Montana-Dakota Utilities

Docket N2011.8.70

Fact Sheet

PREPARED BY: DATE PREPARED: June 15, 2012

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BACKGROUND AND SUMMARY OF FILING REQUIREMENTS

Montana-Dakota Utilities (MDU) provides service through an integrated electric system to territories in Montana, North Dakota, South Dakota, and Wyoming. The Montana territory includes portions of 10 eastern counties. MDU files an integrated[1] resource plan (IRP) biennially with the Montana Public Service Commission (PSC, Commission) as required in ARM 38.5.2001 – ARM 38.5.2012 (IRP Rules). MDU should file an IRP by September 15 of odd numbered years.

Pursuant to the IRP Rules, an IRP should outline a strategy to meet its customers' needs for adequate, reliable and efficient electric energy services at the lowest expected long-term societal cost (least cost) while remaining financially sound. Societal cost is the sum of costs to the utility and external costs imposed on the global society. Least cost analysis in the IRP should include a discussion of any uncertainty or risk that may qualify or modify expected least costs.

The IRP should describe a timely acquisition of integrated resources, including active pursuit and acquisition of all cost effective energy conservation. Utility investment in conservation measures installed on the customer's side of the meter should be considered cost effective up to 115% of the utility's long-term avoided cost. All resource decisions should be thoroughly documented and reasonably clear.

IRP filings do not consider cost recovery for new or expected acquisitions, or cost recovery for existing assets deemed no longer useful. If an IRP filing demonstrates that abandonment of an existing resource or construction of a new resource is least cost, the Commission may open a new docket to address cost recovery.

Rate design is a key element in the planning process. Although rate designs are determined in contested proceedings, a utility should explicitly recognize and utilize the ability of rate design to yield demand-side resources. An IRP should be consistent with the established goals and objectives of rate design, including rate stability and the assignment of external costs to their appropriate causes when possible. If a utility is faced with potential loss of a large industrial load and is considering a request for a retention rate, its IRP should evaluate the impacts of load loss, and consider efficiency improvements and pricing alternatives.

In rate case filings, the utility shall base its marginal cost of service and rate design upon the IRP filed in that year or in the year previous. An IRP may not bind the Commission in its

[1] In this case, “integrated” refers to the integration of supply-side with demand-side resources.

review of a rate case or in setting rates. Although the Commission may determine that the utility's forecast methods are documented and reasonably clear, the Commission may not endorse the methods or transfer forecast risk to ratepayers. The Commission may waive the requirement to file an IRP upon request and with good cause shown.

PROCEDURAL HISTORY

On August 15, 2011 MDU filed its 2011 IRP with the Commission. On August 29, 2011 the PSC issued a Notice of Filing with a comment deadline of October 28, 2011. The Department of Environmental Quality (DEQ) filed comments on October 19, 2011. On June 5, 2012, the Commission issued a Notice of Public Meeting that will take place on June 28, 2012.

SUMMARY OF THE 2009 IRP AND PSC COMMENTS

In 2009 MDU filed an IRP that proposed the construction of several additional resources to meet expected capacity increases, including a 131 megawatt (MW) share in a 580 MW coal-fired thermal plant – Big Stone II – a 10.5 MW expansion of the Diamond Willow wind farm, and new construction of the 19.5 MW Cedar Hills wind farm. Cedar Hills and the Diamond Willow expansion came on-line in June 2010. MDU abandoned its commitment in Big Stone II after other project partners cancelled their interests in late 2009. MDU also planned to purchase 105-110 MW capacity in 2009-2011 from Northern States Power, and 110-120 MW capacity in 2012-2015 from Wisconsin Electric Power Company.

The PSC posted fourteen comments on the 2009 MDU IRP. A brief summary of these comments and responses (in italics) from the 2011 IRP are included below:

1) In future IRPs, MDU should provide responses to comments filed by the Commission and DEQ. *MDU provided Chapter 9 to address Commission comments.*
2) MDU should provide in future IRPs the details of proposed transmission and infrastructure upgrades, including Midwest Independent Transmission System Operator (MISO) and MISO Transmission Expansion Planning (MTEP) projects, which may impact Montana ratepayers. *Attachment J addresses projected transmission service charge impacts. There are no major Montana service area distribution infrastructure projects identified in MDU's five year capital budget.*
3) MDU should continue to provide information and analysis regarding the MISO energy,

capacity, and ancillary service markets. *MDU describes MISO energy, capacity, and ancillary service markets in Chapter 6.*

4) MDU should provide complete explanation of calculations for supply, capacity, and avoided costs in future IRPs. *MDU offers all of its generation into the MISO market and secures its energy requirements from this market. If MDU generation is not equal to its load requirement, its position is either net sales or net purchases. The position depends upon the MISO energy price and MDU's marginal generating cost, e.g. if MDU's marginal generating cost is less than the MISO energy price, MDU will generate and sell surplus energy into the market for gain. In that case, marginal cost is the marginal cost of generation. MDU uses a simulation algorithm to model economic dispatch and estimate its marginal cost of generation. If MDU is a net purchaser of energy, its marginal cost is the MISO energy price. MDU defines avoided cost in a time period to be the simple average of the hourly marginal cost values for that period.*
5) MDU should provide details in the 2011 IRP on how it will replace Big Stone II. *MDU is proposing an 88 MW simple-cycle combustion turbine, a 25 MW third party demand response (DR) program, 24.5 MW of demand-side management (DSM), and a new request for proposal (RFP) for capacity and energy resources to be issued in 2012. Chapters 6 and 7 of the IRP describe results of the resource expansion analysis. Attachments B and C provide detailed information.*
6) MDU should specifically address how it will achieve its DSM commitments in future IRP cycles. *Customer participation in Montana DSM programs is lower than expected, probably because of customer demographics, customer awareness, market barriers, and low electric rates. In an effort to increase participation, MDU has stepped up its marketing activities, and is evaluating third party program marketing and delivery. MDU will commission an energy efficiency potential and market assessment study for Montana customers. The study is on track for completion in mid-2012.*
7) MDU should review the execution of its previous DSM commitments in future IRPs. *MDU provided a summary of 2010 DSM activity in Attachment B.*
8) MDU should fully describe DSM program costs, results, and plans on a state-by-state basis, and describe the progress made in previously planned programs. *MDU provided DSM analysis and implementation plans in Chapter 3 and Attachment B.*

9) In the 2011 IRP, MDU should provide details regarding cost analysis performed on an irrigation demand response program proposed in the 2009 IRP. *Results from the proposed study were inconclusive. Results from an expanded study will be reported in the upcoming 2013 IRP.*
10) In future IRPs MDU should provide the total DSM outreach and education budget. *The detail for projected administration and marketing budgets is provided in Appendix A of Attachment B of the 2011 IRP.*
11) In the 2011 IRP MDU should describe its method for evaluation, measurement, and verification (EM&V) of DSM achievements, and address proposed changes to EM&V. *Low customer participation does not warrant external EM&V. MDU recommends an impact evaluation based upon the deemed savings described in Attachment B, pre-determined criteria and reporting for all project-based programs, and an EM&V approach that will verify the initial load reductions for the large DR programs such as residential air-conditioning (AC) cycling and commercial DR.*
12) MDU should evaluate the possible use of third party EM&V. *MDU recommends an approach that balances EM&V cost with the expected benefits from the programs.*
13) MDU should evaluate critical peak pricing and rebates that may be available through the use of automated meter reading (AMR) technology, and provide information regarding the communication of customer energy use and peak period events. *The residential AC cycling program is planned for delivery in late 2012. The program is expected to provide 4 MW of dispatchable DR in the summer of 2013. Initial indications are that AMR will provide the necessary data for EM&V. MDU expects that a third party will provide initial EM&V for this program. MDU is not certain whether interval energy information will be available to customers enrolled in the residential AC cycling program. The specific customer communication protocol will depend upon the chosen technology.*
14) MDU should continue to explicitly recognize and utilize the ability of rate design to yield demand-side resources, should update and explain participation levels in its optional time-of-day (TOD) tariffs, should reconsider an optional TOD irrigation tariff, and should analyze opportunities for cost-effective interruptible loads. *MDU is serving seven customers under the large general service TOD Rate 31 schedule as June 30, 2011. No customers have elected service under the residential or small general service TOD rate*

schedules. Based upon empirical evidence only, MDU attributes low participation to a customer reluctance to shift energy use to off-peak hours. MDU is considering an optional TOD irrigation rate. The results from the expanded irrigation loads study should provide data to support the rate. MDU does offer interruptible electric service to Montana customers with demand greater than 500 kilowatts (kW). MDU will describe to qualifying customers the economic advantages available in the interruptible Rate 38 due to the $5/kW difference in the monthly demand charge compared to the firm Rate 30.

SUMMARY OF THE 2011 IRP

The main report outlines MDU's strategy to procure electric supply and demand resources to meet projected energy and capacity needs during the five year (2011-2015), and twenty year (2011-2030) planning cycles. MDU used load forecasting analysis, supply-side analysis, demand-side analysis, and analysis of integration and risk to evaluate resource options. Detailed descriptions of analytic methods and results are provided in Attachments A-J submitted with the main report. A brief summary of methods and results is provided below.

Load Forecast

MDU projected 20-year energy needs using a variety of econometric models. MDU estimated sales separately for residential, small commercial and industrial, large commercial and industrial, street lighting, and miscellaneous sectors. The miscellaneous sector included public authorities, interdepartmental sales, and company use. In general, heating degree days, cooling degree days, and a time trend variable were the most important predictors of annual sales for the various sectors.

MDU estimated sales individually for several customers in the large commercial and industrial sector, including Tesoro refinery, Westmoreland Coal, Sabin Metals, Keystone XL Pipeline, Encore Acquisition, and other aggregated oil field customers. MDU combined specific forecast information with regression estimates to estimate sales for these industrial customers.

MDU projected summer and winter system peak demands for all sectors in aggregate. Variables for cooling degree days, average peak temperature, and annual energy requirement were used to estimate summer peak demand. Variables for average peak temperature, annual energy requirement, and a Christmas season indicator were used to estimate winter peak demand.

The estimates of annual energy sales and seasonal peak demands were adjusted for the expected effects of DSM programs, interruptible loads, and system losses to derive the 20-year estimates for energy and capacity requirements. MDU projects net energy needs to increase from 2.75 million megawatt-hours (MWh) in 2011 to 4.03 million MWh in 2030 (2.1%/year), summer net peak demand to increase from 500 MW in 2011 to 703 MW in 2030 (1.8%/year), and winter net peak demand to increase from 450 MW in 2011 to 645 MW in 2030 (1.9%/year).

Load Forecast Risk Analysis

MDU expanded the base forecast in a couple of ways to incorporate additional risk and uncertainty. In the first instance, MDU assumed that the peak load event would occur on a hotter afternoon. In the base forecast, MDU assumed that the temperature at peak would equal 97.0 degrees Fahrenheit (^{o} F), since MDU had determined through statistical analysis that the peak temperature would be less than 97° F with 50% probability, and greater than 97° F with 50% probability. Because of this MDU refers to the base forecast as a 50/50 forecast.

MDU modeled a 90/10 forecast using a peak temperature of 102.6^{o} F, where the peak temperature is expected to exceed this temperature 10% of the time. Since the modeled peak temperature is higher in this case, and peak loads increase directly with peak temperature, expected demand is greater than in the base model. The 90/10 model forecasts summer peak demand of 531 MW in 2011 and 747 MW in 2030.

MDU also modeled low-growth and high-growth energy and capacity forecasts. Low and high average growth rates taken from past periods of exceptional growth were used in these models. MDU obtained the low growth rate from the period 1985-1993, and the high growth rate from 1977 to 1985.

Planning Reserve Margin and Required Capacity

Resource plans in previous IRP's were required to meet a reserve capacity obligation of 15% that was added to peak load and compared to maximum generation at peak. The reserve capacity obligation was determined by the Mid-Continent Area Power Pool Generation Reserve Sharing Pool (MAPP GRSP). However, the MAPP GRSP was eliminated on December 31, 2009, and MDU is currently a member of MISO.

As a MISO member, MDU is required to estimate installed capacity for each resource at the MISO summer peak. The estimates are adjusted downward for expected forced outage reductions to estimate unforced capacity (UCAP). The estimates of UCAP are called planning resource credits (PRC), and are compared to required capacity to determine resource adequacy.

Required capacity equals expected MDU demand at the MISO summer peak, inflated for expected transmission and distribution losses (currently 1.16%), and adjusted further for a planning reserve margin (PRM) of 3.81%. Thus if expected peak demand equals 500 MW, then required capacity equals 525 MW {500 MW * 1.0116 * 1.0381}. MISO uses a loss of load expectation study to adjust the PRM annually. For example, the 2011 PRM of 3.81% decreased to 3.79% in 2012.

MDU projected required capacity in the 20 year period using the 50/50 forecast to estimate peak demand. MDU compared PRC from all resources to expected required capacity to determine if additional capacity resources would be necessary. Table 1 below shows expected capacity requirements and PRC from all resources.

Table 1
Base Forecast Required Capacity and Existing MDU Resource Capacity (MW)

Year	Forecast MISO Required Capacity[1] (MW)	Existing Coal Planning Resource Credits[2]	Existing Oil & Gas Resource Credits	Existing Renewable Resource Credits	Existing Peaking Purchase Contracts	Proposed Commercial Demand Response Program	Existing and Proposed DSM Projects	Total Planning Resource Credits	Forecast Surplus / (Deficit)
2011	525	337	88	15	140		7	587	62
2012	543	337	88	15	110	5	12	566	24
2013	564	337	88	15	115	15	17	587	23
2014	573	337	88	15	120	25	25	609	36
2015	590	337	176	15		25	25	577	(13)
2016	599	335	176	15		25	25	576	(24)
2017	608	335	176	15		25	25	576	(33)
2018	618	335	176	15		25	25	576	(42)
2019	627	335	176	15		25	25	576	(52)
2020	636	335	176	15		25	25	576	(61)
2021	646	335	176	15		25	25	576	(70)
2022	655	335	176	15		25	25	576	(80)
2023	665	335	176	15		25	25	576	(90)
2024	675	335	176	15		25	25	576	(100)
2025	685	335	176	15		25	25	576	(110)
2026	695	335	176	15		25	25	576	(120)
2027	706	335	176	15		25	25	576	(130)
2028	716	335	176	15		25	25	576	(141)
2029	727	335	176	15		25	25	576	(151)
2030	738	335	176	15		25	25	576	(162)

1. Forecast MISO capacity includes allowance of 1.16% for losses and 3.81% for a planning reserve margin.
2. Expected Coal Planning Resource Credit decrease of 2 MW in 2016 due to AQCS upgrades at Big Stone.

Portfolio Analysis

To meet expected capacity and energy deficits, MDU conducted an integrated demand and supply-side analysis to identify feasible existing and proposed capacity and load-modifying resources. MDU used Electric Generation Expansion Analysis System (EGEAS) to integrate feasible resources into a single least-cost plan for the period 2011-2030. MDU loaded EGEAS with information regarding load forecasts, reserve requirements, existing resources, potential resources, and other key variables to obtain least cost portfolio projections. MDU modeled supply-side portfolio risk through assuming high and low values for select variables in addition to base case assumptions. Demand and supply-side resources are summarized below.

Demand-Side Resources

MDU plans to implement several DSM programs. The utility expects to spend approximately $865,000 on energy efficiency programs in 2011-2013, with expected total lifetime cost of $0.053/kilowatt-hour. MDU's DSM energy savings goals equal 0.04% of total integrated sales in 2011, 0.10% in 2012, 0.18% in 2013, and 0.25% of total annual sales in 2014 through 2030. MDU asserted that these goals are appropriate in the interim, and that the goals will be adjusted if the perceived energy savings potential changes. MDU plans to commission an Energy Efficiency Potential and Market Assessment Study for Montana customers in order to refine its energy efficiency goals and programs. The expected completion date for this study is mid-2012.

MDU plans to meet a portion of its capacity needs through a DR portfolio that will include a residential AC cycling program (10 MW), a commercial DR program in contract with Constellation Energy (25 MW), and adjustments to interruptible Rate 38 (13 MW). The combined goal from these programs is 48 MW in capacity savings by 2015, or 8.3% of total forecast peak demand for the integrated system. Energy efficiency programs are expected to reduce demand 1.5 MW by 2015, for total expected capacity savings of 49.5 MW.

MDU considered an irrigation demand response program in 2009, and concluded that more research would be necessary due to uncertainty in the load profile. MDU performed another study in 2010 using the existing AMR system, and determined that the sampled load was not representative of the irrigation population, as golf courses were the primary customers sampled. MDU is planning to expand this study to incorporate a larger, more diverse sample of

irrigation customers. The expansion will include at least 12 additional customers, or about 15% of MDU's total irrigation customer base.

Existing Montana DSM Programs

MDU offered Montana customers several residential and commercial DSM programs in 2010-11 that were funded through the Universal System Benefits (USB) charge. These programs are briefly described below.

Residential Central Air Conditioning

In 2010 Montana residential customers earned a rebate of $175/ton[2] for replacing an existing system with Seasonal Energy Efficiency Ratio[3] of 10 (10 SEER) or less with a new 15 SEER or better system.

Residential Rebates for Refrigerators and Freezers

Montana residential customers received $10 rebates on the purchase of ENERGY STAR® rated refrigerators and freezers. However, MDU has cancelled this program.

Commercial Central Air Conditioning

Within a program that was implemented October 1, 2010 Montana commercial customers qualified for rebate if they installed central AC 14.5 SEER or better ($100/ton), central AC 16 SEER or better ($200/ton), or $100/ton for split systems[4] that met efficiency standards based upon unit size – with larger units held to lower efficiency standards.

Commercial Motors

Commercial customers qualify for rebates upon purchase and installation of high efficiency motors or variable speed drives and pumps. A new National Electrical Manufacturers Association (NEMA) Premium® rated motor warrants a $4/horsepower (hp) rebate.

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[2] One ton of refrigeration equals 12,000 Btu/hr, or approximately the power required to melt 2,000 lbs. of ice at 0° C in 24 hours. In the old days, one ton of refrigeration "replaced" delivery of one ton of ice per day.

[3] Seasonal Energy Efficiency Ratio (SEER) equals total cooling season output (in BTU) divided by total electric energy input (in watt-hours). For example, a 10 SEER AC unit should require (on average) 1200 Wh to produce 12,000 Btu of cooling. A 16 SEER unit should require only 750 Wh on average to produce 12,000 Btu of cooling.

[4] Split systems separate the compressor and condenser (hot) functions from the evaporator (cold) function, with the compressor and condenser typically installed outside.

Replacement of an existing motor with a NEMA Premium® motor qualifies for a $15/hp rebate, and the purchase and installation of a variable speed drive fan or pump qualifies for a $30/hp rebate. MDU plans to continue this program through 2013.

Commercial Lighting

Customers who replace low efficiency lighting products with high efficiency products qualify for rebates equal to $0.20/watt saved. Customers may replace existing fixtures with high efficiency fixtures, or design a custom project that may involve system re-configuration, changing fixture types, or de-lamping.

Proposed Additions and Modifications to Montana DSM Programs

MDU proposed to modify several existing DSM programs and to add several new projects in 2012-13. These programs are described briefly below. Following current practice, MDU plans to pay for the Montana programs using USB funding. If lost revenues become significant in the future, MDU may submit a filing in request of lost revenue compensation.

Residential Central Air Conditioning

MDU is proposing to replace the current customer incentives in this program with a two tier incentive system in 2012. Tier I rebates will be $100/ton for existing customers who replace an old central AC unit with a new unit – minimum 14.5 SEER. Tier II rebates will be $200/ton for new units minimum 16 SEER, and will be available for new construction and replacement of existing units. The TRC statistic is less than one for the Tier II programs, but they were included in the DSM portfolio because the programs target a large energy use in the home, and because the portfolio as a whole passes all tests with the programs included.

Residential Window Air Conditioning

Beginning in 2012, a rebate of $50/unit will be available to customers who purchase an ENERGY STAR® rated unit.

Residential Air Conditioning Tune-Up

Beginning in 2012, a rebate of $45/tune-up will be available to existing residential customers. The tune-up must be performed by a qualified contractor, and should include a refrigerant check, computer diagnostics, and air flow corrections.

Residential Thermal Storage with Air-Source Heat Pump

Beginning in 2012, a rebate of $60/kW up to a 38.4 kW maximum will be available to residential customers when they purchase and install a brick electric thermal storage unit with a high-efficiency air-source heat pump.

Residential Lighting

This program is proposed for 2012-13. Rebates are $2/bulb for high efficiency compact fluorescent lighting (CFL) in single family dwellings, up to a 15 bulb maximum.

Residential Air Conditioner Cycling

This program is sweetened with a $50/year incentive for customers who allow AC cycling. MDU will cycle air conditioning using various control strategies for 3-4 hours/day from June 1 to September 30. Interruptions would be limited to a maximum of 40 hours/year. MDU expects to offer customers a limited number of "opt-out" periods. A third party vendor will implement the program for the first two years, after which MDU will maintain the program.

Commercial Lighting

Through 2012, T-12[5] lighting technology will be baseline and T-8 will be high efficiency. Beyond 2012, T-8 technology will be baseline and T-5 will be high efficiency. Outdoor lighting and CFL lighting will not qualify. The program will retain the standard replacement and custom design features of the existing program. Proposed rebates increase to $0.40/watt saved.

[5] Fluorescent tube diameter in eighths of an inch. A T-12 tube is $1^1/_2$" and a T-8 is 1" diameter.

Commercial Central Air Conditioning

MDU is proposing to implement new and modified commercial central AC programs in 2012 or 2013. Rebates on split and packaged systems will decrease to $75/ton. A rebate of $25/ton will be offered on centrifugal chillers and water cooled chillers.

Commercial Partnership Program

This program allows for custom designed projects not included in prescriptive rebate projects. Rebates will be based on expected energy and demand savings. The project must pass the TRC test described below. The project must meet additional criteria, including:

- Installed equipment must be more efficient than industry standard;
- Simple payback must exceed 18 months;
- Rebate may not exceed 50% of incremental cost of equipment;
- Weatherization is not available for rebate;
- Distributed renewables (<50 kW wind, solar) will be considered under net metering;
- Additional measurement and verification of savings may be required; and
- Rebates are available to new construction.

Commercial Demand Response

This program will be offered to commercial and industrial customers, with priority established for customers with loads of 150 kW or higher. The program will be administered by Constellation Energy, who will market and promote the program. Customers will receive capacity and energy payments for shedding non-critical load during events initiated by MDU. Customers will be provided one hour advance notification of events. The maximum event period will be four hours, with fifty total hours of events per year. Payments will be pursuant to negotiated contracts between customers and the aggregator.

<u>MDU Program Evaluation</u>

MDU used five cost tests to evaluate the cost efficiency of each program over its projected life on a stand-alone, discounted cash flow basis. The tests evaluated cost efficiency from the perspective of an average participant, a ratepayer, the utility, society, and total resource costs. Each test provided a test statistic equal to the ratio of total benefit over total cost, so that a

test statistic greater than one implied that the program could be considered cost effective given the tested perspective. Details on calculation and method are provided pp. 5-9 of Volume III.

MDU used the TRC statistic to determine the feasibility of a program. TRC equals the sum of utility and participant costs net of program rebates. Program feasibility requires a TRC statistic greater than one. Table 2 below shows the cost test results for potential Montana DSM programs evaluated in this IRP.

Table 2
Potential Montana DSM Program Evaluation Cost Test Statistics

Program	Participant Cost Test	Utility Cost Test	Societal Cost Test	Ratepayer Cost Test	Total Resource Cost Test
RESIDENTIAL PROGRAMS					
Central AC (14.5 SEER)	2.04	2.69	3.27	1.62	1.72
Central AC (16 SEER - Replace)	1.45	1.36	1.65	0.97	0.87
Central AC (16 SEER - New)	0.90	1.08	1.31	0.94	0.69
Window Air Conditioning	1.16	1.82	2.17	1.50	1.31
Air Conditioning Tune-Up	1.91	1.75	2.60	1.39	1.75
New Construction Bundle	1.34	0.90	1.25	0.70	0.66
Brick Thermal Storage	1.24	7.48	8.17	5.12	4.30
Residential Lighting	5.89	3.11	4.66	1.25	3.11
Residential AC Cycling	NA	1.24	3.85	1.24	2.09
COMMERCIAL PROGRAMS					
Commercial Lighting	2.85	3.96	5.33	2.29	2.54
Commercial Motors - Replacement	2.44	7.27	4.83	2.84	2.27
Commercial Motors - New / On Failure	4.19	6.76	7.92	2.77	3.73
Variable Speed Drives - VFD's	5.50	19.99	13.53	4.98	6.94
Commercial AC - Split Systems	3.53	5.12	7.64	3.03	3.92
Commercial AC - Packaged Systems	1.94	4.44	5.66	3.53	2.90
Commercial AC - Water Cooled Chillers	3.30	2.88	7.40	2.39	3.44
Commercial AC - Centrifugal Chillers	0.97	5.53	4.69	4.88	2.18
Commercial Partnership Program	2.79	4.48	4.26	2.45	2.48
Commercial Demand Response	NA	2.50	3.47	2.50	2.50
Total Portfolio	**3.63**	**7.39**	**4.06**	**5.29**	**2.52**

The "New Construction Bundle" program evaluated above included rebates on lighting, AC, dishwasher, clothes washer, and refrigerator installed in new residential construction. The program is not proposed in this IRP because the program is not cost effective, new construction growth was low in the service territory when the IRP was developed, and experience in another jurisdiction indicated that ala-carte rebates were more popular.

Evaluation of DSM programs generally requires numerous assumptions regarding program design, participation, cost information, and other important details. MDU obtained the majority of this information from a deemed database that NEXANT, an independent third party, developed for the State of Minnesota. The deemed database allows MDU to use a deemed savings approach to evaluate, measure, and verify program savings. MDU argued that using the deemed database provides an appropriate level of verification and low administrative costs. Table 3 below shows deemed lifetime savings, total resource cost, and net benefit for MDU's Montana DSM programs in the period 2011-2013.

Table 3
Expected Number Participants, Project Life, and Lifetime Net Benefit
MDU's Montana Proposed DSM Projects Evaluated in Period 2011-2013

	Number[1] Customers	Project Life[2] (Years)	Energy Savings[3]	Demand Savings	Total Savings	Total Resource Cost[4]	Net Benefit
RESIDENTIAL PROGRAMS							
Central AC (14.5 SEER)	35	14	$ 9,705	$ 22,335	$ 32,040	$ 18,675	$ 13,365
Central AC (16 SEER - Replace)	35	14	11,729	20,572	32,301	37,257	(4,956)
Central AC (16 SEER - New)	15	14	1,973	9,394	11,367	16,519	(5,152)
Window Air Conditioning	15	9	216	1,381	1,597	1,220	377
Air Conditioning Tune-Up	100	5	1,503	7,504	9,007	5,149	3,858
Brick Thermal Storage	12	14	17,951	220,230	238,182	55,374	182,808
Residential Lighting	300	5	1,145	989	2,134	686	1,448
Residential AC Cycling	800	15	-	845,160	845,160	404,508	440,652
Total Residential	1,312		$ 44,222	$ 1,127,565	$1,171,787	$ 539,388	$ 632,399
COMMERCIAL PROGRAMS							
Commercial Lighting	20	18	$ 136,055	$ 129,868	$ 265,924	$ 104,491	$ 161,433
Commercial Motors - Replacement	30	20	53,986	36,059	90,044	39,661	50,383
Commercial Motors - New / On Failure	30	20	13,265	9,064	22,328	5,990	16,338
Variable Speed Drives - VFD's	20	15	139,554	193,283	332,837	47,951	284,886
Commercial AC - Split Systems	20	15	31,925	53,284	85,209	21,749	63,460
Commercial AC - Packaged Systems	17	15	9,979	51,608	61,587	21,242	40,345
Commercial AC - Water Cooled Chillers	3	20	4,893	19,667	24,560	7,139	17,421
Commercial AC - Centrifugal Chillers	3	20	3,130	43,962	47,092	21,628	25,464
Commercial Partnership Program	10	10	249,088	246,113	495,201	199,458	295,743
Commercial Demand Response	8	10	19,661	2,585,669	2,605,330	1,043,758	1,561,572
Total Commercial	161		$ 661,535	$ 3,368,577	$4,030,112	$1,513,067	$ 2,517,045
TOTAL PORTFOLIO	1,473		$ 705,757	$ 4,496,142	$5,201,900	$2,052,455	$ 3,149,445

1. Number of customers expected to participate in the period 2011-2013.
2. Based on the estimated useful life of the energy saving equipment.
3. Savings and Costs are expected lifetime net present values, discounted at 9.61% per annum, equal to MDU's authorized cost of capital.
4. Total Resource Cost equals MDU's expected program costs plus net participant costs. Does not include lost revenue margin.

The deemed database uses generally accepted engineering algorithms and developed operating data to derive deemed savings for each DSM measure. The database also defines

program parameters such as baseline efficiency standards, high efficiency standards, incremental costs, and peak demand factors.

Supply-Side Resources

MDU plans to satisfy the remaining portion of its resource needs through a combination of supply-side measures; including the dispatch of existing resources, construction of additional resources, and purchase of third party capacity.

Existing Baseload Coal Generation

MDU currently owns a combination of lignite and sub-bituminous coal fired baseload resources. These facilities provide MDU with 338 PRC. Lignite tends to have lower energy output and higher moisture content than sub-bituminous. Because lignite has lower economic value than other types of coal, it is typically used only in mine-mouth thermal facilities. Powder River Basin sub-bituminous is a low sulfur coal. Thermal facilities throughout the United States have converted to Powder River Basin sub-bituminous in lieu of retooling with sulfur scrubber technology. Table 4 below shows average ash, sulfur, heat, and moisture contents of lignite used at MDU's Lewis & Clark facility and sub-bituminous coal used at the Big Stone facility, along with typical content ranges from general coal types.

Table 4
MDU Specific and General Coal Comparison

	Ash	Sulfur	Heat (Btu/lb)	Moisture
Lewis & Clark Lignite[1]	12%	1.0%	6,200	39%
Big Stone Sub-Bituminous[2]	7%	0.5%	8,300	20%
Antracite[3]	10 - 20%	0.6 - 0.8%	13,000 -15,000	< 15%
Bituminous[3]	3 - 12%	0.7 - 4.0%	11,000 - 15,000	2 - 15%
Sub-Bituminous[3]	< 10%	< 2%	8,500 - 13,000	10 - 45%
Lignite[3]	10 - 50%	0.4 - 1.0%	4,000 - 8,300	30 - 60%

1. Lewis & Clark lignite coal comes from the Savage Mine near Sidney.
2. Big Stone sub-bituminous coal comes from the Powder River Basin.
3. Data from the Indiana Center for Coal Technology Research.

MDU's lignite plants include Heskett Station Units I and II at Mandan, ND; Lewis and Clark Station at Sidney, MT; and a 25% share of Coyote Station outside of Beulah, ND. The sole sub-bituminous resource is a 22% share of the Big Stone plant located at Milbank, SD. MDU plans to retain all existing coal resources in the baseload portfolio, modified if necessary to comply with expected changes in federal and state regulation.

Proposed Upgrades to Existing Resources

The Environmental Protection Agency (EPA) has proposed or intends to propose several significant changes to existing air quality regulations that aim to reduce emissions at coal-fired electric generation facilities. The regulations include the Regional Haze Rule (Haze Rule) and the Maximum Achievable Control Technology Rule (MACT Rule).

The MACT Rule was published on February 16, 2012. It requires coal-fired electric generators to install maximum achievable control technology pollution controls in plant to reduce hazardous air pollutant emissions. MDU expects the MACT Rule to potentially have significant impact on coal-fired generation, but did not explore this impact within the 2011 IRP. MDU plans to address potential MACT Rule impact in a future IRP.

The EPA first released the Haze Rule in 1999, and revised the rule in 2005 to include guidelines for control technology such as Best Available Retrofit Technology (BART). South Dakota and North Dakota submitted State Implementation Plans (SIP) to EPA that outline strategies to reduce regional haze, and to set reasonable progress goals toward the ultimate goal of no man-made visibility impairment in Class I areas by 2064. Montana did not submit a SIP to EPA, so EPA prepared a Federal Implementation Plan (FIP) to accomplish the task. This FIP does not recommend upgrades to any MDU facilities.

On March 1, 2012, the EPA issued a final rule on the North Dakota SIP. The final rule disapproved some of North Dakota's proposed actions to reduce emissions at the Milton R. Young, Leland Olds, Coal Creek, and Antelope Valley stations. MDU does not own interest in these electric generating stations. MDU's proposed upgrades to Coyote and Heskett II are consistent with the EPA approved North Dakota SIP. The approved SIP does not recommend upgrades at this time for MDU's other North Dakota facilities.

On April 26, 2012 the EPA issued a final rule approving the South Dakota SIP, effective May 29, 2012. The South Dakota SIP recommends upgrades to the Big Stone plant. Proposed upgrades to MDU plants are described below.

Big Stone: Proposed upgrades to the Big Stone coal plant are consistent with recommended treatment filed in the South Dakota SIP, and must be complete within five years of the effective date of approval, May 29, 2012. MDU is proposing an air quality control system (AQCS) to meet federal haze requirements, and activated carbon injection (ACI) in order to meet federal mercury standards. MDU plans to install the upgrades concurrently. The MDU share of expected cost for the projects is approximately $111.1 million for the AQCS and $1.1 million for the ACI. The AQCS will be installed using BART, with expected completion in 2016.

The AQCS project will include selective catalytic reduction (SCR) with separated overfire air (SOFA) to reduce nitrogen oxide (NO_x) emissions, semi-dry flue gas desulfurization to reduce sulfur dioxide (SO_2) emissions, and a baghouse to reduce particulate matter. MDU expects this suite of control technologies to reduce emissions to a level that will not contribute to visibility impairment in several Class I areas including the Boundary Waters Wilderness, Voyageurs, Isle Royale, Badlands, and Theodore Roosevelt National Parks.

Construction is expected to begin in 2013, with equipment tie-ins timed to coincide with a scheduled outage for boiler, turbine, and generator maintenance in 2015. The upgrade is expected to reduce Big Stone PRC from 103.3 MW to 101.4 MW. Big Stone currently provides MDU with a little less than 20% of its required peak capacity.

R.M. Heskett Station Unit 2: MDU has committed to implement limestone injection at Heskett II in order to reduce SO_2 and acid gas emissions. The operation is expected to cost approximately $6.5 million and must be complete in 2017.

Coyote Station: MDU has committed to implement SOFA at Coyote Station to reduce NO_x emissions. As a part owner, MDU will be responsible for 25% of the expected $6 million cost. Coyote Station must demonstrate compliance by July 1, 2018.

Existing Oil and Natural Gas Generation

MDU obtains 88 MW PRC from three natural gas peaking plants and a 2 MW portable diesel unit. The natural gas peaking resources include Glendive Units I and II, and Miles City. MDU will continue to rely upon the capacity provided by these resources. The 1950's vintage Williston combustion turbine facility was recently decommissioned.

Existing Renewable Generation

MDU owns three renewable generation resources; the Diamond Willow and Cedar Hills wind farms, and the waste heat powered Glen Ullin Station 6. MDU obtains 15 MW PRC from these resources. Variable O&M costs for the wind resources are modeled using a $22/MWh production tax credit that will continue to apply for ten years after the year of installation.

For comparison, Table 5 below shows PRC credits and expected 2011 short-run marginal costs associated with each of MDU's generating resources. Big Stone is listed at current PRC of 103.3 MW rather than expected post-AQCS PRC of 101.4 MW.

Table 5
Summary Expected 2011 Short-Run Marginal Generation Costs

Plant Name	Fuel Type	MDU Planning Resource Credits	2011 Energy (MWh)	Heat Rate (Dkt/ MWh)	Fuel Cost ($/Dkt)	Fuel Cost ($/MWh)	Variable O&M ($/MWh)	Fixed O&M ($/MWh)	Combined Fuel and O&M Cost ($MWh)
Big Stone	Sub Bit Coal	103.3	760,240	10.41	$ 2.180	$ 22.70	$ 1.51	$ 3.28	$ 27.49
Coyote	Lignite Coal	96.2	693,450	11.23	1.420	15.94	2.72	3.62	22.28
Heskett I	Lignite Coal	20.8	68,720	15.89	1.600	25.41	6.53	23.60	55.54
Heskett II	Lignite Coal	64.8	354,110	13.72	1.800	24.69	8.15	11.52	44.36
Lewis & Clark	Lignite Coal	52.1	366,480	12.69	1.389	17.63	2.78	7.20	27.61
Glendive I	Natural Gas	29.5	24,760	11.96	5.750	68.74	2.50	5.94	77.18
Glendive II	Natural Gas	36.6	47,840	8.71	5.750	50.04	2.49	5.37	57.90
Miles City	Natural Gas	20.0	11,400	13.85	5.750	79.65	2.46	29.30	111.40
Glendive Diesel	Diesel	1.8	70	11.00	23.110	242.86	-	85.71	328.57
Diamond Willow	Wind	6.4	102,790	NA	-	-	(28.14)	4.56	(23.57)
Cedar Hills	Wind	3.9	66,810	NA	-	-	(30.19)	3.89	(26.30)
Glen Ullin	Waste Heat	4.5	38,900	NA	-	-	6.89	6.63	13.52
Total		439.9	2,535,570						

Existing Purchased Capacity Resources

MDU purchased 105 MW peaking capacity from Northern States Power to cover the 2011 summer season, and 35 MW of capacity in 2011 from Basin Electric Power Cooperative to cover the winter months. Wisconsin Electric Power Company has agreed to sell peaking

capacity to MDU for three years from June 2012 through May 2015. The capacity will equal 110 MW in the first year, 115 MW in the second year, and 120 MW in the third year.

MDU Modeling of Potential Resources

MDU modeled potential capacity and energy resources to address expected shortfalls in the mid to long term outlook. These resources were modeled in the same manner as existing resources using EGEAS. Table 6 below describes modeled resources.

Table 6
Cost and Capacity Summary of New Modeled Resources

Plant Name	Size (MW)	Planning Resource Credits	Available Date	Installed Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Fuel Cost[5] ($/MWh)
Simple Cycle CT	43	33.4	2015	$ 850	$ 15.82	$ 2.00	$ 44.95
Simple Cycle CT	88	82.3	2015	857	12.08	2.00	53.81
Combined Cycle CT	140	132.5	2015	750	15.36	6.00	42.93
Coal	Blocks of 30	27.7	2017	3,900	48.00	2.50	14.55
Wind (Self-Built)	Blocks of 30	6.4	2013	2,400	23.28	2.00	-
Wind (Self-Built) 2012[1]	Blocks of 30	6.4	2011	2,400	23.28	(31.85)	-
Purchased Capacity[2]	Blocks of 10	10.0	2012	-	34.80	113.80	-
Purchased Energy - Wind	Blocks of 25	0.0	2015	-	12.00	49.50	-
Purchased Energy - Wind	Blocks of 25	0.0	2020	-	12.00	51.00	-
Demand Response	Blocks of 12.5	12.5	2015	-	50.04	300.00	-
Big Stone AQCS[3]	105.9	101.4	2015	1,049	32.20	3.19	28.04
Purchased Capacity - 5 yr[4]	155	155.0	2015	-	75.00	107.41	-
Purchased Capacity - 10 yr[4]	155	155.0	2015	-	76.80	107.41	-
Purchased Capacity - 20 yr[4]	345	345.0	2015	-	120.00	65.79	-

1. Variable O&M cost includes the Production Tax Credit.
2. Prices based on the result of 2008 RFP.
3. All costs in 2015 dollars.
4. Prices based on the result of 2010 RFP with costs in 2015 dollars.
5. Assumed natural gas cost is $5.05/Dkt, coal cost is $1.50/Dkt, and coal cost (Big Stone) is $2.66/Dkt.

Expected Future Generation Resources

MDU stated that new coal-fired generation is unlikely to be considered in the foreseeable future due to proposed significant changes to federal air quality, water discharge, and waste management regulations.

MDU is proposing to construct an 88 MW Simple Cycle Combustion Turbine (SCCT) at Mandan, ND, to be available in 2015. MDU expects to obtain 82.3 MW PRC from this facility. After evaluating the costs and benefits of constructing the SCCT at several locations, MDU

chose to build the new peaking plant at Mandan in order to take advantage of existing transmission facilities and the unlimited river water intake at Heskett Station.

The plant will require construction of a 24 mile natural gas delivery line that will tap off of the Northern Border Pipeline; a high pressure transmission line that will allow MDU to build either a heavy duty frame type generator or an aero-derivative type. MDU chose to build the frame type due to its simplicity, low capital and maintenance costs, and operational flexibility.

On April 11, 2012 the North Dakota Public Service Commission issued a certificate of public convenience and necessity for the Mandan SCCT. MDU expects to begin construction in 2013. MDU modeled this SCCT allowing for an extra $3.8 million in environmental permitting costs, as MDU expects that permitting may be complicated by the necessary integration with Heskett Station. A conservative estimate of total capital cost is $75.4 million.

Expected Future Purchased Capacity Resources

MDU recommends the purchase of 10 MW of capacity in 2013 and 20 MW in 2014 through the MISO capacity auction or bilateral agreements.

In June 2010 MDU issued an RFP to acquire capacity and energy for the five year period from June 1, 2015 through May 31, 2020. The RFP expressed preference for unit specific resources over which MDU would have full scheduling and dispatch authority.

Although this RFP did not lead to a capacity or energy purchase for this period, MDU did use information and prices provided in responses to set values for three options used in the least cost modeling procedure. Two of the options represent purchased capacity from a 155 MW SCCT at five and ten year terms, beginning in 2015. The required fixed cost obligation is stated to be $75.00/kW-year in 2015 dollars for the five year term, and $76.80/kW-year for the ten year term. The variable cost obligation equaled $107.41/MWh for both terms.

The third option represented a capacity purchase of 345 MW for a twenty year term, 290 MW from a combined cycle combustion turbine and 55 MW from an SCCT. The total fixed cost for the capacity equaled $120/kW-year, and the variable cost was $65.79/MWh. MDU did not find any of these options to be least cost resources.

Supply Side Risk Analysis

MDU performed risk or sensitivity analysis of supply side measures through modifying key inputs to test whether the results were robust to reasonable variation in the input values. For instance, MDU modeled a carbon tax that was applied to emissions from existing and proposed coal and natural gas fired units, and energy purchases from the MISO market. MDU modeled two levels of tax, $30/ton and $50/ton. MDU modeled the tax to estimate impacts to customers and changes in the optimal resource mix in the event a carbon tax becomes law. At $30/ton the net present value (NPV) of the revenue requirement increased 35% over the base case, and at $50/ton the revenue requirement NPV increased 58% over the base case.

MDU modeled variability in the price of natural gas. The base case delivery price began at $5.05/dekatherm (Dkt) in the base year 2010, with 3.5% annual escalation. From this base MDU developed high and low gas price scenarios. The high price began in 2010 at $8.05/Dkt and the low price began at $4.05/Dkt. The high price scenario caused a shift to wind and coal in later years to offset the high gas price, and a 1.0% increase in NPV of required revenue from the base case. The low price scenario showed 50 MW less wind energy selected than the base case, and a decrease of 2.7% in required revenue NPV.

MDU modeled a high environmental cost scenario that included the $30/ton tax on carbon emissions described above, combined with a $1.25/MWh adder for mercury control and $3.00/MWh for solid waste regulation on coal fired units. This scenario also included the high gas price beginning at $8.05/Dkt, under the assumption that additional coal fired regulation would cause fuel switching and increase the demand for natural gas. The least cost plan selected under this case contained more wind in the resource mix, and showed a 43% increase in NPV of the revenue requirement over the base case.

Finally, MDU modeled high combustion turbine (CT) costs and high Big Stone AQCS cost. The high CT cost model assumed a 20% increase in capital and O&M costs for future combustion turbines. The selected least cost plan under this scenario changes from the base case to include an addition of 30 MW of coal fired baseload in 2025, and an increase of 2.3% in revenue requirement NPV. In the high Big Stone AQCS model, the project remained a part of the selected least cost portfolio even as the assumed project cost nearly doubled. The least cost portfolio changed from the base case only to include additional 30 MW of coal fired baseload in 2028, and to reflect a 3.6% increase in revenue requirement NPV.

Table 7 below lists the least cost portfolio additions for the studied scenarios.

Table 7
Least Cost Plans for the Studied Scenarios

Year	Base	Base w/New DSM Package	Low Gas Price $1 Down	High Gas Price $3 Up	$30 Carbon Tax	$50 Carbon Tax	$30 Carb High Gas Add'l Env.	High CT Capital Cost	High Big Stone AQCS Cost	Low Growth	High Growth
2012											2 Purchase
2013	Purchase	Purchase	Purchase	Purchase	Purchase	Purchase	Purchase	Purchase	Purchase		3 Purchase
2014	2 Purchase	Purchase New DSM	2 Purchase	2 Purchase	2 Purchase	2 Purchase	2 Purchase	2 Purchase	2 Purchase		5 Purchase
2015	2 CT43 2 DSM CT88 AQCS	2 CT88 2 DSM AQCS	2 CT43 2 DSM CT88 AQCS	2 CT43 2 DSM, Wind CT88 AQCS	2 DSM 2 CT88 AQCS 5 Wind	2 DSM 2 CT88 AQCS 5 Wind 2 Wind-SB	2 CT43 2 DSM CT88 AQCS 5 Wind	2 CT43 2 DSM CT88 AQCS	2 CT43 2 DSM CT88 AQCS	2 CT43 2 DSM AQCS	2 CT88 2 DSM AQCS 2 Wind
2016											CT43
2017											CT43
2018	CT43		CT43	CT43			CT43	CT43	CT43		CT43
2019											
2020	4 Wind	4 Wind	2 Wind	5 Wind	CT43 5 Wind	5 Wind	5 Wind	4 Wind	4 Wind		CT43 5 Wind
2021		CT43				CT43					CT43
2022	CT43		CT43	CT43			Base Load	CT43	CT43		CT43
2023					CT43						CT43
2024		CT43					Base Load				CT43
2025	CT43		CT43	Base Load		CT43		Base Load	CT43		CT43
2026											CT43
2027		CT43			CT43		Wind-SB				CC140
2028	CT43		CT43	CT43		CT43	CT43	CT43	Base Load		CT43
2029											CT43 Base Load
2030					2 Wind-SB						CT43
NPV[1]	$ 3,724	$ 3,616	$ 3,624	$ 3,759	$ 5,014	$ 5,876	$ 5,317	$ 3,809	$ 3,857	$ 2,529	$ 5,990

1. Total Net Present Value shown in millions of dollars.
"CT43" is a 43 MW (33.4 PRC) simple cycle CT (SCCT); "CT88" is an 88 MW (82.3 PRC) SCCT; "CC140" is a 140 MW (132.5 PRC) combined cycle CT;
"Base Load" is a 30 MW (27.7 PRC) coal-fired generator; "DSM" is 12.5 MW (12.5 PRC) of DSM; "AQCS" is the proposed Big Stone AQCS;
"Purchase" is 10 MW (10 PRC) of purchased capacity; "Wind" is 25 MW of purchased wind energy;
"Wind-SB" is 30 MW of self-built wind; "New DSM" is the proposed new DSM package.

MDU recommends a course through 2016 that varies from the base case least cost analysis. For instance, MDU is not planning to construct two 43 MW combustion turbines in 2015. In the 2011-2016 interval MDU is committed to:

- Pursue the purchase of 10 MW of capacity in 2013 and 20 MW in 2014 through the MISO capacity auction or bilateral agreements;
- A 25 MW third party demand response program that is expected to provide 5 MW of capacity in 2012, 15 MW in 2013, and 25 MW total demand response in 2014;
- Implement DSM programs expected to provide 24.5 MW of capacity and annual energy savings of 7.3 MWh by 2015;

- Install the Big Stone AQCS; and
- Construct the 88 MW SCCT at Mandan.

MDU believes that this course of action will best meet customer requirements over the five year planning horizon. MDU has not committed to a course of action beyond 2016, but the analysis described above may inform later decisions.

Summary of DEQ Comments

DEQ filed comments on the IRP in October 2011. Many of the comments were requests for clarification of IRP statements, particularly with respect to the description of DSM energy and savings projections. DEQ was also concerned that MDU was setting its DSM expectations high compared with modest recent DSM achievements. For instance, DEQ requested explication of expected energy savings increases from 1.0 MWh in 2011 to 2.7 MWh in 2012, 5.0 MWh in 2013, and 7.3 MWh in 2015. DEQ also requested that MDU:

- Propose a plan to amend its general tendency to undershoot energy and capacity requirements as expressed on p.14 of Volume I;
- Explain projected growth in capacity and energy with direct reference to expected future growth in the Bakken oil fields and the proposed Keystone XL Marketlink;
- Note that the expected additional load due to completion of Keystone XL will not come on-line in June 2012;
- Address the variation in annual energy losses as well as the ten-year average;
- Explain why energy efficiency improvements throughout the society would not cause the average energy use per customer to flatten out and decline by 2030, rather than increase through 2030 as shown on p.27 of Volume II;
- Clarify the estimation procedure of the low-growth and high-growth demand series shown on p.32 of Volume II;
- Provide precise definitions of "Demand Response" and "Conservation" as used throughout Volume III, and the difference between the terms;
- Explain why the proposed DSM package includes "New Construction Bundle" although the ratio of total savings benefit to TRC is less than one;
- Question the effect of a $10 rebate offered on purchase of a refrigerator;
- Clarify the choice of DSM programs for Montana and North Dakota;

- Clarify the term “Net New DSM” used on pp.36-37 of Volume III;
- Clarify the contribution of existing coal-fired and renewable generation to MDU energy requirements;
- Explain why customers are described on p.25 of Volume IV as being vulnerable to natural gas and energy market pricing for 20% of their energy needs, while customer exposure to future carbon controls is not addressed;
- Expand upon the potential of the MISO capacity market to satisfy expected needs.

DEQ concluded that the IRP should be used to methodically review needs and alternative measures to satisfy needs, and to evaluate expected costs and risks of the alternative measures. DEQ recommended that MDU continue to develop DSM analysis and investment, focusing in particular on measures that reduce system peak. DEQ also recommended that MDU investigate MISO supply side market opportunities more thoroughly.