ 263
Cumulative Cost per kWh	$ 0.054

DSM Program Summary - Sensitivity A - High Participation

All Programs

ɜnsitivity A DSM #	DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Interruptible Rate - Demand Response Only	CI	PC	6.65	6.74	4.67	2.46
2	Commercial High Efficiency Motors	CI	SC	3.46	6.63	1.87	1.14
3	Energy Star Washers with electric heat	R	SC	1.23	4.22	2.07	3.12
4	Energy Star Dishwashers with electric heat	R	SC	0.28	0.52	0.39	2.59
5	Energy Star Refrigerators	R	SC	4.39	10.16	7.42	2.91
6	Energy Star Freezers	R	SC	4.11	7.70	5.40	2.04
7	High Efficiency A/C Residential	R	SC	1.67	2.16	1.49	1.20
8	High Efficiency A/C Commercial	CI	SC	2.61	3.00	2.07	1.63
9	Residential A/C Cycling (T-Stat)	R	PC	2.78	3.26	5.05	INF
10	Commercial A/C Cycling (T-Stat)	CI	PC	5.66	6.44	13.87	INF
11	Refrigerator Round-Up	R	SC	2.93	6.03	9.44	INF
12	Ground Source Heat Pumps	R	SLG /SC	6.02	6.47	2.25	1.86
13	Commercial Lighting	CI	SC	6.43	14.02	3.80	1.58
14	LED Exit Signs	CI	SC	2.70	7.20	2.34	2.18

INF= Infinity as partcipant has no cost participation amount

PC = Peak Clipping
C= Commercial

SLG = Strategic Load Growth
R= Residential

SC = Strategic Conservation
I = Industrial

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03255
1a) Retail Rate Winter ($/kWh) =	$0.03255
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$10.00
3a) Retail Winter Demand Rate ($/kW/season) =	$20.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	93
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$186,000
Total Utility Project Costs Year 1 =	**$209,429**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$372,000
Total Utility Project Costs Year 2 =	**$395,429**
15b) Total Utilty Cost Year 3 =	**$581,429**
15c) Total Utilty Cost Year 4 =	**$581,429**
15d) Total Utility Cost Year 5 =	**$581,429**
15e) Total Utility Operating Cost (Program Life) =	**$581,429**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$90,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 6,499
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 20,264
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	166.7
20a) Avg Winter kW/part Saved =	333.3
21) Avg. Summer kWh/Part. Saved =	26,986
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	12
22a) Number of Participants (Second Year) =	12
22a) Number of Participants (Third Year) =	12
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15,000

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Interruptible Rate - Demand Response**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$2,349,145
Total Program Participants	37
Utility Cost per Participant (First Year) =	$16,889.44
Utility Cost per Participant (Program) =	$63,149.06
Total kW Reduction	20,060
Total Energy Reduction (kWh)	15,157,572
Societal Cost per kwh	$0.56

Test Results

	NPV	B/C
Utility Test	$27,308,677	6.65
Ratepayer Test	$27,374,079	6.74
Societal Cost Test	$31,072,474	4.67
Participant Test	$7,279,819	2.46

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	360,895	$0.0190	$0	6,687	$140.17	$944,143	$209,429	3,568	$212,997	$731,146
2	2009	721,789	$0.0195	0	13,373	$147.02	1,980,287	$395,429	6,886	402,315	1,577,972
3	2010	1,082,684	$0.0201	0	20,060	$154.25	3,116,116	$581,429	9,942	591,371	2,524,745
4	2011	1,082,684	$0.0207	0	20,060	$161.89	3,269,915	$581,429	9,544	590,973	2,678,942
5	2012	1,082,684	$0.0213	0	20,060	$169.95	3,432,279	$581,429	9,133	590,562	2,841,716
6	2013	1,082,684	$0.0220	0	20,060	$178.46	3,603,685	$581,429	8,711	590,140	3,013,546
7	2014	1,082,684	$0.0226	0	20,060	$187.44	3,784,639	$581,429	8,275	589,704	3,194,934
8	2015	1,082,684	$0.0233	0	20,060	$196.93	3,975,671	$581,429	7,827	589,256	3,386,415
9	2016	1,082,684	$0.0240	0	20,060	$206.95	4,177,343	$581,429	7,365	588,794	3,588,549
10	2017	1,082,684	$0.0247	0	20,060	$217.52	4,390,250	$581,429	6,890	588,319	3,801,931
11	2018	1,082,684	$0.0255	0	20,060	$228.68	4,615,016	$581,429	6,400	587,829	4,027,187
12	2019	1,082,684	$0.0262	0	20,060	$240.47	4,852,304	$581,429	5,895	587,324	4,264,980
13	2020	1,082,684	$0.0270	0	20,060	$252.92	5,102,811	$581,429	5,375	586,804	4,516,007
14	2021	1,082,684	$0.0278	0	20,060	$266.06	5,367,274	$581,429	4,840	586,269	4,781,005
15	2022	1,082,684	$0.0287	0	20,060	$279.93	5,646,472	$581,429	4,288	585,717	5,060,754
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		15,157,572			280,841		$58,258,203	$8,163,435	$104,940	$8,268,375	$49,989,829
NPV =							32,143,192	4,769,113	65,402	4,834,515	27,308,677

Total NPV = $27,308,677
Benefit/Cost Ratio = 6.65

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Interruptible Rate - Demand Response**

	Decreases			Increases			
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$6,840	$0	$937,303	$944,143	$209,429	$209,429	$734,714
2009	14,090	0	1,966,197	1,980,287	$395,429	395,429	1,584,858
2010	21,769	0	3,094,347	3,116,116	$581,429	581,429	2,534,687
2011	22,422	0	3,247,493	3,269,915	$581,429	581,429	2,688,486
2012	23,094	0	3,409,184	3,432,279	$581,429	581,429	2,850,850
2013	23,787	0	3,579,898	3,603,685	$581,429	581,429	3,022,256
2014	24,501	0	3,760,138	3,784,639	$581,429	581,429	3,203,210
2015	25,236	0	3,950,435	3,975,671	$581,429	581,429	3,394,242
2016	25,993	0	4,151,350	4,177,343	$581,429	581,429	3,595,914
2017	26,773	0	4,363,477	4,390,250	$581,429	581,429	3,808,821
2018	27,576	0	4,587,440	4,615,016	$581,429	581,429	4,033,587
2019	28,403	0	4,823,901	4,852,304	$581,429	581,429	4,270,875
2020	29,255	0	5,073,556	5,102,811	$581,429	581,429	4,521,382
2021	30,133	0	5,337,141	5,367,274	$581,429	581,429	4,785,845
2022	31,037	0	5,615,435	5,646,472	$581,429	581,429	5,065,043
2023	0	0	0	0	0	0	0
Total =	$360,907	$0	$57,897,296	$58,258,203	$8,163,435	$8,163,435	$50,094,768
NPV =	203,624	0	31,939,568	32,143,192	4,769,113	4,769,113	27,374,079

Total NPV = $27,374,079

Benefit/Cost Ratio = 6.74

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Interruptible Rate - Demand Response**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$6,840	$0	$937,303	$145,870	$1,090,013	$209,429	$1,199,007	$186,000	$1,222,436	($132,423)
2009	$14,090	$0	$1,966,197	$315,133	2,295,419	$395,429	1,286,995	$372,000	1,310,424	984,996
2010	$21,769	$0	$3,094,347	$510,760	3,626,875	$581,429	1,292,125	$558,000	1,315,554	2,311,322
2011	$22,422	$0	$3,247,493	$552,048	3,821,962	$581,429	181,409	$0	762,838	3,059,125
2012	$23,094	$0	$3,409,184	$596,843	4,029,122	$581,429	186,851	$0	768,280	3,260,842
2013	$23,787	$0	$3,579,898	$645,448	4,249,134	$581,429	192,456	$0	773,885	3,475,248
2014	$24,501	$0	$3,760,138	$698,194	4,482,833	$581,429	198,230	$0	779,659	3,703,174
2015	$25,236	$0	$3,950,435	$755,439	4,731,110	$581,429	204,177	$0	785,606	3,945,504
2016	$25,993	$0	$4,151,350	$817,573	4,994,916	$581,429	210,302	$0	791,731	4,203,185
2017	$26,773	$0	$4,363,477	$885,019	5,275,269	$581,429	216,611	$0	798,040	4,477,229
2018	$27,576	$0	$4,587,440	$958,239	5,573,255	$581,429	223,110	$0	804,539	4,768,717
2019	$28,403	$0	$4,823,901	$1,037,734	5,890,038	$581,429	229,803	$0	811,232	5,078,806
2020	$29,255	$0	$5,073,556	$1,124,047	6,226,858	$581,429	236,697	$0	818,126	5,408,732
2021	$30,133	$0	$5,337,141	$1,217,773	6,585,047	$581,429	243,798	$0	825,227	5,759,820
2022	$31,037	$0	$5,615,435	$1,319,553	6,966,025	$581,429	251,112	$0	832,541	6,133,484
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$360,907	$0	$57,897,296	$11,579,673	$69,837,876	$8,163,435	$6,352,683	$1,116,000	$13,400,118	$56,437,758
NPV =	203,624	0	31,939,568	7,394,294	39,537,486	4,769,113	4,649,121	953,223	8,465,011	31,072,474

Total NPV = $31,072,474

Benefit/Cost Ratio = 4.67

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Benefits									Costs				
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.1324	$186,000	334,626	0	$0.040	$0.040	2,067	4,133	$10.56	$21.12	$559,770	$1,116,000	$83,007	$1,199,007	($639,237)
2009	0.2630	$372,000	669,253	0	$0.042	$0.042	4,133	8,267	$11.15	$22.29	$1,133,211	1,116,000	$170,995	1,286,995	(153,784)
2010	0.2611	$558,000	1,003,879	0	$0.045	$0.045	6,200	12,400	$11.77	$23.54	$1,721,466	1,116,000	$176,125	1,292,125	429,341
2011	0.2593	$0	1,003,879	0	$0.047	$0.047	6,200	12,400	$12.43	$24.85	$1,186,324	0	$181,409	181,409	1,004,916
2012	0.2575	$0	1,003,879	0	$0.050	$0.050	6,200	12,400	$13.12	$26.24	$1,210,458	0	$186,851	186,851	1,023,607
2013	0.2557	$0	1,003,879	0	$0.053	$0.053	6,200	12,400	$13.85	$27.70	$1,235,938	0	$192,456	192,456	1,043,482
2014	0.2540	$0	1,003,879	0	$0.055	$0.055	6,200	12,400	$14.62	$29.25	$1,262,840	0	$198,230	198,230	1,064,610
2015	0.2522	$0	1,003,879	0	$0.059	$0.059	6,200	12,400	$15.44	$30.88	$1,291,244	0	$204,177	204,177	1,087,067
2016	0.2504	$0	1,003,879	0	$0.062	$0.062	6,200	12,400	$16.30	$32.60	$1,321,232	0	$210,302	210,302	1,110,930
2017	0.2487	$0	1,003,879	0	$0.065	$0.065	6,200	12,400	$17.21	$34.42	$1,352,894	0	$216,611	216,611	1,136,282
2018	0.2470	$0	1,003,879	0	$0.069	$0.069	6,200	12,400	$18.17	$36.34	$1,386,322	0	$223,110	223,110	1,163,212
2019	0.2453	$0	1,003,879	0	$0.073	$0.073	6,200	12,400	$19.19	$38.37	$1,421,615	0	$229,803	229,803	1,191,812
2020	0.2435	$0	1,003,879	0	$0.077	$0.077	6,200	12,400	$20.26	$40.51	$1,458,878	0	$236,697	236,697	1,222,181
2021	0.2419	$0	1,003,879	0	$0.081	$0.081	6,200	12,400	$21.39	$42.77	$1,498,220	0	$243,798	243,798	1,254,423
2022	0.2402	$0	1,003,879	0	$0.086	$0.086	6,200	12,400	$22.58	$45.16	$1,539,758	0	$251,112	251,112	1,288,646
2023	0.2385	0	0	0	$0.090	$0.090	0	0	$23.84	$47.68	$0	0	$0	0	0
			14,054,309	0							$19,580,171	$3,348,000	$3,004,683	$6,352,683	$13,227,488
											$12,256,703	3,132,351	1,844,534	4,976,884	7,279,819

Total NPV = $7,279,819
Benefit/Cost Ratio = 2.46

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$56,334
Total Utility Project Costs Year 1 =	**$76,163**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$56,334
Total Utility Project Costs Year 2 =	**$76,163**
15b) Total Utilty Cost Year 3 =	**$76,163**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,467.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.13
20a) Avg Winter kW/part Saved =	0.27
21) Avg. Summer kWh/Part. Saved =	588
21a) Avg. Winter kWh/Part. Saved =	1,175
22) Number of Participants (First Year) =	213
22a) Number of Participants (Second Year) =	213
22a) Number of Participants (Third Year) =	213
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 264

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$228,490
Total Program Participants	639
Utility Cost per Participant (First Year) =	$357.53
Utility Cost per Participant (Program) =	$357.53
Total kW Reduction	276
Total Energy Reduction (kWh)	17,011,881
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$941,387	3.46
Ratepayer Test	$1,124,189	6.63
Societal Cost Test	$756,245	1.87
Participant Test	$120,735	1.14

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	405,045	$0.0190	$0	92	$349.78	$39,821	$76,163	5,411	$81,575	($41,754)
2	2009	810,090	$0.0195	0	184	$366.87	83,243	76,163	11,306	87,470	(4,227)
3	2010	1,215,134	$0.0201	0	276	$384.91	130,551	76,163	17,736	93,899	36,651
4	2011	1,215,134	$0.0207	0	276	$403.96	136,536	0	18,567	18,567	117,969
5	2012	1,215,134	$0.0213	0	276	$424.07	142,836	0	19,456	19,456	123,380
6	2013	1,215,134	$0.0220	0	276	$445.31	149,468	0	20,406	20,406	129,061
7	2014	1,215,134	$0.0226	0	276	$467.73	156,450	0	21,422	21,422	135,028
8	2015	1,215,134	$0.0233	0	276	$491.40	163,801	0	22,507	22,507	141,294
9	2016	1,215,134	$0.0240	0	276	$516.39	171,541	0	23,666	23,666	147,875
10	2017	1,215,134	$0.0247	0	276	$542.78	179,691	0	24,903	24,903	154,788
11	2018	1,215,134	$0.0255	0	276	$570.64	188,273	0	26,222	26,222	162,051
12	2019	1,215,134	$0.0262	0	276	$600.05	197,311	0	27,629	27,629	169,682
13	2020	1,215,134	$0.0270	0	276	$631.11	206,829	0	29,130	29,130	177,699
14	2021	1,215,134	$0.0278	0	276	$663.90	216,853	0	30,729	30,729	186,125
15	2022	1,215,134	$0.0287	0	276	$698.51	227,412	0	32,433	32,433	194,979
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		17,011,881			3,860		$2,390,614	$228,490	$331,523	$560,013	$1,830,601
NPV =							1,323,884	199,695	182,802	382,497	941,387

Total NPV = $941,387
Benefit/Cost Ratio = 3.46

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$7,676	$0	$32,144	$39,821	$76,163	$76,163	($36,343)
2009	15,813	0	67,430	83,243	76,163	76,163	7,080
2010	24,432	0	106,119	130,551	76,163	76,163	54,387
2011	25,165	0	111,371	136,536	0	0	136,536
2012	25,920	0	116,916	142,836	0	0	142,836
2013	26,697	0	122,771	149,468	0	0	149,468
2014	27,498	0	128,952	156,450	0	0	156,450
2015	28,323	0	135,478	163,801	0	0	163,801
2016	29,173	0	142,368	171,541	0	0	171,541
2017	30,048	0	149,643	179,691	0	0	179,691
2018	30,949	0	157,324	188,273	0	0	188,273
2019	31,878	0	165,433	197,311	0	0	197,311
2020	32,834	0	173,995	206,829	0	0	206,829
2021	33,819	0	183,034	216,853	0	0	216,853
2022	34,834	0	192,578	227,412	0	0	227,412
2023	0	0	0	0	0	0	0
Total =	$405,059	$0	$1,985,555	$2,390,614	$228,490	$228,490	$2,162,124
NPV =	228,534	0	1,095,350	1,323,884	199,695	199,695	1,124,189

Total NPV = $1,124,189
Benefit/Cost Ratio = 6.63

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$7,676	$0	$32,144	$6,152	$45,973	$76,163	$312,508	$56,334	$332,337	($286,364)
2009	$15,813	$0	$67,430	$13,247	96,490	76,163	312,508	$56,334	332,337	(235,847)
2010	$24,432	$0	$106,119	$21,398	151,949	76163.461	312,508	$56,334	332,337	(180,388)
2011	$25,165	$0	$111,371	$23,051	159,586	0	0	$0	0	159,586
2012	$25,920	$0	$116,916	$24,838	167,674	0	0	$0	0	167,674
2013	$26,697	$0	$122,771	$26,771	176,239	0	0	$0	0	176,239
2014	$27,498	$0	$128,952	$28,862	185,312	0	0	$0	0	185,312
2015	$28,323	$0	$135,478	$31,125	194,926	0	0	$0	0	194,926
2016	$29,173	$0	$142,368	$33,573	205,114	0	0	$0	0	205,114
2017	$30,048	$0	$149,643	$36,223	215,914	0	0	$0	0	215,914
2018	$30,949	$0	$157,324	$39,092	227,365	0	0	$0	0	227,365
2019	$31,878	$0	$165,433	$42,198	239,509	0	0	$0	0	239,509
2020	$32,834	$0	$173,995	$45,560	252,389	0	0	$0	0	252,389
2021	$33,819	$0	$183,034	$49,202	266,055	0	0	$0	0	266,055
2022	$34,834	$0	$192,578	$53,145	280,557	0	0	$0	0	280,557
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$405,059	$0	$1,985,555	$474,437	$2,865,052	$228,490	$937,523	$169,003	$997,010	$1,868,042
NPV =	228,534	0	1,095,350	303,721	1,627,605	199,695	819,370	147,704	871,360	756,245

Total NPV = $756,245
Benefit/Cost Ratio = 1.87

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0124	$56,334	125,188	250,375	$0.045	$0.045	28	57	$47.41	$69.46	$78,471	$312,508	$0	$312,508	($234,037)
2009	0.0247	$56,334	250,375	500,751	$0.047	$0.047	57	114	$50.05	$73.34	$103,078	312,508	$0	312,508	(209,430)
2010	0.0245	$56,334	375,563	751,126	$0.050	$0.050	85	170	$52.84	$77.43	$130,362	312,508	$0	312,508	(182,146)
2011	0.0243	$0	375,563	751,126	$0.053	$0.053	85	170	$55.79	$81.75	$78,158	0	$0	0	78,158
2012	0.0241	$0	375,563	751,126	$0.056	$0.056	85	170	$58.91	$86.31	$82,519	0	$0	0	82,519
2013	0.0240	0	375,563	751,126	$0.059	$0.059	85	170	$62.19	$91.13	$87,124	0	$0	0	87,124
2014	0.0238	0	375,563	751,126	$0.062	$0.062	85	170	$65.66	$96.21	$91,986	0	$0	0	91,986
2015	0.0236	0	375,563	751,126	$0.066	$0.066	85	170	$69.33	$101.58	$97,118	0	$0	0	97,118
2016	0.0235	0	375,563	751,126	$0.069	$0.069	85	170	$73.19	$107.25	$102,538	0	$0	0	102,538
2017	0.0233	0	375,563	751,126	$0.073	$0.073	85	170	$77.28	$113.23	$108,259	0	$0	0	108,259
2018	0.0232	0	375,563	751,126	$0.077	$0.077	85	170	$81.59	$119.55	$114,300	0	$0	0	114,300
2019	0.0230	0	375,563	751,126	$0.082	$0.082	85	170	$86.14	$126.22	$120,678	0	$0	0	120,678
2020	0.0228	0	375,563	751,126	$0.086	$0.086	85	170	$90.95	$133.27	$127,412	0	$0	0	127,412
2021	0.0227	0	375,563	751,126	$0.091	$0.091	85	170	$96.03	$140.70	$134,521	0	$0	0	134,521
2022	0.0225	0	375,563	751,126	$0.096	$0.096	85	170	$101.38	$148.55	$142,028	0	$0	0	142,028
2023	0.0224	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			5,257,883	10,515,766							$1,598,552	$937,523	$0	$937,523	$661,029
											$997,871	877,136	0	877,136	120,735

Total NPV = $120,735
Benefit/Cost Ratio = 1.14

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$43,674
Total Utility Project Costs Year 1 =	**$63,503**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$43,674
Total Utility Project Costs Year 2 =	**$63,503**
15b) Total Utilty Cost Year 3 =	**$63,503**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$300.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$ (35.00)
Escalation Rate =	3.00%
18) Project Life (Years) =	11
20) Avg Summer kW/part. Saved =	0.01
20a) Avg Winter kW/part Saved =	0.02
21) Avg. Summer kWh/Part. Saved =	99
21a) Avg. Winter kWh/Part. Saved =	198
22) Number of Participants (First Year) =	1,747
22a) Number of Participants (Second Year) =	1,747
22a) Number of Participants (Third Year) =	1,747
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 25.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	11
Total Progam Cost (Utility)	$190,510
Total Program Participants	5,241
Utility Cost per Participant (First Year) =	$36.35
Utility Cost per Participant (Program) =	$36.35
Total kW Reduction	157
Total Energy Reduction (kWh)	16,787,392
Societal Cost per kwh	$0.02

Test Results

	NPV	B/C
Utility Test	$129,611	1.23
Ratepayer Test	$536,154	4.22
Societal Cost Test	$438,380	2.07
Participant Test	$813,561	3.12

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	559,580	$0.0190	$0	52	$349.78	$28,860	$63,503	16,648	$80,151	($51,291)
2	2009	1,119,159	$0.0195	0	104	$366.87	60,140	63,503	34,658	98,161	(38,021)
3	2010	1,678,739	$0.0201	0	157	$384.91	94,018	63503.24	54,160	117,663	(23,645)
4	2011	1,678,739	$0.0207	0	157	$403.96	98,014	0	56,470	56,470	41,544
5	2012	1,678,739	$0.0213	0	157	$424.07	102,206	0	58,924	58,924	43,281
6	2013	1,678,739	$0.0220	0	157	$445.31	106,605	0	61,532	61,532	45,072
7	2014	1,678,739	$0.0226	0	157	$467.73	111,222	0	64,303	64,303	46,919
8	2015	1,678,739	$0.0233	0	157	$491.40	116,067	0	67,245	67,245	48,823
9	2016	1,678,739	$0.0240	0	157	$516.39	121,154	0	70,369	70,369	50,785
10	2017	1,678,739	$0.0247	0	157	$542.78	126,495	0	73,687	73,687	52,808
11	2018	1,678,739	$0.0255	0	157	$570.64	132,102	0	77,208	77,208	54,894
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		16,787,392			1,566		$1,096,882	$190,510	$635,204	$825,714	$271,169
NPV =							702,654	166,500	406,542	573,043	129,611

Total NPV = $129,611
Benefit/Cost Ratio = 1.23

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)
(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$10,605	$0	$18,255	$28,860	$63,503	$63,503	($34,643)
2009	21,847	0	38,294	60,140	63,503	63,503	(3,363)
2010	33,753	0	60,265	94,018	63,503	63,503	30,515
2011	34,766	0	63,248	98,014	0	0	98,014
2012	35,809	0	66,397	102,206	0	0	102,206
2013	36,883	0	69,722	106,605	0	0	106,605
2014	37,989	0	73,232	111,222	0	0	111,222
2015	39,129	0	76,938	116,067	0	0	116,067
2016	40,303	0	80,851	121,154	0	0	121,154
2017	41,512	0	84,983	126,495	0	0	126,495
2018	42,757	0	89,345	132,102	0	0	132,102
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$375,352	$0	$721,530	$1,096,882	$190,510	$190,510	$906,373
NPV =	242,250	0	460,404	702,654	166,500	166,500	536,154

Total NPV = $536,154

Benefit/Cost Ratio = 4.22

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$10,605	$0	$18,255	$4,459	$33,319	$63,503	$461,113	$43,674	$480,942	($447,623)
2009	$21,847	$0	$38,294	$9,570	69,711	63,503	394,356	$43,674	414,185	(344,474)
2010	$33,753	$0	$60,265	$15,410	109,429	63503.242	390,464	$43,674	410,293	(300,864)
2011	$34,766	$0	$63,248	$16,547	114,561	0	(137,636)	$0	(137,636)	252,197
2012	$35,809	$0	$66,397	$17,773	119,978	0	(141,765)	$0	(141,765)	261,743
2013	$36,883	$0	$69,722	$19,094	125,698	0	(146,018)	$0	(146,018)	271,717
2014	$37,989	$0	$73,232	$20,518	131,740	0	(150,399)	$0	(150,399)	282,138
2015	$39,129	$0	$76,938	$22,055	138,122	0	(154,911)	$0	(154,911)	293,033
2016	$40,303	$0	$80,851	$23,712	144,866	0	(159,558)	$0	(159,558)	304,424
2017	$41,512	$0	$84,983	$25,500	151,995	0	(164,345)	$0	(164,345)	316,339
2018	$42,757	$0	$89,345	$27,429	159,531	0	(169,275)	$0	(169,275)	328,806
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$375,352	$0	$721,530	$202,067	$1,298,949	$190,510	$22,026	$131,023	$81,513	$1,217,437
NPV =	242,250	0	460,404	145,433	848,088	166,500	357,718	114,510	409,708	438,380

Total NPV = $438,380

Benefit/Cost Ratio = 2.07

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

		Benefits										Costs				
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0200	$43,674	172,950	345,900	$0.074	$0.074	16	32	$0.00	$0.00	$82,250	$524,091	($62,978)	$461,113	($378,862)
2009	0.0393	$43,674	345,900	691,800	$0.078	$0.078	32	65	$0.00	$0.00	$125,132	524,091	($129,735)	394,356	(269,224)
2010	0.0387	$43,674	518,850	1,037,700	$0.083	$0.083	48	97	$0.00	$0.00	$172,679	524,091	($133,627)	390,464	(217,785)
2011	0.0381	$0	518,850	1,037,700	$0.088	$0.088	48	97	$0.00	$0.00	$136,203	0	($137,636)	(137,636)	273,839
2012	0.0375	$0	518,850	1,037,700	$0.092	$0.092	48	97	$0.00	$0.00	$143,803	0	($141,765)	(141,765)	285,568
2013	0.0369	0	518,850	1,037,700	$0.098	$0.098	48	97	$0.00	$0.00	$151,827	0	($146,018)	(146,018)	297,845
2014	0.0363	0	518,850	1,037,700	$0.103	$0.103	48	97	$0.00	$0.00	$160,299	0	($150,399)	(150,399)	310,698
2015	0.0357	0	518,850	1,037,700	$0.109	$0.109	48	97	$0.00	$0.00	$169,244	0	($154,911)	(154,911)	324,154
2016	0.0352	0	518,850	1,037,700	$0.115	$0.115	48	97	$0.00	$0.00	$178,687	0	($159,558)	(159,558)	338,245
2017	0.0346	0	518,850	1,037,700	$0.121	$0.121	48	97	$0.00	$0.00	$188,658	0	($164,345)	(164,345)	353,003
2018	0.0341	0	518,850	1,037,700	$0.128	$0.128	48	97	$0.00	$0.00	$199,185	0	($169,275)	(169,275)	368,460
2019	0.0335	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0330	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0325	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0320	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0315	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			5,188,500	10,377,000							$1,707,967	$1,572,273	($1,550,247)	$22,026	$1,685,941
											$1,196,498	1,471,001	(1,088,064)	382,937	813,561

Total NPV = $813,561
Benefit/Cost Ratio = 3.12

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$10,629
Total Utility Project Costs Year 1 =	**$30,458**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$10,629
Total Utility Project Costs Year 2 =	**$30,458**
15b) Total Utilty Cost Year 3 =	**$30,458**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$50.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	($3.00)
Escalation Rate =	3.00%
18) Project Life (Years) =	13
20) Avg Summer kW/part. Saved =	0.00
20a) Avg Winter kW/part Saved =	0.00
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	1,063
22a) Number of Participants (Second Year) =	1,063
22a) Number of Participants (Third Year) =	1,063
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 10.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	13
Total Progam Cost (Utility)	$91,374
Total Program Participants	3,189
Utility Cost per Participant (First Year) =	$28.66
Utility Cost per Participant (Program) =	$28.66
Total kW Reduction	0
Total Energy Reduction (kWh)	2,971,277
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	($108,900)	0.28
Ratepayer Test	($38,500)	0.52
Societal Cost Test	($80,160)	0.39
Participant Test	$133,363	2.59

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	82,535	$0.0190	$0	0	$349.78	$1,564	$30,458	2,455	$32,913	($31,349)
2	2009	165,071	$0.0195	0	0	$366.87	3,222	30,458	5,112	35,570	(32,348)
3	2010	247,606	$0.0201	0	0	$384.91	4,978	30457.89	7,988	38,446	(33,468)
4	2011	247,606	$0.0207	0	0	$403.96	5,128	0	8,329	8,329	(3,201)
5	2012	247,606	$0.0213	0	0	$424.07	5,282	0	8,691	8,691	(3,409)
6	2013	247,606	$0.0220	0	0	$445.31	5,440	0	9,076	9,076	(3,636)
7	2014	247,606	$0.0226	0	0	$467.73	5,603	0	9,484	9,484	(3,881)
8	2015	247,606	$0.0233	0	0	$491.40	5,771	0	9,918	9,918	(4,147)
9	2016	247,606	$0.0240	0	0	$516.39	5,944	0	10,379	10,379	(4,435)
10	2017	247,606	$0.0247	0	0	$542.78	6,123	0	10,868	10,868	(4,746)
11	2018	247,606	$0.0255	0	0	$570.64	6,307	0	11,388	11,388	(5,081)
12	2019	247,606	$0.0262	0	0	$600.05	6,496	0	11,939	11,939	(5,443)
13	2020	247,606	$0.0270	0	0	$631.11	6,691	0	12,524	12,524	(5,833)
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		2,971,277			0		$68,549	$91,374	$118,153	$209,527	($140,977)
NPV =							41,358	79,858	70,400	150,258	(108,900)

Total NPV = ($108,900)
Benefit/Cost Ratio = 0.28

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,564	$0	$0	$1,564	$30,458	$30,458	($28,894)
2009	3,222	0	0	3,222	30,458	30,458	(27,236)
2010	4,978	0	0	4,978	30,458	30,458	(25,479)
2011	5,128	0	0	5,128	0	0	5,128
2012	5,282	0	0	5,282	0	0	5,282
2013	5,440	0	0	5,440	0	0	5,440
2014	5,603	0	0	5,603	0	0	5,603
2015	5,771	0	0	5,771	0	0	5,771
2016	5,944	0	0	5,944	0	0	5,944
2017	6,123	0	0	6,123	0	0	6,123
2018	6,307	0	0	6,307	0	0	6,307
2019	6,496	0	0	6,496	0	0	6,496
2020	6,691	0	0	6,691	0	0	6,691
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$68,549	$0	$0	$68,549	$91,374	$91,374	($22,825)
NPV =	41,358	0	0	41,358	79,858	79,858	(38,500)

Total NPV = ($38,500)

Benefit/Cost Ratio = 0.52

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,564	$0	$0	$242	$1,806	$30,458	$49,860	$10,629	$69,689	($67,883)
2009	$3,222	$0	$0	$513	3,735	30,458	46,379	$10,629	66,208	(62,473)
2010	$4,978	$0	$0	$816	5,794	30457.892	46,176	$10,629	66,005	(60,210)
2011	$5,128	$0	$0	$866	5,993	0	(7,178)	$0	(7,178)	13,171
2012	$5,282	$0	$0	$918	6,200	0	(7,393)	$0	(7,393)	13,593
2013	$5,440	$0	$0	$974	6,414	0	(7,615)	$0	(7,615)	14,029
2014	$5,603	$0	$0	$1,034	6,637	0	(7,843)	$0	(7,843)	14,480
2015	$5,771	$0	$0	$1,097	6,868	0	(8,079)	$0	(8,079)	14,947
2016	$5,944	$0	$0	$1,163	7,108	0	(8,321)	$0	(8,321)	15,429
2017	$6,123	$0	$0	$1,234	7,357	0	(8,571)	$0	(8,571)	15,928
2018	$6,307	$0	$0	$1,309	7,616	0	(8,828)	$0	(8,828)	16,444
2019	$6,496	$0	$0	$1,389	7,885	0	(9,093)	$0	(9,093)	16,977
2020	$6,691	$0	$0	$1,474	8,164	0	(9,365)	$0	(9,365)	17,530
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$68,549	$0	$0	$13,029	$81,579	$91,374	$60,130	$31,887	$119,617	($38,038)
NPV =	41,358	0	0	8,929	50,287	79,858	78,457	27,868	130,447	(80,160)

Total NPV = ($80,160)
Benefit/Cost Ratio = 0.39

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

		Benefits										Costs				
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0121	$10,629	25,509	51,019	$0.074	$0.074	0	0	$0.00	$0.00	$16,319	$53,144	($3,284)	$49,860	($33,541)
2009	0.0239	$10,629	51,019	102,037	$0.078	$0.078	0	0	$0.00	$0.00	$22,644	53,144	($6,766)	46,379	(23,735)
2010	0.0235	$10,629	76,528	153,056	$0.083	$0.083	0	0	$0.00	$0.00	$29,656	53,144	($6,969)	46,176	(16,519)
2011	0.0232	$0	76,528	153,056	$0.088	$0.088	0	0	$0.00	$0.00	$20,089	0	($7,178)	(7,178)	27,267
2012	0.0228	$0	76,528	153,056	$0.092	$0.092	0	0	$0.00	$0.00	$21,210	0	($7,393)	(7,393)	28,603
2013	0.0224	0	76,528	153,056	$0.098	$0.098	0	0	$0.00	$0.00	$22,394	0	($7,615)	(7,615)	30,009
2014	0.0221	0	76,528	153,056	$0.103	$0.103	0	0	$0.00	$0.00	$23,643	0	($7,843)	(7,843)	31,487
2015	0.0217	0	76,528	153,056	$0.109	$0.109	0	0	$0.00	$0.00	$24,963	0	($8,079)	(8,079)	33,041
2016	0.0214	0	76,528	153,056	$0.115	$0.115	0	0	$0.00	$0.00	$26,356	0	($8,321)	(8,321)	34,677
2017	0.0211	0	76,528	153,056	$0.121	$0.121	0	0	$0.00	$0.00	$27,826	0	($8,571)	(8,571)	36,397
2018	0.0207	0	76,528	153,056	$0.128	$0.128	0	0	$0.00	$0.00	$29,379	0	($8,828)	(8,828)	38,207
2019	0.0204	0	76,528	153,056	$0.135	$0.135	0	0	$0.00	$0.00	$31,018	0	($9,093)	(9,093)	40,111
2020	0.0201	0	76,528	153,056	$0.143	$0.143	0	0	$0.00	$0.00	$32,749	0	($9,365)	(9,365)	42,114
2021	0.0198	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0194	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0191	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			918,336	1,836,672							$328,246	$159,433	($99,304)	$60,130	$268,116
											$217,351	149,164	(65,175)	83,989	133,363

Total NPV = $133,363
Benefit/Cost Ratio = 2.59

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Oemand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$43,076
Total Utility Project Costs Year 1 =	**$62,905**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$43,076
Total Utility Project Costs Year 2 =	**$62,905**
15b) Total Utilty Cost Year 3 =	**$62,905**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$30.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.014
20a) Avg Winter kW/part Saved =	0.028
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	2,872
22a) Number of Participants (Second Year) =	2,872
22a) Number of Participants (Third Year) =	2,872
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential ENERGY STAR Refridgerators**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$188,714
Total Program Participants	8,615
Utility Cost per Participant (First Year) =	$21.90
Utility Cost per Participant (Program) =	$21.90
Total kW Reduction	390
Total Energy Reduction (kWh)	9,365,716
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$1,293,999	4.39
Ratepayer Test	$1,511,311	10.16
Societal Cost Test	$1,783,543	7.42
Participant Test	$462,264	2.91

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	222,993	$0.0190	$0	130	$349.78	$49,725	$62,905	6,634	$69,539	($19,814)
2	2009	445,986	$0.0195	0	260	$366.87	104,150	62,905	13,811	76,716	27,434
3	2010	668,980	$0.0201	0	390	$384.91	163,658	62904.5	21,583	84,487	79,170
4	2011	668,980	$0.0207	0	390	$403.96	171,495	0	22,503	22,503	148,992
5	2012	668,980	$0.0213	0	390	$424.07	179,760	0	23,481	23,481	156,278
6	2013	668,980	$0.0220	0	390	$445.31	188,475	0	24,521	24,521	163,954
7	2014	668,980	$0.0226	0	390	$467.73	197,665	0	25,625	25,625	172,040
8	2015	668,980	$0.0233	0	390	$491.40	207,357	0	26,797	26,797	180,559
9	2016	668,980	$0.0240	0	390	$516.39	217,577	0	28,042	28,042	189,535
10	2017	668,980	$0.0247	0	390	$542.78	228,356	0	29,364	29,364	198,992
11	2018	668,980	$0.0255	0	390	$570.64	239,724	0	30,767	30,767	208,957
12	2019	668,980	$0.0262	0	390	$600.05	251,714	0	32,257	32,257	219,457
13	2020	668,980	$0.0270	0	390	$631.11	264,359	0	33,837	33,837	230,522
14	2021	668,980	$0.0278	0	390	$663.90	277,697	0	35,514	35,514	242,182
15	2022	668,980	$0.0287	0	390	$698.51	291,764	0	37,293	37,293	254,471
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		9,365,716			5,463		$3,033,476	$188,714	$392,032	$580,745	$2,452,731
NPV =							1,676,241	164,931	217,312	382,243	1,293,999

Total NPV = $1,293,999
Benefit/Cost Ratio = 4.39

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential ENERGY STAR Refridgerators**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable D & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$4,226	$0	$45,499	$49,725	$62,905	$62,905	($13,179)
2009	8,706	0	95,444	104,150	62,905	62,905	41,245
2010	13,451	0	150,207	163,658	62,905	62,905	100,753
2011	13,854	0	157,641	171,495	0	0	171,495
2012	14,270	0	165,490	179,760	0	0	179,760
2013	14,698	0	173,777	188,475	0	0	188,475
2014	15,139	0	182,526	197,665	0	0	197,665
2015	15,593	0	191,764	207,357	0	0	207,357
2016	16,061	0	201,517	217,577	0	0	217,577
2017	16,543	0	211,814	228,356	0	0	228,356
2018	17,039	0	222,685	239,724	0	0	239,724
2019	17,550	0	234,164	251,714	0	0	251,714
2020	18,077	0	246,283	264,359	0	0	264,359
2021	18,619	0	259,078	277,697	0	0	277,697
2022	19,177	0	272,587	291,764	0	0	291,764
2023	0	0	0	0	0	0	0
Total =	$223,001	$0	$2,810,475	$3,033,476	$188,714	$188,714	$2,844,763
NPV =	125,817	0	1,550,424	1,676,241	164,931	164,931	1,511,311

Total NPV = $1,511,311

Benefit/Cost Ratio = 10.16

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable D&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$4,226	$0	$45,499	$7,683	$57,408	$62,905	$86,151	$43,076	$105,980	($48,572)
2009	$8,706	$0	$95,444	$16,574	120,724	62,905	86,151	$43,076	105,980	14,744
2010	$13,451	$0	$150,207	$26,825	190,483	62904.5	86,151	$43,076	105,980	84,503
2011	$13,854	$0	$157,641	$28,953	200,448	0	0	$0	0	200,448
2012	$14,270	$0	$165,490	$31,259	211,019	0	0	$0	0	211,019
2013	$14,698	$0	$173,777	$33,757	222,232	0	0	$0	0	222,232
2014	$15,139	$0	$182,526	$36,465	234,130	0	0	$0	0	234,130
2015	$15,593	$0	$191,764	$39,401	246,758	0	0	$0	0	246,758
2016	$16,061	$0	$201,517	$42,583	260,161	0	0	$0	0	260,161
2017	$16,543	$0	$211,814	$46,034	274,390	0	0	$0	0	274,390
2018	$17,039	$0	$222,685	$49,775	289,500	0	0	$0	0	289,500
2019	$17,550	$0	$234,164	$53,833	305,546	0	0	$0	0	305,546
2020	$18,077	$0	$246,283	$58,233	322,592	0	0	$0	0	322,592
2021	$18,619	$0	$259,078	$63,006	340,703	0	0	$0	0	340,703
2022	$19,177	$0	$272,587	$68,184	359,948	0	0	$0	0	359,948
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$223,001	$0	$2,810,475	$602,565	$3,636,041	$188,714	$258,453	$129,227	$317,940	$3,318,101
NPV =	125,817	0	1,550,424	385,173	2,061,414	164,931	225,881	112,941	277,871	1,783,543

Total NPV = $1,783,543
Benefit/Cost Ratio = 7.42

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

		Benefits							Costs						
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0328	$43,076	68,921	137,842	$0.074	$0.074	40	80	$0.00	$0.00	$58,448	$86,151	$0	$86,151	($27,703)
2009	0.0646	$43,076	137,842	275,683	$0.078	$0.078	80	161	$0.00	$0.00	$75,536	86,151	$0	86,151	(10,615)
2010	0.0636	$43,076	206,762	413,525	$0.083	$0.083	121	241	$0.00	$0.00	$94,484	86,151	$0	86,151	8,333
2011	0.0626	$0	206,762	413,525	$0.088	$0.088	121	241	$0.00	$0.00	$54,277	0	$0	0	54,277
2012	0.0616	$0	206,762	413,525	$0.092	$0.092	121	241	$0.00	$0.00	$57,306	0	$0	0	57,306
2013	0.0606	0	206,762	413,525	$0.098	$0.098	121	241	$0.00	$0.00	$60,503	0	$0	0	60,503
2014	0.0597	0	206,762	413,525	$0.103	$0.103	121	241	$0.00	$0.00	$63,879	0	$0	0	63,879
2015	0.0587	0	206,762	413,525	$0.109	$0.109	121	241	$0.00	$0.00	$67,444	0	$0	0	67,444
2016	0.0578	0	206,762	413,525	$0.115	$0.115	121	241	$0.00	$0.00	$71,207	0	$0	0	71,207
2017	0.0569	0	206,762	413,525	$0.121	$0.121	121	241	$0.00	$0.00	$75,181	0	$0	0	75,181
2018	0.0560	0	206,762	413,525	$0.128	$0.128	121	241	$0.00	$0.00	$79,376	0	$0	0	79,376
2019	0.0551	0	206,762	413,525	$0.135	$0.135	121	241	$0.00	$0.00	$83,805	0	$0	0	83,805
2020	0.0542	0	206,762	413,525	$0.143	$0.143	121	241	$0.00	$0.00	$88,481	0	$0	0	88,481
2021	0.0534	0	206,762	413,525	$0.151	$0.151	121	241	$0.00	$0.00	$93,418	0	$0	0	93,418
2022	0.0525	0	206,762	413,525	$0.159	$0.159	121	241	$0.00	$0.00	$98,631	0	$0	0	98,631
2023	0.0517	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			2,894,674	5,789,347							$1,121,976	$258,453	$0	$258,453	$863,523
											$704,069	241,806	0	241,806	462,264

Total NPV = $462,264
Benefit/Cost Ratio = 2.91

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$33,543
Total Utility Project Costs Year 1 =	**$53,372**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$33,543
Total Utility Project Costs Year 2 =	**$53,372**
15b) Total Utilty Cost Year 3 =	**$53,372**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$33.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.012
20a) Avg Winter kW/part Saved =	0.023
21) Avg. Summer kWh/Part. Saved =	17
21a) Avg. Winter kWh/Part. Saved =	35
22) Number of Participants (First Year) =	2,236
22a) Number of Participants (Second Year) =	2,236
22a) Number of Participants (Third Year) =	2,236
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential ENERGY STAR Freezers**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$160,116
Total Program Participants	6,709
Utility Cost per Participant (First Year) =	$23.87
Utility Cost per Participant (Program) =	$23.87
Total kW Reduction	253
Total Energy Reduction (kWh)	5,267,227
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$814,703	4.11
Ratepayer Test	$936,918	7.70
Societal Cost Test	$1,078,864	5.40
Participant Test	$214,993	2.04

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	125,410	$0.0190	$0	84	$349.78	$31,902	$53,372	3,731	$57,103	($25,201)
2	2009	250,820	$0.0195	0	169	$366.87	66,831	53,372	7,767	61,139	5,692
3	2010	376,230	$0.0201	0	253	$384.91	105,036	53371.89	12,138	65,510	39,526
4	2011	376,230	$0.0207	0	253	$403.96	110,087	0	12,656	12,656	97,432
5	2012	376,230	$0.0213	0	253	$424.07	115,415	0	13,206	13,206	102,209
6	2013	376,230	$0.0220	0	253	$445.31	121,033	0	13,790	13,790	107,242
7	2014	376,230	$0.0226	0	253	$467.73	126,958	0	14,411	14,411	112,547
8	2015	376,230	$0.0233	0	253	$491.40	133,208	0	15,071	15,071	118,137
9	2016	376,230	$0.0240	0	253	$516.39	139,800	0	15,771	15,771	124,029
10	2017	376,230	$0.0247	0	253	$542.78	146,753	0	16,514	16,514	130,239
11	2018	376,230	$0.0255	0	253	$570.64	154,087	0	17,303	17,303	136,783
12	2019	376,230	$0.0262	0	253	$600.05	161,823	0	18,141	18,141	143,682
13	2020	376,230	$0.0270	0	253	$631.11	169,983	0	19,030	19,030	150,953
14	2021	376,230	$0.0278	0	253	$663.90	178,591	0	19,973	19,973	158,618
15	2022	376,230	$0.0287	0	253	$698.51	187,671	0	20,974	20,974	166,698
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		5,267,227			3,545		$1,949,179	$160,116	$220,476	$380,592	$1,568,587
NPV =							1,076,855	139,937	122,215	262,152	814,703

Total NPV = $814,703
Benefit/Cost Ratio = 4.11

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential ENERGY STAR Freezers**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,377	$0	$29,525	$31,902	$53,372	$53,372	($21,470)
2009	4,896	0	61,935	66,831	53,372	53,372	13,459
2010	7,565	0	97,472	105,036	53,372	53,372	51,665
2011	7,791	0	102,296	110,087	0	0	110,087
2012	8,025	0	107,389	115,415	0	0	115,415
2013	8,266	0	112,767	121,033	0	0	121,033
2014	8,514	0	118,444	126,958	0	0	126,958
2015	8,769	0	124,439	133,208	0	0	133,208
2016	9,032	0	130,767	139,800	0	0	139,800
2017	9,303	0	137,449	146,753	0	0	146,753
2018	9,583	0	144,504	154,087	0	0	154,087
2019	9,870	0	151,953	161,823	0	0	161,823
2020	10,166	0	159,817	169,983	0	0	169,983
2021	10,471	0	168,120	178,591	0	0	178,591
2022	10,785	0	176,886	187,671	0	0	187,671
2023	0	0	0	0	0	0	0
Total =	$125,415	$0	$1,823,764	$1,949,179	$160,116	$160,116	$1,789,063
NPV =	70,759	0	1,006,096	1,076,855	139,937	139,937	936,918

Total NPV = $936,918

Benefit/Cost Ratio = 7.70

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,377	$0	$29,525	$4,929	$36,831	$53,372	$73,794	$33,543	$93,623	($56,793)
2009	$4,896	$0	$61,935	$10,635	77,467	53,372	73,794	$33,543	93,623	(16,157)
2010	$7,565	$0	$97,472	$17,216	122,253	53371.892	73,794	$33,543	93,623	28,630
2011	$7,791	$0	$102,296	$18,586	128,673	0	0	$0	0	128,673
2012	$8,025	$0	$107,389	$20,070	135,484	0	0	$0	0	135,484
2013	$8,266	$0	$112,767	$21,678	142,711	0	0	$0	0	142,711
2014	$8,514	$0	$118,444	$23,421	150,380	0	0	$0	0	150,380
2015	$8,769	$0	$124,439	$25,312	158,520	0	0	$0	0	158,520
2016	$9,032	$0	$130,767	$27,361	167,161	0	0	$0	0	167,161
2017	$9,303	$0	$137,449	$29,584	176,336	0	0	$0	0	176,336
2018	$9,583	$0	$144,504	$31,994	186,081	0	0	$0	0	186,081
2019	$9,870	$0	$151,953	$34,608	196,431	0	0	$0	0	196,431
2020	$10,166	$0	$159,817	$37,444	207,427	0	0	$0	0	207,427
2021	$10,471	$0	$168,120	$40,520	219,111	0	0	$0	0	219,111
2022	$10,785	$0	$176,886	$43,858	231,529	0	0	$0	0	231,529
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$125,415	$0	$1,823,764	$387,215	$2,336,394	$160,116	$221,383	$100,629	$280,870	$2,055,524
NPV =	70,759	0	1,006,096	247,482	1,324,337	139,937	193,483	87,947	245,473	1,078,864

Total NPV = $1,078,864
Benefit/Cost Ratio = 5.40

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0255	$33,543	38,761	77,521	$0.074	$0.074	26	52	$0.00	$0.00	$42,188	$73,794	$0	$73,794	($31,606)
2009	0.0503	$33,543	77,521	155,043	$0.078	$0.078	52	104	$0.00	$0.00	$51,799	73,794	$0	73,794	(21,996)
2010	0.0495	$33,543	116,282	232,564	$0.083	$0.083	78	157	$0.00	$0.00	$62,455	73,794	$0	73,794	(11,340)
2011	0.0487	$0	116,282	232,564	$0.088	$0.088	78	157	$0.00	$0.00	$30,525	0	$0	0	30,525
2012	0.0480	$0	116,282	232,564	$0.092	$0.092	78	157	$0.00	$0.00	$32,228	0	$0	0	32,228
2013	0.0472	0	116,282	232,564	$0.098	$0.098	78	157	$0.00	$0.00	$34,027	0	$0	0	34,027
2014	0.0465	0	116,282	232,564	$0.103	$0.103	78	157	$0.00	$0.00	$35,925	0	$0	0	35,925
2015	0.0457	0	116,282	232,564	$0.109	$0.109	78	157	$0.00	$0.00	$37,930	0	$0	0	37,930
2016	0.0450	0	116,282	232,564	$0.115	$0.115	78	157	$0.00	$0.00	$40,047	0	$0	0	40,047
2017	0.0443	0	116,282	232,564	$0.121	$0.121	78	157	$0.00	$0.00	$42,281	0	$0	0	42,281
2018	0.0436	0	116,282	232,564	$0.128	$0.128	78	157	$0.00	$0.00	$44,640	0	$0	0	44,640
2019	0.0429	0	116,282	232,564	$0.135	$0.135	78	157	$0.00	$0.00	$47,131	0	$0	0	47,131
2020	0.0422	0	116,282	232,564	$0.143	$0.143	78	157	$0.00	$0.00	$49,761	0	$0	0	49,761
2021	0.0416	0	116,282	232,564	$0.151	$0.151	78	157	$0.00	$0.00	$52,538	0	$0	0	52,538
2022	0.0409	0	116,282	232,564	$0.159	$0.159	78	157	$0.00	$0.00	$55,470	0	$0	0	55,470
2023	0.0403	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			1,627,948	3,255,897							$658,945	$221,383	$0	$221,383	$437,562
											$422,117	207,124	0	207,124	214,993

Total NPV = $214,993
Benefit/Cost Ratio = 2.04

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$354,562
Total Utility Project Costs Year 1 =	**$374,391**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$354,562
Total Utility Project Costs Year 2 =	**$374,391**
15b) Total Utilty Cost Year 3 =	**$374,391**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,100.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.61
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	720
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	591
22a) Number of Participants (Second Year) =	591
22a) Number of Participants (Third Year) =	591
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 600.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$1,123,173
Total Program Participants	1,773
Utility Cost per Participant (First Year) =	$633.56
Utility Cost per Participant (Program) =	$633.56
Total kW Reduction	1,172
Total Energy Reduction (kWh)	19,272,717
Societal Cost per kwh	$0.09

Test Results

	NPV	B/C
Utility Test	$852,758	1.67
Ratepayer Test	$1,142,547	2.16
Societal Cost Test	$855,578	1.49
Participant Test	$370,726	1.20

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable D & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	458,874	$0.0190	$0	391	$140.17	$63,435	$374,391	12,972	$387,363	($323,928)
2	2009	917,748	$0.0195	0	781	$147.02	132,740	374,391	25,625	400,016	(267,276)
3	2010	1,376,623	$0.0201	0	1,172	$154.25	208,388	374391.0562	37,946	412,337	(203,950)
4	2011	1,376,623	$0.0207	0	1,172	$161.89	218,162	0	37,440	37,440	180,722
5	2012	1,376,623	$0.0213	0	1,172	$169.95	228,460	0	36,918	36,918	191,542
6	2013	1,376,623	$0.0220	0	1,172	$178.46	239,311	0	36,381	36,381	202,930
7	2014	1,376,623	$0.0226	0	1,172	$187.44	250,744	0	35,827	35,827	214,917
8	2015	1,376,623	$0.0233	0	1,172	$196.93	262,792	0	35,257	35,257	227,535
9	2016	1,376,623	$0.0240	0	1,172	$206.95	275,488	0	34,670	34,670	240,818
10	2017	1,376,623	$0.0247	0	1,172	$217.52	288,867	0	34,065	34,065	254,802
11	2018	1,376,623	$0.0255	0	1,172	$228.68	302,968	0	33,442	33,442	269,526
12	2019	1,376,623	$0.0262	0	1,172	$240.47	317,829	0	32,801	32,801	285,029
13	2020	1,376,623	$0.0270	0	1,172	$252.92	333,492	0	32,140	32,140	301,353
14	2021	1,376,623	$0.0278	0	1,172	$266.06	350,002	0	31,459	31,459	318,543
15	2022	1,376,623	$0.0287	0	1,172	$279.93	367,403	0	30,758	30,758	336,646
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		19,272,717			16,401		$3,840,081	$1,123,173	$487,701	$1,610,874	$2,229,207
NPV =							2,124,170	981,624	289,789	1,271,412	852,758

Total NPV = $852,758
Benefit/Cost Ratio = 1.67

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable D&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential High Efficiency Air Conditioning**

	Decreases			Increases			
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$8,697	$0	$54,738	$63,435	$374,391	$374,391	($310,956)
2009	17,915	0	114,826	132,740	374,391	374,391	(241,651)
2010	27,679	0	180,709	208,388	374,391	374,391	(166,003)
2011	28,509	0	189,653	218,162	0	0	218,162
2012	29,364	0	199,096	228,460	0	0	228,460
2013	30,245	0	209,065	239,311	0	0	239,311
2014	31,153	0	219,591	250,744	0	0	250,744
2015	32,087	0	230,705	262,792	0	0	262,792
2016	33,050	0	242,438	275,488	0	0	275,488
2017	34,041	0	254,826	288,867	0	0	288,867
2018	35,062	0	267,906	302,968	0	0	302,968
2019	36,114	0	281,715	317,829	0	0	317,829
2020	37,198	0	296,295	333,492	0	0	333,492
2021	38,314	0	311,688	350,002	0	0	350,002
2022	39,463	0	327,940	367,403	0	0	367,403
2023	0	0	0	0	0	0	0
Total =	$458,890	$0	$3,381,191	$3,840,081	$1,123,173	$1,123,173	$2,716,908
NPV =	258,906	0	1,865,264	2,124,170	981,624	981,624	1,142,547

Total NPV = $1,142,547

Benefit/Cost Ratio = 2.16

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential High Efficiency Air Conditioning**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$8,697	$0	$54,738	$9,801	$73,236	$374,391	$650,030	$354,562	$669,859	($596,624)
2009	$17,915	$0	$114,826	$21,124	153,864	374,391	650,030	$354,562	669,859	(515,995)
2010	$27,679	$0	$180,709	$34,157	242,545	374391.06	650,030	$354,562	669,859	(427,315)
2011	$28,509	$0	$189,653	$36,831	254,993	0	0	$0	0	254,993
2012	$29,364	$0	$199,096	$39,727	268,187	0	0	$0	0	268,187
2013	$30,245	$0	$209,065	$42,862	282,173	0	0	$0	0	282,173
2014	$31,153	$0	$219,591	$46,257	297,001	0	0	$0	0	297,001
2015	$32,087	$0	$230,705	$49,935	312,726	0	0	$0	0	312,726
2016	$33,050	$0	$242,438	$53,917	329,405	0	0	$0	0	329,405
2017	$34,041	$0	$254,826	$58,232	347,099	0	0	$0	0	347,099
2018	$35,062	$0	$267,906	$62,907	365,875	0	0	$0	0	365,875
2019	$36,114	$0	$281,715	$67,972	385,801	0	0	$0	0	385,801
2020	$37,198	$0	$296,295	$73,462	406,954	0	0	$0	0	406,954
2021	$38,314	$0	$311,688	$79,411	429,413	0	0	$0	0	429,413
2022	$39,463	$0	$327,940	$85,860	453,264	0	0	$0	0	453,264
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$458,890	$0	$3,381,191	$762,456	$4,602,537	$1,123,173	$1,950,091	$1,063,686	$2,009,578	$2,592,959
NPV =	258,906	0	1,865,264	487,726	2,611,896	981,624	1,704,328	929,634	1,756,318	855,578

Total NPV = $855,578

Benefit/Cost Ratio = 1.49

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Benefits							Costs						
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0068	$354,562	425,474	0	$0.074	$0.074	362	0	$0.00	$0.00	$386,196	$650,030	$0	$650,030	($263,835)
2009	0.0133	$354,562	850,949	0	$0.078	$0.078	724	0	$0.00	$0.00	$421,360	650,030	$0	650,030	(228,670)
2010	0.0131	$354,562	1,276,423	0	$0.083	$0.083	1,086	0	$0.00	$0.00	$460,350	650,030	$0	650,030	(189,681)
2011	0.0129	$0	1,276,423	0	$0.088	$0.088	1,086	0	$0.00	$0.00	$111,691	0	$0	0	111,691
2012	0.0127	$0	1,276,423	0	$0.092	$0.092	1,086	0	$0.00	$0.00	$117,923	0	$0	0	117,923
2013	0.0125	0	1,276,423	0	$0.098	$0.098	1,086	0	$0.00	$0.00	$124,503	0	$0	0	124,503
2014	0.0123	0	1,276,423	0	$0.103	$0.103	1,086	0	$0.00	$0.00	$131,451	0	$0	0	131,451
2015	0.0121	0	1,276,423	0	$0.109	$0.109	1,086	0	$0.00	$0.00	$138,785	0	$0	0	138,785
2016	0.0119	0	1,276,423	0	$0.115	$0.115	1,086	0	$0.00	$0.00	$146,530	0	$0	0	146,530
2017	0.0117	0	1,276,423	0	$0.121	$0.121	1,086	0	$0.00	$0.00	$154,706	0	$0	0	154,706
2018	0.0115	0	1,276,423	0	$0.128	$0.128	1,086	0	$0.00	$0.00	$163,339	0	$0	0	163,339
2019	0.0113	0	1,276,423	0	$0.135	$0.135	1,086	0	$0.00	$0.00	$172,453	0	$0	0	172,453
2020	0.0112	0	1,276,423	0	$0.143	$0.143	1,086	0	$0.00	$0.00	$182,076	0	$0	0	182,076
2021	0.0110	0	1,276,423	0	$0.151	$0.151	1,086	0	$0.00	$0.00	$192,236	0	$0	0	192,236
2022	0.0108	0	1,276,423	0	$0.159	$0.159	1,086	0	$0.00	$0.00	$202,962	0	$0	0	202,962
2023	0.0106	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			17,869,928	0							$3,106,560	$1,950,091	$0	$1,950,091	$1,156,469
											$2,195,209	1,824,483	0	1,824,483	370,726

Total NPV = $370,726
Benefit/Cost Ratio = 1.20

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.037,11
1a) Retail Rate Winter ($/kWh) =	$0.037,11
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$71,001
Total Utility Project Costs Year 1 =	**$90,830**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$71,001
Total Utility Project Costs Year 2 =	**$90,830**
15b) Total Utilty Cost Year 3 =	**$90,830**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,000.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.87
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	950
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	142
22a) Number of Participants (Second Year) =	142
22a) Number of Participants (Third Year) =	142
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 500.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial High Efficiency A/C**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$272,491
Total Program Participants	426
Utility Cost per Participant (First Year) =	$639.64
Utility Cost per Participant (Program) =	$639.64
Total kW Reduction	398
Total Energy Reduction (kWh)	6,110,671
Societal Cost per kwh	$0.07

Test Results

	NPV	B/C
Utility Test	$441,742	2.61
Ratepayer Test	$477,300	3.00
Societal Cost Test	$455,433	2.07
Participant Test	$251,339	1.63

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	145,492	$0.0190	$0	133	$140.17	$21,344	$90,830	1,814	$92,644	($71,300)
2	2009	290,984	$0.0195	0	265	$147.02	44,670	90,830	3,526	94,357	(49,687)
3	2010	436,477	$0.0201	0	398	$154.25	70,137	90830.23	5,134	95,964	(25,827)
4	2011	436,477	$0.0207	0	398	$161.89	73,437	0	4,973	4,973	68,464
5	2012	436,477	$0.0213	0	398	$169.95	76,914	0	4,808	4,808	72,107
6	2013	436,477	$0.0220	0	398	$178.46	80,579	0	4,637	4,637	75,941
7	2014	436,477	$0.0226	0	398	$187.44	84,441	0	4,462	4,462	79,979
8	2015	436,477	$0.0233	0	398	$196.93	88,511	0	4,281	4,281	84,229
9	2016	436,477	$0.0240	0	398	$206.95	92,800	0	4,095	4,095	88,705
10	2017	436,477	$0.0247	0	398	$217.52	97,321	0	3,903	3,903	93,418
11	2018	436,477	$0.0255	0	398	$228.68	102,086	0	3,706	3,706	98,380
12	2019	436,477	$0.0262	0	398	$240.47	107,108	0	3,502	3,502	103,606
13	2020	436,477	$0.0270	0	398	$252.92	112,402	0	3,293	3,293	109,110
14	2021	436,477	$0.0278	0	398	$266.06	117,983	0	3,077	3,077	114,906
15	2022	436,477	$0.0287	0	398	$279.93	123,866	0	2,855	2,855	121,012
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		6,110,671			5,569		$1,293,598	$272,491	$58,066	$330,557	$963,042
NPV =							715,450	238,150	35,559	273,708	441,742

Total NPV = $441,742
Benefit/Cost Ratio = 2.61

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial High Efficiency A/C**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,757	$0	$18,587	$21,344	$90,830	$90,830	($69,486)
2009	5,680	0	38,990	44,670	90,830	90,830	(46,160)
2010	8,776	0	61,361	70,137	90,830	90,830	(20,694)
2011	9,039	0	64,398	73,437	0	0	73,437
2012	9,310	0	67,604	76,914	0	0	76,914
2013	9,590	0	70,989	80,579	0	0	80,579
2014	9,877	0	74,563	84,441	0	0	84,441
2015	10,174	0	78,337	88,511	0	0	88,511
2016	10,479	0	82,321	92,800	0	0	92,800
2017	10,793	0	86,528	97,321	0	0	97,321
2018	11,117	0	90,969	102,086	0	0	102,086
2019	11,451	0	95,658	107,108	0	0	107,108
2020	11,794	0	100,608	112,402	0	0	112,402
2021	12,148	0	105,835	117,983	0	0	117,983
2022	12,512	0	111,354	123,866	0	0	123,866
2023	0	0	0	0	0	0	0
Total =	$145,497	$0	$1,148,101	$1,293,598	$272,491	$272,491	$1,021,108
NPV =	82,090	0	633,360	715,450	238,150	238,150	477,300

Total NPV =	$477,300
Benefit/Cost Ratio =	3.00

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,757	$0	$18,587	$3,298	$24,642	$90,830	$142,002	$71,001	$161,831	($137,190)
2009	$5,680	$0	$38,990	$7,109	51,778	90,830	142,002	$71,001	161,831	(110,053)
2010	$8,776	$0	$61,361	$11,496	81,633	90830.233	142,002	$71,001	161,831	(80,199)
2011	$9,039	$0	$64,398	$12,398	85,835	0	0	$0	0	85,835
2012	$9,310	$0	$67,604	$13,375	90,289	0	0	$0	0	90,289
2013	$9,590	$0	$70,989	$14,432	95,011	0	0	$0	0	95,011
2014	$9,877	$0	$74,563	$15,578	100,018	0	0	$0	0	100,018
2015	$10,174	$0	$78,337	$16,818	105,329	0	0	$0	0	105,329
2016	$10,479	$0	$82,321	$18,162	110,962	0	0	$0	0	110,962
2017	$10,793	$0	$86,528	$19,619	116,939	0	0	$0	0	116,939
2018	$11,117	$0	$90,969	$21,197	123,282	0	0	$0	0	123,282
2019	$11,451	$0	$95,658	$22,907	130,015	0	0	$0	0	130,015
2020	$11,794	$0	$100,608	$24,760	137,162	0	0	$0	0	137,162
2021	$12,148	$0	$105,835	$26,769	144,752	0	0	$0	0	144,752
2022	$12,512	$0	$111,354	$28,947	152,813	0	0	$0	0	152,813
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$145,497	$0	$1,148,101	$256,864	$1,550,462	$272,491	$426,007	$213,004	$485,494	$1,064,967
NPV =	82,090	0	633,360	164,292	879,742	238,150	372,319	186,160	424,309	455,433

Total NPV = $455,433
Benefit/Cost Ratio = 2.07

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

		Benefits							Costs						
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0083	$71,001	134,902	0	$0.045	$0.045	123	0	$47.41	$69.46	$82,880	$142,002	$0	$142,002	($59,123)
2009	0.0164	$71,001	269,805	0	$0.047	$0.047	246	0	$50.05	$73.34	$96,084	142,002	$0	142,002	(45,918)
2010	0.0163	$71,001	404,707	0	$0.050	$0.050	369	0	$52.84	$77.43	$110,725	142,002	$0	142,002	(31,277)
2011	0.0162	$0	404,707	0	$0.053	$0.053	369	0	$55.79	$81.75	$41,941	0	$0	0	41,941
2012	0.0161	$0	404,707	0	$0.056	$0.056	369	0	$58.91	$86.31	$44,281	0	$0	0	44,281
2013	0.0160	0	404,707	0	$0.059	$0.059	369	0	$62.19	$91.13	$46,752	0	$0	0	46,752
2014	0.0159	0	404,707	0	$0.062	$0.062	369	0	$65.66	$96.21	$49,361	0	$0	0	49,361
2015	0.0158	0	404,707	0	$0.066	$0.066	369	0	$69.33	$101.58	$52,115	0	$0	0	52,115
2016	0.0157	0	404,707	0	$0.069	$0.069	369	0	$73.19	$107.25	$55,023	0	$0	0	55,023
2017	0.0155	0	404,707	0	$0.073	$0.073	369	0	$77.28	$113.23	$58,093	0	$0	0	58,093
2018	0.0154	0	404,707	0	$0.077	$0.077	369	0	$81.59	$119.55	$61,335	0	$0	0	61,335
2019	0.0153	0	404,707	0	$0.082	$0.082	369	0	$86.14	$126.22	$64,757	0	$0	0	64,757
2020	0.0152	0	404,707	0	$0.086	$0.086	369	0	$90.95	$133.27	$68,371	0	$0	0	68,371
2021	0.0151	0	404,707	0	$0.091	$0.091	369	0	$96.03	$140.70	$72,186	0	$0	0	72,186
2022	0.0150	0	404,707	0	$0.096	$0.096	369	0	$101.38	$148.55	$76,214	0	$0	0	76,214
2023	0.0149	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			5,665,898	0							$980,118	$426,007	$0	$426,007	$554,110
											$649,906	398,568	0	398,568	251,339

Total NPV = $251,339
Benefit/Cost Ratio = 1.63

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$2,193,222
Incentive Costs =	$644,924
Total Utility Project Costs Year 1 =	**$2,861,575**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$1,069,321
Incentive Costs =	$322,462
Total Utility Project Costs Year 2 =	**$1,415,212**
15b) Total Utilty Cost Year 3 =	**$1,415,212**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$0.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	1.00
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	360
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	6,649
22a) Number of Participants (Second Year) =	3,324
22a) Number of Participants (Third Year) =	3,324
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 97.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$5,692,000
Total Program Participants	13,297
Utility Cost per Participant (First Year) =	$430.40
Utility Cost per Participant (Program) =	$428.05
Total kW Reduction	14,301
Total Energy Reduction (kWh)	47,756,373
Societal Cost per kwh	$0.08

Test Results

	NPV	B/C
Utility Test	$10,546,221	2.78
Ratepayer Test	$11,415,957	3.26
Societal Cost Test	$15,875,036	5.05
Participant Test	$4,308,910	#DIV/0!

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	2,581,426	$0.0190	$0	7,151	$140.17	$1,051,246	$2,861,575	72,974	$2,934,549	($1,883,303)
2	2009	3,872,138	$0.0195	0	10,726	$147.02	1,652,529	1,415,212	108,118	1,523,330	129,198
3	2010	5,162,851	$0.0201	0	14,301	$154.25	2,309,804	1415212.444	142,313	1,557,525	752,279
4	2011	5,162,851	$0.0207	0	14,301	$161.89	2,422,098	0	140,413	140,413	2,281,685
5	2012	5,162,851	$0.0213	0	14,301	$169.95	2,540,577	0	138,457	138,457	2,402,121
6	2013	5,162,851	$0.0220	0	14,301	$178.46	2,665,585	0	136,441	136,441	2,529,144
7	2014	5,162,851	$0.0226	0	14,301	$187.44	2,797,483	0	134,366	134,366	2,663,118
8	2015	5,162,851	$0.0233	0	14,301	$196.93	2,936,653	0	132,228	132,228	2,804,426
9	2016	5,162,851	$0.0240	0	14,301	$206.95	3,083,499	0	130,025	130,025	2,953,473
10	2017	5,162,851	$0.0247	0	14,301	$217.52	3,238,445	0	127,757	127,757	3,110,688
11	2018	0	$0.0255	0	0	$228.68	0	0	0	0	0
12	2019	0	$0.0262	0	0	$240.47	0	0	0	0	0
13	2020	0	$0.0270	0	0	$252.92	0	0	0	0	0
14	2021	0	$0.0278	0	0	$266.06	0	0	0	0	0
15	2022	0	$0.0287	0	0	$279.93	0	0	0	0	0
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		47,756,373			132,285		$24,697,920	$5,692,000	$1,263,092	$6,955,092	$17,742,828
NPV =							16,477,641	5,061,684	869,736	5,931,420	10,546,221

Total NPV = $10,546,221
Benefit/Cost Ratio = 2.78

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

	Decreases			Increases			
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$48,923	$0	$1,002,323	$1,051,246	$2,861,575	$2,861,575	($1,810,329)
2009	75,586	0	1,576,942	1,652,529	1,415,212	1,415,212	237,316
2010	103,805	0	2,205,999	2,309,804	1,415,212	1,415,212	894,592
2011	106,919	0	2,315,179	2,422,098	0	0	2,422,098
2012	110,127	0	2,430,451	2,540,577	0	0	2,540,577
2013	113,431	0	2,552,155	2,665,585	0	0	2,665,585
2014	116,834	0	2,680,650	2,797,483	0	0	2,797,483
2015	120,339	0	2,816,315	2,936,653	0	0	2,936,653
2016	123,949	0	2,959,550	3,083,499	0	0	3,083,499
2017	127,667	0	3,110,778	3,238,445	0	0	3,238,445
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$1,047,580	$0	$23,650,340	$24,697,920	$5,692,000	$5,692,000	$19,005,920
NPV =	705,432	0	15,772,208	16,477,641	5,061,684	5,061,684	11,415,957

Total NPV = $11,415,957
Benefit/Cost Ratio = 3.26

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential Air Conditioning Cycling T-Stat**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$48,923	$0	$1,002,323	$162,418	$1,213,664	$2,861,575	$0	$644,924	$2,216,651	($1,002,987)
2009	$75,586	$0	$1,576,942	$262,975	1,915,504	1,415,212	0	$322,462	1,092,750	822,753
2010	$103,805	$0	$2,205,999	$378,598	2,688,402	1415212.4	0	$322,462	1,092,750	1,595,652
2011	$106,919	$0	$2,315,179	$408,914	2,831,012	0	0	$0	0	2,831,012
2012	$110,127	$0	$2,430,451	$441,784	2,982,361	0	0	$0	0	2,982,361
2013	$113,431	$0	$2,552,155	$477,427	3,143,012	0	0	$0	0	3,143,012
2014	$116,834	$0	$2,680,650	$516,083	3,313,566	0	0	$0	0	3,313,566
2015	$120,339	$0	$2,816,315	$558,010	3,494,663	0	0	$0	0	3,494,663
2016	$123,949	$0	$2,959,550	$603,490	3,686,989	0	0	$0	0	3,686,989
2017	$127,667	$0	$3,110,778	$652,830	3,891,275	0	0	$0	0	3,891,275
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$1,047,580	$0	$23,650,340	$4,462,528	$29,160,448	$5,692,000	$0	$1,289,848	$4,402,151	$24,758,296
NPV =	705,432	0	15,772,208	3,312,384	19,790,024	5,061,684	0	1,146,696	3,914,988	15,875,036

Total NPV = $15,875,036

Benefit/Cost Ratio = 5.05

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0760	$644,924	2,393,533	0	$0.074	$0.074	6,630	0	$0.00	$0.00	$822,882	$0	$0	$0	$822,882
2009	0.1121	$322,462	3,590,300	0	$0.078	$0.078	9,945	0	$0.00	$0.00	$604,294	0	$0	0	604,294
2010	0.1104	$322,462	4,787,066	0	$0.083	$0.083	13,260	0	$0.00	$0.00	$719,206	0	$0	0	719,206
2011	0.1086	$0	4,787,066	0	$0.088	$0.088	13,260	0	$0.00	$0.00	$418,882	0	$0	0	418,882
2012	0.1069	$0	4,787,066	0	$0.092	$0.092	13,260	0	$0.00	$0.00	$442,256	0	$0	0	442,256
2013	0.1052	0	4,787,066	0	$0.098	$0.098	13,260	0	$0.00	$0.00	$466,934	0	$0	0	466,934
2014	0.1036	0	4,787,066	0	$0.103	$0.103	13,260	0	$0.00	$0.00	$492,989	0	$0	0	492,989
2015	0.1020	0	4,787,066	0	$0.109	$0.109	13,260	0	$0.00	$0.00	$520,498	0	$0	0	520,498
2016	0.1004	0	4,787,066	0	$0.115	$0.115	13,260	0	$0.00	$0.00	$549,541	0	$0	0	549,541
2017	0.0988	0	4,787,066	0	$0.121	$0.121	13,260	0	$0.00	$0.00	$580,206	0	$0	0	580,206
2018	0.0972	0	0	0	$0.128	$0.128	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0957	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0942	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0927	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0912	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0898	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			44,280,365	0							$5,617,688	$0	$0	$0	$5,617,688
											$4,308,910	0	0	0	4,308,910

Total NPV = $4,308,910
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$248,840
Incentive Costs =	$233,262
Total Utility Project Costs Year 1 =	**$505,532**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$135,531
Incentive Costs =	$116,631
Total Utility Project Costs Year 2 =	**$275,591**
15b) Total Utilty Cost Year 3 =	**$275,591**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$ -
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	3.80
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	1,372
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	639
22a) Number of Participants (Second Year) =	320
22a) Number of Participants (Third Year) =	320
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 365.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial Air Conditioning Cycling T-Stat**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$1,056,713
Total Program Participants	1,278
Utility Cost per Participant (First Year) =	$791.04
Utility Cost per Participant (Program) =	$826.75
Total kW Reduction	5,239
Total Energy Reduction (kWh)	17,494,350
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$4,969,144	5.66
Ratepayer Test	$5,098,796	6.44
Socletal Cost Test	$6,726,953	13.87
Participant Test	$3,118,525	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	945,641	$0.0190	$0	2,619	$140.17	$385,098	$505,532	11,788	$517,320	($132,222)
2	2009	1,418,461	$0.0195	0	3,929	$147.02	605,362	275,591	17,191	292,781	312,581
3	2010	1,891,281	$0.0201	0	5,239	$154.25	846,139	275590.763	22,245	297,836	548,303
4	2011	1,891,281	$0.0207	0	5,239	$161.89	887,275	0	21,549	21,549	865,726
5	2012	1,891,281	$0.0213	0	5,239	$169.95	930,677	0	20,832	20,832	909,844
6	2013	1,891,281	$0.0220	0	5,239	$178.46	976,470	0	20,094	20,094	956,376
7	2014	1,891,281	$0.0226	0	5,239	$187.44	1,024,788	0	19,334	19,334	1,005,454
8	2015	1,891,281	$0.0233	0	5,239	$196.93	1,075,769	0	18,551	18,551	1,057,219
9	2016	1,891,281	$0.0240	0	5,239	$206.95	1,129,562	0	17,744	17,744	1,111,819
10	2017	1,891,281	$0.0247	0	5,239	$217.52	1,186,323	0	16,913	16,913	1,169,410
11	2018	0	$0.0255	0	0	$228.68	0	0	0	0	0
12	2019	0	$0.0262	0	0	$240.47	0	0	0	0	0
13	2020	0	$0.0270	0	0	$252.92	0	0	0	0	0
14	2021	0	$0.0278	0	0	$266.06	0	0	0	0	0
15	2022	0	$0.0287	0	0	$279.93	0	0	0	0	0
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		17,494,350			48,459		$9,047,464	$1,056,713	$186,241	$1,242,954	$7,804,510
NPV =							6,036,171	937,375	129,652	1,067,026	4,969,144

Total NPV = $4,969,144
Benefit/Cost Ratio = 5.66

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial Air Conditioning Cycling T-Stat**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$17,922	$0	$367,176	$385,098	$505,532	$505,532	($120,434)
2009	27,689	0	577,673	605,362	275,591	275,591	329,772
2010	38,026	0	808,112	846,139	275,591	275,591	570,548
2011	39,167	0	848,108	887,275	0	0	887,275
2012	40,342	0	890,335	930,677	0	0	930,677
2013	41,553	0	934,918	976,470	0	0	976,470
2014	42,799	0	981,989	1,024,788	0	0	1,024,788
2015	44,083	0	1,031,686	1,075,769	0	0	1,075,769
2016	45,406	0	1,084,157	1,129,562	0	0	1,129,562
2017	46,768	0	1,139,555	1,186,323	0	0	1,186,323
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$383,755	$0	$8,663,709	$9,047,464	$1,056,713	$1,056,713	$7,990,751
NPV =	258,417	0	5,777,753	6,036,171	937,375	937,375	5,098,796

Total NPV =	$5,098,796
Benefit/Cost Ratio =	6.44

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Commercial Air Conditioning Cycling T-Stat**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$17,922	$0	$367,176	$59,498	$444,595	$505,532	$0	$233,262	$272,269	$172,326
2009	$27,689	$0	$577,673	$96,334	701,697	275,591	0	$116,631	158,960	542,737
2010	$38,026	$0	$808,112	$138,690	984,829	275590.76	0	$116,631	158,960	825,869
2011	$39,167	$0	$848,108	$149,795	1,037,070	0	0	$0	0	1,037,070
2012	$40,342	$0	$890,335	$161,836	1,092,513	0	0	$0	0	1,092,513
2013	$41,553	$0	$934,918	$174,893	1,151,364	0	0	$0	0	1,151,364
2014	$42,799	$0	$981,989	$189,054	1,213,842	0	0	$0	0	1,213,842
2015	$44,083	$0	$1,031,686	$204,413	1,280,182	0	0	$0	0	1,280,182
2016	$45,406	$0	$1,084,157	$221,073	1,350,636	0	0	$0	0	1,350,636
2017	$46,768	$0	$1,139,555	$239,148	1,425,471	0	0	$0	0	1,425,471
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$383,755	$0	$8,663,709	$1,634,735	$10,682,199	$1,056,713	$0	$466,525	$590,188	$10,092,011
NPV =	258,417	0	5,777,753	1,213,409	7,249,579	937,375	0	414,748	522,627	6,726,953

Total NPV = $6,726,953

Benefit/Cost Ratio = 13.87

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0372	$233,262	876,811	0	$0.045	$0.045	2,429	0	$47.41	$69.46	$387,724	$0	$0	$0	$387,724
2009	0.0555	$116,631	1,315,216	0	$0.047	$0.047	3,643	0	$50.05	$73.34	$361,253	0	$0	0	361,253
2010	0.0551	$116,631	1,753,622	0	$0.050	$0.050	4,858	0	$52.84	$77.43	$460,993	0	$0	0	460,993
2011	0.0547	$0	1,753,622	0	$0.053	$0.053	4,858	0	$55.79	$81.75	$363,577	0	$0	0	363,577
2012	0.0543	$0	1,753,622	0	$0.056	$0.056	4,858	0	$58.91	$86.31	$383,865	0	$0	0	383,865
2013	0.0539	0	1,753,622	0	$0.059	$0.059	4,858	0	$62.19	$91.13	$405,284	0	$0	0	405,284
2014	0.0536	0	1,753,622	0	$0.062	$0.062	4,858	0	$65.66	$96.21	$427,899	0	$0	0	427,899
2015	0.0532	0	1,753,622	0	$0.066	$0.066	4,858	0	$69.33	$101.58	$451,776	0	$0	0	451,776
2016	0.0528	0	1,753,622	0	$0.069	$0.069	4,858	0	$73.19	$107.25	$476,985	0	$0	0	476,985
2017	0.0525	0	1,753,622	0	$0.073	$0.073	4,858	0	$77.28	$113.23	$503,601	0	$0	0	503,601
2018	0.0521	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0517	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0514	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0510	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0507	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0503	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			16,221,002	0							$4,222,958	$0	$0	$0	$4,222,958
											$3,118,525	0	0	0	3,118,525

Total NPV = $3,118,525
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$47,116
Incentive Costs =	$21,987
Total Utility Project Costs Year 1 =	**$88,932**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$47,116
Incentive Costs =	$21,987
Total Utility Project Costs Year 2 =	**$88,932**
15b) Total Utilty Cost Year 3 =	**$88,932**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$ -
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	5
20) Avg Summer kW/part. Saved =	0.165
20a) Avg Winter kW/part Saved =	0.330
21) Avg. Summer kWh/Part. Saved =	389
21a) Avg. Winter kWh/Part. Saved =	777
22) Number of Participants (First Year) =	628
22a) Number of Participants (Second Year) =	628
22a) Number of Participants (Third Year) =	628
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 35.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Refridgerator Round Up**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	5
Total Progam Cost (Utility)	$266,797
Total Program Participants	1,885
Utility Cost per Participant (First Year) =	$141.56
Utility Cost per Participant (Program) =	$141.56
Total kW Reduction	1,007
Total Energy Reduction (kWh)	9,479,969
Societal Cost per kwh	$0.02

Test Results

	NPV	B/C
Utility Test	$926,669	2.93
Ratepayer Test	$1,173,529	6.03
Societal Cost Test	$1,481,420	9.44
Participant Test	$693,860	#DIV/0!

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

		Cost of Energy Saved				Project Cost					Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	789,997	$0.0190	$0	336	$349.78	$132,339	$88,932	23,503	$112,435	$19,903
2	2009	1,579,995	$0.0195	0	671	$366.87	277,044	88,932	48,929	137,862	139,183
3	2010	2,369,992	$0.0201	0	1,007	$384.91	435,118	88932.44	76,462	165,394	269,723
4	2011	2,369,992	$0.0207	0	1,007	$403.96	455,724	0	79,722	79,722	376,001
5	2012	2,369,992	$0.0213	0	1,007	$424.07	477,443	0	83,188	83,188	394,255
6	2013	0	$0.0220	0	0	$445.31	0	0	0	0	0
7	2014	0	$0.0226	0	0	$467.73	0	0	0	0	0
8	2015	0	$0.0233	0	0	$491.40	0	0	0	0	0
9	2016	0	$0.0240	0	0	$516.39	0	0	0	0	0
10	2017	0	$0.0247	0	0	$542.78	0	0	0	0	0
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		9,479,969			4,027		$1,777,667	$266,797	$311,804	$578,601	$1,199,065
NPV =							1,406,703	233,174	246,860	480,033	926,669

Total NPV = $926,669
Benefit/Cost Ratio = 2.93

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$14,972	$0	$117,367	$132,339	$88,932	$88,932	$43,406
2009	30,842	0	246,202	277,044	88,932	88,932	188,112
2010	47,651	0	387,466	435,118	88,932	88,932	346,185
2011	49,081	0	406,643	455,724	0	0	455,724
2012	50,553	0	426,889	477,443	0	0	477,443
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$193,100	$0	$1,584,566	$1,777,667	$266,797	$266,797	$1,510,869
NPV =	153,077	0	1,253,626	1,406,703	233,174	233,174	1,173,529

Total NPV =	$1,173,529
Benefit/Cost Ratio =	6.03

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Residential Refridgerator Round Up**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$14,972	$0	$117,367	$20,446	$152,785	$88,932	$0	$21,987	$66,945	$85,840
2009	$30,842	$0	$246,202	$44,087	321,132	88,932	0	$21,987	66,945	254,187
2010	$47,651	$0	$387,466	$71,320	506,437	88932.44	0	$21,987	66,945	439,492
2011	$49,081	$0	$406,643	$76,938	532,662	0	0	$0	0	532,662
2012	$50,553	$0	$426,889	$83,023	560,466	0	0	$0	0	560,466
2013	$0	$0	$0	$0	0	0	0	$0	0	0
2014	$0	$0	$0	$0	0	0	0	$0	0	0
2015	$0	$0	$0	$0	0	0	0	$0	0	0
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$193,100	$0	$1,584,566	$295,815	$2,073,481	$266,797	$0	$65,962	$200,835	$1,872,647
NPV =	153,077	0	1,253,626	250,241	1,656,944	233,174	0	57,649	175,524	1,481,420

Total NPV = $1,481,420

Benefit/Cost Ratio = 9.44

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0072	$21,987	244,165	488,331	$0.074	$0.074	104	207	$0.00	$0.00	$76,448	$0	$0	$0	$76,448
2009	0.0141	$21,987	488,331	976,662	$0.078	$0.078	207	415	$0.00	$0.00	$136,987	0	$0	0	136,987
2010	0.0139	$21,987	732,496	1,464,993	$0.083	$0.083	311	622	$0.00	$0.00	$204,112	0	$0	0	204,112
2011	0.0137	$0	732,496	1,464,993	$0.088	$0.088	311	622	$0.00	$0.00	$192,287	0	$0	0	192,287
2012	0.0135	$0	732,496	1,464,993	$0.092	$0.092	311	622	$0.00	$0.00	$203,016	0	$0	0	203,016
2013	0.0133	0	0	0	$0.098	$0.098	0	0	$0.00	$0.00	$0	0	$0	0	0
2014	0.0131	0	0	0	$0.103	$0.103	0	0	$0.00	$0.00	$0	0	$0	0	0
2015	0.0128	0	0	0	$0.109	$0.109	0	0	$0.00	$0.00	$0	0	$0	0	0
2016	0.0126	0	0	0	$0.115	$0.115	0	0	$0.00	$0.00	$0	0	$0	0	0
2017	0.0124	0	0	0	$0.121	$0.121	0	0	$0.00	$0.00	$0	0	$0	0	0
2018	0.0122	0	0	0	$0.128	$0.128	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0121	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0119	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0117	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0115	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0113	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			2,929,986	5,859,972							$812,850	$0	$0	$0	$812,850
											$693,860	0	0	0	693,860

Total NPV = $693,860
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06987
1a) Retail Rate Winter ($/kWh) =	$0.03431
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5)Heating margin increase per cooling reduc ($/kWh	$0.09
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System Demand Line loss factor	7.85%
14b) System Energy Line Loss Factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$131,446
Total Utility Project Costs Year 1 =	**$136,446**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$131,446
Total Utility Project Costs Year 2 =	**$136,446**
15b) Total Utilty Cost Year 3 =	**$136,446**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$4,000.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
17a) Other Participant Savings vs propane (Annual $/ Part)	$577.00
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.73
20a) Avg Winter kW/part Saved =	0.73
21) Avg. Summer kWh/Part. Saved =	889
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	119
22a) Number of Participants (Second Year) =	119
22a) Number of Participants (Third Year) =	119
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 1,100.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$409,339
Total Program Participants	358
Utility Cost per Participant (First Year) =	$1,141.84
Utility Cost per Participant (Program) =	$1,141.84
Total Summer kW Reduction	263
Total Winter kW Reduction	263
Total Summer Energy Reduction (kWh)	4,461,767
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.26

Test Results

	NPV	B/C
Utility Test	$2,197,277	6.02
Ratepayer Test	$1,957,578	6.47
Societal Cost Test	$1,581,413	2.25
Participant Test	$1,155,594	1.86

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	After Tax Added Margin Heating Load (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	114,572	$0.0190	$10,739	189	$349.78	$78,959	$136,446	3,551	$139,997	($61,038)
2	2009	229,144	$0.0195	22,122	378	$366.87	165,147	136,446	7,023	143,469	21,678
3	2010	343,715	$0.0201	34,178	566	$384.91	259,139	136,446	10,411	146,858	112,281
4	2011	343,715	$0.0207	35,204	566	$403.96	271,163	0	10,285	10,285	260,878
5	2012	343,715	$0.0213	36,260	566	$424.07	283,827	0	10,155	10,155	273,672
6	2013	343,715	$0.0220	37,348	566	$445.31	297,164	0	10,021	10,021	287,143
7	2014	343,715	$0.0226	38,468	566	$467.73	311,212	0	9,882	9,882	301,330
8	2015	343,715	$0.0233	39,622	566	$491.40	326,009	0	9,740	9,740	316,269
9	2016	343,715	$0.0240	40,811	566	$516.39	341,596	0	9,593	9,593	332,002
10	2017	343,715	$0.0247	42,035	566	$542.78	358,016	0	9,442	9,442	348,573
11	2018	343,715	$0.0255	43,296	566	$570.64	375,314	0	9,287	9,287	366,027
12	2019	343,715	$0.0262	44,595	566	$600.05	393,538	0	9,127	9,127	384,411
13	2020	343,715	$0.0270	45,933	566	$631.11	412,739	0	8,962	8,962	403,777
14	2021	343,715	$0.0278	47,311	566	$663.90	432,969	0	8,792	8,792	424,178
15	2022	343,715	$0.0287	48,730	566	$698.51	454,286	0	8,617	8,617	445,670
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		4,812,015			7,931		$4,761,077	$409,339	$134,888	$544,227	$4,216,851
NPV =							2,635,035	357,751	80,006	437,757	2,197,277

Total NPV = $2,197,277
Benefit/Cost Ratio = 6.02

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,171	$0	$66,049	$68,220	$136,446	$136,446	($68,226)
2009	4,473	0	138,552	143,025	136,446	136,446	6,579
2010	6,911	0	218,049	224,960	136,446	136,446	88,514
2011	7,118	0	228,841	235,959	0	0	235,959
2012	7,332	0	240,235	247,567	0	0	247,567
2013	7,552	0	252,265	259,816	0	0	259,816
2014	7,778	0	264,966	272,744	0	0	272,744
2015	8,012	0	278,375	286,387	0	0	286,387
2016	8,252	0	292,533	300,785	0	0	300,785
2017	8,499	0	307,481	315,981	0	0	315,981
2018	8,754	0	323,263	332,018	0	0	332,018
2019	9,017	0	339,926	348,943	0	0	348,943
2020	9,288	0	357,518	366,806	0	0	366,806
2021	9,566	0	376,092	385,659	0	0	385,659
2022	9,853	0	395,703	405,556	0	0	405,556
2023	0	0	0	0	0	0	0
Total =	$114,576	$0	$4,079,849	$4,194,425	$409,339	$409,339	$3,785,086
NPV =	64,644	0	2,250,686	2,315,329	357,751	357,751	1,957,578

Total NPV = $1,957,578
Benefit/Cost Ratio = 6.47

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3
Societal Cost Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,171	$0	$66,049	$10,540	$78,760	$136,446	$477,987	$131,446	$482,987	($404,226)
2009	$4,473	$0	$138,552	$22,760	165,785	136,446	477,987	$131,446	482,987	(317,201)
2010	$6,911	$0	$218,049	$36,873	261,833	136,446	477,987	$131,446	482,987	(221,153)
2011	$7,118	$0	$228,841	$39,836	275,795	0	0	$0	0	275,795
2012	$7,332	$0	$240,235	$43,050	290,616	0	0	$0	0	290,616
2013	$7,552	$0	$252,265	$46,535	306,351	0	0	$0	0	306,351
2014	$7,778	$0	$264,966	$50,316	323,060	0	0	$0	0	323,060
2015	$8,012	$0	$278,375	$54,418	340,805	0	0	$0	0	340,805
2016	$8,252	$0	$292,533	$58,868	359,654	0	0	$0	0	359,654
2017	$8,499	$0	$307,481	$63,698	379,678	0	0	$0	0	379,678
2018	$8,754	$0	$323,263	$68,938	400,956	0	0	$0	0	400,956
2019	$9,017	$0	$339,926	$74,626	423,569	0	0	$0	0	423,569
2020	$9,288	$0	$357,518	$80,800	447,606	0	0	$0	0	447,606
2021	$9,566	$0	$376,092	$87,501	473,160	0	0	$0	0	473,160
2022	$9,853	$0	$395,703	$94,776	500,333	0	0	$0	0	500,333
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$114,576	$0	$4,079,849	$833,537	$5,027,962	$409,339	$1,433,960	$394,339	$1,448,960	$3,579,002
NPV =	64,644	0	2,250,686	532,436	2,847,765	357,751	1,253,243	344,642	1,266,353	1,581,413

Total NPV = $1,581,413
Benefit/Cost Ratio = 2.25

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Benefits							Costs						
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0014	$131,446	106,233	0	$0.079	$0.042	88	88	$0.00	$0.00	$208,835	$477,987	$0	$477,987	($269,152)
2009	0.0027	$131,446	212,465	0	$0.084	$0.044	175	175	$0.00	$0.00	$287,165	477,987	$0	477,987	(190,822)
2010	0.0026	$131,446	318,698	0	$0.089	$0.047	263	263	$0.00	$0.00	$366,516	477,987	$0	477,987	(111,471)
2011	0.0026	$0	318,698	0	$0.093	$0.049	263	263	$0.00	$0.00	$236,644	0	$0	0	236,644
2012	0.0026	$0	318,698	0	$0.099	$0.052	263	263	$0.00	$0.00	$238,307	0	$0	0	238,307
2013	0.0025	0	318,698	0	$0.104	$0.055	263	263	$0.00	$0.00	$240,062	0	$0	0	240,062
2014	0.0025	0	318,698	0	$0.110	$0.058	263	263	$0.00	$0.00	$241,916	0	$0	0	241,916
2015	0.0024	0	318,698	0	$0.116	$0.061	263	263	$0.00	$0.00	$243,873	0	$0	0	243,873
2016	0.0024	0	318,698	0	$0.123	$0.065	263	263	$0.00	$0.00	$245,938	0	$0	0	245,938
2017	0.0024	0	318,698	0	$0.129	$0.068	263	263	$0.00	$0.00	$248,120	0	$0	0	248,120
2018	0.0023	0	318,698	0	$0.137	$0.072	263	263	$0.00	$0.00	$250,423	0	$0	0	250,423
2019	0.0023	0	318,698	0	$0.144	$0.076	263	263	$0.00	$0.00	$252,854	0	$0	0	252,854
2020	0.0023	0	318,698	0	$0.152	$0.080	263	263	$0.00	$0.00	$255,421	0	$0	0	255,421
2021	0.0022	0	318,698	0	$0.161	$0.085	263	263	$0.00	$0.00	$258,131	0	$0	0	258,131
2022	0.0022	0	318,698	0	$0.170	$0.090	263	263	$0.00	$0.00	$260,993	0	$0	0	260,993
2023	0.0022	0	0	0	$0.179	$0.095	0	0	$0.00	$0.00	$0	0	$0	0	0
			4,461,767	0							$3,835,199	$1,433,960	$0	$1,433,960	$2,401,239
											$2,497,191	1,341,597	0	1,341,597	1,155,594

Total NPV = $1,155,594
Benefit/Cost Ratio = 1.86

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$125,429
Total Utility Project Costs Year 1 =	**$145,258**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$125,429
Total Utility Project Costs Year 2 =	**$145,258**
15b) Total Utilty Cost Year 3 =	**$145,258**
15c) Total Utilty Cost Year 4 =	**$145,258**
15d) Total Utility Cost Year 5 =	**$145,258**
16) Direct Participant Costs ($/Part.) =	$ 920.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0.29
20a) Avg Winter kW/part Saved =	0.57
21) Avg. Summer kWh/Part. Saved =	715
21a) Avg. Winter kWh/Part. Saved =	1,430
22) Number of Participants (First Year) =	682
22a) Number of Participants (Second Year) =	682
22a) Number of Participants (Third Year) =	682
22a) Number of Participants (Fourth Year) =	682
22a) Number of Participants (Fifth Year) =	682
23) Incentive/Participant (All) =	$ 184.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$726,291
Total Program Participants	3,408
Utility Cost per Participant (First Year) =	$213.09
Utility Cost per Participant (Program) =	$213.09
Total kW Reduction	3,154
Total Energy Reduction (kWh)	63,072,111
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$7,042,055	6.43
Ratepayer Test	$7,743,448	14.02
Societal Cost Test	$7,409,577	3.80
Participant Test	$1,586,911	1.58

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	1,576,803	$0.0190	$0	631	$349.78	$250,496	$145,258	21,066	$166,324	$84,172
2	2009	3,153,606	$0.0195	0	1,261	$366.87	524,343	145,258	44,014	189,272	335,071
3	2010	4,730,408	$0.0201	0	1,892	$384.91	823,426	145258.1	69,044	214,302	609,124
4	2011	6,307,211	$0.0207	0	2,523	$403.96	1,149,766	145258.1	96,372	241,630	908,136
5	2012	7,884,014	$0.0213	0	3,154	$424.07	1,505,535	145258.1	126,234	271,492	1,234,043
6	2013	7,884,014	$0.0220	0	3,154	$445.31	1,577,548	0	132,401	132,401	1,445,147
7	2014	7,884,014	$0.0226	0	3,154	$467.73	1,653,450	0	138,991	138,991	1,514,458
8	2015	7,884,014	$0.0233	0	3,154	$491.40	1,733,452	0	146,032	146,032	1,587,420
9	2016	7,884,014	$0.0240	0	3,154	$516.39	1,817,781	0	153,549	153,549	1,664,232
10	2017	7,884,014	$0.0247	0	3,154	$542.78	1,906,673	0	161,573	161,573	1,745,100
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		63,072,111			25,229		$12,942,470	$726,291	$1,089,274	$1,815,565	$11,126,905
NPV =							8,338,238	594,790	701,393	1,296,184	7,042,055

Total NPV = $7,042,055
Benefit/Cost Ratio = 6.43

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$29,884	$0	$220,613	$250,496	$145,258	$145,258	$105,238
2009	61,560	0	462,783	524,343	145,258	145,258	379,085
2010	95,110	0	728,315	823,426	145,258	145,258	678,168
2011	130,618	0	1,019,148	1,149,766	145258.1	145,258	1,004,508
2012	168,171	0	1,337,364	1,505,535	145258.1	145,258	1,360,277
2013	173,216	0	1,404,332	1,577,548	0	0	1,577,548
2014	178,413	0	1,475,037	1,653,450	0	0	1,653,450
2015	183,765	0	1,549,687	1,733,452	0	0	1,733,452
2016	189,278	0	1,628,503	1,817,781	0	0	1,817,781
2017	194,956	0	1,711,716	1,906,673	0	0	1,906,673
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$1,404,972	$0	$11,537,498	$12,942,470	$726,291	$726,291	$12,216,179
NPV =	911,813	0	7,426,426	8,338,238	594,790	594,790	7,743,448

Total NPV = $7,743,448

Benefit/Cost Ratio = 14.02

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$29,884	$0	$220,613	$38,702	$289,198	$145,258	$627,146	$125,429	$646,975	($357,777)
2009	$61,560	$0	$462,783	$83,441	607,784	145,258	627,146	$125,429	646,975	(39,190)
2010	$95,110	$0	$728,315	$134,967	958,393	145258.12	627,146	$125,429	646,975	311,418
2011	$130,618	$0	$1,019,148	$194,111	1,343,877	145258.12	627,146	$125,429	646,975	696,903
2012	$168,171	$0	$1,337,364	$261,799	1,767,334	145258.12	627,146	$125,429	646,975	1,120,360
2013	$173,216	$0	$1,404,332	$282,551	1,860,099	0	0	$0	0	1,860,099
2014	$178,413	$0	$1,475,037	$305,030	1,958,480	0	0	$0	0	1,958,480
2015	$183,765	$0	$1,549,687	$329,383	2,062,835	0	0	$0	0	2,062,835
2016	$189,278	$0	$1,628,503	$355,769	2,173,550	0	0	$0	0	2,173,550
2017	$194,956	$0	$1,711,716	$384,361	2,291,034	0	0	$0	0	2,291,034
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$1,404,972	$0	$11,537,498	$2,370,114	$15,312,584	$726,291	$3,135,728	$627,146	$3,234,873	$12,077,711
NPV =	911,813	0	7,426,426	1,720,515	10,058,753	594,790	2,567,982	513,596	2,649,176	7,409,577

Total NPV = $7,409,577
Benefit/Cost Ratio = 3.80

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0397	$125,429	487,344	974,689	$0.045	$0.045	195	390	$47.41	$69.46	$227,324	$627,146	$0	$627,146	($399,821)
2009	0.0789	$125,429	974,689	1,949,378	$0.047	$0.047	390	780	$50.05	$73.34	$340,591	627,146	$0	627,146	(286,555)
2010	0.0783	$125,429	1,462,033	2,924,066	$0.050	$0.050	585	1,170	$52.84	$77.43	$466,180	627,146	$0	627,146	(160,965)
2011	0.0778	$125,429	1,949,378	3,898,755	$0.053	$0.053	780	1,560	$55.79	$81.75	$605,116	627,146	$0	627,146	(22,029)
2012	0.0773	$125,429	2,436,722	4,873,444	$0.056	$0.056	975	1,949	$58.91	$86.31	$758,496	627,146	$0	627,146	131,350
2013	0.0767	0	2,436,722	4,873,444	$0.059	$0.059	975	1,949	$62.19	$91.13	$668,392	0	$0	0	668,392
2014	0.0762	0	2,436,722	4,873,444	$0.062	$0.062	975	1,949	$65.66	$96.21	$705,688	0	$0	0	705,688
2015	0.0757	0	2,436,722	4,873,444	$0.066	$0.066	975	1,949	$69.33	$101.58	$745,066	0	$0	0	745,066
2016	0.0751	0	2,436,722	4,873,444	$0.069	$0.069	975	1,949	$73.19	$107.25	$786,640	0	$0	0	786,640
2017	0.0746	0	2,436,722	4,873,444	$0.073	$0.073	975	1,949	$77.28	$113.23	$830,535	0	$0	0	830,535
2018	0.0741	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0736	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0731	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0726	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0721	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0716	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			19,493,776	38,987,551							$6,134,029	$3,135,728	$0	$3,135,728	$2,998,301
											$4,335,935	2,749,025	0	2,749,025	1,586,911

Total NPV = $1,586,911
Benefit/Cost Ratio = 1.58

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$8,521
Total Utility Project Costs Year 1 =	**$28,350**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$8,521
Total Utility Project Costs Year 2 =	**$28,350**
15b) Total Utilty Cost Year 3 =	**$28,350**
15c) Total Utilty Cost Year 4 =	**$28,350**
15d) Total Utility Cost Year 5 =	**$28,350**
16) Direct Participant Costs ($/Part.) =	$ 250.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0.05
20a) Avg Winter kW/part Saved =	0.09
21) Avg. Summer kWh/Part. Saved =	394
21a) Avg. Winter kWh/Part. Saved =	788
22) Number of Participants (First Year) =	341
22a) Number of Participants (Second Year) =	341
22a) Number of Participants (Third Year) =	341
22a) Number of Participants (Fourth Year) =	341
22a) Number of Participants (Fifth Year) =	341
23) Incentive/Participant (All) =	$ 25.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$141,750
Total Program Participants	1,704
Utility Cost per Participant (First Year) =	$83.18
Utility Cost per Participant (Program) =	$83.18
Total kW Reduction	248
Total Energy Reduction (kWh)	17,388,758
Societal Cost per kwh	$0.02

Test Results

	NPV	B/C
Utility Test	$526,242	2.70
Ratepayer Test	$719,613	7.20
Societal Cost Test	$577,833	2.34
Participant Test	$441,766	2.18

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	434,719	$0.0190	$0	50	$349.78	$25,597	$28,350	5,808	$34,158	($8,561)
2	2009	869,438	$0.0195	0	99	$366.87	53,384	28,350	12,134	40,484	12,899
3	2010	1,304,157	$0.0201	0	149	$384.91	83,526	28350	19,035	47,385	36,141
4	2011	1,738,876	$0.0207	0	199	$403.96	116,198	28350	26,569	54,919	61,279
5	2012	2,173,595	$0.0213	0	248	$424.07	151,589	28350	34,802	63,152	88,436
6	2013	2,173,595	$0.0220	0	248	$445.31	158,249	0	36,502	36,502	121,746
7	2014	2,173,595	$0.0226	0	248	$467.73	165,244	0	38,319	38,319	126,925
8	2015	2,173,595	$0.0233	0	248	$491.40	172,594	0	40,260	40,260	132,333
9	2016	2,173,595	$0.0240	0	248	$516.39	180,315	0	42,333	42,333	137,982
10	2017	2,173,595	$0.0247	0	248	$542.78	188,427	0	44,545	44,545	143,883
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		17,388,758			1,985		$1,295,122	$141,750	$300,309	$442,059	$853,063
NPV =							835,698	116,085	193,372	309,457	526,242

Total NPV = $526,242
Benefit/Cost Ratio = 2.70

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$8,239	$0	$17,358	$25,597	$28,350	$28,350	($2,753)
2009	16,972	0	36,412	53,384	28,350	28,350	25,034
2010	26,222	0	57,304	83,526	28,350	28,350	55,176
2011	36,011	0	80,187	116,198	28350	28,350	87,848
2012	46,364	0	105,224	151,589	28350	28,350	123,239
2013	47,755	0	110,494	158,249	0	0	158,249
2014	49,188	0	116,057	165,244	0	0	165,244
2015	50,663	0	121,930	172,594	0	0	172,594
2016	52,183	0	128,131	180,315	0	0	180,315
2017	53,749	0	134,679	188,427	0	0	188,427
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$387,346	$0	$907,776	$1,295,122	$141,750	$141,750	$1,153,372
NPV =	251,384	0	584,315	835,698	116,085	116,085	719,613

Total NPV =	$719,613
Benefit/Cost Ratio =	7.20

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$8,239	$0	$17,358	$3,955	$29,551	$28,350	$85,210	$8,521	$105,039	($75,488)
2009	$16,972	$0	$36,412	$8,495	61,879	28,350	85,210	$8,521	105,039	(43,160)
2010	$26,222	$0	$57,304	$13,691	97,216	28350	85,210	$8,521	105,039	(7,823)
2011	$36,011	$0	$80,187	$19,617	135,815	28350	85,210	$8,521	105,039	30,776
2012	$46,364	$0	$105,224	$26,360	177,949	28350	85,210	$8,521	105,039	72,910
2013	$47,755	$0	$110,494	$28,344	186,592	0	0	$0	0	186,592
2014	$49,188	$0	$116,057	$30,484	195,729	0	0	$0	0	195,729
2015	$50,663	$0	$121,930	$32,795	205,389	0	0	$0	0	205,389
2016	$52,183	$0	$128,131	$35,290	215,605	0	0	$0	0	215,605
2017	$53,749	$0	$134,679	$37,985	226,412	0	0	$0	0	226,412
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$387,346	$0	$907,776	$237,016	$1,532,138	$141,750	$426,050	$42,605	$525,195	$1,006,943
NPV =	251,384	0	584,315	172,239	1,007,937	116,085	348,911	34,891	430,105	577,833

Total NPV = $577,833
Benefit/Cost Ratio = 2.34

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0199	$8,521	134,359	268,718	$0.045	$0.045	15	31	$47.41	$69.46	$29,457	$85,210	$0	$85,210	($55,753)
2009	0.0394	$8,521	268,718	537,437	$0.047	$0.047	31	61	$50.05	$73.34	$52,730	85,210	$0	85,210	(32,480)
2010	0.0392	$8,521	403,077	806,155	$0.050	$0.050	46	92	$52.84	$77.43	$78,534	85,210	$0	85,210	(6,676)
2011	0.0389	$8,521	537,437	1,074,873	$0.053	$0.053	61	123	$55.79	$81.75	$107,081	85,210	$0	85,210	21,871
2012	0.0386	$8,521	671,796	1,343,591	$0.056	$0.056	77	153	$58.91	$86.31	$138,595	85,210	$0	85,210	53,385
2013	0.0384	0	671,796	1,343,591	$0.059	$0.059	77	153	$62.19	$91.13	$137,332	0	$0	0	137,332
2014	0.0381	0	671,796	1,343,591	$0.062	$0.062	77	153	$65.66	$96.21	$144,995	0	$0	0	144,995
2015	0.0378	0	671,796	1,343,591	$0.066	$0.066	77	153	$69.33	$101.58	$153,086	0	$0	0	153,086
2016	0.0376	0	671,796	1,343,591	$0.069	$0.069	77	153	$73.19	$107.25	$161,628	0	$0	0	161,628
2017	0.0373	0	671,796	1,343,591	$0.073	$0.073	77	153	$77.28	$113.23	$170,647	0	$0	0	170,647
2018	0.0370	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0368	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0365	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0363	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0360	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0358	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			5,374,365	10,748,730							$1,174,086	$426,050	$0	$426,050	$748,036
											$815,274	373,509	0	373,509	441,766

Total NPV = $441,766
Benefit/Cost Ratio = 2.18

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Appendix E

Scenario B Inputs

Program Data Key Assumption Sources

Table XXXXX

DSM #	DSM Program	Energy Calculation Data	Program Cost Data	Customer Cost Data	Participation Rate Estimate
1	Interruptible Rate - Demand Response Only	500 kW Model	Operationg, Admin & Mkting Cost Estimate	Industry Data	Potential Customers - Customer Reps
2	Interruptible Rate - Energy & Demand Response	500 kW Model	Operationg, Admin & Mkting Cost Estimate	Industry Data	Potential Customers - Customer Reps
3	Commercial High Efficiency Motors	Motor Master Program - DOE & AEE for LF	Operationg, Admin & Mkting Cost Estimate	Motor Master - DOE	Estimate
4	Energy Star Washers with electric heat	Energy Star	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
5	Energy Star Dishwashers with electric heat	Energy Star	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
6	Energy Star Refrigerators	Energy Star, AHAM, WAPA DSM Guide	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
7	Energy Star Freezers	Energy Star, AHAM	Operationg, Admin & Mkting Cost Estimate	Energy Star , DOE 2004	End Use Survey, Energy Star, AHAM
8	High Efficiency A/C Residential	Energy Star, Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	Industry Data	Customer End Use Survey, Estimate
9	High Efficiency A/C Commercial	Energy Star, Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	Industry Data	Estimate
10	Residential A/C Cycling (T-Stat)	Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	NA	End Use Survey, Vendor Data
11	Commercial A/C Cycling (T-Stat)	Industry Data, EPRI	Operationg, Admin & Mkting Cost Estimate	NA	End Use Survey, Vendor Data
12	Refrigerator Round-Up	WAPA DSM Guide	Operationg, Admin & Mkting Cost Estimate	NA	End Use Survey, Industry Data
13	Ground Source Heat Pumps	Industry Data, DOE	Operationg, Admin & Mkting Cost Estimate	Industry Data	Customer End Use Survey, Estimate
14	Commercial Lighting	Industry Data, IES	Operationg, Admin & Mkting Cost Estimate	Industry Data	Xenergy Survey, Estimate
15	LED Exit Signs	Industry Data, IES	Operationg, Admin & Mkting Cost Estimate	Industry Data	Xenergy Survey, Estimate

AHAM - Association of Home Appliance Manufacturers
EPRI - Electric Power Research Institute
IES - Illumination Engineering Society

WAPA - Western Area Power Association 1992 DSM Guide
DOE - Department of Energy
AEE - Associtation onf Energy Engineers

Interruptible Rate - Demand Response
Quantitative DSM # 1

Customer Class:	Commercial and Industrial	

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ 3,600		$ 387	$ 3,600	$ 3,600	$ 3,600	$ 10,800
Incentive Costs	$ 15,000		$ 15,000	$ 46,500	$ 93,000	$ 139,500	$ 279,000
Admin & Advertising	$ 19,829		$ 6,396	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 21,784**	**$ 69,929**	**$ 116,429**	**$ 162,929**	**$ 349,287**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 2.50	per kW/month

Participant Costs (Incremental Cost Basis)

Estimated Average cost of inteconnection	$ 50,000	Average interconnection costs - Estimated
Estimated cost of Primary Service	$ 40,000	Cost for Transformer, Primary Metering, Switch Fuse
Total Cost	**$ 90,000**	
Other Partcipant Costs (Diesel @ 100 hrs of curtailment)	$ 6,499	

Participation Rate Calc

	% of Cust	Cust	
C& I Customers over 500 kW	100.00%	93	RA provided Query of CIS

		Total MW		
Total Customer Available for program	93			
Total Estimated Saturation Percentage	10.0%			
Total Participantion Rate	**9**	4.7	10.00%	Of total Customer Base
Participation Year 1	3	1.6		
Participation Year 2	3	1.6		
Participation Year 3	3	1.6		

Energy Savings Calculation

IT Rate	Total conn kW	kW/Customer	Avg kW per event	Coincident Rate
Rate 38 - DR	500	500.0	500	100.0%

Avg Customer KWh Avoided @ 100 hrs	**26,986**	75% Customer LF
Primary Service Rate Savings per year	**$ 20,264**	Included in other particapant savings

	Per Part
Summer Demand Reduction	166.7
Winter Demand Reduction	333.3
Total Demand Reduction	**500**
Summer Energy Reduction	26,986
Winter Energy Reduction	0

Proposed IT DR Rate	
Summer kW	$ 8.254
Winter kW	$ 5.254
Energy kWh	$ 0.03255
Demand Credit kW	$ 2.50

Note:
MW of IT is the target not Customers
Incentive is equal to our lost Margin between ND Rate 30 Secondary and IT Rate

Commercial High Efficiency Motors
Quantitative DSM # 2

Customer Class:	Commercial & Industrial

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$0	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$264	$ 264	$ 14,084	$ 14,084	$ 14,084	$ 42,251
Admin & Advertising	$19,829	$ 372	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 637**	**$ 33,913**	**$ 33,913**	**$ 33,913**	**$ 101,738**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 0.150	Per kWh Saved

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Motor	$ 3,320	50HP 3600 rpm - Motor Master
Avg Cost of High Efficiency Motor	$ 4,787	50 HP 3600 rpm - Motor Master
Increased cost of Higher Eff Model	**$ 1,467**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	17,042	
Customer with Standard Motors	75.00%	12,782	
Estimated Motors per Customer		5	
Total Motors Available for Program	63,908		
Total Estimated Saturation Percentage	0.25%		
Total Motors	**160**	0.94%	Of total Customer Base
Participation Year 1	53		
Participation Year 2	53		
Participation Year 3	53		

Energy Savings Calculation

Electric Motor Data	kw Conn	Annual kWh	Utilization Factor	
Standard Motor (50hp)	37.3	106,860	100%	4380 hrs per year operation @ 60 % Load Factor
High Efficiency Motor(50hp)	36.9	105,097	100%	4380 hrs per year operation @ 60% Load Factor
Energy Savings	**0.4**	**1,763**		Energy Calculation based on Motor Master - DOE
				Example is based on 50 hp - 3600 rpm - 460 v TEFC

	Per Part	
Summer Demand Reduction	0.133	Levelized for 4 months
Winter Demand Reduction	0.267	Levelized for 8 Months
Total Demand Reduction	**0.400**	**Total demand Reduction for Measure**
Summer Energy Reduction	588	
Winter Energy Reduction	1175	

Notes:
TEFC = Total Enclosed Fan Cooled

Energy Star Clothes Washer Program
Quantitative DSM # 3

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	Per year	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 25	Per Particpant	$ 25	$ 10,919	$ 10,919	$ 10,919	$ 32,756
Admin & Advertising	$ 19,829	Per year	$ 45	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 70**	**$ 30,748**	**$ 30,748**	**$ 30,748**	**$ 92,243**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per Energy Star - DOE 2004	
Avg Cost of Energy Star Model	$ 750	Per Energy Star - DOE 2004	
Increased cost of Higher Eff Model	**$ 300**		

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers with Electric Water heating	32.83%	28,283	Per 2004 Customer Survey
Customer with Clothes Washers	92.65%	26,205	Per 2004 Customer Survey

Total Customers Available for program	26,205		
Total Estimated Saturation Percentage	5.0%		
Total Particapants	**1,310**	1.52%	Of total Customer Base
Participation Year 1	437		
Participation Year 2	437		
Participation Year 3	437		

Energy Savings Calculation

Clothes Washer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.469	531	10%	Savings is Due to reduceed Water Consumption
Energy Star	0.192	234	10%	Savings is based on Energy Star Calculator
Energy Savings	**0.277**	**297**		

	Per Part	
Summer Demand Reduction	0.009	Levelized for 4 months
Winter Demand Reduction	0.018	Levelized for 8 Months
Total Demand Reduction	**0.028**	**Total demand Reduction for Measure**
Summer Energy Reduction	99	
Winter Energy Reduction	198	
Other Particpants Costs / Savings	$ (35.00)	

***** Note water & detergent savings is estimated at $35 per year (7,000 gallons) entered as Other Part Costs (neg)***

Energy Star Dishwasher Program
Quantitative DSM # 4

Customer Class:	Residential	*Electric Water Heating Only*

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 10	$ 10	$ 2,657	$ 2,657	$ 2,657	$ 7,972
Admin & Advertising	$ 19,829	$ 75	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 85**	**$ 22,486**	**$ 22,486**	**$ 22,486**	**$ 67,459**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 450	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 500	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 50**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Total Customers with electric water heating	32.83%	28,283	
Customer with Automatic Dishwashers	56.37%	15,943	Per 2004 Customer Survey

Total Customers Available for program	15,943	
Total Estimated Saturation Percentage	5.0%	
Total Participants	**797**	0.93% Of total Customer Base
Participation Year 1	266	
Participation Year 2	266	
Participation Year 2	266	

Energy Savings Calculation

Dishwasher Data	kw Conn	Annual kWh	Utilization Factor
Conventional	0	413	20%
Energy Star	0	341	20%
Energy Savings	**0**	**72**	

Savings is Driven by Reduce Water Consumption
Savings is based on Energy Star Calculator

	Per Part	
Summer Demand Reduction	0.000	Levelized for 4 months
Winter Demand Reduction	0.000	Levelized for 8 Months
Total Demand Reduction	**0.000**	**Total demand Reduction for Measure**
Summer Energy Reduction	24	
Winter Energy Reduction	48	
Other Participants Cost / Savings	$ (3.00)	

**** Water savings is estimated at 830 gallons per year! Not used in model as savings insignificant at $3.00/yr/part

Energy Star Refrigerators Program
Quantitative DSM # 5

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 15	$ 15	$ 10,769	$ 10,769	$ 10,769	$ 32,307
Admin & Advertising	$ 19,829	$ 28	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 43**	**$ 30,598**	**$ 30,598**	**$ 30,598**	**$ 91,794**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 1,070	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 1,100	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 30**	Partial automatic defrost

Participation Rate Calc

	% of Cust	Cust
Total Customers is Class	100.00%	86,151

Total Customers Available for program	86,151	
Total Estimated Saturation Percentage	2.5%	
Total Participants	**2,154**	2.50% Of total Customer Base
Participation Year 1	718	
Participation Year 2	718	
Participation Year 2	718	

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Conventional	0.8	479	35%	18 Cu Ft Top Freezer ice maker
Energy Star	0.68	407	35%	As per survey results 88% for FF
Energy Savings	**0.12**	**72**		Energy Star - DOE 2004

	Per Part	
Summer Demand Reduction	0.014	Levelized for 4 months
Winter Demand Reduction	0.028	Levelized for 8 Months
Total Demand Reduction	**0.042**	**Total demand Reduction for Measure**
Summer Energy Reduction	24	
Winter Energy Reduction	48	

Energy Star Freezers Program
Quantitative DSM # 6

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 15		$ 15	$ 8,386	$ 8,386	$ 8,386	$ 25,157
Admin & Advertising	$ 19,829		$ 35	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 50**	**$ 28,215**	**$ 28,215**	**$ 28,215**	**$ 84,644**

Notes

Admin & Advertising	Calculated
Operating Cost	Calculated

Participant Costs (Incremental Cost Basis)

Avg Cost of Standard Efficiency Model	$ 329	Per Energy Star - DOE 2004
Avg Cost of Energy Star Model	$ 362	Per Energy Star - DOE 2004
Increased cost of Higher Eff Model	**$ 33**	23 Cu ft Chest Manual DF

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Customer with Freezers	77.87%	67,086	Per 2004 Customer Survey

Total Customers Available for program	67,086	
Total Estimated Saturation Percentage	2.5%	
Total Participants	**1,677**	1.95% Of total Customer Base
Participation Year 1	559	
Participation Year 2	559	
Participation Year 3	559	

Energy Savings Calculation

Freezer Data	kw Conn	Annual kWh	Utilization Factor	
Conventional Freezer	0.9	520	35%	22 Cu ft Chest Manual DF
Energy Star Freezer	0.8	468	35%	Energy Star -DOE 2004
Energy Savings	**0.1**	**52**		

	Per Part	
Summer Demand Reduction	0.012	Levelized for 4 months
Winter Demand Reduction	0.023	Levelized for 8 Months
Total Demand Reduction	**0.035**	**Total demand Reduction for Measure**
Summer Energy Reduction	17	
Winter Energy Reduction	35	

Residential High Efficiency A/C (Energy Star Rated)
Quantitative DSM # 7

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -		$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 600		$ 600	$ 88,641	$ 88,641	$ 88,641	$ 265,922
Admin & Advertising	$ 19,829		$ 134	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 734**	**$ 108,470**	**$ 108,470**	**$ 108,470**	**$ 325,409**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 200	Per Ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (13 SEER)	$ 1,200	Market Reasearch with local HVAC Dealers
Cost of High Efficiency Model (15 SEER)	$ 2,300	Market Reasearch with local HVAC Dealers
Increased cost of Higher Eff Model	**$ 1,100**	

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	86,151	
Total Customers With Central AC		50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers		0.81%	698	Per 2004 Customer Survey
Total Available for program	44,325			
Total Estimated Saturation Percentage	1.0%			
Total Participants	**443**		0.51%	Of total Customer Base
Participation Year 1	148			
Participation Year 2	148			
Participation Year 3	148			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
10 SEER Unit	3.8	2,160	67%
15 SEER Unit	2.9	1,440	
Energy Reduction	**0.92**	**720**	

EPRI for Utilization Factor
BismarckWeather Data used for cooling hrs

	Per Part
Summer Demand Reduction	0.6
Winter Demand Reduction	0.0
Summer Energy Reduction	720
Winter Energy Reduction	0

Commercial High Efficiency A/C
Quantitative DSM # 8

Customer Class:	Commercial

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$	-	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$	500	$ 500	$ 17,750	$ 17,750	$ 17,750	$ 53,251
Admin & Advertising	$	19,829	$ 558	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 1,058**	**$ 37,579**	**$ 37,579**	**$ 37,579**	**$ 112,738**

Notes

Admin & Advertising			Calculated
Operating Cost			Calculated
Incentive	$	100.00	per ton

Participant Costs (Incremental Cost Basis)

Cost of STD Eff Model (10 SEER)	$ 2,000	Trane 5 Ton Packaged Unit ($400 per ton Mike S)
Cost of High Efficiency Model (12 SEER)	$ 3,000	Trane 5 Ton Packaged Unit ($600 per ton Mike S)
Increased cost of Higher Eff Model	**$ 1,000**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	17,042	
Total Customers With Central AC	50.00%	8,521	Estimated no survey data
Total Customers with Evap or Swamp Coolers	0.00%	-	

Total Available for program	8,521		
Total Estimated Saturation Percentage	1.3%		
Total Participants	**107**	0.63%	Of total Customer Base
Participation Year 1	36		
Participation Year 2	36		
Participation Year 3	36		

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
10 SEER Unit	6.86	5,700	67%	Trane 5 ton Unit
12 Seer Unit	5.56	4,750		Trane 5 ton Unit
Energy Reduction	**1.3**	**950**		

	Per Part
Summer Demand Reduction	0.9
Winter Demand Reduction	0.0
Summer Energy Reduction	950
Winter Energy Reduction	0

Residential A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 9

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 45,421	$ 308	$ 657,371	$ 301,396	$ 301,396	$ 1,260,163
Incentive Costs ($89 t-Stat)	$ 93	$ 97	$ 161,231	$ 80,616	$ 80,616	$ 322,462
Admin & Advertising (MDU)	$ 23,429	$ 21.14	$ 23,429	$ 23,429	$ 23,429	$ 70,287
Total Cost		**$ 426**	**$ 842,031**	**$ 405,441**	**$ 405,441**	**$ 1,652,912**

Notes
Increased 2005 numbers by 4% inflation per year
MDU operational cost is less field operations

Participant Costs

None / Comfort Issues	$ -

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	86,151	
Total Customers With Central AC		50.64%	43,627	Per 2004 Customer Survey
Total Customers with Evap or Swamp Coolers		0.81%	698	
Total Available for program	44,325			
Total Estimated Saturation Percentage	7.5%			
Total Participants	**3,324**		3.86%	Of total Customer Base
Participation Year 1	1,662			
Participation Year 2	831			
Participation Year 3	831			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
3 Ton 10 SEER Unit	3.6	2,340	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**1.00**		

Av is 1 kW per particpant (Honeywell)
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized kW redcction per partcipant

	Per Part
Summer Demand Reduction	1.00
Winter Demand Reduction	0.000
Summer Energy Reduction	360
Winter Energy Reduction	0

Commercial A/C Cycling (T-Stat Turnkey)
Quantitative DSM # 10

Customer Class:	Small Comm

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs (Honeywell Turnkey)	$ 45,421	$ 282	$ 113,676	$ 67,948	$ 67,948	$ 249,573
Incentive Costs ($337 t-Stat)	$ 365	$ 365	$ 58,316	$ 29,158	$ 29,158	$ 116,631
Admin & Advertising (MDU)	$ 23,429	$ 220	$ 23,429	$ 23,429	$ 23,429	$ 70,287
Total Cost		**$ 867**	**$ 195,420**	**$ 120,535**	**$ 120,535**	**$ 436,491**

Notes
Increased 2005 numbers by 4% inflation per year
MDU operational cost is less field operations

Participant Costs

None / Comfort Issues	$ -

Participation Rate Calc

		% of Cust	Cust	
Total Customers is Class		100.00%	17,042	
Total Customers in class available for program		50.00%	8,521	Estimate
Total Customer with A/C		50.00%	4,261	Estimate
Total Available for program	4,261			
Total Estimated Saturation Percentage	7.5%			
Total Participants	**320**		1.88%	Of total Customer Base
Participation Year 1	160			
Participation Year 2	80			
Participation Year 3	80			

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor
(2) 5 Ton Unit 11.8 SEER	13.72	10800	28%
Cycling Hours per Year		100 hrs	
Peak kW Reduced	**3.80**		

Per Trane
100 hrs of curtailment per year or 10% cycling rate
Utilization Factor is based on Honeywell realized kW redcction per partcipant

	Per Part
Summer Demand Reduction	3.8
Winter Demand Reduction	0.000
Summer Energy Reduction	1,372
Winter Energy Reduction	0

Refrigerator Round-Up Program
Quantitative DSM # 11

Customer Class:	Residential

Cost MDU

			$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Transport & Recycling (Operating)	$	-	$ 25	$ 11,779	$ 11,779	$ 11,779	$ 35,337
Incentive Costs	$	35	$ 35	$ 5,497	$ 5,497	$ 5,497	$ 16,491
Admin & Advertising	$	19,829	$ 126	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost			**$ 186**	**$ 37,105**	**$ 37,105**	**$ 37,105**	**$ 111,315**

Notes

Operating Costs	Calculated	
Pick up and Recycling is estimated at loaded rate for 1.5 hr plus mileage & $20 recycling fee at Porter Bros		$ 75

Participant Costs

None	$ -

Participation Rate Calc

		% of Cust	Cust
Total Customers is Class		100.00%	86,151
Total Customers with 2 Refrigerators		34.03%	29,317
Total Customers with 3 or more Refrigerators		2.43%	2,093
Total Available for program	31,411		
Total Estimated Saturation Percentage	1.5%		
Total Partcipation	**471**	0.55%	Of total Customer Base
Participation Year 1	157		
Participation Year 2	157		
Participation Year 2	157		

Energy Savings Calculation

Refrigerators Data	kw Conn	Annual kWh	Utilization Factor	
Frost Free	1.5	1200	35%	As per WAPA DSM Pocket Guide 1992
Standard	1	1000	35%	Assumes 1987 vintage 17.3 cu ft
Avg (WAC)	**1.415**	**1166**		As per survey results 88% for FF
		Per Part		UPA 1992 Study - Older Fridges
Summer Demand Reduction		0.165	Levelized for 4 months	
Winter Demand Reduction		0.330	Levelized for 8 Months	
Total Demand Reduction		**0.495**	**Total demand Reduction for Measure**	
Summer Energy Reduction		389		
Winter Energy Reduction		777		

Residential GSHP
Quantitative DSM # 12

Customer Class:	Residential

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Costs	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 1,100	$ 1,100	$ 32,862	$ 32,862	$ 32,862	$ 98,585
Admin & Advertising	$ 19,829	$ 167	$ 5,000	$ 5,000	$ 5,000	$ 15,000
Total Cost		**$ 1,267**	**$ 37,862**	**$ 37,862**	**$ 37,862**	**$ 113,585**

Notes

Program is based in straight electric areas only

Participant Costs (Incremental Cost Basis)

Furnace & Central Air (STD Eff)	$ 6,000	3 Ton A/C & 75,000 BTU Furnace 80%
GS Heat pump	$ 10,000	3 Ton Unit 17 SEER 14.5 EER
Increased cost of GSHP	**$ 4,000**	

Participation Rate Calc

	% of Cust	Cust	
Total Customers is Class	100.00%	86,151	
Combination Customers	58.39%	50,302	Per 2004 Customer Survey
Total Electric Only Customers	41.61%	35,849	Per 2004 Customer Survey

Total Available for program	35,849	
Total Estimated Saturation Percentage	0.25%	
Total Participants	**90**	0.10% Of total Customer Base
Participation Year 1	30	
Participation Year 2	30	
Participation Year 3	30	

Energy Savings Calculation

Equipment	kw Conn	Annual kWh	Utilization Factor	
Std A/C Cooling (10 SEER)	3.6	2,160	67%	
Heat pump Cooling	2.5	1,271		
Cooling Energy Reduction	**1.1**	**889**		
Heating Energy Add	**2.5**	**6,638**		COP of 3

	Per Part
Peak Demand Reduction	0.7
Winter Demand Reduction	-2.5
Summer Energy Reduction	889
Winter Energy Reduction	(6,638)
Savings Electric vs Propane	$ 577
Electric Heat after tax margin per cooling kwh reduction	$ 0.0911

**Heat Pump vs. propane at 80% AFUE & 5 yr avg price of $0.89 per gal ($827 annual cost for 930 Gallons)
** Annaul cost of electric heat $250

T-8 Lighting Retrofit (4 Lamp fixture model)
Quantitative DSM # 13

Customer Class:	Comm & Ind

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 184	$ 184	$ 31,357	$ 31,357	$ 31,357	$ 31,357	$ 31,357	$ 156,786
Admin & Advertising	$ 19,829	$ 116	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 99,145
Total Cost		**$ 300**	**$ 51,186**	**$ 51,186**	**$ 51,186**	**$ 51,186**	**$ 51,186**	**$ 255,931**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
	$ 8.00	per fix

Participant Costs

Avg Cost per Fixture	$ 40.00	4 Lamp Fixture with Ballast per ESG Avg Pricing plus labor
Fixtures per Participant	23	
Total Direct Cost per Part	**$ 920**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated fixtures per Customer	23	Derived from xenergy survey
Estimated fixtures on System	**391,966**	

Total fixtures Available for program	391,966
Estimated Conversion Percentage	5.0%
Part Rate of Light fixtures	19,598
Total Partcipants	**852**
Participation Year 1	170
Participation Year 2	170
Participation Year 3	170
Participation Year 4	170
Participation Year 5	170

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	hrs/yr	
Existing T-12 4 lamp Fixture	144	360	100%	2500	34 w bulbs energy saving magnetic ballast
T-8 4 Lamp Fixture	107	267	100%	2500	electronic ballast
Reduction Per fixture	**37**	**93**	**100%**		

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.0373	0.29	Levelized for 4 months
Winter Demand Reduction	0.0373	0.57	Levelized for 8 Months
Total Demand Reduction		**0.86**	**Total demand Reduction for Measure**
Summer Energy Reduction	31	715	
Winter Energy Reduction	62	1,430	

***** kWh calculation assumes 2,500 hrs per year of operation as is typically for M-F 8-5pm operation**

****** Actual Lighting program with be more comprehensive and include CFL & MH, however incentive will follow the same $ per watt of savings**

LED Exits Signs (Incandescent Model)
Quantitative DSM # 14

Customer Class:	Comm & Ind

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $ Yr 4	Total $ Yr 5	Total $
Operating Costs (Non Incentive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incentive Costs	$ 25.00	$ 25	$ 2,130	$ 2,130	$ 2,130	$ 2,130	$ 2,130	$ 10,651
Admin & Advertising	$ 19,829	$ 233	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 19,829	$ 99,145
Total Cost		**$ 258**	**$ 21,959**	**$ 21,959**	**$ 21,959**	**$ 21,959**	**$ 21,959**	**$ 109,796**

Notes

Admin & Advertising	Calculated	
Operating Cost	Calculated	
Incentive	$ 5.00	per Fixture

Participant Costs

Cost Per Exit Light	$ 50.00	*Replacement cost as per ESG Todd Kaduan (Retrofit cost is $20/fix)*
Exit Signs per Part	5	
Total Direct Cost per Part	**$ 250**	

Participation Rate Calc

	Cust	
Total Customers is Class	17,042	
Estimated Exit Signs per Customer	5	derived Per Xenergy Study
Estimated Exit Signs on System	**85,210**	

Total Exit Lights Available for program	85,210
Estimated Conversion Percentage	2.5%
Part Rate of Exit Lights	2,130
Total Partcipants	**426**
Participation Year 1	85
Participation Year 2	85
Participation Year 3	85
Participation Year 4	85
Participation Year 5	85

Energy Savings Calculation

Exit Light Data (per Fix)	Watts Conn	Annual kWh	Utilization Factor	kW Redc	kWh Reduc
Existing Incandescent	32	280	100%	0.032	280
Existing CFL	10	88	100%	0.01	88
LED (Replace the others)	5	44	100%	0.005	44

Energy Reduced	Per Fixture	Per Part	
Summer Demand Reduction	0.027	0.05	Levelized for 4 months
Winter Demand Reduction	0.027	0.09	Levelized for 8 Months
Total Demand Reduction		**0.14**	**Total demand Reduction for Measure**
Summer Energy Reduction	79	394	
Winter Energy Reduction	158	788	

***** Note For Program development that if CFL's are replaced incentive is reduced to 1/4 of incentive for incandescent**
******* LED Signs Must be energy star rated which is 5 watts or less (1 Watt is the best available)**
Fixture life is 10 years

Appendix F

Scenario B Runs

2007 Input Data Summary
Demand-Side Management Model

Table - XXXX

Input Data Description	Information Source
Retail Rate	System Average retail rate for customer class that DSM is applicable to.
System Marginal Energy Costs	System Marginal energy costs are based on ND & SD Cogeneration filings July 2006 - June 2006
Retail Demand Cost	Seasonal demand cost for customer class that DSM is applicable - ND Rate 30
System Peak Shaving Demand Costs	Demand Cost is based on estimated levelized cost of Combustion turbine
System Conservation Demand Costs	Demand cost is based on estimated levelized costs of Big Stone II - Base Load
MRO Reserve Margin	Current required capacity reserve margin
Variable O&M	Based on Montana-Dakota's historical information
Environmental Damage Factor	Based on MT PSC 1993 IRP order
Total Sales By Class	2006 total sales for customer class that DSM program is applicable.
Total Customers	2006 total customers for customer class that DSM program is applicable
Growth and Escalation Factors	Projected based on consumer indexes and forecasted escalation rates
Utility Discount Rate	MDU's capital structure of incremental WACC 2006
Societal Discount Rate	Equal to the 30 year T-Bill rate average of 52 weeks ending January 24, 2007
General Input Data Year	Year data was input
Project Analysis Year	Year program will be implemented
Effective Tax Rate	Avg of MDU's current state and local tax rate for integrated system
System Demand Line Loss Factor	Historical demand line loss factor for integrated electric system
System Energy Line Loss Factor	Historical energy line loss factor for integrated electric system
Direct Utility Project Costs	Total direct cost to the utility caused by implementing the DSM program
Administrative Costs	Total projected administrative costs including general admin and marketing costs of the DSM program
Direct Operating Costs	Direct operating cost estimated for the specific DSM program
Incentive Costs	Total annual cost of the incentive paid to the program participant
Direct Participant Project Costs	Direct costs that the participant would have to pay to participate in the DSM program
Other Participant Project Costs	Other costs or savings (neg) to the participant for participating in the DSM program
Project Life	Based on the estimated useful life of the energy saving equipment
Avg. Energy Reduction	Avg energy reduction (kWh) caused by the DSM program
Avg. Demand Reduction	Avg energy reduction (kW) caused by the DSM program
Number of Participants	Total projected participation by customers or kW load target, or equipment saturation

Potential DSM Phases - Sensitivey B - Low Participation

Current DSM Programs (2006-2007)

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Particpants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Incentive Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
1	IT Rate - Demand Response	2007	3	10	9	3,789,393	5,015	$46,500	$19,829	$3,600	$ 69,929	$ 675,145	$135	$0.178
7	**Residential High Efficiency A/C	2006	3	15	443	4,818,179	293	$88,641	$19,829	$0	$ 108,470	$ 325,409	$1,111	$0.068
13	Commercial Lighting	2006	5	10	852	15,768,028	788	$31,357	$19,829	$0	$ 51,186	$ 255,931	$325	$0.016
	Totals					**24,375,600**	**6,096**	**$166,498**	**$59,487**	**$3,600**	**$ 229,585**	**$ 1,256,485**		

** Current Program for 2007 - Higher SEER Requirement & Incentive for 2008

Net Cost per kW	**$ 206**
Net Cost per kWh	**$ 0.052**

Programs Added for 2008

5	Energy Star Refridgerators	2008	3	15	2,154	2,341,429	98	$10,769	$19,829	$0	$ 30,598	$ 91,794	$941	$0.039
6	Energy Star Freezers	2008	3	15	1,677	1,316,807	63	$8,386	$19,829	$0	$ 28,215	$ 84,644	$1,337	$0.064
11	Refridgerator Round-Up	2008	3	10	471	2,369,992	252	$5,497	$19,829	$11,779	$ 37,105	$ 111,315	$442	$0.047
14	Led Exit Signs	2008	5	10	426	4,347,190	62	$2,130	$19,829	$0	$ 21,959	$ 109,796	$1,770	$0.025
	Totals					**10,375,418**	**475**	**$26,782**	**$79,316**	**$11,779**	**$ 117,877**	**$ 397,549**		

Net Cost per kW	**$ 838**
Net Cost per kWh	**$ 0.038**

Programs Added for 2009

9	Residential A/C Cycling	2009	3	10	3,324	11,939,093	3,575	$161,231	$23,429	$657,371	$842,031	$1,652,912	$462	$0.138
10	Commercial A/C Cycling	2009	3	10	320	4,373,588	1,310	$58,316	$23,429	$113,676	$195,420	$436,491	$333	$0.100
	Total Increase 2010					**16,312,681**	**4,885**	**$219,547**	**$46,858**	**$771,047**	**$1,037,452**	**$2,089,403**		

Net Cost per kW	**$ 428**
Net Cost per kWh	**$ 0.128**

Programs Added for 2010

8	Commercial High Efficiency A/C	2008	3	15	107	1,527,668	99	$17,750	$19,829	$0	$ 37,579	$112,738	$1,134	$0.074
2	High Efficiency Motors	2008	3	15	160	4,252,970	69	$14,084	$19,829	$0	$33,913	$101,738	$1,476	$0.024
						5,780,638	**168**	**$ 31,834**	**$ 39,658**	**$ -**	**$ 71,492**	**$214,476**		

Includes Admin at full amount per program

Net Cost per kW	**$ 1,274**
Net Cost per kWh	**$ 0.024**

Cumulative Cost per kW	**$ 340**
Cumulative Cost per kWh	**$ 0.070**

DSM Program Summary - Sensitivity B - Low Participation

All Programs

DSM #	DSM Program	Customer Segment	Program Objective	Utility B/C Ratio	Rate Payer B/C Ratio	Societal B/C Ratio	Participant B/C Ratio
1	Interruptible Rate - Demand Response Only	CI	PC	5.87	5.94	4.34	2.46
2	Commercial High Efficiency Motors	CI	SC	2.46	3.72	1.58	1.14
3	Energy Star Washers with electric heat	R	SC	0.96	2.18	1.50	3.12
4	Energy Star Dishwashers with electric heat	R	SC	0.14	0.18	0.18	2.59
5	Energy Star Refrigerators	R	SC	3.11	5.22	4.75	2.91
6	Energy Star Freezers	R	SC	2.58	3.64	3.30	2.04
7	High Efficiency A/C Residential	R	SC	1.49	1.87	1.37	1.20
8	High Efficiency A/C Commercial	CI	SC	1.67	1.82	1.52	1.63
9	Residential A/C Cycling (T-Stat)	R	PC	2.44	2.80	4.18	INF
10	Commercial A/C Cycling (T-Stat)	CI	PC	3.61	3.91	6.42	INF
11	Refrigerator Round-Up	R	SC	2.21	3.61	5.00	INF
12	Ground Source Heat Pumps	R	SLG /SC	5.52	5.83	2.18	1.86
13	Commercial Lighting	CI	SC	5.42	9.95	3.48	1.58
14	LED Exit Signs	CI	SC	1.51	2.32	1.50	2.18

INF= Infinity as partcipant has no cost participation amount

PC = Peak Clipping
C= Commercial

SLG = Strategic Load Growth
R= Residential

SC = Strategic Conservation
I = Industrial

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03255
1a) Retail Rate Winter ($/kWh) =	$0.03255
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$10.00
3a) Retail Winter Demand Rate ($/kW/season) =	$20.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	93
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$46,500
Total Utility Project Costs Year 1 =	**$69,929**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$93,000
Total Utility Project Costs Year 2 =	**$116,429**
15b) Total Utilty Cost Year 3 =	**$162,929**
15c) Total Utilty Cost Year 4 =	**$162,929**
15d) Total Utility Cost Year 5 =	**$162,929**
15e) Total Utility Operating Cost (Program Life) =	**$162,929**
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$90,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 6,499
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 20,264
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	166.7
20a) Avg Winter kW/part Saved =	333.3
21) Avg. Summer kWh/Part. Saved =	26,986
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	3
22a) Number of Participants (Second Year) =	3
22a) Number of Participants (Third Year) =	3
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15,000

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$675,145
Total Program Participants	9
Utility Cost per Participant (First Year) =	$22,557.74
Utility Cost per Participant (Program) =	$72,596.24
Total kW Reduction	5,015
Total Energy Reduction (kWh)	3,789,393
Societal Cost per kwh	$0.60

Test Results

	NPV	B/C
Utility Test	$6,667,631	5.87
Ratepayer Test	$6,683,982	5.94
Societal Cost Test	$7,608,581	4.34
Participant Test	$1,819,955	2.46

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	90,224	$0.0190	$0	1,672	$140.17	$236,036	$69,929	892	$70,821	$165,215
2	2009	180,447	$0.0195	0	3,343	$147.02	495,072	$116,429	1,721	118,150	376,921
3	2010	270,671	$0.0201	0	5,015	$154.25	779,029	$162,929	2,486	165,415	613,614
4	2011	270,671	$0.0207	0	5,015	$161.89	817,479	$162,929	2,386	165,315	652,164
5	2012	270,671	$0.0213	0	5,015	$169.95	858,070	$162,929	2,283	165,212	692,857
6	2013	270,671	$0.0220	0	5,015	$178.46	900,921	$162,929	2,178	165,107	735,815
7	2014	270,671	$0.0226	0	5,015	$187.44	946,160	$162,929	2,069	164,998	781,162
8	2015	270,671	$0.0233	0	5,015	$196.93	993,918	$162,929	1,957	164,886	829,032
9	2016	270,671	$0.0240	0	5,015	$206.95	1,044,336	$162,929	1,841	164,770	879,565
10	2017	270,671	$0.0247	0	5,015	$217.52	1,097,562	$162,929	1,722	164,651	932,911
11	2018	270,671	$0.0255	0	5,015	$228.68	1,153,754	$162,929	1,600	164,529	989,225
12	2019	270,671	$0.0262	0	5,015	$240.47	1,213,076	$162,929	1,474	164,403	1,048,673
13	2020	270,671	$0.0270	0	5,015	$252.92	1,275,703	$162,929	1,344	164,273	1,111,430
14	2021	270,671	$0.0278	0	5,015	$266.06	1,341,819	$162,929	1,210	164,139	1,177,680
15	2022	270,671	$0.0287	0	5,015	$279.93	1,411,618	$162,929	1,072	164,001	1,247,617
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		3,789,393			70,210		$14,564,551	$2,304,435	$26,235	$2,330,670	$12,233,881
NPV =							8,035,798	1,351,816	16,350	1,368,166	6,667,631

Total NPV = $6,667,631
Benefit/Cost Ratio = 5.87

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Interruptible Rate - Demand Response**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,710	$0	$234,326	$236,036	$69,929	$69,929	$166,107
2009	3,522	0	491,549	495,072	$116,429	116,429	378,643
2010	5,442	0	773,587	779,029	$162,929	162,929	616,100
2011	5,605	0	811,873	817,479	$162,929	162,929	654,550
2012	5,774	0	852,296	858,070	$162,929	162,929	695,141
2013	5,947	0	894,975	900,921	$162,929	162,929	737,992
2014	6,125	0	940,034	946,160	$162,929	162,929	783,231
2015	6,309	0	987,609	993,918	$162,929	162,929	830,989
2016	6,498	0	1,037,838	1,044,336	$162,929	162,929	881,407
2017	6,693	0	1,090,869	1,097,562	$162,929	162,929	934,633
2018	6,894	0	1,146,860	1,153,754	$162,929	162,929	990,825
2019	7,101	0	1,205,975	1,213,076	$162,929	162,929	1,050,147
2020	7,314	0	1,268,389	1,275,703	$162,929	162,929	1,112,774
2021	7,533	0	1,334,285	1,341,819	$162,929	162,929	1,178,890
2022	7,759	0	1,403,859	1,411,618	$162,929	162,929	1,248,689
2023	0	0	0	0	0	0	0
Total =	$90,227	$0	$14,474,324	$14,564,551	$2,304,435	$2,304,435	$12,260,116
NPV =	50,906	0	7,984,892	8,035,798	1,351,816	1,351,816	6,683,982

Total NPV = $6,683,982

Benefit/Cost Ratio = 5.94

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,710	$0	$234,326	$36,468	$272,503	$69,929	$299,752	$46,500	$323,181	($50,678)
2009	$3,522	$0	$491,549	$78,783	573,855	$116,429	321,749	$93,000	345,178	228,677
2010	$5,442	$0	$773,587	$127,690	906,719	$162,929	323,031	$139,500	346,460	560,259
2011	$5,605	$0	$811,873	$138,012	955,491	$162,929	45,352	$0	208,281	747,209
2012	$5,774	$0	$852,296	$149,211	1,007,280	$162,929	46,713	$0	209,642	797,639
2013	$5,947	$0	$894,975	$161,362	1,062,283	$162,929	48,114	$0	211,043	851,240
2014	$6,125	$0	$940,034	$174,549	1,120,708	$162,929	49,558	$0	212,487	908,222
2015	$6,309	$0	$987,609	$188,860	1,182,777	$162,929	51,044	$0	213,973	968,804
2016	$6,498	$0	$1,037,838	$204,393	1,248,729	$162,929	52,576	$0	215,505	1,033,224
2017	$6,693	$0	$1,090,869	$221,255	1,318,817	$162,929	54,153	$0	217,082	1,101,735
2018	$6,894	$0	$1,146,860	$239,560	1,393,314	$162,929	55,777	$0	218,706	1,174,607
2019	$7,101	$0	$1,205,975	$259,433	1,472,509	$162,929	57,451	$0	220,380	1,252,130
2020	$7,314	$0	$1,268,389	$281,012	1,556,715	$162,929	59,174	$0	222,103	1,334,611
2021	$7,533	$0	$1,334,285	$304,443	1,646,262	$162,929	60,949	$0	223,878	1,422,383
2022	$7,759	$0	$1,403,859	$329,888	1,741,506	$162,929	62,778	$0	225,707	1,515,799
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$90,227	$0	$14,474,324	$2,894,918	$17,459,469	$2,304,435	$1,588,171	$279,000	$3,613,606	$13,845,863
NPV =	50,906	0	7,984,892	1,848,574	9,884,371	1,351,816	1,162,280	238,306	2,275,791	7,608,581

Total NPV = $7,608,581
Benefit/Cost Ratio = 4.34

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0331	$46,500	83,657	0	$0.040	$0.040	517	1,033	$10.56	$21.12	$139,943	$279,000	$20,752	$299,752	($159,809)
2009	0.0657	$93,000	167,313	0	$0.042	$0.042	1,033	2,067	$11.15	$22.29	$283,303	279,000	$42,749	321,749	(38,446)
2010	0.0653	$139,500	250,970	0	$0.045	$0.045	1,550	3,100	$11.77	$23.54	$430,367	279,000	$44,031	323,031	107,335
2011	0.0648	$0	250,970	0	$0.047	$0.047	1,550	3,100	$12.43	$24.85	$296,581	0	$45,352	45,352	251,229
2012	0.0644	$0	250,970	0	$0.050	$0.050	1,550	3,100	$13.12	$26.24	$302,614	0	$46,713	46,713	255,902
2013	0.0639	$0	250,970	0	$0.053	$0.053	1,550	3,100	$13.85	$27.70	$308,985	0	$48,114	48,114	260,870
2014	0.0635	$0	250,970	0	$0.055	$0.055	1,550	3,100	$14.62	$29.25	$315,710	0	$49,558	49,558	266,153
2015	0.0630	$0	250,970	0	$0.059	$0.059	1,550	3,100	$15.44	$30.88	$322,811	0	$51,044	51,044	271,767
2016	0.0626	$0	250,970	0	$0.062	$0.062	1,550	3,100	$16.30	$32.60	$330,308	0	$52,576	52,576	277,732
2017	0.0622	$0	250,970	0	$0.065	$0.065	1,550	3,100	$17.21	$34.42	$338,223	0	$54,153	54,153	284,071
2018	0.0617	$0	250,970	0	$0.069	$0.069	1,550	3,100	$18.17	$36.34	$346,580	0	$55,777	55,777	290,803
2019	0.0613	$0	250,970	0	$0.073	$0.073	1,550	3,100	$19.19	$38.37	$355,404	0	$57,451	57,451	297,953
2020	0.0609	$0	250,970	0	$0.077	$0.077	1,550	3,100	$20.26	$40.51	$364,720	0	$59,174	59,174	305,545
2021	0.0605	$0	250,970	0	$0.081	$0.081	1,550	3,100	$21.39	$42.77	$374,555	0	$60,949	60,949	313,606
2022	0.0600	$0	250,970	0	$0.086	$0.086	1,550	3,100	$22.58	$45.16	$384,939	0	$62,778	62,778	322,162
2023	0.0596	0	0	0	$0.090	$0.090	0	0	$23.84	$47.68	$0	0	$0	0	0
			3,513,577	0							$4,895,043	$837,000	$751,171	$1,588,171	$3,306,872
											$3,064,176	783,088	461,133	1,244,221	1,819,955

Total NPV = $1,819,955
Benefit/Cost Ratio = 2.46

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$14,084
Total Utility Project Costs Year 1 =	**$33,913**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$14,084
Total Utility Project Costs Year 2 =	**$33,913**
15b) Total Utilty Cost Year 3 =	**$33,913**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,467.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.13
20a) Avg Winter kW/part Saved =	0.27
21) Avg. Summer kWh/Part. Saved =	588
21a) Avg. Winter kWh/Part. Saved =	1,175
22) Number of Participants (First Year) =	53
22a) Number of Participants (Second Year) =	53
22a) Number of Participants (Third Year) =	53
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 264

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$101,738
Total Program Participants	160
Utility Cost per Participant (First Year) =	$636.78
Utility Cost per Participant (Program) =	$636.78
Total kW Reduction	69
Total Energy Reduction (kWh)	4,252,970
Societal Cost per kwh	$0.06

Test Results

	NPV	B/C
Utility Test	$196,354	2.46
Ratepayer Test	$242,055	3.72
Societal Cost Test	$150,069	1.58
Participant Test	$30,184	1.14

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	101,261	$0.0190	$0	23	$349.78	$9,955	$33,913	1,353	$35,265	($25,310)
2	2009	202,522	$0.0195	0	46	$366.87	20,811	33,913	2,827	36,739	(15,928)
3	2010	303,784	$0.0201	0	69	$384.91	32,638	33,913	4,434	38,347	(5,709)
4	2011	303,784	$0.0207	0	69	$403.96	34,134	0	4,642	4,642	29,492
5	2012	303,784	$0.0213	0	69	$424.07	35,709	0	4,864	4,864	30,845
6	2013	303,784	$0.0220	0	69	$445.31	37,367	0	5,102	5,102	32,265
7	2014	303,784	$0.0226	0	69	$467.73	39,112	0	5,356	5,356	33,757
8	2015	303,784	$0.0233	0	69	$491.40	40,950	0	5,627	5,627	35,323
9	2016	303,784	$0.0240	0	69	$516.39	42,885	0	5,916	5,916	36,969
10	2017	303,784	$0.0247	0	69	$542.78	44,923	0	6,226	6,226	38,697
11	2018	303,784	$0.0255	0	69	$570.64	47,068	0	6,556	6,556	40,513
12	2019	303,784	$0.0262	0	69	$600.05	49,328	0	6,907	6,907	42,420
13	2020	303,784	$0.0270	0	69	$631.11	51,707	0	7,282	7,282	44,425
14	2021	303,784	$0.0278	0	69	$663.90	54,213	0	7,682	7,682	46,531
15	2022	303,784	$0.0287	0	69	$698.51	56,853	0	8,108	8,108	48,745
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		4,252,970			965		$597,654	$101,738	$82,881	$184,619	$413,035
NPV =							330,971	88,916	45,701	134,617	196,354

Total NPV = $196,354
Benefit/Cost Ratio = 2.46

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,919	$0	$8,036	$9,955	$33,913	$33,913	($23,957)
2009	3,953	0	16,857	20,811	33,913	33,913	(13,102)
2010	6,108	0	26,530	32,638	33,913	33,913	(1,275)
2011	6,291	0	27,843	34,134	0	0	34,134
2012	6,480	0	29,229	35,709	0	0	35,709
2013	6,674	0	30,693	37,367	0	0	37,367
2014	6,875	0	32,238	39,112	0	0	39,112
2015	7,081	0	33,869	40,950	0	0	40,950
2016	7,293	0	35,592	42,885	0	0	42,885
2017	7,512	0	37,411	44,923	0	0	44,923
2018	7,737	0	39,331	47,068	0	0	47,068
2019	7,969	0	41,358	49,328	0	0	49,328
2020	8,209	0	43,499	51,707	0	0	51,707
2021	8,455	0	45,759	54,213	0	0	54,213
2022	8,708	0	48,145	56,853	0	0	56,853
2023	0	0	0	0	0	0	0
Total =	$101,265	$0	$496,389	$597,654	$101,738	$101,738	$495,916
NPV =	57,134	0	273,837	330,971	88,916	88,916	242,055

Total NPV =	$242,055
Benefit/Cost Ratio =	3.72

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Commercial High Efficiency Motors**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,919	$0	$8,036	$1,538	$11,493	$33,913	$78,127	$14,084	$97,956	($86,463)
2009	$3,953	$0	$16,857	$3,312	24,122	33,913	78,127	$14,084	97,956	(73,833)
2010	$6,108	$0	$26,530	$5,350	37,987	33912.615	78,127	$14,084	97,956	(59,969)
2011	$6,291	$0	$27,843	$5,763	39,897	0	0	$0	0	39,897
2012	$6,480	$0	$29,229	$6,209	41,918	0	0	$0	0	41,918
2013	$6,674	$0	$30,693	$6,693	44,060	0	0	$0	0	44,060
2014	$6,875	$0	$32,238	$7,216	46,328	0	0	$0	0	46,328
2015	$7,081	$0	$33,869	$7,781	48,731	0	0	$0	0	48,731
2016	$7,293	$0	$35,592	$8,393	51,279	0	0	$0	0	51,279
2017	$7,512	$0	$37,411	$9,056	53,979	0	0	$0	0	53,979
2018	$7,737	$0	$39,331	$9,773	56,841	0	0	$0	0	56,841
2019	$7,969	$0	$41,358	$10,549	59,877	0	0	$0	0	59,877
2020	$8,209	$0	$43,499	$11,390	63,097	0	0	$0	0	63,097
2021	$8,455	$0	$45,759	$12,300	66,514	0	0	$0	0	66,514
2022	$8,708	$0	$48,145	$13,286	70,139	0	0	$0	0	70,139
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$101,265	$0	$496,389	$118,609	$716,263	$101,738	$234,381	$42,251	$293,868	$422,395
NPV =	57,134	0	273,837	75,930	406,901	88,916	204,843	36,926	256,833	150,069

Total NPV = $150,069

Benefit/Cost Ratio = 1.58

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency Motors**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0031	$14,084	31,297	62,594	$0.045	$0.045	7	14	$47.41	$69.46	$19,618	$78,127	$0	$78,127	($58,509)
2009	0.0062	$14,084	62,594	125,188	$0.047	$0.047	14	28	$50.05	$73.34	$25,769	78,127	$0	78,127	(52,357)
2010	0.0061	$14,084	93,891	187,782	$0.050	$0.050	21	43	$52.84	$77.43	$32,590	78,127	$0	78,127	(45,536)
2011	0.0061	$0	93,891	187,782	$0.053	$0.053	21	43	$55.79	$81.75	$19,540	0	$0	0	19,540
2012	0.0060	$0	93,891	187,782	$0.056	$0.056	21	43	$58.91	$86.31	$20,630	0	$0	0	20,630
2013	0.0060	0	93,891	187,782	$0.059	$0.059	21	43	$62.19	$91.13	$21,781	0	$0	0	21,781
2014	0.0060	0	93,891	187,782	$0.062	$0.062	21	43	$65.66	$96.21	$22,996	0	$0	0	22,996
2015	0.0059	0	93,891	187,782	$0.066	$0.066	21	43	$69.33	$101.58	$24,280	0	$0	0	24,280
2016	0.0059	0	93,891	187,782	$0.069	$0.069	21	43	$73.19	$107.25	$25,634	0	$0	0	25,634
2017	0.0058	0	93,891	187,782	$0.073	$0.073	21	43	$77.28	$113.23	$27,065	0	$0	0	27,065
2018	0.0058	0	93,891	187,782	$0.077	$0.077	21	43	$81.59	$119.55	$28,575	0	$0	0	28,575
2019	0.0057	0	93,891	187,782	$0.082	$0.082	21	43	$86.14	$126.22	$30,169	0	$0	0	30,169
2020	0.0057	0	93,891	187,782	$0.086	$0.086	21	43	$90.95	$133.27	$31,853	0	$0	0	31,853
2021	0.0057	0	93,891	187,782	$0.091	$0.091	21	43	$96.03	$140.70	$33,630	0	$0	0	33,630
2022	0.0056	0	93,891	187,782	$0.096	$0.096	21	43	$101.38	$148.55	$35,507	0	$0	0	35,507
2023	0.0056	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			1,314,471	2,628,942							$399,638	$234,381	$0	$234,381	$165,257
											$249,468	219,284	0	219,284	30,184

Total NPV = $30,184
Benefit/Cost Ratio = 1.14

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program -.DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$10,919
Total Utility Project Costs Year 1 =	**$30,748**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$10,919
Total Utility Project Costs Year 2 =	**$30,748**
15b) Total Utilty Cost Year 3 =	**$30,748**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$300.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$ (35.00)
Escalation Rate =	3.00%
18) Project Life (Years) =	11
20) Avg Summer kW/part. Saved =	0.01
20a) Avg Winter kW/part Saved =	0.02
21) Avg. Summer kWh/Part. Saved =	99
21a) Avg. Winter kWh/Part. Saved =	198
22) Number of Participants (First Year) =	437
22a) Number of Participants (Second Year) =	437
22a) Number of Participants (Third Year) =	437
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 25.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Res E-STAR Clothes Washers w/ Elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	11
Total Progam Cost (Utility)	$92,243
Total Program Participants	1,310
Utility Cost per Participant (First Year) =	$70.40
Utility Cost per Participant (Program) =	$70.40
Total kW Reduction	39
Total Energy Reduction (kWh)	4,196,848
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	($6,590)	0.96
Ratepayer Test	$95,046	2.18
Societal Cost Test	$70,602	1.50
Participant Test	$203,390	3.12

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	139,895	$0.0190	$0	13	$349.78	$7,215	$30,748	4,162	$34,910	($27,695)
2	2009	279,790	$0.0195	0	26	$366.87	15,035	30,748	8,665	39,412	(24,377)
3	2010	419,685	$0.0201	0	39	$384.91	23,505	30747.56	13,540	44,288	(20,783)
4	2011	419,685	$0.0207	0	39	$403.96	24,503	0	14,117	14,117	10,386
5	2012	419,685	$0.0213	0	39	$424.07	25,551	0	14,731	14,731	10,820
6	2013	419,685	$0.0220	0	39	$445.31	26,651	0	15,383	15,383	11,268
7	2014	419,685	$0.0226	0	39	$467.73	27,805	0	16,076	16,076	11,730
8	2015	419,685	$0.0233	0	39	$491.40	29,017	0	16,811	16,811	12,206
9	2016	419,685	$0.0240	0	39	$516.39	30,289	0	17,592	17,592	12,696
10	2017	419,685	$0.0247	0	39	$542.78	31,624	0	18,422	18,422	13,202
11	2018	419,685	$0.0255	0	39	$570.64	33,026	0	19,302	19,302	13,724
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		4,196,848			391		$274,221	$92,243	$158,801	$251,044	$23,177
NPV =							175,664	80,618	101,636	182,253	(6,590)

Total NPV = ($6,590)
Benefit/Cost Ratio = 0.96

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,651	$0	$4,564	$7,215	$30,748	$30,748	($23,533)
2009	5,462	0	9,573	15,035	30,748	30,748	(15,713)
2010	8,438	0	15,066	23,505	30,748	30,748	(7,243)
2011	8,691	0	15,812	24,503	0	0	24,503
2012	8,952	0	16,599	25,551	0	0	25,551
2013	9,221	0	17,430	26,651	0	0	26,651
2014	9,497	0	18,308	27,805	0	0	27,805
2015	9,782	0	19,235	29,017	0	0	29,017
2016	10,076	0	20,213	30,289	0	0	30,289
2017	10,378	0	21,246	31,624	0	0	31,624
2018	10,689	0	22,336	33,026	0	0	33,026
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$93,838	$0	$180,383	$274,221	$92,243	$92,243	$181,978
NPV =	60,562	0	115,101	175,664	80,618	80,618	95,046

Total NPV = $95,046

Benefit/Cost Ratio = 2.18

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,651	$0	$4,564	$1,115	$8,330	$30,748	$115,278	$10,919	$135,107	($126,777)
2009	$5,462	$0	$9,573	$2,393	17,428	30,748	98,589	$10,919	118,418	(100,990)
2010	$8,438	$0	$15,066	$3,853	27,357	30747.561	97,616	$10,919	117,445	(90,088)
2011	$8,691	$0	$15,812	$4,137	28,640	0	(34,409)	$0	(34,409)	63,049
2012	$8,952	$0	$16,599	$4,443	29,995	0	(35,441)	$0	(35,441)	65,436
2013	$9,221	$0	$17,430	$4,773	31,425	0	(36,505)	$0	(36,505)	67,929
2014	$9,497	$0	$18,308	$5,130	32,935	0	(37,600)	$0	(37,600)	70,535
2015	$9,782	$0	$19,235	$5,514	34,531	0	(38,728)	$0	(38,728)	73,258
2016	$10,076	$0	$20,213	$5,928	36,217	0	(39,889)	$0	(39,889)	76,106
2017	$10,378	$0	$21,246	$6,375	37,999	0	(41,086)	$0	(41,086)	79,085
2018	$10,689	$0	$22,336	$6,857	39,883	0	(42,319)	$0	(42,319)	82,202
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$93,838	$0	$180,383	$50,517	$324,737	$92,243	$5,506	$32,756	$64,993	$259,744
NPV =	60,562	0	115,101	36,358	212,022	80,618	89,429	28,628	141,420	70,602

Total NPV = $70,602

Benefit/Cost Ratio = 1.50

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Clothes Washers w/ Elec Wtr Ht**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0050	$10,919	43,237	86,475	$0.074	$0.074	4	8	$0.00	$0.00	$20,563	$131,023	($15,745)	$115,278	($94,716)
2009	0.0098	$10,919	86,475	172,950	$0.078	$0.078	8	16	$0.00	$0.00	$31,283	131,023	($32,434)	98,589	(67,306)
2010	0.0097	$10,919	129,712	259,425	$0.083	$0.083	12	24	$0.00	$0.00	$43,170	131,023	($33,407)	97,616	(54,446)
2011	0.0095	$0	129,712	259,425	$0.088	$0.088	12	24	$0.00	$0.00	$34,051	0	($34,409)	(34,409)	68,460
2012	0.0094	$0	129,712	259,425	$0.092	$0.092	12	24	$0.00	$0.00	$35,951	0	($35,441)	(35,441)	71,392
2013	0.0092	0	129,712	259,425	$0.098	$0.098	12	24	$0.00	$0.00	$37,957	0	($36,505)	(36,505)	74,461
2014	0.0091	0	129,712	259,425	$0.103	$0.103	12	24	$0.00	$0.00	$40,075	0	($37,600)	(37,600)	77,674
2015	0.0089	0	129,712	259,425	$0.109	$0.109	12	24	$0.00	$0.00	$42,311	0	($38,728)	(38,728)	81,039
2016	0.0088	0	129,712	259,425	$0.115	$0.115	12	24	$0.00	$0.00	$44,672	0	($39,889)	(39,889)	84,561
2017	0.0087	0	129,712	259,425	$0.121	$0.121	12	24	$0.00	$0.00	$47,165	0	($41,086)	(41,086)	88,251
2018	0.0085	0	129,712	259,425	$0.128	$0.128	12	24	$0.00	$0.00	$49,796	0	($42,319)	(42,319)	92,115
2019	0.0084	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0082	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0081	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0080	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0079	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			1,297,125	2,594,250							$426,992	$393,068	($387,562)	$5,506	$421,485
											$299,125	367,750	(272,016)	95,734	203,390

Total NPV = $203,390
Benefit/Cost Ratio = 3.12

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$2,657
Total Utility Project Costs Year 1 =	**$22,486**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$2,657
Total Utility Project Costs Year 2 =	**$22,486**
15b) Total Utilty Cost Year 3 =	**$22,486**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$50.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	($3.00)
Escalation Rate =	3.00%
18) Project Life (Years) =	13
20) Avg Summer kW/part. Saved =	0.00
20a) Avg Winter kW/part Saved =	0.00
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	266
22a) Number of Participants (Second Year) =	266
22a) Number of Participants (Third Year) =	266
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 10.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	13
Total Progam Cost (Utility)	$67,459
Total Program Participants	797
Utility Cost per Participant (First Year) =	$84.62
Utility Cost per Participant (Program) =	$84.62
Total kW Reduction	0
Total Energy Reduction (kWh)	742,819
Societal Cost per kwh	$0.10

Test Results

	NPV	B/C
Utility Test	($66,218)	0.14
Ratepayer Test	($48,618)	0.18
Societal Cost Test	($59,033)	0.18
Participant Test	$33,341	2.59

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable D & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	20,634	$0.0190	$0	0	$349.78	$391	$22,486	614	$23,100	($22,709)
2	2009	41,268	$0.0195	0	0	$366.87	806	22,486	1,278	23,764	(22,959)
3	2010	61,902	$0.0201	0	0	$384.91	1,245	22486.22	1,997	24,483	(23,239)
4	2011	61,902	$0.0207	0	0	$403.96	1,282	0	2,082	2,082	(800)
5	2012	61,902	$0.0213	0	0	$424.07	1,320	0	2,173	2,173	(852)
6	2013	61,902	$0.0220	0	0	$445.31	1,360	0	2,269	2,269	(909)
7	2014	61,902	$0.0226	0	0	$467.73	1,401	0	2,371	2,371	(970)
8	2015	61,902	$0.0233	0	0	$491.40	1,443	0	2,480	2,480	(1,037)
9	2016	61,902	$0.0240	0	0	$516.39	1,486	0	2,595	2,595	(1,109)
10	2017	61,902	$0.0247	0	0	$542.78	1,531	0	2,717	2,717	(1,186)
11	2018	61,902	$0.0255	0	0	$570.64	1,577	0	2,847	2,847	(1,270)
12	2019	61,902	$0.0262	0	0	$600.05	1,624	0	2,985	2,985	(1,361)
13	2020	61,902	$0.0270	0	0	$631.11	1,673	0	3,131	3,131	(1,458)
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		742,819			0		$17,137	$67,459	$29,538	$96,997	($79,860)
NPV =							10,340	58,957	17,600	76,557	(66,218)

Total NPV = ($66,218)
Benefit/Cost Ratio = 0.14

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable D&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$391	$0	$0	$391	$22,486	$22,486	($22,095)
2009	806	0	0	806	22,486	22,486	(21,681)
2010	1,245	0	0	1,245	22,486	22,486	(21,242)
2011	1,282	0	0	1,282	0	0	1,282
2012	1,320	0	0	1,320	0	0	1,320
2013	1,360	0	0	1,360	0	0	1,360
2014	1,401	0	0	1,401	0	0	1,401
2015	1,443	0	0	1,443	0	0	1,443
2016	1,486	0	0	1,486	0	0	1,486
2017	1,531	0	0	1,531	0	0	1,531
2018	1,577	0	0	1,577	0	0	1,577
2019	1,624	0	0	1,624	0	0	1,624
2020	1,673	0	0	1,673	0	0	1,673
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$17,137	$0	$0	$17,137	$67,459	$67,459	($50,321)
NPV =	10,340	0	0	10,340	58,957	58,957	(48,618)

Total NPV = ($48,618)
Benefit/Cost Ratio = 0.18

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$391	$0	$0	$60	$451	$22,486	$12,465	$2,657	$32,294	($31,843)
2009	$806	$0	$0	$128	934	22,486	11,595	$2,657	31,424	(30,490)
2010	$1,245	$0	$0	$204	1,449	22486.223	11,544	$2,657	31,373	(29,924)
2011	$1,282	$0	$0	$216	1,498	0	(1,794)	$0	(1,794)	3,293
2012	$1,320	$0	$0	$230	1,550	0	(1,848)	$0	(1,848)	3,398
2013	$1,360	$0	$0	$244	1,604	0	(1,904)	$0	(1,904)	3,507
2014	$1,401	$0	$0	$258	1,659	0	(1,961)	$0	(1,961)	3,620
2015	$1,443	$0	$0	$274	1,717	0	(2,020)	$0	(2,020)	3,737
2016	$1,486	$0	$0	$291	1,777	0	(2,080)	$0	(2,080)	3,857
2017	$1,531	$0	$0	$309	1,839	0	(2,143)	$0	(2,143)	3,982
2018	$1,577	$0	$0	$327	1,904	0	(2,207)	$0	(2,207)	4,111
2019	$1,624	$0	$0	$347	1,971	0	(2,273)	$0	(2,273)	4,244
2020	$1,673	$0	$0	$368	2,041	0	(2,341)	$0	(2,341)	4,382
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$17,137	$0	$0	$3,257	$20,395	$67,459	$15,032	$7,972	$74,519	($54,125)
NPV =	10,340	0	0	2,232	12,572	58,957	19,614	6,967	71,604	(59,033)

Total NPV = ($59,033)
Benefit/Cost Ratio = 0.18

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Res E-STAR Dishwashers w/ Elec Wtr Ht**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0030	$2,657	6,377	12,755	$0.074	$0.074	0	0	$0.00	$0.00	$4,080	$13,286	($821)	$12,465	($8,385)
2009	0.0060	$2,657	12,755	25,509	$0.078	$0.078	0	0	$0.00	$0.00	$5,661	13,286	($1,691)	11,595	(5,934)
2010	0.0059	$2,657	19,132	38,264	$0.083	$0.083	0	0	$0.00	$0.00	$7,414	13,286	($1,742)	11,544	(4,130)
2011	0.0058	$0	19,132	38,264	$0.088	$0.088	0	0	$0.00	$0.00	$5,022	0	($1,794)	(1,794)	6,817
2012	0.0057	$0	19,132	38,264	$0.092	$0.092	0	0	$0.00	$0.00	$5,303	0	($1,848)	(1,848)	7,151
2013	0.0056	0	19,132	38,264	$0.098	$0.098	0	0	$0.00	$0.00	$5,598	0	($1,904)	(1,904)	7,502
2014	0.0055	0	19,132	38,264	$0.103	$0.103	0	0	$0.00	$0.00	$5,911	0	($1,961)	(1,961)	7,872
2015	0.0054	0	19,132	38,264	$0.109	$0.109	0	0	$0.00	$0.00	$6,241	0	($2,020)	(2,020)	8,260
2016	0.0053	0	19,132	38,264	$0.115	$0.115	0	0	$0.00	$0.00	$6,589	0	($2,080)	(2,080)	8,669
2017	0.0053	0	19,132	38,264	$0.121	$0.121	0	0	$0.00	$0.00	$6,957	0	($2,143)	(2,143)	9,099
2018	0.0052	0	19,132	38,264	$0.128	$0.128	0	0	$0.00	$0.00	$7,345	0	($2,207)	(2,207)	9,552
2019	0.0051	0	19,132	38,264	$0.135	$0.135	0	0	$0.00	$0.00	$7,755	0	($2,273)	(2,273)	10,028
2020	0.0050	0	19,132	38,264	$0.143	$0.143	0	0	$0.00	$0.00	$8,187	0	($2,341)	(2,341)	10,529
2021	0.0049	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0049	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0048	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			229,584	459,168							$82,062	$39,858	($24,826)	$15,032	$67,029
											$54,338	37,291	(16,294)	20,997	33,341

Total NPV = $33,341
Benefit/Cost Ratio = 2.59

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$10,769
Total Utility Project Costs Year 1 =	**$30,598**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$10,769
Total Utility Project Costs Year 2 =	**$30,598**
15b) Total Utilty Cost Year 3 =	**$30,598**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$30.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.014
20a) Avg Winter kW/part Saved =	0.028
21) Avg. Summer kWh/Part. Saved =	24
21a) Avg. Winter kWh/Part. Saved =	48
22) Number of Participants (First Year) =	718
22a) Number of Participants (Second Year) =	718
22a) Number of Participants (Third Year) =	718
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$91,794
Total Program Participants	2,154
Utility Cost per Participant (First Year) =	$42.62
Utility Cost per Participant (Program) =	$42.62
Total kW Reduction	98
Total Energy Reduction (kWh)	2,341,429
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$284,507	3.11
Ratepayer Test	$338,835	5.22
Societal Cost Test	$406,893	4.75
Participant Test	$115,566	2.91

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential ENERGY STAR Refridgerators**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	55,748	$0.0190	$0	33	$349.78	$12,431	$30,598	1,659	$32,256	($19,825)
2	2009	111,497	$0.0195	0	65	$366.87	26,037	30,598	3,453	34,051	(8,013)
3	2010	167,245	$0.0201	0	98	$384.91	40,914	30597.88	5,396	35,994	4,921
4	2011	167,245	$0.0207	0	98	$403.96	42,874	0	5,626	5,626	37,248
5	2012	167,245	$0.0213	0	98	$424.07	44,940	0	5,870	5,870	39,070
6	2013	167,245	$0.0220	0	98	$445.31	47,119	0	6,130	6,130	40,989
7	2014	167,245	$0.0226	0	98	$467.73	49,416	0	6,406	6,406	43,010
8	2015	167,245	$0.0233	0	98	$491.40	51,839	0	6,699	6,699	45,140
9	2016	167,245	$0.0240	0	98	$516.39	54,394	0	7,011	7,011	47,384
10	2017	167,245	$0.0247	0	98	$542.78	57,089	0	7,341	7,341	49,748
11	2018	167,245	$0.0255	0	98	$570.64	59,931	0	7,692	7,692	52,239
12	2019	167,245	$0.0262	0	98	$600.05	62,928	0	8,064	8,064	54,864
13	2020	167,245	$0.0270	0	98	$631.11	66,090	0	8,459	8,459	57,630
14	2021	167,245	$0.0278	0	98	$663.90	69,424	0	8,879	8,879	60,546
15	2022	167,245	$0.0287	0	98	$698.51	72,941	0	9,323	9,323	63,618
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		2,341,429			1,366		$758,369	$91,794	$98,008	$189,802	$568,568
NPV =							419,060	80,225	54,328	134,553	284,507

Total NPV = $284,507

Benefit/Cost Ratio = 3.11

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,057	$0	$11,375	$12,431	$30,598	$30,598	($18,167)
2009	2,176	0	23,861	26,037	30,598	30,598	(4,560)
2010	3,363	0	37,552	40,914	30,598	30,598	10,317
2011	3,464	0	39,410	42,874	0	0	42,874
2012	3,567	0	41,373	44,940	0	0	44,940
2013	3,674	0	43,444	47,119	0	0	47,119
2014	3,785	0	45,632	49,416	0	0	49,416
2015	3,898	0	47,941	51,839	0	0	51,839
2016	4,015	0	50,379	54,394	0	0	54,394
2017	4,136	0	52,953	57,089	0	0	57,089
2018	4,260	0	55,671	59,931	0	0	59,931
2019	4,388	0	58,541	62,928	0	0	62,928
2020	4,519	0	61,571	66,090	0	0	66,090
2021	4,655	0	64,769	69,424	0	0	69,424
2022	4,794	0	68,147	72,941	0	0	72,941
2023	0	0	0	0	0	0	0
Total =	$55,750	$0	$702,619	$758,369	$91,794	$91,794	$666,575
NPV =	31,454	0	387,606	419,060	80,225	80,225	338,835

Total NPV = $338,835
Benefit/Cost Ratio = 5.22

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,057	$0	$11,375	$1,921	$14,352	$30,598	$21,538	$10,769	$41,367	($27,015)
2009	$2,176	$0	$23,861	$4,143	30,181	30,598	21,538	$10,769	41,367	(11,186)
2010	$3,363	$0	$37,552	$6,706	47,621	30597.875	21,538	$10,769	41,367	6,254
2011	$3,464	$0	$39,410	$7,238	50,112	0	0	$0	0	50,112
2012	$3,567	$0	$41,373	$7,815	52,755	0	0	$0	0	52,755
2013	$3,674	$0	$43,444	$8,439	55,558	0	0	$0	0	55,558
2014	$3,785	$0	$45,632	$9,116	58,533	0	0	$0	0	58,533
2015	$3,898	$0	$47,941	$9,850	61,689	0	0	$0	0	61,689
2016	$4,015	$0	$50,379	$10,646	65,040	0	0	$0	0	65,040
2017	$4,136	$0	$52,953	$11,508	68,598	0	0	$0	0	68,598
2018	$4,260	$0	$55,671	$12,444	72,375	0	0	$0	0	72,375
2019	$4,388	$0	$58,541	$13,458	76,387	0	0	$0	0	76,387
2020	$4,519	$0	$61,571	$14,558	80,648	0	0	$0	0	80,648
2021	$4,655	$0	$64,769	$15,752	85,176	0	0	$0	0	85,176
2022	$4,794	$0	$68,147	$17,046	89,987	0	0	$0	0	89,987
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$55,750	$0	$702,619	$150,641	$909,010	$91,794	$64,613	$32,307	$124,100	$784,910
NPV =	31,454	0	387,606	96,293	515,354	80,225	56,470	28,235	108,460	406,893

Total NPV = $406,893
Benefit/Cost Ratio = 4.75

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Refridgerators**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0082	$10,769	17,230	34,460	$0.074	$0.074	10	20	$0.00	$0.00	$14,612	$21,538	$0	$21,538	($6,926)
2009	0.0161	$10,769	34,460	68,921	$0.078	$0.078	20	40	$0.00	$0.00	$18,884	21,538	$0	21,538	(2,654)
2010	0.0159	$10,769	51,691	103,381	$0.083	$0.083	30	60	$0.00	$0.00	$23,621	21,538	$0	21,538	2,083
2011	0.0156	$0	51,691	103,381	$0.088	$0.088	30	60	$0.00	$0.00	$13,569	0	$0	0	13,569
2012	0.0154	$0	51,691	103,381	$0.092	$0.092	30	60	$0.00	$0.00	$14,326	0	$0	0	14,326
2013	0.0152	0	51,691	103,381	$0.098	$0.098	30	60	$0.00	$0.00	$15,126	0	$0	0	15,126
2014	0.0149	0	51,691	103,381	$0.103	$0.103	30	60	$0.00	$0.00	$15,970	0	$0	0	15,970
2015	0.0147	0	51,691	103,381	$0.109	$0.109	30	60	$0.00	$0.00	$16,861	0	$0	0	16,861
2016	0.0144	0	51,691	103,381	$0.115	$0.115	30	60	$0.00	$0.00	$17,802	0	$0	0	17,802
2017	0.0142	0	51,691	103,381	$0.121	$0.121	30	60	$0.00	$0.00	$18,795	0	$0	0	18,795
2018	0.0140	0	51,691	103,381	$0.128	$0.128	30	60	$0.00	$0.00	$19,844	0	$0	0	19,844
2019	0.0138	0	51,691	103,381	$0.135	$0.135	30	60	$0.00	$0.00	$20,951	0	$0	0	20,951
2020	0.0136	0	51,691	103,381	$0.143	$0.143	30	60	$0.00	$0.00	$22,120	0	$0	0	22,120
2021	0.0133	0	51,691	103,381	$0.151	$0.151	30	60	$0.00	$0.00	$23,355	0	$0	0	23,355
2022	0.0131	0	51,691	103,381	$0.159	$0.159	30	60	$0.00	$0.00	$24,658	0	$0	0	24,658
2023	0.0129	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			723,668	1,447,337							$280,494	$64,613	$0	$64,613	$215,881
											$176,017	60,451	0	60,451	115,566

Total NPV = $115,566
Benefit/Cost Ratio = 2.91

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$8,386
Total Utility Project Costs Year 1 =	**$28,215**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$8,386
Total Utility Project Costs Year 2 =	**$28,215**
15b) Total Utilty Cost Year 3 =	**$28,215**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$33.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.012
20a) Avg Winter kW/part Saved =	0.023
21) Avg. Summer kWh/Part. Saved =	17
21a) Avg. Winter kWh/Part. Saved =	35
22) Number of Participants (First Year) =	559
22a) Number of Participants (Second Year) =	559
22a) Number of Participants (Third Year) =	559
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 15.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential ENERGY STAR Freezers**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$84,644
Total Program Participants	1,677
Utility Cost per Participant (First Year) =	$50.47
Utility Cost per Participant (Program) =	$50.47
Total kW Reduction	63
Total Energy Reduction (kWh)	1,316,807
Societal Cost per kwh	$0.08

Test Results

	NPV	B/C
Utility Test	$164,683	2.58
Ratepayer Test	$195,237	3.64
Societal Cost Test	$230,723	3.30
Participant Test	$53,748	2.04

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	31,353	$0.0190	$0	21	$349.78	$7,975	$28,215	933	$29,147	($21,172)
2	2009	62,705	$0.0195	0	42	$366.87	16,708	28,215	1,942	30,157	(13,449)
3	2010	94,058	$0.0201	0	63	$384.91	26,259	28214.72	3,035	31,249	(4,990)
4	2011	94,058	$0.0207	0	63	$403.96	27,522	0	3,164	3,164	24,358
5	2012	94,058	$0.0213	0	63	$424.07	28,854	0	3,301	3,301	25,552
6	2013	94,058	$0.0220	0	63	$445.31	30,258	0	3,448	3,448	26,811
7	2014	94,058	$0.0226	0	63	$467.73	31,740	0	3,603	3,603	28,137
8	2015	94,058	$0.0233	0	63	$491.40	33,302	0	3,768	3,768	29,534
9	2016	94,058	$0.0240	0	63	$516.39	34,950	0	3,943	3,943	31,007
10	2017	94,058	$0.0247	0	63	$542.78	36,688	0	4,129	4,129	32,560
11	2018	94,058	$0.0255	0	63	$570.64	38,522	0	4,326	4,326	34,196
12	2019	94,058	$0.0262	0	63	$600.05	40,456	0	4,535	4,535	35,920
13	2020	94,058	$0.0270	0	63	$631.11	42,496	0	4,757	4,757	37,738
14	2021	94,058	$0.0278	0	63	$663.90	44,648	0	4,993	4,993	39,654
15	2022	94,058	$0.0287	0	63	$698.51	46,918	0	5,243	5,243	41,674
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		1,316,807			886		$487,295	$84,644	$55,119	$139,763	$347,531
NPV =							269,214	73,977	30,554	104,531	164,683

Total NPV = $164,683
Benefit/Cost Ratio = 2.58

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable D & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$594	$0	$7,381	$7,975	$28,215	$28,215	($20,239)
2009	1,224	0	15,484	16,708	28,215	28,215	(11,507)
2010	1,891	0	24,368	26,259	28,215	28,215	(1,956)
2011	1,948	0	25,574	27,522	0	0	27,522
2012	2,006	0	26,847	28,854	0	0	28,854
2013	2,066	0	28,192	30,258	0	0	30,258
2014	2,128	0	29,611	31,740	0	0	31,740
2015	2,192	0	31,110	33,302	0	0	33,302
2016	2,258	0	32,692	34,950	0	0	34,950
2017	2,326	0	34,362	36,688	0	0	36,688
2018	2,396	0	36,126	38,522	0	0	38,522
2019	2,468	0	37,988	40,456	0	0	40,456
2020	2,542	0	39,954	42,496	0	0	42,496
2021	2,618	0	42,030	44,648	0	0	44,648
2022	2,696	0	44,222	46,918	0	0	46,918
2023	0	0	0	0	0	0	0
Total =	$31,354	$0	$455,941	$487,295	$84,644	$84,644	$402,651
NPV =	17,690	0	251,524	269,214	73,977	73,977	195,237

Total NPV =	$195,237
Benefit/Cost Ratio =	3.64

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable D&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$594	$0	$7,381	$1,232	$9,208	$28,215	$18,449	$8,386	$38,278	($29,070)
2009	$1,224	$0	$15,484	$2,659	19,367	28,215	18,449	$8,386	38,278	(18,911)
2010	$1,891	$0	$24,368	$4,304	30,563	28214.723	18,449	$8,386	38,278	(7,714)
2011	$1,948	$0	$25,574	$4,646	32,168	0	0	$0	0	32,168
2012	$2,006	$0	$26,847	$5,017	33,871	0	0	$0	0	33,871
2013	$2,066	$0	$28,192	$5,419	35,678	0	0	$0	0	35,678
2014	$2,128	$0	$29,611	$5,855	37,595	0	0	$0	0	37,595
2015	$2,192	$0	$31,110	$6,328	39,630	0	0	$0	0	39,630
2016	$2,258	$0	$32,692	$6,840	41,790	0	0	$0	0	41,790
2017	$2,326	$0	$34,362	$7,396	44,084	0	0	$0	0	44,084
2018	$2,396	$0	$36,126	$7,998	46,520	0	0	$0	0	46,520
2019	$2,468	$0	$37,988	$8,652	49,108	0	0	$0	0	49,108
2020	$2,542	$0	$39,954	$9,361	51,857	0	0	$0	0	51,857
2021	$2,618	$0	$42,030	$10,130	54,778	0	0	$0	0	54,778
2022	$2,696	$0	$44,222	$10,964	57,882	0	0	$0	0	57,882
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$31,354	$0	$455,941	$96,804	$584,099	$84,644	$55,346	$25,157	$114,833	$469,266
NPV =	17,690	0	251,524	61,870	331,084	73,977	48,371	21,987	100,361	230,723

Total NPV = $230,723
Benefit/Cost Ratio = 3.30

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential ENERGY STAR Freezers**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0064	$8,386	9,690	19,380	$0.074	$0.074	7	13	$0.00	$0.00	$10,547	$18,449	$0	$18,449	($7,901)
2009	0.0126	$8,386	19,380	38,761	$0.078	$0.078	13	26	$0.00	$0.00	$12,950	18,449	$0	18,449	(5,499)
2010	0.0124	$8,386	29,071	58,141	$0.083	$0.083	20	39	$0.00	$0.00	$15,614	18,449	$0	18,449	(2,835)
2011	0.0122	$0	29,071	58,141	$0.088	$0.088	20	39	$0.00	$0.00	$7,631	0	$0	0	7,631
2012	0.0120	$0	29,071	58,141	$0.092	$0.092	20	39	$0.00	$0.00	$8,057	0	$0	0	8,057
2013	0.0118	0	29,071	58,141	$0.098	$0.098	20	39	$0.00	$0.00	$8,507	0	$0	0	8,507
2014	0.0116	0	29,071	58,141	$0.103	$0.103	20	39	$0.00	$0.00	$8,981	0	$0	0	8,981
2015	0.0114	0	29,071	58,141	$0.109	$0.109	20	39	$0.00	$0.00	$9,483	0	$0	0	9,483
2016	0.0113	0	29,071	58,141	$0.115	$0.115	20	39	$0.00	$0.00	$10,012	0	$0	0	10,012
2017	0.0111	0	29,071	58,141	$0.121	$0.121	20	39	$0.00	$0.00	$10,570	0	$0	0	10,570
2018	0.0109	0	29,071	58,141	$0.128	$0.128	20	39	$0.00	$0.00	$11,160	0	$0	0	11,160
2019	0.0107	0	29,071	58,141	$0.135	$0.135	20	39	$0.00	$0.00	$11,783	0	$0	0	11,783
2020	0.0106	0	29,071	58,141	$0.143	$0.143	20	39	$0.00	$0.00	$12,440	0	$0	0	12,440
2021	0.0104	0	29,071	58,141	$0.151	$0.151	20	39	$0.00	$0.00	$13,134	0	$0	0	13,134
2022	0.0102	0	29,071	58,141	$0.159	$0.159	20	39	$0.00	$0.00	$13,867	0	$0	0	13,867
2023	0.0101	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			406,987	813,974							$164,736	$55,346	$0	$55,346	$109,391
											$105,529	51,781	0	51,781	53,748

Total NPV = $53,748
Benefit/Cost Ratio = 2.04

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$88,641
Total Utility Project Costs Year 1 =	**$108,470**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$88,641
Total Utility Project Costs Year 2 =	**$108,470**
15b) Total Utilty Cost Year 3 =	**$108,470**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,100.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.61
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	720
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	148
22a) Number of Participants (Second Year) =	148
22a) Number of Participants (Third Year) =	148
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 600.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$325,409
Total Program Participants	443
Utility Cost per Participant (First Year) =	$734.22
Utility Cost per Participant (Program) =	$734.22
Total kW Reduction	293
Total Energy Reduction (kWh)	4,818,179
Societal Cost per kwh	$0.10

Test Results

	NPV	B/C
Utility Test	$174,197	1.49
Ratepayer Test	$246,644	1.87
Societal Cost Test	$174,902	1.37
Participant Test	$92,682	1.20

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	114,719	$0.0190	$0	98	$140.17	$15,859	$108,470	3,243	$111,712	($95,854)
2	2009	229,437	$0.0195	0	195	$147.02	33,185	108,470	6,406	114,876	(81,691)
3	2010	344,156	$0.0201	0	293	$154.25	52,097	108469.5141	9,487	117,956	(65,859)
4	2011	344,156	$0.0207	0	293	$161.89	54,540	0	9,360	9,360	45,181
5	2012	344,156	$0.0213	0	293	$169.95	57,115	0	9,230	9,230	47,885
6	2013	344,156	$0.0220	0	293	$178.46	59,828	0	9,095	9,095	50,732
7	2014	344,156	$0.0226	0	293	$187.44	62,686	0	8,957	8,957	53,729
8	2015	344,156	$0.0233	0	293	$196.93	65,698	0	8,814	8,814	56,884
9	2016	344,156	$0.0240	0	293	$206.95	68,872	0	8,667	8,667	60,204
10	2017	344,156	$0.0247	0	293	$217.52	72,217	0	8,516	8,516	63,701
11	2018	344,156	$0.0255	0	293	$228.68	75,742	0	8,361	8,361	67,381
12	2019	344,156	$0.0262	0	293	$240.47	79,457	0	8,200	8,200	71,257
13	2020	344,156	$0.0270	0	293	$252.92	83,373	0	8,035	8,035	75,338
14	2021	344,156	$0.0278	0	293	$266.06	87,500	0	7,865	7,865	79,636
15	2022	344,156	$0.0287	0	293	$279.93	91,851	0	7,689	7,689	84,161
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		4,818,179			4,100		$960,020	$325,409	$121,925	$447,334	$512,686
NPV =							531,043	284,398	72,447	356,846	174,197

Total NPV = $174,197
Benefit/Cost Ratio = 1.49

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential High Efficiency Air Conditioning**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,174	$0	$13,685	$15,859	$108,470	$108,470	($92,611)
2009	4,479	0	28,706	33,185	108,470	108,470	(75,284)
2010	6,920	0	45,177	52,097	108,470	108,470	(56,373)
2011	7,127	0	47,413	54,540	0	0	54,540
2012	7,341	0	49,774	57,115	0	0	57,115
2013	7,561	0	52,266	59,828	0	0	59,828
2014	7,788	0	54,898	62,686	0	0	62,686
2015	8,022	0	57,676	65,698	0	0	65,698
2016	8,262	0	60,610	68,872	0	0	68,872
2017	8,510	0	63,707	72,217	0	0	72,217
2018	8,766	0	66,976	75,742	0	0	75,742
2019	9,029	0	70,429	79,457	0	0	79,457
2020	9,299	0	74,074	83,373	0	0	83,373
2021	9,578	0	77,922	87,500	0	0	87,500
2022	9,866	0	81,985	91,851	0	0	91,851
2023	0	0	0	0	0	0	0
Total =	$114,723	$0	$845,298	$960,020	$325,409	$325,409	$634,612
NPV =	64,727	0	466,316	531,043	284,398	284,398	246,644

Total NPV = $246,644

Benefit/Cost Ratio = 1.87

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,174	$0	$13,685	$2,450	$18,309	$108,470	$162,508	$88,641	$182,337	($164,028)
2009	$4,479	$0	$28,706	$5,281	38,466	108,470	162,508	$88,641	182,337	(143,871)
2010	$6,920	$0	$45,177	$8,539	60,636	108469.51	162,508	$88,641	182,337	(121,700)
2011	$7,127	$0	$47,413	$9,208	63,748	0	0	$0	0	63,748
2012	$7,341	$0	$49,774	$9,932	67,047	0	0	$0	0	67,047
2013	$7,561	$0	$52,266	$10,716	70,543	0	0	$0	0	70,543
2014	$7,788	$0	$54,898	$11,564	74,250	0	0	$0	0	74,250
2015	$8,022	$0	$57,676	$12,484	78,182	0	0	$0	0	78,182
2016	$8,262	$0	$60,610	$13,479	82,351	0	0	$0	0	82,351
2017	$8,510	$0	$63,707	$14,558	86,775	0	0	$0	0	86,775
2018	$8,766	$0	$66,976	$15,727	91,469	0	0	$0	0	91,469
2019	$9,029	$0	$70,429	$16,993	96,450	0	0	$0	0	96,450
2020	$9,299	$0	$74,074	$18,365	101,739	0	0	$0	0	101,739
2021	$9,578	$0	$77,922	$19,853	107,353	0	0	$0	0	107,353
2022	$9,866	$0	$81,985	$21,465	113,316	0	0	$0	0	113,316
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$114,723	$0	$845,298	$190,614	$1,150,634	$325,409	$487,523	$265,922	$547,010	$603,624
NPV =	64,727	0	466,316	121,931	652,974	284,398	426,082	232,408	478,072	174,902

Total NPV = $174,902
Benefit/Cost Ratio = 1.37

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential High Efficiency Air Conditioning**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0017	$88,641	106,369	0	$0.074	$0.074	91	0	$0.00	$0.00	$96,549	$162,508	$0	$162,508	($65,959)
2009	0.0033	$88,641	212,737	0	$0.078	$0.078	181	0	$0.00	$0.00	$105,340	162,508	$0	162,508	(57,168)
2010	0.0033	$88,641	319,106	0	$0.083	$0.083	272	0	$0.00	$0.00	$115,087	162,508	$0	162,508	(47,420)
2011	0.0032	$0	319,106	0	$0.088	$0.088	272	0	$0.00	$0.00	$27,923	0	$0	0	27,923
2012	0.0032	$0	319,106	0	$0.092	$0.092	272	0	$0.00	$0.00	$29,481	0	$0	0	29,481
2013	0.0031	0	319,106	0	$0.098	$0.098	272	0	$0.00	$0.00	$31,126	0	$0	0	31,126
2014	0.0031	0	319,106	0	$0.103	$0.103	272	0	$0.00	$0.00	$32,863	0	$0	0	32,863
2015	0.0030	0	319,106	0	$0.109	$0.109	272	0	$0.00	$0.00	$34,696	0	$0	0	34,696
2016	0.0030	0	319,106	0	$0.115	$0.115	272	0	$0.00	$0.00	$36,632	0	$0	0	36,632
2017	0.0029	0	319,106	0	$0.121	$0.121	272	0	$0.00	$0.00	$38,677	0	$0	0	38,677
2018	0.0029	0	319,106	0	$0.128	$0.128	272	0	$0.00	$0.00	$40,835	0	$0	0	40,835
2019	0.0028	0	319,106	0	$0.135	$0.135	272	0	$0.00	$0.00	$43,113	0	$0	0	43,113
2020	0.0028	0	319,106	0	$0.143	$0.143	272	0	$0.00	$0.00	$45,519	0	$0	0	45,519
2021	0.0027	0	319,106	0	$0.151	$0.151	272	0	$0.00	$0.00	$48,059	0	$0	0	48,059
2022	0.0027	0	319,106	0	$0.159	$0.159	272	0	$0.00	$0.00	$50,741	0	$0	0	50,741
2023	0.0027	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			4,467,482	0							$776,640	$487,523	$0	$487,523	$289,117
											$548,802	456,121	0	456,121	92,682

Total NPV = $92,682
Benefit/Cost Ratio = 1.20

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$17,750
Total Utility Project Costs Year 1 =	**$37,579**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$17,750
Total Utility Project Costs Year 2 =	**$37,579**
15b) Total Utilty Cost Year 3 =	**$37,579**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$1,000.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.87
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	950
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	36
22a) Number of Participants (Second Year) =	36
22a) Number of Participants (Third Year) =	36
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 500.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial High Efficiency A/C**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$112,738
Total Program Participants	107
Utility Cost per Participant (First Year) =	$1,058.55
Utility Cost per Participant (Program) =	$1,058.55
Total kW Reduction	99
Total Energy Reduction (kWh)	1,527,668
Societal Cost per kwh	$0.09

Test Results

	NPV	B/C
Utility Test	$71,443	1.67
Ratepayer Test	$80,333	1.82
Societal Cost Test	$74,866	1.52
Participant Test	$62,835	1.63

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	36,373	$0.0190	$0	33	$140.17	$5,336	$37,579	453	$38,033	($32,697)
2	2009	72,746	$0.0195	0	66	$147.02	11,167	37,579	882	38,461	(27,293)
3	2010	109,119	$0.0201	0	99	$154.25	17,534	37579.31	1,283	38,863	(21,329)
4	2011	109,119	$0.0207	0	99	$161.89	18,359	0	1,243	1,243	17,116
5	2012	109,119	$0.0213	0	99	$169.95	19,229	0	1,202	1,202	18,027
6	2013	109,119	$0.0220	0	99	$178.46	20,145	0	1,159	1,159	18,985
7	2014	109,119	$0.0226	0	99	$187.44	21,110	0	1,115	1,115	19,995
8	2015	109,119	$0.0233	0	99	$196.93	22,128	0	1,070	1,070	21,057
9	2016	109,119	$0.0240	0	99	$206.95	23,200	0	1,024	1,024	22,176
10	2017	109,119	$0.0247	0	99	$217.52	24,330	0	976	976	23,354
11	2018	109,119	$0.0255	0	99	$228.68	25,521	0	926	926	24,595
12	2019	109,119	$0.0262	0	99	$240.47	26,777	0	876	876	25,901
13	2020	109,119	$0.0270	0	99	$252.92	28,101	0	823	823	27,277
14	2021	109,119	$0.0278	0	99	$266.06	29,496	0	769	769	28,727
15	2022	109,119	$0.0287	0	99	$279.93	30,967	0	714	714	30,253
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		1,527,668			1,392		$323,400	$112,738	$14,516	$127,254	$196,145
NPV =							178,862	98,530	8,890	107,420	71,443

Total NPV = $71,443
Benefit/Cost Ratio = 1.67

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$689	$0	$4,647	$5,336	$37,579	$37,579	($32,243)
2009	1,420	0	9,747	11,167	37,579	37,579	(26,412)
2010	2,194	0	15,340	17,534	37,579	37,579	(20,045)
2011	2,260	0	16,099	18,359	0	0	18,359
2012	2,328	0	16,901	19,229	0	0	19,229
2013	2,397	0	17,747	20,145	0	0	20,145
2014	2,469	0	18,641	21,110	0	0	21,110
2015	2,543	0	19,584	22,128	0	0	22,128
2016	2,620	0	20,580	23,200	0	0	23,200
2017	2,698	0	21,632	24,330	0	0	24,330
2018	2,779	0	22,742	25,521	0	0	25,521
2019	2,863	0	23,914	26,777	0	0	26,777
2020	2,949	0	25,152	28,101	0	0	28,101
2021	3,037	0	26,459	29,496	0	0	29,496
2022	3,128	0	27,838	30,967	0	0	30,967
2023	0	0	0	0	0	0	0
Total =	$36,374	$0	$287,025	$323,400	$112,738	$112,738	$210,662
NPV =	20,522	0	158,340	178,862	98,530	98,530	80,333

Total NPV = $80,333
Benefit/Cost Ratio = 1.82

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$689	$0	$4,647	$824	$6,160	$37,579	$35,501	$17,750	$55,330	($49,169)
2009	$1,420	$0	$9,747	$1,777	12,945	37,579	35,501	$17,750	55,330	(42,385)
2010	$2,194	$0	$15,340	$2,874	20,408	37579.308	35,501	$17,750	55,330	(34,921)
2011	$2,260	$0	$16,099	$3,100	21,459	0	0	$0	0	21,459
2012	$2,328	$0	$16,901	$3,344	22,572	0	0	$0	0	22,572
2013	$2,397	$0	$17,747	$3,608	23,753	0	0	$0	0	23,753
2014	$2,469	$0	$18,641	$3,894	25,005	0	0	$0	0	25,005
2015	$2,543	$0	$19,584	$4,205	26,332	0	0	$0	0	26,332
2016	$2,620	$0	$20,580	$4,541	27,741	0	0	$0	0	27,741
2017	$2,698	$0	$21,632	$4,905	29,235	0	0	$0	0	29,235
2018	$2,779	$0	$22,742	$5,299	30,821	0	0	$0	0	30,821
2019	$2,863	$0	$23,914	$5,727	32,504	0	0	$0	0	32,504
2020	$2,949	$0	$25,152	$6,190	34,291	0	0	$0	0	34,291
2021	$3,037	$0	$26,459	$6,692	36,188	0	0	$0	0	36,188
2022	$3,128	$0	$27,838	$7,237	38,203	0	0	$0	0	38,203
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$36,374	$0	$287,025	$64,216	$387,615	$112,738	$106,502	$53,251	$165,989	$221,627
NPV =	20,522	0	158,340	41,073	219,935	98,530	93,080	46,540	145,070	74,866

Total NPV = $74,866
Benefit/Cost Ratio = 1.52

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial High Efficiency A/C**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0021	$17,750	33,726	0	$0.045	$0.045	31	0	$47.41	$69.46	$20,720	$35,501	$0	$35,501	($14,781)
2009	0.0041	$17,750	67,451	0	$0.047	$0.047	61	0	$50.05	$73.34	$24,021	35,501	$0	35,501	(11,480)
2010	0.0041	$17,750	101,177	0	$0.050	$0.050	92	0	$52.84	$77.43	$27,681	35,501	$0	35,501	(7,819)
2011	0.0041	$0	101,177	0	$0.053	$0.053	92	0	$55.79	$81.75	$10,485	0	$0	0	10,485
2012	0.0040	$0	101,177	0	$0.056	$0.056	92	0	$58.91	$86.31	$11,070	0	$0	0	11,070
2013	0.0040	0	101,177	0	$0.059	$0.059	92	0	$62.19	$91.13	$11,688	0	$0	0	11,688
2014	0.0040	0	101,177	0	$0.062	$0.062	92	0	$65.66	$96.21	$12,340	0	$0	0	12,340
2015	0.0039	0	101,177	0	$0.066	$0.066	92	0	$69.33	$101.58	$13,029	0	$0	0	13,029
2016	0.0039	0	101,177	0	$0.069	$0.069	92	0	$73.19	$107.25	$13,756	0	$0	0	13,756
2017	0.0039	0	101,177	0	$0.073	$0.073	92	0	$77.28	$113.23	$14,523	0	$0	0	14,523
2018	0.0039	0	101,177	0	$0.077	$0.077	92	0	$81.59	$119.55	$15,334	0	$0	0	15,334
2019	0.0038	0	101,177	0	$0.082	$0.082	92	0	$86.14	$126.22	$16,189	0	$0	0	16,189
2020	0.0038	0	101,177	0	$0.086	$0.086	92	0	$90.95	$133.27	$17,093	0	$0	0	17,093
2021	0.0038	0	101,177	0	$0.091	$0.091	92	0	$96.03	$140.70	$18,046	0	$0	0	18,046
2022	0.0038	0	101,177	0	$0.096	$0.096	92	0	$101.38	$148.55	$19,053	0	$0	0	19,053
2023	0.0037	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			1,416,475	0							$245,029	$106,502	$0	$106,502	$138,528
											$162,477	99,642	0	99,642	62,835

Total NPV = $62,835
Benefit/Cost Ratio = 1.63

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$657,371
Incentive Costs =	$161,231
Total Utility Project Costs Year 1 =	**$842,031**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$301,396
Incentive Costs =	$80,616
Total Utility Project Costs Year 2 =	**$405,441**
15b) Total Utilty Cost Year 3 =	**$405,441**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$0.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	1.00
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	360
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	1,662
22a) Number of Participants (Second Year) =	831
22a) Number of Participants (Third Year) =	831
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 97.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Air Conditioning Cycling T-Stat**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$1,652,912
Total Program Participants	3,324
Utility Cost per Participant (First Year) =	$506.58
Utility Cost per Participant (Program) =	$497.21
Total kW Reduction	3,575
Total Energy Reduction (kWh)	11,939,093
Societal Cost per kwh	$0.10

Test Results

	NPV	B/C
Utility Test	$2,431,105	2.44
Ratepayer Test	$2,648,539	2.80
Societal Cost Test	$3,763,309	4.18
Participant Test	$1,077,228	#DIV/0!

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	645,356	$0.0190	$0	1,788	$140.17	$262,812	$842,031	18,243	$860,275	($597,463)
2	2009	968,035	$0.0195	0	2,681	$147.02	413,132	405,441	27,029	432,470	(19,338)
3	2010	1,290,713	$0.0201	0	3,575	$154.25	577,451	405440.6109	35,578	441,019	136,432
4	2011	1,290,713	$0.0207	0	3,575	$161.89	605,525	0	35,103	35,103	570,421
5	2012	1,290,713	$0.0213	0	3,575	$169.95	635,144	0	34,614	34,614	600,530
6	2013	1,290,713	$0.0220	0	3,575	$178.46	666,396	0	34,110	34,110	632,286
7	2014	1,290,713	$0.0226	0	3,575	$187.44	699,371	0	33,591	33,591	665,779
8	2015	1,290,713	$0.0233	0	3,575	$196.93	734,163	0	33,057	33,057	701,106
9	2016	1,290,713	$0.0240	0	3,575	$206.95	770,875	0	32,506	32,506	738,368
10	2017	1,290,713	$0.0247	0	3,575	$217.52	809,611	0	31,939	31,939	777,672
11	2018	0	$0.0255	0	0	$228.68	0	0	0	0	0
12	2019	0	$0.0262	0	0	$240.47	0	0	0	0	0
13	2020	0	$0.0270	0	0	$252.92	0	0	0	0	0
14	2021	0	$0.0278	0	0	$266.06	0	0	0	0	0
15	2022	0	$0.0287	0	0	$279.93	0	0	0	0	0
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		11,939,093			33,071		$6,174,480	$1,652,912	$315,773	$1,968,686	$4,205,794
NPV =							4,119,410	1,470,871	217,434	1,688,305	2,431,105

Total NPV = $2,431,105
Benefit/Cost Ratio = 2.44

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)
(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Residential Air Conditioning Cycling T-Stat**

	Decreases			Increases			
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Oecrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$12,231	$0	$250,581	$262,812	$842,031	$842,031	($579,220)
2009	18,897	0	394,236	413,132	405,441	405,441	7,692
2010	25,951	0	551,500	577,451	405,441	405,441	172,010
2011	26,730	0	578,795	605,525	0	0	605,525
2012	27,532	0	607,613	635,144	0	0	635,144
2013	28,358	0	638,039	666,396	0	0	666,396
2014	29,208	0	670,162	699,371	0	0	699,371
2015	30,085	0	704,079	734,163	0	0	734,163
2016	30,987	0	739,887	770,875	0	0	770,875
2017	31,917	0	777,694	809,611	0	0	809,611
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$261,895	$0	$5,912,585	$6,174,480	$1,652,912	$1,652,912	$4,521,568
NPV =	176,358	0	3,943,052	4,119,410	1,470,871	1,470,871	2,648,539

Total NPV = $2,648,539

Benefit/Cost Ratio = 2.80

(A) = Energy Red/Part (21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable D & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$12,231	$0	$250,581	$40,604	$303,416	$842,031	$0	$161,231	$680,800	($377,384)
2009	$18,897	$0	$394,236	$65,744	478,876	405,441	0	$80,616	324,825	154,051
2010	$25,951	$0	$551,500	$94,649	672,101	405440.61	0	$80,616	324,825	347,275
2011	$26,730	$0	$578,795	$102,228	707,753	0	0	$0	0	707,753
2012	$27,532	$0	$607,613	$110,446	745,590	0	0	$0	0	745,590
2013	$28,358	$0	$638,039	$119,357	785,753	0	0	$0	0	785,753
2014	$29,208	$0	$670,162	$129,021	828,391	0	0	$0	0	828,391
2015	$30,085	$0	$704,079	$139,502	873,666	0	0	$0	0	873,666
2016	$30,987	$0	$739,887	$150,872	921,747	0	0	$0	0	921,747
2017	$31,917	$0	$777,694	$163,207	972,819	0	0	$0	0	972,819
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$261,895	$0	$5,912,585	$1,115,632	$7,290,112	$1,652,912	$0	$322,462	$1,330,450	$5,959,662
NPV =	176,358	0	3,943,052	828,096	4,947,506	1,470,871	0	286,674	1,184,197	3,763,309

Total NPV = $3,763,309
Benefit/Cost Ratio = 4.18

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable D&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Dther (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Air Conditioning Cycling T-Stat**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0190	$161,231	598,383	0	$0.074	$0.074	1,658	0	$0.00	$0.00	$205,721	$0	$0	$0	$205,721
2009	0.0280	$80,616	897,575	0	$0.078	$0.078	2,486	0	$0.00	$0.00	$151,073	0	$0	0	151,073
2010	0.0276	$80,616	1,196,767	0	$0.083	$0.083	3,315	0	$0.00	$0.00	$179,802	0	$0	0	179,802
2011	0.0272	$0	1,196,767	0	$0.088	$0.088	3,315	0	$0.00	$0.00	$104,721	0	$0	0	104,721
2012	0.0267	$0	1,196,767	0	$0.092	$0.092	3,315	0	$0.00	$0.00	$110,564	0	$0	0	110,564
2013	0.0263	0	1,196,767	0	$0.098	$0.098	3,315	0	$0.00	$0.00	$116,733	0	$0	0	116,733
2014	0.0259	0	1,196,767	0	$0.103	$0.103	3,315	0	$0.00	$0.00	$123,247	0	$0	0	123,247
2015	0.0255	0	1,196,767	0	$0.109	$0.109	3,315	0	$0.00	$0.00	$130,124	0	$0	0	130,124
2016	0.0251	0	1,196,767	0	$0.115	$0.115	3,315	0	$0.00	$0.00	$137,385	0	$0	0	137,385
2017	0.0247	0	1,196,767	0	$0.121	$0.121	3,315	0	$0.00	$0.00	$145,051	0	$0	0	145,051
2018	0.0243	0	0	0	$0.128	$0.128	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0239	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0235	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0232	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0228	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0224	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			11,070,091	0							$1,404,422	$0	$0	$0	$1,404,422
											$1,077,228	0	0	0	1,077,228

Total NPV = $1,077,228
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$113,676
Incentive Costs =	$58,316
Total Utility Project Costs Year 1 =	**$195,420**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$23,429
Direct Operating Costs =	$67,948
Incentive Costs =	$29,158
Total Utility Project Costs Year 2 =	**$120,535**
15b) Total Utilty Cost Year 3 =	**$120,535**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$ -
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	3.80
20a) Avg Winter kW/part Saved =	0
21) Avg. Summer kWh/Part. Saved =	1,372
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	160
22a) Number of Participants (Second Year) =	80
22a) Number of Participants (Third Year) =	80
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 365.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Commercial Air Conditioning Cycling T-Stat**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	10
Total Progam Cost (Utility)	$436,491
Total Program Participants	320
Utility Cost per Participant (First Year) =	$1,223.15
Utility Cost per Participant (Program) =	$1,366.01
Total kW Reduction	1,310
Total Energy Reduction (kWh)	4,373,588
Societal Cost per kwh	$0.06

Test Results

	NPV	B/C
Utility Test	$1,090,643	3.61
Ratepayer Test	$1,123,055	3.91
Societal Cost Test	$1,530,095	6.42
Participant Test	$779,631	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial Air Conditioning Cycling T-Stat**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	236,410	$0.0190	$0	655	$140.17	$96,274	$195,420	2,947	$198,367	($102,093)
2	2009	354,615	$0.0195	0	982	$147.02	151,341	120,535	4,298	124,833	26,508
3	2010	472,820	$0.0201	0	1,310	$154.25	211,535	120535.2	5,561	126,096	85,438
4	2011	472,820	$0.0207	0	1,310	$161.89	221,819	0	5,387	5,387	216,431
5	2012	472,820	$0.0213	0	1,310	$169.95	232,669	0	5,208	5,208	227,461
6	2013	472,820	$0.0220	0	1,310	$178.46	244,118	0	5,024	5,024	239,094
7	2014	472,820	$0.0226	0	1,310	$187.44	256,197	0	4,833	4,833	251,364
8	2015	472,820	$0.0233	0	1,310	$196.93	268,942	0	4,638	4,638	264,305
9	2016	472,820	$0.0240	0	1,310	$206.95	282,391	0	4,436	4,436	277,955
10	2017	472,820	$0.0247	0	1,310	$217.52	296,581	0	4,228	4,228	292,353
11	2018	0	$0.0255	0	0	$228.68	0	0	0	0	0
12	2019	0	$0.0262	0	0	$240.47	0	0	0	0	0
13	2020	0	$0.0270	0	0	$252.92	0	0	0	0	0
14	2021	0	$0.0278	0	0	$266.06	0	0	0	0	0
15	2022	0	$0.0287	0	0	$279.93	0	0	0	0	0
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		4,373,588			12,115		$2,261,866	$436,491	$46,560	$483,051	$1,778,815
NPV =							1,509,043	385,987	32,413	418,400	1,090,643

Total NPV = $1,090,643

Benefit/Cost Ratio = 3.61

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)

(B) = System Energy Cost (2)

(C) = (A) x Variable O&M (5)

(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)

(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)

(G) = Total Utility Project Costs (15)

(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]

(I) = (G) + (H)

(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Commercial Air Conditioning Cycling T-Stat**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$4,480	$0	$91,794	$96,274	$195,420	$195,420	($99,146)
2009	6,922	0	144,418	151,341	120,535	120,535	30,805
2010	9,507	0	202,028	211,535	120,535	120,535	91,000
2011	9,792	0	212,027	221,819	0	0	221,819
2012	10,086	0	222,584	232,669	0	0	232,669
2013	10,388	0	233,729	244,118	0	0	244,118
2014	10,700	0	245,497	256,197	0	0	256,197
2015	11,021	0	257,922	268,942	0	0	268,942
2016	11,351	0	271,039	282,391	0	0	282,391
2017	11,692	0	284,889	296,581	0	0	296,581
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$95,939	$0	$2,165,927	$2,261,866	$436,491	$436,491	$1,825,375
NPV =	64,604	0	1,444,438	1,509,043	385,987	385,987	1,123,055

Total NPV = $1,123,055

Benefit/Cost Ratio = 3.91

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

	Decreases				Increases					
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$4,480	$0	$91,794	$14,874	$111,149	$195,420	$0	$58,316	$137,105	($25,956)
2009	$6,922	$0	$144,418	$24,084	175,424	120,535	0	$29,158	91,377	84,047
2010	$9,507	$0	$202,028	$34,672	246,207	120535.19	0	$29,158	91,377	154,830
2011	$9,792	$0	$212,027	$37,449	259,268	0	0	$0	0	259,268
2012	$10,086	$0	$222,584	$40,459	273,128	0	0	$0	0	273,128
2013	$10,388	$0	$233,729	$43,723	287,841	0	0	$0	0	287,841
2014	$10,700	$0	$245,497	$47,263	303,460	0	0	$0	0	303,460
2015	$11,021	$0	$257,922	$51,103	320,046	0	0	$0	0	320,046
2016	$11,351	$0	$271,039	$55,268	337,659	0	0	$0	0	337,659
2017	$11,692	$0	$284,889	$59,787	356,368	0	0	$0	0	356,368
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$95,939	$0	$2,165,927	$408,684	$2,670,550	$436,491	$0	$116,631	$319,860	$2,350,690
NPV =	64,604	0	1,444,438	303,352	1,812,395	385,987	0	103,687	282,300	1,530,095

Total NPV = $1,530,095
Benefit/Cost Ratio = 6.42

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Commercial Air Conditioning Cycling T-Stat**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0093	$58,316	219,203	0	$0.045	$0.045	607	0	$47.41	$69.46	$96,931	$0	$0	$0	$96,931
2009	0.0139	$29,158	328,804	0	$0.047	$0.047	911	0	$50.05	$73.34	$90,313	0	$0	0	90,313
2010	0.0138	$29,158	438,405	0	$0.050	$0.050	1,214	0	$52.84	$77.43	$115,248	0	$0	0	115,248
2011	0.0137	$0	438,405	0	$0.053	$0.053	1,214	0	$55.79	$81.75	$90,894	0	$0	0	90,894
2012	0.0136	$0	438,405	0	$0.056	$0.056	1,214	0	$58.91	$86.31	$95,966	0	$0	0	95,966
2013	0.0135	0	438,405	0	$0.059	$0.059	1,214	0	$62.19	$91.13	$101,321	0	$0	0	101,321
2014	0.0134	0	438,405	0	$0.062	$0.062	1,214	0	$65.66	$96.21	$106,975	0	$0	0	106,975
2015	0.0133	0	438,405	0	$0.066	$0.066	1,214	0	$69.33	$101.58	$112,944	0	$0	0	112,944
2016	0.0132	0	438,405	0	$0.069	$0.069	1,214	0	$73.19	$107.25	$119,246	0	$0	0	119,246
2017	0.0131	0	438,405	0	$0.073	$0.073	1,214	0	$77.28	$113.23	$125,900	0	$0	0	125,900
2018	0.0130	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0129	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0128	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0128	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0127	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0126	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			4,055,250	0							$1,055,739	$0	$0	$0	$1,055,739
											$779,631	0	0	0	779,631

Total NPV = $779,631
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06505
1a) Retail Rate Winter ($/kWh) =	$0.06505
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$0.00
3a) Retail Winter Demand Rate ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$11,779
Incentive Costs =	$5,497
Total Utility Project Costs Year 1 =	**$37,105**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$11,779
Incentive Costs =	$5,497
Total Utility Project Costs Year 2 =	**$37,105**
15b) Total Utilty Cost Year 3 =	**$37,105**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$ -
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	5
20) Avg Summer kW/part. Saved =	0.165
20a) Avg Winter kW/part Saved =	0.330
21) Avg. Summer kWh/Part. Saved =	389
21a) Avg. Winter kWh/Part. Saved =	777
22) Number of Participants (First Year) =	157
22a) Number of Participants (Second Year) =	157
22a) Number of Participants (Third Year) =	157
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 35.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company:	**Montana-Dakota Utilities Co.**
Project:	**Residential Refridgerator Round Up**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	5
Total Progam Cost (Utility)	$111,315
Total Program Participants	471
Utility Cost per Participant (First Year) =	$236.26
Utility Cost per Participant (Program) =	$236.26
Total kW Reduction	252
Total Energy Reduction (kWh)	2,369,992
Societal Cost per kwh	$0.03

Test Results

	NPV	B/C
Utility Test	$192,675	2.21
Ratepayer Test	$254,390	3.61
Societal Cost Test	$331,362	5.00
Participant Test	$173,465	#DIV/0!

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	197,499	$0.0190	$0	84	$349.78	$33,085	$37,105	5,876	$42,981	($9,896)
2	2009	394,999	$0.0195	0	168	$366.87	69,261	37,105	12,232	49,337	19,924
3	2010	592,498	$0.0201	0	252	$384.91	108,779	37104.86	19,115	56,220	52,559
4	2011	592,498	$0.0207	0	252	$403.96	113,931	0	19,931	19,931	94,000
5	2012	592,498	$0.0213	0	252	$424.07	119,361	0	20,797	20,797	98,564
6	2013	0	$0.0220	0	0	$445.31	0	0	0	0	0
7	2014	0	$0.0226	0	0	$467.73	0	0	0	0	0
8	2015	0	$0.0233	0	0	$491.40	0	0	0	0	0
9	2016	0	$0.0240	0	0	$516.39	0	0	0	0	0
10	2017	0	$0.0247	0	0	$542.78	0	0	0	0	0
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		2,369,992			1,007		$444,417	$111,315	$77,951	$189,266	$255,151
NPV =							351,676	97,286	61,715	159,001	192,675

Total NPV = $192,675
Benefit/Cost Ratio = 2.21

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$3,743	$0	$29,342	$33,085	$37,105	$37,105	($4,020)
2009	7,711	0	61,551	69,261	37,105	37,105	32,156
2010	11,913	0	96,867	108,779	37,105	37,105	71,675
2011	12,270	0	101,661	113,931	0	0	113,931
2012	12,638	0	106,722	119,361	0	0	119,361
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$48,275	$0	$396,142	$444,417	$111,315	$111,315	$333,102
NPV =	38,269	0	313,406	351,676	97,286	97,286	254,390

Total NPV = $254,390
Benefit/Cost Ratio = 3.61

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$3,743	$0	$29,342	$5,112	$38,196	$37,105	$0	$5,497	$31,608	$6,588
2009	$7,711	$0	$61,551	$11,022	80,283	37,105	0	$5,497	31,608	48,675
2010	$11,913	$0	$96,867	$17,830	126,609	37104.86	0	$5,497	31,608	95,001
2011	$12,270	$0	$101,661	$19,235	133,165	0	0	$0	0	133,165
2012	$12,638	$0	$106,722	$20,756	140,116	0	0	$0	0	140,116
2013	$0	$0	$0	$0	0	0	0	$0	0	0
2014	$0	$0	$0	$0	0	0	0	$0	0	0
2015	$0	$0	$0	$0	0	0	0	$0	0	0
2016	$0	$0	$0	$0	0	0	0	$0	0	0
2017	$0	$0	$0	$0	0	0	0	$0	0	0
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$48,275	$0	$396,142	$73,954	$518,370	$111,315	$0	$16,491	$94,824	$423,546
NPV =	38,269	0	313,406	62,560	414,236	97,286	0	14,412	82,874	331,362

Total NPV = $331,362
Benefit/Cost Ratio = 5.00

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Refridgerator Round Up**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0018	$5,497	61,041	122,083	$0.074	$0.074	26	52	$0.00	$0.00	$19,112	$0	$0	$0	$19,112
2009	0.0035	$5,497	122,083	244,165	$0.078	$0.078	52	104	$0.00	$0.00	$34,247	0	$0	0	34,247
2010	0.0035	$5,497	183,124	366,248	$0.083	$0.083	78	156	$0.00	$0.00	$51,028	0	$0	0	51,028
2011	0.0034	$0	183,124	366,248	$0.088	$0.088	78	156	$0.00	$0.00	$48,072	0	$0	0	48,072
2012	0.0034	$0	183,124	366,248	$0.092	$0.092	78	156	$0.00	$0.00	$50,754	0	$0	0	50,754
2013	0.0033	0	0	0	$0.098	$0.098	0	0	$0.00	$0.00	$0	0	$0	0	0
2014	0.0033	0	0	0	$0.103	$0.103	0	0	$0.00	$0.00	$0	0	$0	0	0
2015	0.0032	0	0	0	$0.109	$0.109	0	0	$0.00	$0.00	$0	0	$0	0	0
2016	0.0032	0	0	0	$0.115	$0.115	0	0	$0.00	$0.00	$0	0	$0	0	0
2017	0.0031	0	0	0	$0.121	$0.121	0	0	$0.00	$0.00	$0	0	$0	0	0
2018	0.0031	0	0	0	$0.128	$0.128	0	0	$0.00	$0.00	$0	0	$0	0	0
2019	0.0030	0	0	0	$0.135	$0.135	0	0	$0.00	$0.00	$0	0	$0	0	0
2020	0.0030	0	0	0	$0.143	$0.143	0	0	$0.00	$0.00	$0	0	$0	0	0
2021	0.0029	0	0	0	$0.151	$0.151	0	0	$0.00	$0.00	$0	0	$0	0	0
2022	0.0029	0	0	0	$0.159	$0.159	0	0	$0.00	$0.00	$0	0	$0	0	0
2023	0.0028	0	0	0	$0.168	$0.168	0	0	$0.00	$0.00	$0	0	$0	0	0
			732,496	1,464,993							$203,212	$0	$0	$0	$203,212
											$173,465	0	0	0	173,465

Total NPV = $173,465
Benefit/Cost Ratio = #DIV/0!

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.06987
1a) Retail Rate Winter ($/kWh) =	$0.03431
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Cost ($/kW/season) =	$0.00
3a) Retail Winter Demand Cost ($/kW/season) =	$0.00
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5)Heating margin increase per cooling reduc ($/kWl	$0.09
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	768,951,893
Growth Rate =	0.80%
8) Total Customers by class =	86,151
Growth Rate =	1.60%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System Demand Line loss factor	7.85%
14b) System Energy Line Loss Factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$32,862
Total Utility Project Costs Year 1 =	**$37,862**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$5,000
Direct Operating Costs =	$0
Incentive Costs =	$32,862
Total Utility Project Costs Year 2 =	**$37,862**
15b) Total Utilty Cost Year 3 =	**$37,862**
15c) Total Utilty Cost Year 4 =	**$0**
15d) Total Utility Cost Year 5 =	**$0**
16) Direct Participant Costs ($/Part.) =	$4,000.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
17a) Other Participant Savings vs propane (Annual $/ Part)	$577.00
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	0.73
20a) Avg Winter kW/part Saved =	0.73
21) Avg. Summer kWh/Part. Saved =	889
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	30
22a) Number of Participants (Second Year) =	30
22a) Number of Participants (Third Year) =	30
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 1,100.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$113,585
Total Program Participants	90
Utility Cost per Participant (First Year) =	$1,267.37
Utility Cost per Participant (Program) =	$1,267.37
Total Summer kW Reduction	66
Total Winter kW Reduction	66
Total Summer Energy Reduction (kWh)	1,115,442
Total Winter Energy Reduction (kWh)	0
Societal Cost per kwh	$0.27

Test Results

	NPV	B/C
Utility Test	$539,487	5.52
Ratepayer Test	$479,562	5.83
Societal Cost Test	$385,521	2.18
Participant Test	$288,899	1.86

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	After Tax Added Margin Heating Load (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	28,643	$0.0190	$2,685	47	$349.78	$19,740	$37,862	888	$38,749	($19,010)
2	2009	57,286	$0.0195	5,530	94	$366.87	41,287	37,862	1,756	39,617	1,669
3	2010	85,929	$0.0201	8,545	142	$384.91	64,785	37,862	2,603	40,464	24,320
4	2011	85,929	$0.0207	8,801	142	$403.96	67,791	0	2,571	2,571	65,220
5	2012	85,929	$0.0213	9,065	142	$424.07	70,957	0	2,539	2,539	68,418
6	2013	85,929	$0.0220	9,337	142	$445.31	74,291	0	2,505	2,505	71,786
7	2014	85,929	$0.0226	9,617	142	$467.73	77,803	0	2,471	2,471	75,332
8	2015	85,929	$0.0233	9,906	142	$491.40	81,502	0	2,435	2,435	79,067
9	2016	85,929	$0.0240	10,203	142	$516.39	85,399	0	2,398	2,398	83,001
10	2017	85,929	$0.0247	10,509	142	$542.78	89,504	0	2,361	2,361	87,143
11	2018	85,929	$0.0255	10,824	142	$570.64	93,828	0	2,322	2,322	91,507
12	2019	85,929	$0.0262	11,149	142	$600.05	98,384	0	2,282	2,282	96,103
13	2020	85,929	$0.0270	11,483	142	$631.11	103,185	0	2,240	2,240	100,944
14	2021	85,929	$0.0278	11,828	142	$663.90	108,242	0	2,198	2,198	106,044
15	2022	85,929	$0.0287	12,183	142	$698.51	113,572	0	2,154	2,154	111,417
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		1,203,004			1,983		$1,190,269	$113,585	$33,722	$147,307	$1,042,963
NPV =							658,759	99,270	20,001	119,272	539,487

Total NPV = $539,487
Benefit/Cost Ratio = 5.52

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$543	$0	$16,512	$17,055	$37,862	$37,862	($20,807)
2009	1,118	0	34,638	35,756	37,862	37,862	(2,105)
2010	1,728	0	54,512	56,240	37,862	37,862	18,378
2011	1,780	0	57,210	58,990	0	0	58,990
2012	1,833	0	60,059	61,892	0	0	61,892
2013	1,888	0	63,066	64,954	0	0	64,954
2014	1,945	0	66,241	68,186	0	0	68,186
2015	2,003	0	69,594	71,597	0	0	71,597
2016	2,063	0	73,133	75,196	0	0	75,196
2017	2,125	0	76,870	78,995	0	0	78,995
2018	2,189	0	80,816	83,004	0	0	83,004
2019	2,254	0	84,981	87,236	0	0	87,236
2020	2,322	0	89,380	91,701	0	0	91,701
2021	2,392	0	94,023	96,415	0	0	96,415
2022	2,463	0	98,926	101,389	0	0	101,389
2023	0	0	0	0	0	0	0
Total =	$28,644	$0	$1,019,962	$1,048,606	$113,585	$113,585	$935,022
NPV =	16,161	0	562,671	578,832	99,270	99,270	479,562

Total NPV = $479,562
Benefit/Cost Ratio = 5.83

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including environmental externalities and both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$543	$0	$16,512	$2,635	$19,690	$37,862	$119,497	$32,862	$124,497	($104,807)
2009	$1,118	$0	$34,638	$5,690	41,446	37,862	119,497	$32,862	124,497	(83,050)
2010	$1,728	$0	$54,512	$9,218	65,458	37,862	119,497	$32,862	124,497	(59,038)
2011	$1,780	$0	$57,210	$9,959	68,949	0	0	$0	0	68,949
2012	$1,833	$0	$60,059	$10,762	72,654	0	0	$0	0	72,654
2013	$1,888	$0	$63,066	$11,634	76,588	0	0	$0	0	76,588
2014	$1,945	$0	$66,241	$12,579	80,765	0	0	$0	0	80,765
2015	$2,003	$0	$69,594	$13,604	85,201	0	0	$0	0	85,201
2016	$2,063	$0	$73,133	$14,717	89,913	0	0	$0	0	89,913
2017	$2,125	$0	$76,870	$15,924	94,920	0	0	$0	0	94,920
2018	$2,189	$0	$80,816	$17,235	100,239	0	0	$0	0	100,239
2019	$2,254	$0	$84,981	$18,657	105,892	0	0	$0	0	105,892
2020	$2,322	$0	$89,380	$20,200	111,901	0	0	$0	0	111,901
2021	$2,392	$0	$94,023	$21,875	118,290	0	0	$0	0	118,290
2022	$2,463	$0	$98,926	$23,694	125,083	0	0	$0	0	125,083
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$28,644	$0	$1,019,962	$208,384	$1,256,991	$113,585	$358,490	$98,585	$373,490	$883,501
NPV =	16,161	0	562,671	133,109	711,941	99,270	313,311	86,160	326,420	385,521

Total NPV = $385,521
Benefit/Cost Ratio = 2.18

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Residential Ground Source Heat Pump**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Cost (F1)	Winter Demand Cost (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0003	$32,862	26,558	0	$0.079	$0.042	22	22	$0.00	$0.00	$52,209	$119,497	$0	$119,497	($67,288)
2009	0.0007	$32,862	53,116	0	$0.084	$0.044	44	44	$0.00	$0.00	$71,791	119,497	$0	119,497	(47,705)
2010	0.0007	$32,862	79,674	0	$0.089	$0.047	66	66	$0.00	$0.00	$91,629	119,497	$0	119,497	(27,868)
2011	0.0007	$0	79,674	0	$0.093	$0.049	66	66	$0.00	$0.00	$59,161	0	$0	0	59,161
2012	0.0006	$0	79,674	0	$0.099	$0.052	66	66	$0.00	$0.00	$59,577	0	$0	0	59,577
2013	0.0006	0	79,674	0	$0.104	$0.055	66	66	$0.00	$0.00	$60,016	0	$0	0	60,016
2014	0.0006	0	79,674	0	$0.110	$0.058	66	66	$0.00	$0.00	$60,479	0	$0	0	60,479
2015	0.0006	0	79,674	0	$0.116	$0.061	66	66	$0.00	$0.00	$60,968	0	$0	0	60,968
2016	0.0006	0	79,674	0	$0.123	$0.065	66	66	$0.00	$0.00	$61,485	0	$0	0	61,485
2017	0.0006	0	79,674	0	$0.129	$0.068	66	66	$0.00	$0.00	$62,030	0	$0	0	62,030
2018	0.0006	0	79,674	0	$0.137	$0.072	66	66	$0.00	$0.00	$62,606	0	$0	0	62,606
2019	0.0006	0	79,674	0	$0.144	$0.076	66	66	$0.00	$0.00	$63,213	0	$0	0	63,213
2020	0.0006	0	79,674	0	$0.152	$0.080	66	66	$0.00	$0.00	$63,855	0	$0	0	63,855
2021	0.0006	0	79,674	0	$0.161	$0.085	66	66	$0.00	$0.00	$64,533	0	$0	0	64,533
2022	0.0005	0	79,674	0	$0.170	$0.090	66	66	$0.00	$0.00	$65,248	0	$0	0	65,248
2023	0.0005	0	0	0	$0.179	$0.095	0	0	$0.00	$0.00	$0	0	$0	0	0
			1,115,442	0							$958,800	$358,490	$0	$358,490	$600,310
											$624,298	335,399	0	335,399	288,899

Total NPV = $288,899
Benefit/Cost Ratio = 1.86

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$31,357
Total Utility Project Costs Year 1 =	**$51,186**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$31,357
Total Utility Project Costs Year 2 =	**$51,186**
15b) Total Utilty Cost Year 3 =	**$51,186**
15c) Total Utilty Cost Year 4 =	**$51,186**
15d) Total Utility Cost Year 5 =	**$51,186**
16) Direct Participant Costs ($/Part.) =	$ 920.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0.29
20a) Avg Winter kW/part Saved =	0.57
21) Avg. Summer kWh/Part. Saved =	715
21a) Avg. Winter kWh/Part. Saved =	1,430
22) Number of Participants (First Year) =	170
22a) Number of Participants (Second Year) =	170
22a) Number of Participants (Third Year) =	170
22a) Number of Participants (Fourth Year) =	170
22a) Number of Participants (Fifth Year) =	170
23) Incentive/Participant (All) =	$ 184.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$255,931
Total Program Participants	852
Utility Cost per Participant (First Year) =	$300.35
Utility Cost per Participant (Program) =	$300.35
Total kW Reduction	788
Total Energy Reduction (kWh)	15,768,028
Societal Cost per kwh	$0.05

Test Results

	NPV	B/C
Utility Test	$1,699,618	5.42
Ratepayer Test	$1,874,966	9.95
Societal Cost Test	$1,791,499	3.48
Participant Test	$396,728	1.58

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	394,201	$0.0190	$0	158	$349.78	$62,624	$51,186	5,266	$56,453	$6,171
2	2009	788,401	$0.0195	0	315	$366.87	131,086	51,186	11,003	62,190	68,896
3	2010	1,182,602	$0.0201	0	473	$384.91	205,856	51186.28	17,261	68,447	137,409
4	2011	1,576,803	$0.0207	0	631	$403.96	287,442	51186.28	24,093	75,279	212,162
5	2012	1,971,003	$0.0213	0	788	$424.07	376,384	51186.28	31,558	82,745	293,639
6	2013	1,971,003	$0.0220	0	788	$445.31	394,387	0	33,100	33,100	361,287
7	2014	1,971,003	$0.0226	0	788	$467.73	413,362	0	34,748	34,748	378,615
8	2015	1,971,003	$0.0233	0	788	$491.40	433,363	0	36,508	36,508	396,855
9	2016	1,971,003	$0.0240	0	788	$516.39	454,445	0	38,387	38,387	416,058
10	2017	1,971,003	$0.0247	0	788	$542.78	476,668	0	40,393	40,393	436,275
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		15,768,028			6,307		$3,235,617	$255,931	$272,319	$528,250	$2,707,368
NPV =							2,084,560	209,593	175,348	384,941	1,699,618

Total NPV = $1,699,618
Benefit/Cost Ratio = 5.42

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$7,471	$0	$55,153	$62,624	$51,186	$51,186	$11,438
2009	15,390	0	115,696	131,086	51,186	51,186	79,899
2010	23,778	0	182,079	205,856	51,186	51,186	154,670
2011	32,655	0	254,787	287,442	51186.28	51,186	236,255
2012	42,043	0	334,341	376,384	51186.28	51,186	325,197
2013	43,304	0	351,083	394,387	0	0	394,387
2014	44,603	0	368,759	413,362	0	0	413,362
2015	45,941	0	387,422	433,363	0	0	433,363
2016	47,320	0	407,126	454,445	0	0	454,445
2017	48,739	0	427,929	476,668	0	0	476,668
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$351,243	$0	$2,884,374	$3,235,617	$255,931	$255,931	$2,979,686
NPV =	227,953	0	1,856,606	2,084,560	209,593	209,593	1,874,966

Total NPV = $1,874,966
Benefit/Cost Ratio = 9.95

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (A) + (B) + (C)
(E) = Total Utility Project Costs (15)
(F) = (E)
(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$7,471	$0	$55,153	$9,675	$72,299	$51,186	$156,786	$31,357	$176,615	($104,316)
2009	$15,390	$0	$115,696	$20,860	151,946	51,186	156,786	$31,357	176,615	(24,669)
2010	$23,778	$0	$182,079	$33,742	239,598	51186.28	156,786	$31,357	176,615	62,983
2011	$32,655	$0	$254,787	$48,528	335,969	51186.28	156,786	$31,357	176,615	159,354
2012	$42,043	$0	$334,341	$65,450	441,834	51186.28	156,786	$31,357	176,615	265,218
2013	$43,304	$0	$351,083	$70,638	465,025	0	0	$0	0	465,025
2014	$44,603	$0	$368,759	$76,258	489,620	0	0	$0	0	489,620
2015	$45,941	$0	$387,422	$82,346	515,709	0	0	$0	0	515,709
2016	$47,320	$0	$407,126	$88,942	543,387	0	0	$0	0	543,387
2017	$48,739	$0	$427,929	$96,090	572,759	0	0	$0	0	572,759
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$351,243	$0	$2,884,374	$592,529	$3,828,146	$255,931	$783,932	$156,786	$883,077	$2,945,069
NPV =	227,953	0	1,856,606	430,129	2,514,688	209,593	641,995	128,399	723,190	1,791,499

Total NPV = $1,791,499
Benefit/Cost Ratio = 3.48

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **T-8 Lighting Retrofit 4 Lamp Model**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0099	$31,357	121,836	243,672	$0.045	$0.045	49	97	$47.41	$69.46	$56,831	$156,786	$0	$156,786	($99,955)
2009	0.0197	$31,357	243,672	487,344	$0.047	$0.047	97	195	$50.05	$73.34	$85,148	156,786	$0	156,786	(71,639)
2010	0.0196	$31,357	365,508	731,017	$0.050	$0.050	146	292	$52.84	$77.43	$116,545	156,786	$0	156,786	(40,241)
2011	0.0194	$31,357	487,344	974,689	$0.053	$0.053	195	390	$55.79	$81.75	$151,279	156,786	$0	156,786	(5,507)
2012	0.0193	$31,357	609,180	1,218,361	$0.056	$0.056	244	487	$58.91	$86.31	$189,624	156,786	$0	156,786	32,838
2013	0.0192	0	609,180	1,218,361	$0.059	$0.059	244	487	$62.19	$91.13	$167,098	0	$0	0	167,098
2014	0.0190	0	609,180	1,218,361	$0.062	$0.062	244	487	$65.66	$96.21	$176,422	0	$0	0	176,422
2015	0.0189	0	609,180	1,218,361	$0.066	$0.066	244	487	$69.33	$101.58	$186,266	0	$0	0	186,266
2016	0.0188	0	609,180	1,218,361	$0.069	$0.069	244	487	$73.19	$107.25	$196,660	0	$0	0	196,660
2017	0.0187	0	609,180	1,218,361	$0.073	$0.073	244	487	$77.28	$113.23	$207,634	0	$0	0	207,634
2018	0.0185	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0184	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0183	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0181	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0180	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0179	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			4,873,444	9,746,888							$1,533,507	$783,932	$0	$783,932	$749,575
											$1,083,984	687,256	0	687,256	396,728

Total NPV = $396,728
Benefit/Cost Ratio = 1.58

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03711
1a) Retail Rate Winter ($/kWh) =	$0.03711
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$44.90
3a) Retail Winter Demand Rate ($/kW/season) =	$65.79
Escalation Rate =	5.58%
4) System Conservation Demand Cost ($/kW/yr)	$290.08
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	17,042
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$2,130
Total Utility Project Costs Year 1 =	**$21,959**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$0
Incentive Costs =	$2,130
Total Utility Project Costs Year 2 =	**$21,959**
15b) Total Utilty Cost Year 3 =	**$21,959**
15c) Total Utilty Cost Year 4 =	**$21,959**
15d) Total Utility Cost Year 5 =	**$21,959**
16) Direct Participant Costs ($/Part.) =	$ 250.00
Escalation Rate =	3.00%
17) Other Participant Costs (Annual $/Part.) =	$0.00
Escalation Rate =	3.00%
18) Project Life (Years) =	10
20) Avg Summer kW/part. Saved =	0.05
20a) Avg Winter kW/part Saved =	0.09
21) Avg. Summer kWh/Part. Saved =	394
21a) Avg. Winter kWh/Part. Saved =	788
22) Number of Participants (First Year) =	85
22a) Number of Participants (Second Year) =	85
22a) Number of Participants (Third Year) =	85
22a) Number of Participants (Fourth Year) =	85
22a) Number of Participants (Fifth Year) =	85
23) Incentive/Participant (All) =	$ 25.00

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

Cost Summary

Program Promotion (Years)	5
Project Life (Years)	10
Total Progam Cost (Utility)	$109,796
Total Program Participants	426
Utility Cost per Participant (First Year) =	$257.71
Utility Cost per Participant (Program) =	$257.71
Total kW Reduction	62
Total Energy Reduction (kWh)	4,347,190
Societal Cost per kwh	$0.04

Test Results

	NPV	B/C
Utility Test	$70,665	1.51
Ratepayer Test	$119,008	2.32
Societal Cost Test	$83,563	1.50
Participant Test	$110,441	2.18

Table 1

Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

		Cost of Energy Saved					Project Cost				Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	108,680	$0.0190	$0	12	$349.78	$6,399	$21,959	1,452	$23,411	($17,012)
2	2009	217,359	$0.0195	0	25	$366.87	13,346	21,959	3,034	24,993	(11,647)
3	2010	326,039	$0.0201	0	37	$384.91	20,881	21959.25	4,759	26,718	(5,837)
4	2011	434,719	$0.0207	0	50	$403.96	29,050	21959.25	6,642	28,602	448
5	2012	543,399	$0.0213	0	62	$424.07	37,897	21959.25	8,701	30,660	7,237
6	2013	543,399	$0.0220	0	62	$445.31	39,562	0	9,126	9,126	30,437
7	2014	543,399	$0.0226	0	62	$467.73	41,311	0	9,580	9,580	31,731
8	2015	543,399	$0.0233	0	62	$491.40	43,148	0	10,065	10,065	33,083
9	2016	543,399	$0.0240	0	62	$516.39	45,079	0	10,583	10,583	34,495
10	2017	543,399	$0.0247	0	62	$542.78	47,107	0	11,136	11,136	35,971
11	2018	0	$0.0255	0	0	$570.64	0	0	0	0	0
12	2019	0	$0.0262	0	0	$600.05	0	0	0	0	0
13	2020	0	$0.0270	0	0	$631.11	0	0	0	0	0
14	2021	0	$0.0278	0	0	$663.90	0	0	0	0	0
15	2022	0	$0.0287	0	0	$698.51	0	0	0	0	0
16	2023	0	$0.0295	0	0	$735.06	0	0	0	0	0
Total =		4,347,190			496		$323,780	$109,796	$75,077	$184,874	$138,907
NPV =							208,925	89,917	48,343	138,260	70,665

Total NPV = $70,665
Benefit/Cost Ratio = 1.51

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4]

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **LED Exit Signs (Incandescent Model)**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$2,060	$0	$4,339	$6,399	$21,959	$21,959	($15,560)
2009	4,243	0	9,103	13,346	21,959	21,959	(8,613)
2010	6,555	0	14,326	20,881	21,959	21,959	(1,078)
2011	9,003	0	20,047	29,050	21959.25	21,959	7,090
2012	11,591	0	26,306	37,897	21959.25	21,959	15,938
2013	11,939	0	27,623	39,562	0	0	39,562
2014	12,297	0	29,014	41,311	0	0	41,311
2015	12,666	0	30,483	43,148	0	0	43,148
2016	13,046	0	32,033	45,079	0	0	45,079
2017	13,437	0	33,670	47,107	0	0	47,107
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
Total =	$96,836	$0	$226,944	$323,780	$109,796	$109,796	$213,984
NPV =	62,846	0	146,079	208,925	89,917	89,917	119,008

Total NPV = $119,008

Benefit/Cost Ratio = 2.32

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$2,060	$0	$4,339	$989	$7,388	$21,959	$21,303	$2,130	$41,132	($33,744)
2009	$4,243	$0	$9,103	$2,124	15,470	21,959	21,303	$2,130	41,132	(25,662)
2010	$6,555	$0	$14,326	$3,423	24,304	21959.25	21,303	$2,130	41,132	(16,827)
2011	$9,003	$0	$20,047	$4,904	33,954	21959.25	21,303	$2,130	41,132	(7,178)
2012	$11,591	$0	$26,306	$6,590	44,487	21959.25	21,303	$2,130	41,132	3,356
2013	$11,939	$0	$27,623	$7,086	46,648	0	0	$0	0	46,648
2014	$12,297	$0	$29,014	$7,621	48,932	0	0	$0	0	48,932
2015	$12,666	$0	$30,483	$8,199	51,347	0	0	$0	0	51,347
2016	$13,046	$0	$32,033	$8,823	53,901	0	0	$0	0	53,901
2017	$13,437	$0	$33,670	$9,496	56,603	0	0	$0	0	56,603
2018	$0	$0	$0	$0	0	0	0	$0	0	0
2019	$0	$0	$0	$0	0	0	0	$0	0	0
2020	$0	$0	$0	$0	0	0	0	$0	0	0
2021	$0	$0	$0	$0	0	0	0	$0	0	0
2022	$0	$0	$0	$0	0	0	0	$0	0	0
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$96,836	$0	$226,944	$59,254	$383,035	$109,796	$106,513	$10,651	$205,658	$177,377
NPV =	62,846	0	146,079	43,060	251,984	89,917	87,228	8,723	168,422	83,563

Total NPV = $83,563
Benefit/Cost Ratio = 1.50

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)
(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)
(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)
(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)
(E) = (A) + (B) + (C) + (D)
(F) = Total Utility Project Costs (15)
(G) = Direct (16) + Other (17) Participant Costs x Participants (22)
(H) = Incentive Costs (15)
(I) = (F) + (G) - (H)
(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **LED Exit Signs (Incandescent Model)**

		Benefits										Costs			
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0050	$2,130	33,590	67,180	$0.045	$0.045	4	8	$47.41	$69.46	$7,364	$21,303	$0	$21,303	($13,938)
2009	0.0099	$2,130	67,180	134,359	$0.047	$0.047	8	15	$50.05	$73.34	$13,182	21,303	$0	21,303	(8,120)
2010	0.0098	$2,130	100,769	201,539	$0.050	$0.050	12	23	$52.84	$77.43	$19,634	21,303	$0	21,303	(1,669)
2011	0.0097	$2,130	134,359	268,718	$0.053	$0.053	15	31	$55.79	$81.75	$26,770	21,303	$0	21,303	5,468
2012	0.0097	$2,130	167,949	335,898	$0.056	$0.056	19	38	$58.91	$86.31	$34,649	21,303	$0	21,303	13,346
2013	0.0096	0	167,949	335,898	$0.059	$0.059	19	38	$62.19	$91.13	$34,333	0	$0	0	34,333
2014	0.0095	0	167,949	335,898	$0.062	$0.062	19	38	$65.66	$96.21	$36,249	0	$0	0	36,249
2015	0.0095	0	167,949	335,898	$0.066	$0.066	19	38	$69.33	$101.58	$38,272	0	$0	0	38,272
2016	0.0094	0	167,949	335,898	$0.069	$0.069	19	38	$73.19	$107.25	$40,407	0	$0	0	40,407
2017	0.0093	0	167,949	335,898	$0.073	$0.073	19	38	$77.28	$113.23	$42,662	0	$0	0	42,662
2018	0.0093	0	0	0	$0.077	$0.077	0	0	$81.59	$119.55	$0	0	$0	0	0
2019	0.0092	0	0	0	$0.082	$0.082	0	0	$86.14	$126.22	$0	0	$0	0	0
2020	0.0091	0	0	0	$0.086	$0.086	0	0	$90.95	$133.27	$0	0	$0	0	0
2021	0.0091	0	0	0	$0.091	$0.091	0	0	$96.03	$140.70	$0	0	$0	0	0
2022	0.0090	0	0	0	$0.096	$0.096	0	0	$101.38	$148.55	$0	0	$0	0	0
2023	0.0089	0	0	0	$0.101	$0.101	0	0	$107.04	$156.84	$0	0	$0	0	0
			1,343,591	2,687,183							$293,521	$106,513	$0	$106,513	$187,009
											$203,819	93,377	0	93,377	110,441

Total NPV = $110,441
Benefit/Cost Ratio = 2.18

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

Appendix G

Scenario C Inputs

Interruptible Rate - Demand Response
Quantitative DSM # 1A

Customer Class:	Commercial and Industrial	

Cost MDU

		$/Part	Total $ Yr 1	Total $ Yr 2	Total $ Yr 3	Total $
Operating Cost	$ 3,600	$ 194	$ 3,600	$ 3,600	$ 3,600	$ 10,800
Incentive Costs	$ 4,500	$ 4,500	$ 27,900	$ 55,800	$ 83,700	$ 167,400
Admin & Advertising	$ 19,829	$ 3,198	$ 19,829	$ 19,829	$ 19,829	$ 59,487
Total Cost		**$ 7,892**	**$ 51,329**	**$ 79,229**	**$ 107,129**	**$ 237,687**

Notes

Admin & Advertising		Calculated
Operating Cost		Calculated
Incentive	$ 2.50	per kW/month

Participant Costs (Incremental Cost Basis)

Estimated Average cost of inteconnection	$ 50,000	Average interconnection costs - Estimated
Estimated cost of Primary Service	$ 40,000	Cost for Transformer, Primary Metering, Switch Fuse
Total Cost	**$ 90,000**	
Other Partcipant Costs (Diesel @ 100 hrs of curtailment)	$ 6,499	

Participation Rate Calc

	% of Cust	Cust	
C& I Customers	100.00%	93	RA provided Query of CIS

Total Customer Available for program	93			
Total Estimated Saturation Percentage	20.0%	**Total MW**		
Total Participantion Rate	**19**	2.8	20.00%	Of total Customer Base
Participation Year 1	6	0.9		
Participation Year 2	6	0.9		
Participation Year 3	6	0.9		

Energy Savings Calculation

IT Rate	Total conn kW	kW/Customer	Avg kW per event	Coincident Rate
Rate 38 - DR	150	150.0	150	100.0%

Avg Customer KWh Avoided @ 100 hrs	**11,096**	75% Customer LF
Primary Service Rate Savings per year	**$ 11,107**	Included in other particapant savings

	Per Part
Summer Demand Reduction	50.0
Winter Demand Reduction	100.0
Total Demand Reduction	**150**
Summer Energy Reduction	11,096
Winter Energy Reduction	0

Proposed IT DR Rate

Summer kW	$ 8.254
Winter kW	$ 5.254
Energy kWh	$ 0.03255
Demand Credit kW	$ 2.50

Note:

MW of IT is the target not Customers

Incentive is equal to our lost Margin between ND Rate 30 Secondary and IT Rate

Appendix H

Scenario C Runs

Demand-Side Management Program - DSM
Integrated Electric System Cost-Effectiveness Analysis

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

Input Data

1) Retail Rate Summer ($/kWh) =	$0.03255
1a) Retail Rate Winter ($/kWh) =	$0.03255
Fuel Clause Adjustment (FCA)	$0.00537
Escalation Rate =	5.58%
2)Avg. System Marginal Energy Cost ($/kWh) =	$0.01840
Escalation Rate =	3.00%
3) Retail Summer Demand Rate ($/kW/season) =	$10.00
3a) Retail Winter Demand Rate ($/kW/season) =	$20.00
Escalation Rate =	5.58%
4) System Peak Shaving Demand Cost ($/kW/yr)	$116.25
MRO Reserve Margin=	15.0%
Escalation Rate =	3.00%
5) System Variable O&M Savings($/kWh) =	$0.00000
Escalation Rate =	3.00%
6) Environmental Damage Factor =	15%
Escalation Rate =	3.00%
7) Total Sales by class (kWh) =	1,375,333,420
Growth Rate =	2.22%
8) Total Customers by class =	93
Growth Rate =	0.70%
9) Utility Discount Rate =	7.05%
10) Social Discount Rate(Tbill) =	4.90%
11) General Input Data Year =	2007
12) Project Analysis Year 1 =	2008
12a) Project Analysis Year 2 =	2009
13) Effective Fed & State Income Tax Rate =	39.00%
14a) System demand Line loss factor	7.85%
14b) System Energy Line loss factor	7.85%

15) Utility Project Costs (First Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$27,900
Total Utility Project Costs Year 1 =	**$51,329**
15a) Utility Project Costs (Second Year)	
Admin & Promotion Costs =	$19,829
Direct Operating Costs =	$3,600
Incentive Costs =	$55,800
Total Utility Project Costs Year 2 =	**$79,229**
15b) Total Utilty Cost Year 3 =	$107,129
15c) Total Utilty Cost Year 4 =	$107,129
15d) Total Utility Cost Year 5 =	$107,129
15e) Total Utility Operating Cost (Program Life) =	$107,129
Escalation Rate =	3.00%
16) Direct Participant Costs ($/Part.) =	$90,000
Escalation Rate =	3.00%
17a) Other Participant Costs (Annual $/Part.) =	$ 6,499
Escalation Rate =	3.00%
17b) Other Participant Savings (Annual $/Part.) =	$ 11,107
Escalation Rate =	0%
18) Project Life (Years) =	15
20) Avg Summer kW/part. Saved =	50.0
20a) Avg Winter kW/part Saved =	100.0
21) Avg. Summer kWh/Part. Saved =	11,096
21a) Avg. Winter kWh/Part. Saved =	0
22) Number of Participants (First Year) =	6
22a) Number of Participants (Second Year) =	6
22a) Number of Participants (Third Year) =	6
22a) Number of Participants (Fourth Year) =	0
22a) Number of Participants (Fifth Year) =	0
23) Incentive/Participant (All) =	$ 4,500

Demand-Side Management Program - DSM

Integrated Electric System Cost-Effectiveness Analysis

Summary Information

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

Cost Summary

Program Promotion (Years)	3
Project Life (Years)	15
Total Progam Cost (Utility)	$451,945
Total Program Participants	19
Utility Cost per Participant (First Year) =	$8,278.87
Utility Cost per Participant (Program) =	$24,298.12
Total kW Reduction	3,009
Total Energy Reduction (kWh)	3,116,216
Societal Cost per kwh	$0.99

Test Results

	NPV	B/C
Utility Test	$3,923,176	5.31
Ratepayer Test	$3,936,621	5.39
Societal Cost Test	$2,866,750	1.93
Participant Test	$195,771	1.08

Table 1
Utility Test

This test quantifies incremental decreases and increases to revenue as a direct result of the project.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Cost of Energy Saved				Project Cost					Cost of Energy Saved Less Project Cost
t	Year	Total Energy (kWh) Reduction (A)	System Energy Cost (B)	Variable O & M Cost Savings (C)	Demand Reduction (D)	System Demand Cost (E)	Annual Cost of Energy Saved (F)	Utility Project Costs (G)	Lost Margin (H)	Annual Project Costs (I)	(J)
1	2008	74,196	$0.0190	$0	1,003	$140.17	$142,002	$51,329	734	$52,063	$89,939
2	2009	148,391	$0.0195	0	2,006	$147.02	297,826	$79,229	1,416	80,645	217,182
3	2010	222,587	$0.0201	0	3,009	$154.25	468,627	$107,129	2,044	109,173	359,454
4	2011	222,587	$0.0207	0	3,009	$161.89	491,734	$107,129	1,962	109,091	382,643
5	2012	222,587	$0.0213	0	3,009	$169.95	516,126	$107,129	1,878	109,007	407,119
6	2013	222,587	$0.0220	0	3,009	$178.46	541,875	$107,129	1,791	108,920	432,955
7	2014	222,587	$0.0226	0	3,009	$187.44	569,058	$107,129	1,701	108,830	460,227
8	2015	222,587	$0.0233	0	3,009	$196.93	597,753	$107,129	1,609	108,738	489,015
9	2016	222,587	$0.0240	0	3,009	$206.95	628,046	$107,129	1,514	108,643	519,403
10	2017	222,587	$0.0247	0	3,009	$217.52	660,026	$107,129	1,416	108,545	551,480
11	2018	222,587	$0.0255	0	3,009	$228.68	693,785	$107,129	1,316	108,445	585,341
12	2019	222,587	$0.0262	0	3,009	$240.47	729,424	$107,129	1,212	108,341	621,083
13	2020	222,587	$0.0270	0	3,009	$252.92	767,048	$107,129	1,105	108,234	658,814
14	2021	222,587	$0.0278	0	3,009	$266.06	806,766	$107,129	995	108,124	698,642
15	2022	222,587	$0.0287	0	3,009	$279.93	848,696	$107,129	882	108,011	740,685
16	2023	0	$0.0295	0	0	$294.58	0	0	0	0	0
Total =		3,116,216			42,126		$8,758,793	$1,523,235	$21,574	$1,544,809	$7,213,983
NPV =							4,832,798	896,176	13,446	909,622	3,923,176

Total NPV = $3,923,176
Benefit/Cost Ratio = 5.31

(A) = Energy Reduction/Part. (21+ 21a) x Participants (22) x energy line loss (14b)
(B) = System Energy Cost (2)
(C) = (A) x Variable O&M (5)
(D) = kW demand Reduction/Part. (20) x Participants (22) x demand line loss (14a)
(E) = SystemDemand Cost (4)

(F) = (A)x(B) + (C) + (D)x(E)
(G) = Total Utility Project Costs (15)
(H) = [1 - Effective Tax Rate (13) x [(A) x Retail Rate (1) - (A+B)]
(I) = (G) + (H)
(J) = (F) - (I)

Table 2

Ratepayer Impact Test

This test compares the cost of energy saved to the total cost of saving that same amount of energy and its impact on all ratepayers.

Company: **Montana-Dakota Utilities Co.**

Project: **Interruptible Rate - Demand Response**

	Decreases				Increases		
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Annual Total Decrease (D)	Utility Program Costs (E)	Annual Total Increase (F)	Net Change (G)
2008	$1,406	$0	$140,595	$142,002	$51,329	$51,329	$90,673
2009	2,897	0	294,930	297,826	$79,229	79,229	218,597
2010	4,475	0	464,152	468,627	$107,129	107,129	361,498
2011	4,610	0	487,124	491,734	$107,129	107,129	384,605
2012	4,748	0	511,378	516,126	$107,129	107,129	408,997
2013	4,890	0	536,985	541,875	$107,129	107,129	434,746
2014	5,037	0	564,021	569,058	$107,129	107,129	461,929
2015	5,188	0	592,565	597,753	$107,129	107,129	490,624
2016	5,344	0	622,703	628,046	$107,129	107,129	520,917
2017	5,504	0	654,522	660,026	$107,129	107,129	552,897
2018	5,669	0	688,116	693,785	$107,129	107,129	586,656
2019	5,839	0	723,585	729,424	$107,129	107,129	622,295
2020	6,015	0	761,033	767,048	$107,129	107,129	659,919
2021	6,195	0	800,571	806,766	$107,129	107,129	699,637
2022	6,381	0	842,315	848,696	$107,129	107,129	741,567
2023	0	0	0	0	0	0	0
Total =	$74,198	$0	$8,684,594	$8,758,793	$1,523,235	$1,523,235	$7,235,558
NPV =	41,863	0	4,790,935	4,832,798	896,176	896,176	3,936,621

Total NPV = $3,936,621

Benefit/Cost Ratio = 5.39

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (A) + (B) + (C)

(E) = Total Utility Project Costs (15)

(F) = (E)

(G) = (D) - (F)

Table 3

Societal Cost Test

This test measures the net cost of the program based on total cost including both the participant's and utility's costs.

Compar **Montana-Dakota Utilities Co.**

Project: **Interruptible Rate - Demand Response**

	Decreases					Increases				
Year	Total Energy Savings (A)	Variable O & M Cost Savings (B)	System Demand Savings (C)	Avoided Environmental Damage Costs (D)	Annual Total Decrease (E)	Utility Program Costs (F)	Total Participants' Costs (G)	Incentives Paid to Participants (H)	Annual Total Increase (I)	Net Change (J)
2008	$1,406	$0	$140,595	$21,939	$163,941	$51,329	$599,504	$27,900	$622,933	($458,992)
2009	$2,897	$0	$294,930	$47,395	345,221	$79,229	643,497	$55,800	666,926	(321,706)
2010	$4,475	$0	$464,152	$76,812	545,440	$107,129	646,062	$83,700	669,491	(124,052)
2011	$4,610	$0	$487,124	$83,018	574,751	$107,129	90,704	$0	197,833	376,918
2012	$4,748	$0	$511,378	$89,750	605,875	$107,129	93,425	$0	200,554	405,321
2013	$4,890	$0	$536,985	$97,054	638,929	$107,129	96,228	$0	203,357	435,572
2014	$5,037	$0	$564,021	$104,980	674,038	$107,129	99,115	$0	206,244	467,794
2015	$5,188	$0	$592,565	$113,582	711,336	$107,129	102,088	$0	209,217	502,118
2016	$5,344	$0	$622,703	$122,919	750,965	$107,129	105,151	$0	212,280	538,685
2017	$5,504	$0	$654,522	$133,053	793,079	$107,129	108,306	$0	215,435	577,644
2018	$5,669	$0	$688,116	$144,054	837,839	$107,129	111,555	$0	218,684	619,156
2019	$5,839	$0	$723,585	$155,998	885,422	$107,129	114,901	$0	222,030	663,392
2020	$6,015	$0	$761,033	$168,965	936,013	$107,129	118,349	$0	225,478	710,536
2021	$6,195	$0	$800,571	$183,046	989,812	$107,129	121,899	$0	229,028	760,784
2022	$6,381	$0	$842,315	$198,336	1,047,032	$107,129	125,556	$0	232,685	814,347
2023	$0	$0	$0	$0	0	0	0	$0	0	0
Total =	$74,198	$0	$8,684,594	$1,740,901	$10,499,694	$1,523,235	$3,176,341	$167,400	$4,532,176	$5,967,517
NPV =	41,863	0	4,790,935	1,111,706	5,944,503	896,176	2,324,561	142,983	3,077,754	2,866,750

Total NPV = $2,866,750

Benefit/Cost Ratio = 1.93

(A) = Energy Red/Part.(21 + 21a) x Parts(22) x Energy L Loss(14b) x Energy Cost(2)

(B) = Energy Reduction/Part. (21) x Participants (22) x Variable O&M (5)

(C) = kW demand Redc/Part. (20) x Participants (22) x demand line loss (14a) x System Demand Cost (4)

(D) = (Energy Savings (A) + System Demand Savings (C)) x Environmental Damage Factor (6)

(E) = (A) + (B) + (C) + (D)

(F) = Total Utility Project Costs (15)

(G) = Direct (16) + Other (17) Participant Costs x Participants (22)

(H) = Incentive Costs (15)

(I) = (F) + (G) - (H)

(J) = (E) - (I)

Table 4
Participant Test

This test quantifies the benefits and costs that accrue directly to the participant.

Company: **Montana-Dakota Utilities Co.**
Project: **Interruptible Rate - Demand Response**

		Benefits							Costs						
Year	Ratio of Part. to Total Customers (A)	Incentives Received (B)	Summer Energy Reduction (C1)	Winter Energy Reduction (C2)	Summer Retail Rate (D1)	Winter Retail Rate (D2)	Summer Demand Reduction (E1)	Winter Demand Reduction (E2)	Summer Demand Rate (F1)	Winter Demand Rate (F2)	Total Annual Benefits (G)	Direct Part. Costs (H)	Other Part. Costs (I)	Total Annual Costs (L)	Annual Benefits Less Costs (M)
2008	0.0662	$27,900	68,795	0	$0.040	$0.040	310	620	$10.56	$21.12	$115,883	$558,000	$41,504	$599,504	($483,621)
2009	0.1315	$55,800	137,590	0	$0.042	$0.042	620	1,240	$11.15	$22.29	$233,899	558,000	$85,497	643,497	(409,599)
2010	0.1306	$83,700	206,386	0	$0.045	$0.045	930	1,860	$11.77	$23.54	$354,227	558,000	$88,062	646,062	(291,835)
2011	0.1297	$0	206,386	0	$0.047	$0.047	930	1,860	$12.43	$24.85	$274,095	0	$90,704	90,704	183,391
2012	0.1288	$0	206,386	0	$0.050	$0.050	930	1,860	$13.12	$26.24	$277,862	0	$93,425	93,425	184,436
2013	0.1279	$0	206,386	0	$0.053	$0.053	930	1,860	$13.85	$27.70	$281,839	0	$96,228	96,228	185,611
2014	0.1270	$0	206,386	0	$0.055	$0.055	930	1,860	$14.62	$29.25	$286,038	0	$99,115	99,115	186,923
2015	0.1261	$0	206,386	0	$0.059	$0.059	930	1,860	$15.44	$30.88	$290,471	0	$102,088	102,088	188,382
2016	0.1252	$0	206,386	0	$0.062	$0.062	930	1,860	$16.30	$32.60	$295,151	0	$105,151	105,151	190,000
2017	0.1243	$0	206,386	0	$0.065	$0.065	930	1,860	$17.21	$34.42	$300,093	0	$108,306	108,306	191,788
2018	0.1235	$0	206,386	0	$0.069	$0.069	930	1,860	$18.17	$36.34	$305,311	0	$111,555	111,555	193,756
2019	0.1226	$0	206,386	0	$0.073	$0.073	930	1,860	$19.19	$38.37	$310,819	0	$114,901	114,901	195,918
2020	0.1218	$0	206,386	0	$0.077	$0.077	930	1,860	$20.26	$40.51	$316,635	0	$118,349	118,349	198,287
2021	0.1209	$0	206,386	0	$0.081	$0.081	930	1,860	$21.39	$42.77	$322,776	0	$121,899	121,899	200,877
2022	0.1201	$0	206,386	0	$0.086	$0.086	930	1,860	$22.58	$45.16	$329,259	0	$125,556	125,556	203,703
2023	0.1193	0	0	0	$0.090	$0.090	0	0	$23.84	$47.68	$0	0	$0	0	0
			2,889,398	0							$4,294,358	$1,674,000	$1,502,341	$3,176,341	$1,118,016
											$2,684,213	1,566,175	922,267	2,488,442	195,771

Total NPV = $195,771
Benefit/Cost Ratio = 1.08

(A) = Total Participants (22) / Total Customers (8)
(B) = Incentive Costs (15)
(C1) = Energy Reduction/Part. (21) x Participants (22)
(C2) = Energy Reduction/Part. (21a) x Participants (22)
(D1) = Summer Retail Rate (1)
(D2) = Winter Retail Rate (1a)
(E1) = kW Demand Reduction/Part. (20) x Participants (22)
(E2) = kW Demand Reduction/Part. (20a) x Participants (22)
(F1) = Summer Retail Demand Rate (3)
(F2) = Winter Retail Demand Rate (3a)
(G) = (B) + (C1 x D1) + (C2 x D2) + (E1 x F1)+(E2 x F2)
(H) = Direct Participant Costs (16) x Participant (22)
(I) = Other Participant Costs (17) x Participant (22)
(L) = (H) + (I)
(M) = (G) - (L)

ATTACHMENT C

-

SUPPLY-SIDE AND INTEGRATION DOCUMENTATION

Montana-Dakota Utilities

Integrated Resource Plan

May 9, 2007

Montana-Dakota Utilities

Integrated Resource Plan

May 9, 2007

Client Confidential

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Version: 1.0

FOREWORD

PA Consulting Group (PA) assisted Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (Montana-Dakota) in the development of the utility's 2007 Integrated Resource Plan (IRP). PA modeled least-cost generation expansion plans under different scenarios using the Strategist software. The expansion plans considered a range of resource options including wind, natural gas-fired combined cycle and combustion turbine plants, conventional and IGCC coal-fired generation, and DSM resources. The least cost mix was identified under alternative assumptions regarding gas prices, load growth, and costs of different supply side technologies. The results of this analysis are presented in this report.

While the analysis considers a range of risk factors related to both supply and demand, it does not necessarily consider all of the potential risk factors.

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1. EXECUTIVE SUMMARY

PA Consulting Group (PA) was requested to perform a range of generation expansion plans for Montana-Dakota based upon alternative assumptions regarding load growth, fuel costs, and generation capital costs. This analysis was conducted in March and April of 2007 and is presented in the report. The purpose of the study was for PA to support Montana-Dakota's development of the 2007 IRP with modeling of least cost resource addition(s) for the Montana-Dakota system. This analysis was completed using the Strategist software developed by NewEnergy Associates.

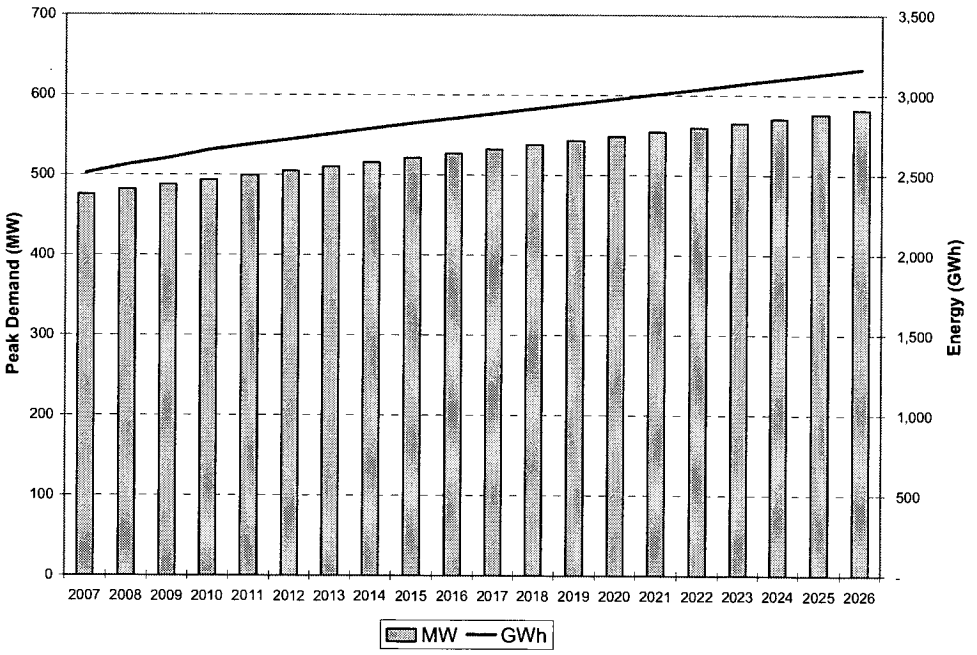
PA performed a base case analysis and additional scenarios to examine the economics of several expansion options including demand side management, wind resources, natural gas fired resources, and coal-fired resources. The results of the analysis are for Montana-Dakota to add a 43 MW combustion turbine in 2010 and 2023, and participate in 116 MW of the proposed Elk Run coal plant in 2012. The expansion plan also identifies extension of the Xcel Energy peaking contract to 2011 as a least cost option as well as the Montana wind project. These generation options in addition to three DSM programs yielded the lowest cost expansion plan. As a point of reference, our modeling indicated that substitution of the Big Stone II coal plant for the Elk Run coal plant in 2012 results in an increase in the NPV of the expansion plan of 2.7%. Furthermore, the top 100 plans all include the addition of a mix of new coal and gas fired generation as well as DSM.

1.1 RESOURCE PLANNING OPTIONS

PA considered a number of supply side options including wind, natural gas fired generation and coal generation. A summary of the initial cost of the options is shown in Figure 1-1 – the base year for dollars in the study was 2006. In addition, PA also included conservation options in the study and new wind resources were modeled as contracts based upon a twenty-year levelized cost of $[redacted] / MWh (2006 dollars). These options were examined in conjunction with the load growth assumptions shown in Figure 1-2. Resource plans were also developed for low and high load growth scenarios, with growth rates of 0.5 percent and 4.4 percent, respectively.

Figure 1-1: Generation Options (Redacted)

Figure 1-2: Montana-Dakota Load Assumptions



1.2 FUEL COST ASSUMPTIONS

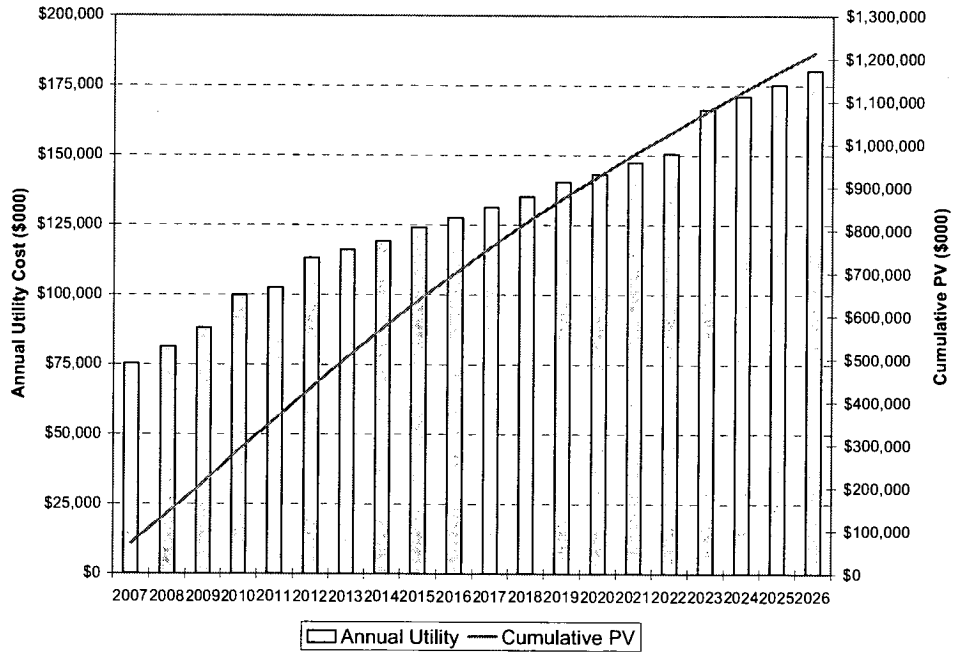
The coal forecast for Big Stone II, Elk Run, and LV-21 along with the natural gas price forecast were used are shown below in Figure 1-3. A resource plan was also developed for a high gas price scenario; the results are shown in Section 5.2.

Figure 1-3: Fuel Forecast – (Redacted)

1.3 RESULTS

The results of the analysis of the least cost expansion plan are based upon current generation plus the planned and committed additions. The committed additions include the short term capacity contract with Xcel Energy (85 -100 MW), the Montana wind project, and an NSP peaking contract. The least cost additions selected using the Strategist model are the Elk Run plant in 2012, combustion turbines in 2010 and 2023, the Xcel peaking contract in 2011, and three DSM programs. A summary of the cost perspective associated with the preferred plan is shown in Figure 1-4.

Figure 1-4: Forecast of Utility System Costs



2. *METHODOLOGY*

PA developed the generation expansion plan analysis with the Strategist software licensed from NewEnergy Associates. The software includes an optimization module that selects the least cost resource using dynamic programming techniques. The optimization was set up to minimize utility system costs based upon existing generation and loads, projected load growth, fuel cost forecasts, and generation expansion options. PA performed the study using a twenty year planning horizon (2007 – 2026) and allowed the optimization to incorporate end effects (accounting for the cost of generation resources that have economic life beyond the end of the study period.)

2.1 DATA SOURCES

PA utilized data provided by Montana-Dakota with regards to existing loads, the load forecast, and the costs associated with existing generation. PA also relied upon information provided by Montana-Dakota to determine the cost of the Big Stone II plant in South Dakota and the Elk Run coal plant in Iowa. PA reviewed the data provided and concur they represent reasonable assumptions. In addition, Montana-Dakota provided the fuel price forecasts.

2.2 SYSTEM CHARACTERIZATION

The Montana-Dakota retail load was modeled as a single system. The analysis did not consider exports or imports to the Montana-Dakota system beyond what was necessary to serve emergency power needs or to assign a value for excess energy as a result of must-run units (dump power). The analysis did not consider optimization of utility system costs by including any benefits from off-system sales.

2.3 SCENARIO/RISK ANALYSIS

For the analysis PA developed alternative resource plans for low and high growth scenarios, a high gas price scenario, and two high capital construction cost scenarios. For each scenario, PA used the Strategist resource optimization model which solves for the least cost plans using the generic unit cost assumptions. The scenarios are summarized in Table 2-1. The results of these scenarios are presented in Section 5.2.

Load growth, capital costs, and fuel costs are the primary drivers of system costs and therefore were selected for testing in the scenario analyses. Risks related to environmental regulations, MISO market design, and other factors were not included in this study.

Table 2-3: Planning Scenarios

Scenario	Description
Base Case	Base cost assumptions; annual peak demand & energy growth at 1.0% and 1.2%, respectively.
Low Growth	Base cost assumptions; annual peak demand & energy growth at 0.5%.
High Growth	Base cost assumptions; annual peak demand & energy growth at 4.4%.
Baseload Generation High Capital Costs	Base load growth; 15% higher capital costs for baseload generation options.
Peaking Generation High Capital Costs	Base load growth; 15% higher capital costs for peaking generation options.
High Gas Prices	Base load growth; gas prices are 2%-17% higher than base case.

3. LOAD AND EXISTING SYSTEM ASSUMPTIONS

Key inputs to the optimization model are the load forecast and the characteristics of the existing system. These assumptions drive both the need and timing for new demand or supply side resources. Upon the request of PA, these data were provided by Montana-Dakota.

3.1 LOAD ASSUMPTIONS

PA treated Montana-Dakota's retail electric load obligations in South Dakota, North Dakota, and Montana as a single system. The system load assumptions are shown in Table 3-1. The average annual energy and load growth during the study period for the base case is 1.2% and 1.0 % respectively.

Two alternative load growth assumptions were modeled as sensitivity scenarios. The low growth case assumes 0.5 percent annual growth in the peak demand and energy from 2007 forward; the high growth case assumes 4.4 percent annual growth in the peak demand and energy from 2007 forward.

These assumptions include implementation of existing DSM programs that provide a reduction of approximately 6.5 MW of peak demand and 38,000 MWh of energy.

Table 3.1: Base Case Load Assumptions

Year	Energy (GWH)	Peak Demand (MW)
2007	2,509	475.3
2008	2,562	481.9
2009	2,603	487.9
2010	2,653	493.7
2011	2,688	499.2
2012	2,722	504.7
2013	2,755	510.1
2014	2,789	515.6
2015	2,822	521.1
2016	2,853	526.6
2017	2,883	532.1
2018	2,914	537.5
2019	2,945	543.0
2020	2,976	548.4
2021	3,006	554.0
2022	3,037	559.4
2023	3,069	564.9
2024	3,100	570.4
2025	3,131	575.9
2026	3,163	581.4

3.2 EXISTING RESOURCES

PA's base case assumes that the existing Montana-Dakota thermal resources are available throughout the study period. A summary of these resources and associated characteristics is provided in Table 3-2. In addition to the thermal resources, PA also included existing contracts with the current expiration dates. A summary of the contracts is provided in Table 3-3.

Table 3.2: Existing Montana-Dakota Resources Modeled

Unit	Fuel / Unit Type	Capacity - MW	Fixed Cost $/kW (2006)	Variable Cost $/MWH (2006)
Big Stone I	Coal / Conventional	107		
Coyote I	Coal / Conventional	107		
Hesket I	Coal / Conventional	29		
Hesket II	Coal / Conventional	74		
Lewis Clark	Coal / Conventional	52	Redacted	Redacted
Glendive I	Natural Gas / CT	43		
Glendive II	Natural Gas / CT	43		
Miles City	Natural Gas / CT	29		
Williston	Natural Gas / CT	11		

Capital costs associated with continued operation of these resources were not included in the analysis and those costs are therefore not reflected in the summary results of total system costs.

Table 3.3: Contracts Modeled

Contract	Expiration	Capacity (MW)	Annual Energy (GWH)	Fixed Cost $/kW-month (2006)	Variable Cost $/MWh (2006)
Montana Wind[1]	2038	12.4 to 18.6	91.5 to 137.3		
WAPA	2031	2.8	14.3	Redacted	Redacted
NSP	2012	10	none		
Xcel Peaking[2]	2010	85.0	215.9		

1. Montana Wind terms change in 2015.
2. The Xcel contract grows to 100 MW in 2010. A 1-year extension is modeled as a new resource alternative.

4. RESOURCE OPTIONS

The Strategist Model solves for the least cost generation expansion plan based upon the identified options. PA's analysis includes natural gas, coal, and wind generation options, and DSM. The parameters associated with these options are identified in this section.

4.1 GENERATION

The characteristics of the generation expansion options are shown below in Table 4-1. The capital costs of the units reflect the likely available options to Montana-Dakota. For example, both the LV-21 and combined cycle costs are relatively high on a dollar per kW basis as a result of not having economies of scale. The variable cost of wind includes wind integration costs. Wind resources were assumed to have a 22% capacity credit for summer months. The Wind option was modeled as a transaction with only a variable cost per MWh as indicated in Table 4-1.

Table 4-1: New Generation Resource Options – North Dakota

Unit	Fuel	Capacity (MW)	Full Load Heat Rate (Btu/kWh)	Capital Cost $/kW (2006)2	Fixed Cost $/kW (2006)	Variable Cost $/MWh (2006)
Combustion Turbine	Natural Gas	43.5				
Combined Cycle	Natural Gas	120.0				
Big Stone II	Coal	116.0				
Elk Run	Coal	116.0	redacted	redacted	redacted	redacted
Wind[1]	Wind	31.5				
IGCC	Coal	116.0				
LV -21	Coal	175.0				

1. Modeled as transaction with 22% of capacity contribution to reserve capacity in summer; $/MWh includes integration costs without the Production Tax Credit.
2. Includes estimates of transmission integration costs.

In addition to the generation options, PA included four DSM options based upon proposed programs developed by Montana-Dakota. The four DSM options are summarized in Tables 4-2. Full program details are provided in Appendix B.

Table 4-2: New DSM Options

Program	Demand (MW)	Program Cost (2007 Dollars)	Total Energy Reduction kWh	Average Cost per kWh
Residential Refrigerators and Freezers (DSM 1)	0.949	$517,491	20,750,835	$0.025
Residential and Commercial AC Cycling (DSM 2)	8.024	$3,366,852	26,793,912	$0.126
High Efficiency Commercial AC and Motors (DSM 3)	0.337	$309,978	11,561,276	$0.056
Interruptible Rate (DSM 4)	4.500	$553,255	3,400,252	$0.163

4.2 FUEL

PA relied upon the coal cost estimates developed by Montana-Dakota for the coal resources and also a Montana-Dakota natural gas forecast associated with the delivery of gas to the combined cycle and combustion turbine options. The prices are shown in Table 4-4 for the North Dakota perspective; coal and natural gas fuel costs are 15 percent higher for the Montana perspective to reflect societal costs.

Table 4-4: Fuel Forecast (Redacted)

Year	Natural Gas	Big Stone II	Elk Run	LV-21 Coal
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				

4.3 OTHER ASSUMPTIONS

Table 4-5 shows the economic assumptions related to the generation alternatives. Fixed charge rates differ due to different book life and tax rates for the state the resource would be located.

Table 4-5: Economic Parameters

Unit	Operating Live	WACC	Fixed Charge Rate
Combustion Turbine	25	8.20	11.54
Combined Cycle	25	8.20	11.54
Bigstone II	40	8.20	9.97
Elk Run	40	8.20	10.23
IGCC	40	8.20	10.27
LV-21	40	8.20	10.27

5. RESULTS

The results for the six planning scenarios are provided in this section. The planning scenarios evaluated are:

1. Base case
2. Low load growth
3. High load growth
4. High capital costs for new base-load generation
5. High capital costs for new peaking generation
6. High gas prices

5.1 BASECASE SCENARIO RESULTS

The optimal plan selects a gas-fired combustion turbine in 2010 and 2023, Elk Run in 2012, and additional DSM programs. The optimal plan also assumes an extension of the Xcel Peaking contract for 2011. In order to understand the relative cost of Elk Run to an alternative coal plant, PA reviewed the top one hundred alternative plans in Strategist's solutions and identified that a comparable plan substituting Big Stone II for Elk Run would increase the NPV of the total resource plan by 2.7%. The top 100 hundred plans all include an additional coal resource, gas-fired peaking plants, and DSM. The plans differ regarding the timing and the amount of gas and conservation resources that are added to the build plan.

5.2 ALTERNATIVE SCENARIO RESULTS

As indicated in Table 5-2, the low and high growth scenarios are the only two of the five alternative scenarios for which the resource plan changed. The greatest change in the resource plan occurs under the high load growth scenario. In order to accommodate the load growth in the high growth scenario, the resource plan includes the addition of seven gas-fired combustion turbines and three 116 MW Big Stone coal units in addition to the Elk Run plant.

The high capital cost scenarios carried the assumption that capital and O&M costs are 15 percent higher than the base case costs, but these cost increases do not change resource selection.

5.3 SUMMARY

Based on the results for the scenarios evaluated, the least cost resource options for the Montana-Dakota electric system are a baseload coal unit and gas-fired combustion turbines. In addition, the Xcel contract should be extended for one year (2011). This extension allows Montana-Dakota to meet its capacity obligations until the base load unit comes on line. Because there is a difference of 2.7% between plans with Elk Run and Bigstone II, the choice between these two primary coal-fired options may involve qualitative considerations such as location and plant specific risks and operational considerations.

In addition, wind is selected in slightly higher cost alternative plans, and depending upon specific opportunities could be a viable supplemental resource to consider.

Table 5-1: Expansion Plan Summary

Least Cost Resource Plan	
Year	**Resource in Least Cost Plan**
2007	
2008	DSM 1 and DSM 3
2009	DSM 2
2010	CT
2011	Extension of Xcel Peaking
2012	Elk Run
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	CT
2024	
2025	
2026	

Table 5-2: Expansion Plan Summaries for Alternative Scenarios

Scenario Analysis Least Cost Resource Plans					
Year	Low Growth	High Growth	High Baseload Generation Costs	High Peaking Generation Costs	High Gas Prices
2007					
2008	DSM 1 & DSM 3	DSM 1 & DSM 3	DSM 1 & DSM 3	DSM 1 & DSM 3	DSM 1 & DSM 3
2009	DSM 2	CT, DSM	DSM 2	DSM 2	DSM 2
2010			CT	CT	CT
2011	Extension of Xcel Peaking	CT, Extension of Xcel Peaking	Extension of Xcel Peaking	Extension of Xcel Peaking	Extension of Xcel Peaking
2012	Elk Run	Elk Run	Elk Run	Elk Run	Elk Run
2013		CT			
2014		CT			
2015					
2016		Big Stone 2			
2017					
2018					
2019		CT			
2020		CT			
2021		Big Stone 3			
2022					
2023			CT	CT	CT
2024		CT			
2025		Big Stone 4			
2026					

APPENDIX A: MODEL RESULTS

This appendix contains the Strategist reports for the Base Case. The reports include the Least Cost Plan Summary, the Integrated Plan Report, the System Cost Report, the Thermal Unit and Transaction reports.

Base Case IRP
PA CONSULTING
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PROVIEW LEAST COST OPTIMIZATION SYSTEM
LEAST COST PLAN SUMMARY

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	PR-B 116.	PWND 20.	PRLV 116.	PRCT 44.	PRIG 116.	DSM1 0.	DSM2 8.	DSM3 0.	DSM4 4.	PRCC 130.	XL11 105.	PRER 116.
2007	475.3	568.2	95.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	481.7	577.8	12.4	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	484.9	582.8	0.0	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	487.8	631.3	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	490.7	636.3	105.0	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	496.1	644.6	116.0	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	501.5	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	507.0	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	512.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	518.0	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	523.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	528.9	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	534.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	539.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	545.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	550.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	556.3	680.4	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	561.8	680.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	567.3	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	572.8	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0

Base Case IRP
PA CONSULTING
CONFIDENTIAL

PROVIEW LEAST COST OPTIMIZATION SYSTEM
INTEGRATED PLAN REPORT

RANK AND PLAN NO. 1
STATE NUMBER 18678

STUDY PERIOD:
UTILITY COST (PV) = 2211256.
RATE (PV) = 34.254
TOTAL COST (PV) = 2211256.
SOCIETAL COST (PV) = 2211256.
DISCOUNTED SALES = 64555.

PLANNING PERIOD:
RANK = 67
UTILITY COST (PV) = 1213658.
RATE (PV) = 34.271
TOTAL COST (PV) = 1213658.
SOCIETAL COST (PV) = 1213658.
DISCOUNTED SALES = 35414.

END EFFECTS ADJUSTMENTS PERIOD:
TIME PERIOD = ALL FUTURE YEARS
LFA/GAF UTL COST (PV) = 763573.
LFA/GAF TRC COST (PV) = 763573.
LFA/GAF SOC COST (PV) = 763573.
FIXED COSTS (PV) = 234025.
DISCOUNTED SALES = 29141.

			NUMBER OF UNITS ADDED											
			PR-B	PWND	PRLV	PRCT	PRIG	DSM1	DSM2	DSM3	DSM4	PRCC	XL11	PRER
			116.	20.	116.	44.	116.	0.	8.	0.	4.	130.	105.	116.
YEAR	TOT. MW	REU MW												
2007	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0.	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	0.	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	105.	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	116.	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0.	0	0	0	0	0	0	0	0	0	0	0	0	0

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

Potential DSM Phases - Base Case

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Participants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Incentive Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
Current DSM Programs (2006-2007)														
1	T Rate - Demand Response	2007	3	10	18	4,178,634	5,500	$51,265	$10,919	$1,905	$ 64,139	$ 675,890	$123	$0.163
7	**Residential High Efficiency A/C	2006	3	15	886	9,639,358	586	$177,261	$19,829	$0	$ 197,110	$ 591,330	$1,010	$0.061
12	Commercial Lighting	2006	5	10	1,704	31,530,056	1,577	$62,715	$19,829	$0	$ 82,544	$ 412,718	$262	$0.013
	Totals					45,350,948	7,893	$291,281	$50,577	$1,985	$ 343,843	$ 1,683,938		
Programs Added for 2008														
5	Energy Star Refrigerators	2008	3	15	4,308	4,002,856	195	$21,530	$19,829	$0	$ 41,357	$ 124,100	$635	$0.027
6	Energy Star Freezers	2008	3	15	3,364	2,605,613	127	[illegible]	$19,829	$0	$ 38,630	$ 109,901	$867	$0.042
11	Refridgerator Round Up	2008	3	10	942	1,739,885	563	$10,084	$10,829	$23,558	$ 44,097	$ 183,142	$324	$0.06[illegible]
14	Exit Signs	2008	5	10	852	8,554,379	124	$4,257	$19,829	$0	$ 24,086	$ 120,448	$971	$0.014
	Totals					20,750,835	949	$53,583	$79,316	$23,558	$ 156,437	$ 517,491		
Programs Added for 2008														
1	IT Rate - Demand Response	2008	3	10	9	3,430,252	4,500	$41,715	$8,813	$1,515	$ 52,040	$ 553,255	$123	$0.163
Programs Added for 2009														
9	Residential A/C Cycling	2009	3	10	5,648	25,878,187	7,151	$322,462	$23,429	$1,100,221	[illegible]	$2,059,275	$419	$0.126
10	Commercial A/C Cycling	2009	3	10	213	2,915,725	873	$38,877	$23,429	[illegible]	[illegible]	[illegible]	$421	$0.128
	Total Increase 2010					28,793,912	8,024	$361,339	$46,858	$1,267,979	$1,676,176	$3,356,852		
Programs added for 2010														
3	Commercial High Efficiency A/C	2010	3	15	210	3,055,333	198	$25,501	$19,829	$0	$ 45,330	$165,660	$835	$0.054
2	High Efficiency Motors	2008	3	15	329	8,605,940	139	$28,167	$19,829	$0	$47,995	$143,988	$1,045	$0.017
	Totals					11,661,276	337	$53,668	$39,658	$0	$ 103,325	$309,978		

** Current Program for 2007 - Higher SEER Requirement & Incentive for 2008

Net Cost per kW	$	219
Net Cost per kWh	$	0.037

(I)

Net Cost per kW	$	545
Net Cost per kWh	$	0.026

(IV)

(II)

Net Cost per kW	$	420
Net Cost per kWh	$	0.126

(III)

Includes Admin at full amount per program

Net Cost per kW	$	921
Net Cost per kWh	$	0.027

Cumulative Cost per kW	$	348
Cumulative Cost per kWh	$	0.056

Potential DSM Phases - Base Case - Societal Test Perspective

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Participants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Part Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
Current DSM Programs (2006-2007)														
1	(1) Rate - Demand Response	2007	3	10	19	4,178,504	5,530	$320,727	$10,010	$1,985	$ 342,631	$ 3,781,677	$664	$0.905
7	(1) Residential High Efficiency A/C	2005	3	15	585	8,636,268	586	$325,055	$19,829	$0	$ 344,844	$ 1,034,533	$1,766	$0.107
12	Commercial Lighting	2006	5	10	1,714	31,536,056	1,577	$313,573	$19,829	$0	$ 333,402	$ 1,687,009	$1,057	$0.053
	Totals					45,350,948	7,693	$958,315	$50,577	$1,985	$ 1,020,877	$ 6,483,219		

(1) Current Program for 2007 Higher SEER Requirement & Incentive for 2009

Net Cost per kW	$ 845
Net Cost per kWh	$ 0.141

(I)

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Participants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Part Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
Programs Added for 2008														
5	Energy Star Refrigerators	2005	3	15	4,330	4,632,958	195	$43,075	$19,829	$0	$ 62,904	$ 185,714	$957	$0.040
3	Energy Star Freezers	2005	3	15	3,354	2,653,613	127	$36,867	$19,829	$0	$ 56,796	$ 55,726	$442	$0.022
11	Refrigerator Round Up	2005	3	10	542	4,730,886	503	$0	$19,829	$23,558	$ 43,387	$ 150,161	$299	$0.027
14	LED Exit Signs	2005	5	20	252	8,654,378	124	$42,635	$19,829	$0	$ 62,464	$ 212,170	$2,516	$0.036
	Totals					20,750,835	949	$122,578	$79,316	$23,558	$ 225,452	$ 687,771		

Net Cost per kW	$ 724
Net Cost per kWh	$ 0.033

(IV)

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Participants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Part Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
Programs Added for 2008														
1	IT Rate - Demand Response	2008	5	10	9	3,400,262	4,000	$205,772	$0,010	$1,8[illegible]	$ 200,032	$ 3,094,099	$688	$0.910

(II)

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Participants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Part Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
Programs Added for 2009														
9	Residential A/C Cycling	2009	3	10	8,019	23,875,187	7,151	$0	$23,429	$1,169,321	$1,192,750	$2,254,351	$328	$0.095
10	Commercial A/C Cycling	2009	3	10	213	2,915,725	873	$0	$23,429	$98,658	$122,087	$289,823	$332	$0.099
	Total Increase 2010					26,793,912	8,024	$0	$46,858	$1,267,979	$1,314,837	$2,544,174		

Net Cost per kW	$ 330
Net Cost per kWh	$ 0.088

(III)

DSM #	DSM Program	Program Start Date	Program Length	Program Life	Total Participants	Total kWh Decreased Project Life	Annual KW Avoided End Program	Year 1 Part Cost	Year 1 Admin Cost	Year 1 Operating Cost	Year 1 Total Est Cost	Estimated Total Cost	Cost Per kW	Cost Per kWh
Programs added for 2010														
6	Commercial High Efficiency A/C	2008	3	15	213	3,055,338	199	$71,001	$19,829	$0	$ 90,830	$272,491	$1,370	$0.088
2	High Efficiency Motors	2008	3	15	320	8,505,940	138	$156,254	$19,829	$0	$176,083	$528,249	$3,832	$0.032
	Totals					11,561,278	337	$227,255	$39,658	$0	$ 266,913	$800,738		

Includes Admin at full amount per program

Net Cost per kW	$ 2,378
Net Cost per kWh	$ 0.069

Cumulative Cost per kW	$ 624
Cumulative Cost per kWh	$ 0.102

DSM Costs from the societal test viewpoint

26 Mar 2007

APPENDIX C: LOW LOAD

This appendix contains the Strategist reports for the Low Load Growth scenario. The reports include the Least Cost Plan Summary, the Integrated Plan Report, the System Cost Report, the Thermal Unit and Transaction reports.

Low Load Growth
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PROVIEW LEAST COST OPTIMIZATION SYSTEM
LEAST COST PLAN SUMMARY

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	PR-B 116.	PWND 20.	PRLV 116.	PRCT 44.	PRIG 116.	DSM1 0.	DSM2 8.	DSM3 0.	DSM4 4.	PRCC 130.	XL11 105.	PRER 116.
2007	475.3	568.2	95.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	477.5	577.8	12.4	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	477.1	582.8	0.0	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	476.6	587.8	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	476.4	592.8	105.0	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	478.7	601.1	116.0	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	481.1	591.1	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	483.6	591.1	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	486.0	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	488.5	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	491.0	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	493.5	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	496.0	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	498.5	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	501.1	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	503.6	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	506.2	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	508.8	593.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	511.3	594.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	513.9	594.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0

Low Load Growth
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PROVIEW LEAST COST OPTIMIZATION SYSTEM
INTEGRATED PLAN REPORT

RANK AND PLAN NO. 1
STATE NUMBER 262

STUDY PERIOD:
UTILITY COST (PV) = 1857374.
RATE (PV) = 31.827
TOTAL COST (PV) = 1857374.
SOCIETAL COST (PV) = 1857374.
DISCOUNTED SALES = 58358.

PLANNING PERIOD:
RANK = 1
UTILITY COST (PV) = 1076655.
RATE (PV) = 32.682
TOTAL COST (PV) = 1076655.
SOCIETAL COST (PV) = 1076655.
DISCOUNTED SALES = 32944.

END EFFECTS ADJUSTMENTS PERIOD:
TIME PERIOD = ALL FUTURE YEARS
LFA/GAF UTL COST (PV) = 622084.
LFA/GAF TRC COST (PV) = 622084.
LFA/GAF SOC COST (PV) = 622084.
FIXED COSTS (PV) = 158635.
DISCOUNTED SALES = 25414.

			NUMBER OF UNITS ADDED										
			PR-B	PWND	PRLV	PRCT	PRIG	DSM1	DSM2	DSM3	DSM4	PRCC	XL11	PRER
			116.	20.	116.	44.	116.	0.	8.	0.	4.	130.	105.	116.
YEAR	TOT. MW	REU MW												
2007	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0.	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	0.	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	105.	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	116.	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0.	0	0	0	0	0	0	0	0	0	0	0	0	0

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

APPENDIX D: HIGH LOAD GROWTH

This appendix contains the Strategist reports for the High Load Growth scenario. The reports include the Least Cost Plan Summary, the Integrated Plan Report, the System Cost Report, the Thermal Unit and Transaction reports.

High Load Growth
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PROVIEW LEAST COST OPTIMIZATION SYSTEM
LEAST COST PLAN SUMMARY

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	PR-B 116.	PWND 118.	PRLV 116.	PRCT 44.	PRIG 116.	DSM1 0.	DSM2 8.	DSM3 0.	DSM4 4.	PRCC 130.	XL11 105.	PRER 116.
2007	475.3	568.2	95.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	496.0	577.8	12.4	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	515.0	626.3	43.5	0	0	0	0	1	0	0	1	0	0	0	0	0
2010	534.9	631.3	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	556.1	679.8	148.5	0	0	0	0	1	0	0	0	0	0	0	1	0
2012	580.9	688.1	116.0	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	606.8	721.6	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2014	633.9	765.1	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2015	662.2	767.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	691.7	883.4	116.0	0	1	0	0	0	0	0	0	0	0	0	0	0
2017	722.5	883.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	754.7	883.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	788.2	926.9	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2020	823.3	1042.9	116.0	0	1	0	0	0	0	0	0	0	0	0	0	0
2021	859.9	1042.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	898.1	1042.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	938.0	1086.4	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	979.7	1129.9	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2025	1023.2	1246.5	116.0	0	1	0	0	0	0	0	0	0	0	0	0	0
2026	1068.6	1246.5	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0

High Load Growth
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PROVIEW LEAST COST OPTIMIZATION SYSTEM
INTEGRATED PLAN REPORT

RANK AND PLAN NO. 1
STATE NUMBER 1996

STUDY PERIOD:
UTILITY COST (PV) = 4429748.
RATE (PV) = 45.019
TOTAL COST (PV) = 4429748.
SOCIETAL COST (PV) = 4429748.
DISCOUNTED SALES = 98397.

PLANNING PERIOD:
RANK = 5
UTILITY COST (PV) = 1983198.
RATE (PV) = 43.154
TOTAL COST (PV) = 1983198.
SOCIETAL COST (PV) = 1983198.
DISCOUNTED SALES = 45957.

END EFFECTS ADJUSTMENTS PERIOD:
TIME PERIOD = ALL FUTURE YEARS
LFA/GAF UTL COST (PV) = 1379344.
LFA/GAF TRC COST (PV) = 1379344.
LFA/GAF SOC COST (PV) = 1379344.
FIXED COSTS (PV) = 1067205.
DISCOUNTED SALES = 52440.

			NUMBER OF UNITS ADDED										
			PR-B	PWND	PRLV	PRCT	PRIG	DSM1	DSM2	DSM3	DSM4	PRCC	XL11	PRER
			116.	118.	116.	44.	116.	0.	8.	0.	4.	130.	105.	116.
YEAR	TOT. MW	REU MW												
2007	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0.	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	44.	0	0	0	0	1	0	0	1	0	0	0	0	0
2010	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	148.	0	0	0	0	1	0	0	0	0	0	0	1	0
2012	116.	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2014	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2015	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	116.	0	1	0	0	0	0	0	0	0	0	0	0	0
2017	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2020	116.	0	1	0	0	0	0	0	0	0	0	0	0	0
2021	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2025	116.	0	1	0	0	0	0	0	0	0	0	0	0	0
2026	0.	0	0	0	0	0	0	0	0	0	0	0	0	0

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

APPENDIX E: HIGH BASELOAD CAPITAL COSTS

This appendix contains the Strategist reports for the High Baseload Generation Capital Costs scenario. The reports include the Least Cost Plan Summary, the Integrated Plan Report, the System Cost Report, the Thermal Unit and Transaction reports.

Baseload Generation High Capital Cost
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PROVIEW LEAST COST OPTIMIZATION SYSTEM
LEAST COST PLAN SUMMARY

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	PR-B 116.	PWND 20.	PRLV 116.	PRCT 44.	PRIG 116.	DSM1 0.	DSM2 8.	DSM3 0.	DSM4 4.	PRCC 130.	XL11 105.	PRER 116.
2007	475.3	568.2	95.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	481.7	577.8	12.4	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	484.9	582.8	0.0	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	487.8	631.3	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	490.7	636.3	105.0	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	496.1	644.6	116.0	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	501.5	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	507.0	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	512.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	518.0	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	523.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	528.9	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	534.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	539.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	545.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	550.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	556.3	680.4	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	561.8	680.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	567.3	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	572.8	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Strategist Page 2

Baseload Generation High Capital Cost
PA CONSULTING PROVIEW LEAST COST OPTIMIZATION SYSTEM
CONFIDENTIAL INTEGRATED PLAN REPORT

RANK AND PLAN NO. 1
STATE NUMBER 186

STUDY PERIOD:
UTILITY COST (PV) = 2265516.
RATE (PV) = 35.095
TOTAL COST (PV) = 2265516.
SOCIETAL COST (PV) = 2265516.
DISCOUNTED SALES = 64555.

PLANNING PERIOD:
RANK = 1
UTILITY COST (PV) = 1244146.
RATE (PV) = 35.132
TOTAL COST (PV) = 1244146.
SOCIETAL COST (PV) = 1244146.
DISCOUNTED SALES = 35414.

END EFFECTS ADJUSTMENTS PERIOD:
TIME PERIOD = ALL FUTURE YEARS
LFA/GAF UTL COST (PV) = 763573.
LFA/GAF TRC COST (PV) = 763573.
LFA/GAF SOC COST (PV) = 763573.
FIXED COSTS (PV) = 257797.
DISCOUNTED SALES = 29141.

			NUMBER OF UNITS ADDED											
			PR-B	PWND	PRLV	PRCT	PRIG	DSM1	DSM2	DSM3	DSM4	PRCC	XL11	PRER
			116.	20.	116.	44.	116.	0.	8.	0.	4.	130.	105.	116.
YEAR	TOT. MW	REU MW												
2007	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0.	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	0.	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	105.	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	116.	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0.	0	0	0	0	0	0	0	0	0	0	0	0	0

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

APPENDIX F: HIGH PEAKING CAPITAL COSTS

This appendix contains the Strategist reports for the High Peaking Generation Capital Costs scenario. The reports include the Least Cost Plan Summary, the Integrated Plan Report, the System Cost Report, the Thermal Unit and Transaction reports.

Peaking Generation High Capital Cost
PA CONSULTING
CONFIDENTIAL

PROVIEW LEAST COST OPTIMIZATION SYSTEM
LEAST COST PLAN SUMMARY

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	PR-B 116.	PWND 20.	PRLV 116.	PRCT 44.	PRIG 116.	DSM1 0.	DSM2 8.	DSM3 0.	DSM4 4.	PRCC 130.	XL11 105.	PRER 116.
2007	475.3	568.2	95.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	481.7	577.8	12.4	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	484.9	582.8	0.0	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	487.8	631.3	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	490.7	636.3	105.0	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	496.1	644.6	116.0	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	501.5	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	507.0	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	512.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	518.0	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	523.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	528.9	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	534.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	539.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	545.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	550.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	556.3	680.4	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	561.8	680.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	567.3	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	572.8	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0

Peaking Generation High Capital Cost
PA CONSULTING
CONFIDENTIAL

PROVIEW LEAST COST OPTIMIZATION SYSTEM
INTEGRATED PLAN REPORT

RANK AND PLAN NO. 1
STATE NUMBER 557

STUDY PERIOD:

UTILITY COST (PV)	=	2206696.
RATE (PV)	=	34.183
TOTAL COST (PV)	=	2206696.
SOCIETAL COST (PV)	=	2206696.
DISCOUNTED SALES	=	64555.

PLANNING PERIOD:

RANK	=	3	TIME PERIOD	=	ALL FUTURE YEARS
UTILITY COST (PV)	=	1212172.	LFA/GAF UTL COST (PV)	=	754468.
RATE (PV)	=	34.229	LFA/GAF TRC COST (PV)	=	754468.
TOTAL COST (PV)	=	1212172.	LFA/GAF SOC COST (PV)	=	754468.
SOCIETAL COST (PV)	=	1212172.	FIXED COSTS (PV)	=	240056.
DISCOUNTED SALES	=	35414.	DISCOUNTED SALES	=	29141.

END EFFECTS ADJUSTMENTS PERIOD:

		NUMBER OF UNITS ADDED											
		PR-B	PWND	PRLV	PRCT	PRIG	DSM1	DSM2	DSM3	DSM4	PRCC	XL11	PRER
		116.	20.	116.	44.	116.	0.	8.	0.	4.	130.	105.	116.
YEAR	TOT. MW	REU MW											
2007	0.	0	0	0	0	0	0	0	0	0	0	0	0
2008	0.	0	0	0	0	0	1	0	1	0	0	0	0
2009	0.	0	0	0	0	0	0	1	0	0	0	0	0
2010	44.	0	0	0	0	1	0	0	0	0	0	0	0
2011	105.	0	0	0	0	0	0	0	0	0	0	1	0
2012	116.	0	0	0	0	0	0	0	0	0	0	0	1
2013	0.	0	0	0	0	0	0	0	0	0	0	0	0
2014	0.	0	0	0	0	0	0	0	0	0	0	0	0
2015	0.	0	0	0	0	0	0	0	0	0	0	0	0
2016	0.	0	0	0	0	0	0	0	0	0	0	0	0
2017	0.	0	0	0	0	0	0	0	0	0	0	0	0
2018	0.	0	0	0	0	0	0	0	0	0	0	0	0
2019	0.	0	0	0	0	0	0	0	0	0	0	0	0
2020	0.	0	0	0	0	0	0	0	0	0	0	0	0
2021	0.	0	0	0	0	0	0	0	0	0	0	0	0
2022	0.	0	0	0	0	0	0	0	0	0	0	0	0
2023	44.	0	0	0	0	1	0	0	0	0	0	0	0
2024	0.	0	0	0	0	0	0	0	0	0	0	0	0
2025	0.	0	0	0	0	0	0	0	0	0	0	0	0
2026	0.	0	0	0	0	0	0	0	0	0	0	0	0

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

APPENDIX G:HIGH GAS PRICES

This appendix contains the Strategist reports for the High Gas Prices scenario. The reports include the Least Cost Plan Summary, the Integrated Plan Report, the System Cost Report, the Thermal Unit and Transaction reports.

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High Gas Prices
PA CONSULTING
CONFIDENTIAL

PROVIEW LEAST COST OPTIMIZATION SYSTEM
LEAST COST PLAN SUMMARY

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	PR-B 116.	PWND 20.	PRLV 116.	PRCT 44.	PRIG 116.	DSM1 0.	DSM2 8.	DSM3 0.	DSM4 4.	PRCC 130.	XL11 105.	PRER 116.
2007	475.3	568.2	95.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	481.7	577.8	12.4	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	484.9	582.8	0.0	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	487.8	631.3	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	490.7	636.3	105.0	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	496.1	644.6	116.0	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	501.5	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	507.0	634.6	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	512.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	518.0	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	523.5	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	528.9	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	534.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	539.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	545.4	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	550.8	636.9	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	556.3	680.4	43.5	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	561.8	680.4	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	567.3	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	572.8	681.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0	0

High Gas Prices
PA CONSULTING
CONFIDENTIAL

PROVIEW LEAST COST OPTIMIZATION SYSTEM
INTEGRATED PLAN REPORT

RANK AND PLAN NO. 1
STATE NUMBER 184

STUDY PERIOD:
UTILITY COST (PV) = 2223398.
RATE (PV) = 34.442
TOTAL COST (PV) = 2223398.
SOCIETAL COST (PV) = 2223398.
DISCOUNTED SALES = 64555.

PLANNING PERIOD:
RANK = 1
UTILITY COST (PV) = 1218825.
RATE (PV) = 34.417
TOTAL COST (PV) = 1218825.
SOCIETAL COST (PV) = 1218825.
DISCOUNTED SALES = 35414.

END EFFECTS ADJUSTMENTS PERIOD:
TIME PERIOD = ALL FUTURE YEARS
LFA/GAF UTL COST (PV) = 770548.
LFA/GAF TRC COST (PV) = 770548.
LFA/GAF SOC COST (PV) = 770548.
FIXED COSTS (PV) = 234025.
DISCOUNTED SALES = 29141.

			NUMBER OF UNITS ADDED											
			PR-B	PWND	PRLV	PRCT	PRIG	DSM1	DSM2	DSM3	DSM4	PRCC	XL11	PRER
			116.	20.	116.	44.	116.	0.	8.	0.	4.	130.	105.	116.
YEAR	TOT. MW	REU MW												
2007	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0.	0	0	0	0	0	0	1	0	1	0	0	0	0
2009	0.	0	0	0	0	0	0	0	1	0	0	0	0	0
2010	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2011	105.	0	0	0	0	0	0	0	0	0	0	0	1	0
2012	116.	0	0	0	0	0	0	0	0	0	0	0	0	1
2013	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	44.	0	0	0	0	1	0	0	0	0	0	0	0	0
2024	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0.	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0.	0	0	0	0	0	0	0	0	0	0	0	0	0

STUDY PERIOD = PLANNING PERIOD + END EFFECTS PERIOD

ATTACHMENT D

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PUBLIC ADVISORY GROUP DOCUMENTATION

ATTACHMENT D

PUBLIC ADVISORY GROUP DOCUMENTATION

This Attachment is comprised of the official PAG 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
PUBLIC ADVISORY GROUP ROSTER

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In addition to the Montana-Dakota personnel included on the roster, the following Montana-Dakota personnel participated in one or more of the PAG meetings as presenters:

Gary Livermont	Electric System Manager
Lynn Paulsen	Special Projects Manager
Duane Steen	Director - New Generation
Jay Skabo	Environmental Manager
Mark Hanson	Public Relations Representative
Joseph Geiger	Professional Development Engineer
Dave Goodin	Executive Vice President Operations and Acquisitions
Henry Ford	Electric Transmission and Substation Manager
Al Jirges	Senior Engineer
Allan Welte	Director of Generation
Bob Morman	Gas Supply Manager

MEETINGS OF THE IRP PUBLIC ADVISORY GROUP

August 28, 2006 Meeting Agenda

The IRP Process & Role of PAG	Hoa Nguyen
Updates on Montana-Dakota's Activities and the Electric Utility Industry - ERO	Karl Tammar Hoa Nguyen
Updates on Midwest Independent Transmission System Operator (MISO) and the Energy Market	Gary Livermont
MISO Transmission Pricing Activity	Lynn Paulsen
Montana-Dakota's Future Generation	Duane Steen
Demand-Side Management Updates	Kathy Baerlocher Larry Oswald
North American and Regional Reliability Organizations	Hoa Nguyen
Workings of the IRP Public Advisory Group Discussion Meeting Logistics Future Meetings Meeting Schedule through 2007	

November 15, 2006 Meeting Agenda

Updates on Montana-Dakota's Activities and the Electric Utility Industry	Karl Tammar Hoa Nguyen
Montana-Dakota's Environmental Policy and Issues	Jay Skabo
Montana Energy Updates	Paul Cartwright
Wind Energy in North Dakota	Bill Huether
Load Forecast Methodology & Results	Kayla Kaul
Demand-Side Management Analysis Procedure	Larry Oswald Kathy Baerlocher

January 30, 2007 Meeting Agenda

About MDU Resources Group, Inc.	Mark Hanson
Updates on Montana-Dakota's Activities and the Electric Utility Industry	Karl Tammar Hoa Nguyen
Montana Legislature Updates	Paul Cartwright
North Dakota Legislature Updates	Annette Bendish
Montana-Dakota's Regulatory Updates	Tamie Aberle
Supply-Side Activity Updates	Lynn Paulsen
Development of DSM Program List and DSM Analysis	Larry Oswald Joseph Geiger
Transmission System History	Lynn Paulsen

March 20, 2007 Meeting Agenda

Updates on Montana-Dakota's Activities and the Electric Utility Industry	Karl Tammar Hoa Nguyen
The Cascade Natural Gas Corporation Merger	Dave Goodin
Load Growth in Eastern Montana	Henry Ford
Selection of the Next Capacity Expansion Model & Other Supply-Side Activities	Lynn Paulsen
Montana-Dakota's Wind Energy Development Activities	Duane Steen
The Automatic Meter Reading Project	Al Jirges
Demand-Side Analysis Results and Recommendations	Larry Oswald Kathy Baerlocher

April 25, 2007 Meeting Agenda

Updates on the 2007 Implementation of the Demand-Side Programs	Kathy Baerlocher
Updates on New Generation Development	Allan Welte
Montana-Dakota Gas Supply Overview	Bob Morman
2007 Integrated Resource Plan	Lynn Paulsen
Discussion and Feedback on PAG Work Plan and Activity	PAG Members