STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. **Case No. PU-10-124**
Electric Rate Increase
Application

ORDER ON SETTLEMENT

June 8, 2011

Appearances

Commissioners Tony Clark, Brian P. Kalk, and Kevin Cramer.

Daniel S. Kuntz, Associate General Counsel, MDU Resources Group, Inc., 918 East Divide Avenue, Bismarck, North Dakota, Attorneys for the Applicant MDU Resources Group.

Annette Bendish, Legal Counsel, Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota, Public Service Commission Advocacy Staff through July 31, 2010.

Richard J. Savelkoul, Attorney, Felhaber Larson Fenlon & Vogt, 444 Cedar Street, Suite 2100, St. Paul, Minnesota, Public Service Commission Advocacy Staff from October 12, 2010.

Illona A. Jeffcoat-Sacco, General Counsel and Mark E. Gruman, Legal Counsel, Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota, Public Service Commission Advisors.

Scott Skokos, Missouri Valley Resource Council, Suite 8, 103 - 1/2 South Third Street, Bismarck, North Dakota, for Intervenor Missouri Valley Resource Council.

James D. Roaché, 707 First Street Southwest, Crosby, North Dakota, Intervenor, appearing *pro se*.

Al Wahl, Administrative Law Judge, Office of Administrative Hearings, 1701 North Ninth Street, Bismarck, North Dakota 58501-1882, as hearing officer.

Preliminary Statement

On April 19, 2010, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU) filed an application with the North Dakota Public Service Commission (Commission) seeking an annual revenue increase of $15,396,303 or 14 percent of total revenues.

On May 12, 2010, the Commission suspended the tariff revisions filed in MDU's Application.

On June 16, 2010 Advocacy Staff filed a Partial Settlement Agreement between MDU and Advocacy Staff relating to overall rate of return on MDU's rate base, including the return on equity component, for use in this proceeding. This Settlement Agreement was also received as MDU Exhibit 2.

Also on June 16, 2010, the Commission issued an Order on Interim Rates approving MDU's proposed interim rate increase.

Also on June 16, 2010, the Commission issued a Notice of Hearing and Notice of Public Input Sessions, scheduling public input sessions for July 12 and 13, 2010, and a formal hearing to begin November 8, 2010. The Notice specified the following issues to be considered:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

On July 6, 2010, MDU filed an amendment to its application eliminating from the application the Big Stone II generation development costs that were addressed in Case No. PU-09-733.

On July 12, 2010, and July 13, 2010, public input sessions were held via interactive television in Bismarck, Dickinson, and Williston, North Dakota.

On August 24, 2010, the Commission issued an Order granting the Petition to Intervene of James D. Roaché.

On October 4, 2010, the Administrative Law Judge issued an Order granting the Petition to Intervene of Harvey A. Christian as a customer of MDU.

On October 25, 2010, the Administrative Law Judge issued an Order granting the Petition to Intervene of Missouri Valley Resource Council (MVRC).

On November 1, 2010, Scott Skokos filed a Petition to Practice Law Before the North Dakota Public Service Commission in Case No. PU-10-124 for permission to represent MVRC. On November 2, 2010, Scott Skokos filed an amended Petition to Practice Law Before the North Dakota Public Service Commission, and on November 5, 2010, Mr. Skokos filed a Second Amended Petition to Practice Before the North Dakota Public Service Commission.

On November 5, 2010, Harvey A. Christian advised the Administrative Law Judge that he was abandoning his intervention.

On November 8, 2010, in response to the petitions of Mr. Skokos, the Administrative Law Judge issued an Order Granting Petition to Practice before Commission.

On November 8, 2010, during the hearing, a second Partial Settlement Agreement between MDU and Advocacy Staff was received as MDU Exhibit No. 3.

The Commission held a hearing on the application on November 8, 9, 10, and 12, 2010, in the Commission Hearing Room.

On March 14, 2011, MDU filed a third partially executed settlement agreement executed by MDU and Advisory Staff. Attached to the March 14, 2011 settlement agreement was an Additional Wind Investment Analysis prepared by MDU.

On March 15, 2011, MVRC filed a copy of the Settlement Agreement executed by MVRC.

On March 24, 2011, the Commission issued a Notice of Hearing and Notice of Intent to Consider Information Not Presented at a Hearing. The Notice indicated that the Commission could consider the Investment Analysis submitted by MDU as an attachment to the Settlement Agreement filed the same day. The Notice set a hearing on May 5, 2011, and specified the following issue to be considered:

> Whether the Settlement Agreement should be approved and adopted by the Commission for the determination of MDU's application to increase it's rates for electric utility service?

On May 5, 2011, the Commission held a formal hearing to consider the third Settlement Agreement.

Also on May 5, 2011, a fully executed copy of the third settlement agreement was received as MDU Exhibit 29.

Discussion

MDU originally proposed to increase its rates for electric utility service to provide $15,396,303 additional annual revenue, or a 14 percent increase over current rates. The proposed increase was based on a 2010 test year, a 9.09 percent return on MDU's rate base, including a 12 percent return on the equity component. MDU identified the primary drivers of the need for a rate increase as increased investment in facilities, including Cedar Hills and Diamond Willow wind generation projects, and a significant loss of wholesale margins.

The interim rate increase implemented by MDU provides $7,617,000 additional annual revenue until final rates are approved by the Commission. The interim rate increased revenue from each customer class by approximately 7 percent and collected the increased revenue using an increased per KWh use charge.

MDU's July 2010 application amended its rate increase application, eliminating from the application the Big Stone II generation development costs that were settled in another case, Case No. PU-09-731. The July 2010 application amendment reduces MDU's proposed rate increase from $15,396,303 to $13,300,000.

In the June 2010 settlement agreement, MDU and Advocacy Staff recommend a 10.75 percent return on the equity component of cost of capital. They also recommend an earnings sharing mechanism by which MDU would refund to customers revenues corresponding to 50 percent of earnings above a 10.75 percent return on equity. The settlement of these matters would reduce MDU's proposed rate increase from $13,300,000 to $11,519,000.

The November 2010 settlement agreement between MDU and Advocacy Staff proposed an 8.736 percent overall rate of return on MDU's rate base and also proposed resolutions for issues regarding:

- Margin sales and sales for resale,
- Aircraft,
- Customer deposits,
- Maintenance costs for the Big Stone and Coyote generating facilities,
- Transmission WAPA costs,
- Storm damages,
- Deferred generation costs, treatment of costs associated with refinancing certain debt at lower interest rate,

- Labor costs,
- Accounting system and jurisdictional allocation process,
- Minimum standard rate case filing requirements, and
- Corporate allocation and affiliate transactions.

The November 2010 settlement would further reduce MDU's proposed rate increase from $11,519,000 to $10,299,000. Intervenor MVRC and Intervenor Jim Roaché did not sign this settlement.

MDU testimony at the November 8, 2010 hearing reflected additional adjustments of investment and expenses related to the wind generation projects. These adjustments would reduce MDU's proposed rate increase from $10,299,000 to $8,825,000.

The March 2011 settlement agreement between MDU, MVRC, and Advocacy Staff, along with the June 15, 2010 and November 8, 2010 settlement agreements, proposes the resolution of all contested issues in the rate proceeding. Intervenor Jim Roaché did not sign this settlement. The settlement recommends that MDU be allowed to file rates for electric utility service to provide an annual test year revenue increase of $7,614,000 or 6.9 percent. The settlement agreement proposes the resolution of additional issues regarding:

- Cedar Hills and Diamond Willow wind projects,
- Employee compensation,
- Board of Director's fees and expenses,
- Renewable energy credits,
- Rate design,
- Time-of-day rates, and
- Customer bill form.

The rate increase would be an approximately equal percent increase to each customer rate class. The rate impact for an individual customer in the residential rate class would vary dependent upon the customer's electric usage.

Having considered this matter, the Commission finds the June 2010, November 2010, and the March 2011 Settlement Agreements are reasonable and should be approved. The Commission finds the return on rate base and the return on equity component proposed by the March 2011 Settlement Agreement is reasonable, however, the environment in which utilities operate continues to change and the Commission intends to investigate the factors affecting return levels for North Dakota utilities and investigate market and regulatory changes that affect those factors.

MDU testified that it has an unfunded pension liability that may need to be addressed in a future rate proceeding. Given that possibility, the Commission provides the following thoughts so that the company can make decisions that align its interests with its customer service obligations.

1. A utility's rates must be just and reasonable. N.D.C.C. § 49-05-06. Just and reasonable rates must reflect only prudent costs. Prudent costs are those necessary and sufficient for efficient utility service. Those costs include the cost to attract and maintain a skilled workforce and costs associated with compliance with federal pension law.
2. Pension costs are affected by many factors. Some of these factors are within the utility's influence, including how it compensates its employees (e.g. salary levels; and the mix of salary, pension contributions and other benefits, including when and why it chose to move from defined benefit to defined contribution).
3. Other factors affecting pension costs are not within the utility's influence. These factors include the nation's economy, labor markets, stock market values and federal pension law.
4. The dividing line between factors within and outside the company's influence is not always clear. That lack of clarity complicates, but in no way eliminates, the Commission's obligation to ensure that the ratepayers bear only reasonable pension costs.
5. While just and reasonable rates may include only prudent costs, prudence does not guarantee cost recovery. There is no constitutional guarantee that a commission will include all prudent costs in rates. See Duquesne Light Co. v. Barasch, 488 U.S. 299, 307-16 (1989). It is lawful for a utility to bear some business uncertainties associated with prudent actions, because the utility's superior knowledge means it is in the best position to expose itself to these risks and manage them.
6. The Commission will apply these principles in reviewing any future utility request to reflect pension costs in rates. On making any such request, a utility should be prepared to:
   a. explain all causes of the unfunded liability;
   b. distinguish those factors over which it has influence, from those factors which are outside its influence;
   c. explain how it managed those factors over which it had influence;
   d. for those factors over which it did not have influence, explain how it anticipated those factors, what actions it took, both in advance and after the fact, to mitigate their effect; and
   e. explain to the commission its understanding of best practices in managing pension costs and how its actions compared to those best practices.

Having considered this matter, the Commission issues the following:

Order

1. The Settlement Agreements filed June 16, 2010, November 8, 2010 and March 15, 2011, a copy of each of which is attached to this Order, excluding the Additional Wind Investment Analysis that was attached to the March 15, 2011 Settlement Agreement, are made a part of this Order and are APPROVED.

2. MDU is authorized to implement an increase in its electric rates sufficient to produce a total annual revenue increase of not more than $7,614,000 in accordance with the rate design provided in the March 11, 2011 Settlement Agreement.

3. MDU shall file compliance tariffs consistent with this Order and the Settlement Agreements at least 30 days prior to the effective date of the rates.

PUBLIC SERVICE COMMISSION

Voting - Nay		
Kevin Cramer	**Tony Clark**	**Brian P. Kalk**
Commissioner	**Chairman**	**Commissioner**

Public Service Commission
State of North Dakota

COMMISSIONERS

Kevin Cramer
Tony Clark
Brian P. Kalk

Executive Secretary
Darrell Nitschke

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June 16, 2010

Darrell Nitschke
Executive Secretary
600 East Boulevard, Dept 408
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rate Increase
Application
Case No. PU-10-124

Dear Mr. Nitschke:

Enclosed is a Partial Settlement Agreement reached between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. and the North Dakota Public Service Commission Advocacy Staff in the above proceedings.

The Parties ask the Commission to approve the Settlement Agreement and are available to provide any additional information the Commission may require.

Please contact us with any questions.

Sincerely,

Annette Bendish
Counsel for Advocacy Staff

Enclosure

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Electric Rate Increase Application	Case No. PU-10-124

PARTIAL SETTLEMENT

This Partial Settlement is entered into this 15th day of June, 2010, by and between the North Dakota Public Service Commission advocacy staff ("Staff") and Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("Montana-Dakota"), (collectively, the "Parties"). This Partial Settlement sets forth the positions and recommendations of the Parties relating to the overall rate of return on the Company's rate base ("ROR"), including the return on equity ("ROE") component, for ratemaking purposes for the Company in the above-captioned proceeding. The Parties' recommendations are consistent with the public interest and will result in just and reasonable rates for the Company's retail electric operations in North Dakota.

TERMS OF SETTLEMENT

Reduced Return on Equity

The Parties agree that a 8.699 percent ROR is appropriate for determining the Company's revenue requirements in this proceeding. The Parties also agree to, and recommend the North Dakota Public Service Commission (the "Commission") approve in its final order, a ROE of 10.75 percent. The components of the recommended ROR are shown on Attachment 1 hereto.

The reasonableness of an 8.699 percent ROR and 10.75 percent ROE are supported by various considerations, including but not limited to the following:

- The 8.699 percent ROR is less than the 8.8 percent ROR approved in the December 31, 2008 final order for Xcel Energy in its most recent electric rate case, Case No. PU-07-776, and is based on the same 10.75 percent ROE as approved in that case.
- The 8.699 percent ROR is only slightly greater than the 8.62 percent ROR, and is the same 10.75 percent ROE, as approved by the Commission in Otter Tail Power Company's recent electric rate case, Case No. PU-08-862.

Customer Refunds for Earnings Above Threshold

The Parties agree to, and recommend that the Commission approve, an earnings sharing mechanism that will result in customer refunds if the Company's net income from electric utility service in North Dakota exceeds a 10.75 percent ROE.

If the Company earns in excess of 10.75 percent ROE as reflected in the annual report of jurisdictional regulated electric earnings for any fiscal year prior to either: (i) January 1, 2013; or (ii) the base period included in the Company's next electric general rate case (whichever occurs sooner); the Company will refund to customers revenues corresponding to 50 percent of earnings above 10.75 percent ROE.

Earnings sharing credits will be applied to customer accounts as soon as practical after July 1, following the annual report of electric earnings for the given fiscal year has been filed with the Commission (typically on April 15). A refund would be administered as a one-time bill credit.

OTHER TERMS AND CONDITIONS

Basis of Settlement

It is agreed this Partial Settlement is a negotiated Settlement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric general rate case and as required in tracking adjustment mechanisms that may be approved by the Commission, this Partial Settlement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

Effect of the Partial Settlement

It is understood and agreed that all offers of settlement and discussions related to this Partial Settlement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. This Partial Settlement shall not be deemed to prevent either the Staff or the Company from responding to positions taken by other intervenors in this proceeding; provided, however, that the Parties agree that such response shall not alter the positions and recommendations set forth in this Partial Settlement.

Effective Date

This Partial Settlement of Facts shall be effective as of the date hereof. It may be executed in counterparts.

Dated this 15th day of June, 2010.

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.

By: ______________________
Dennis L. Haider
Executive Vice President – Regulatory,
Gas Supply and Business Development

Dated this 15th day of June, 2010.

North Dakota Public Service Commission Staff

By: ______________________
Annette M. Bendish
Counsel to Advocacy Staff

ATTACHMENT 1

STIPULATED CAPITAL STRUCTURE AND OVERALL RATE OF RETURN

	Amount	Percent of Total Capitalization	Cost of Capital	Weighted Cost of Capital
Long-Term Debt	$280,502,591	42.232%	6.845%	2.891%
Short-Term Debt	20,829,409	3.136%	2.535%	0.079%
Preferred Stock	15,500,000	2.333%	4.590%	0.107%
Common Equity	347,368,141	52.299%	10.75%	5.622%
Total Capitalization	$664,200,141	100.000%		8.699%

MDU RESOURCES
GROUP, INC.

1200 West Century Avenue
Mailing Address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000

Direct Dial No.
(701) 530-1016
(701) 530-1731 (fax)

March 11, 2011

Darrel Nitschke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

Re: Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Electric Rate Increase
Application
Case No. PU-10-124

Dear Mr. Nitschke:

Enclosed for filing are the original and seven copies of a Settlement Agreement between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., and the North Dakota Public Service Commission Advocacy Staff regarding the issues in the above-referenced proceeding. Montana-Dakota understands the Missouri River Resource Council is considering whether it will join the Settlement Agreement and will advise the Commission and parties upon reaching a decision. Mr. Roache' has previously indicated his opposition to the Settlement Agreement.

Attachment 1 to the Settlement Agreement consists of generation resource modeling information presented by Montana-Dakota Utilities Co. and considered by the parties during their settlement discussions. Attachment 1 is offered pursuant to N.D.C.C. § 28-32-25 solely for the purpose of the Commission's consideration of the Settlement Agreement. If the Commission determines to avail itself of the information presented in

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Settlement Agreement
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Daniel S. Kuntz

Attachment 1 in its consideration of the Settlement Agreement, Montana-Dakota will provide witnesses for examination and cross-examination regarding the information.

Sincerely,

Daniel S. Kuntz
Associate General Counsel

DSK/djv
Enclosure
cc: Illona Jeffcoat-Sacco
Mike Diller
Jim Roche'
Scott Skokos

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co.
a Division of MDU Resources Group, Inc.
Electric Rate Increase Application

Case No. PU-10-124

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 11th day of March, 2011, by and among the North Dakota Public Service Commission Advocacy ("Staff"), Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("Montana-Dakota" or "Company") and Missouri Valley Resource Council (collectively the "Settlement Parties"). The Settlement Parties agree this Settlement Agreement, if approved by the Public Service Commission ("Commission"), in conjunction with the prior settlement agreements between Staff and Montana-Dakota, resolve the issues in the above-captioned proceedings in a manner consistent with the public interest.

BACKGROUND

This proceeding involves Montana-Dakota's request to increase its retail rates in North Dakota to allow it to earn a reasonable return on equity.

Montana-Dakota's initial rate increase request was revised to $11,519,000 or approximately 10 percent, following a partial Settlement Agreement between the Company and Staff dated June 15, 2010. An interim rate increase of $7,617,000 or 7.04 percent was subsequently approved effective June 18, 2010.

Montana-Dakota identified the primary drivers for the need for its requested rate increase as increased investment in facilities, including the Cedar Hills and Diamond Willow wind generation projects, and the significant loss of wholesale sales margins.

By Settlement Agreement dated June 15, 2010, Montana-Dakota and Staff agreed on the values for Cost of Debt, Return on Equity, and overall Rate of Return for purposes of determining a test year revenue requirement in this proceeding. The June 15, 2010 settlement agreement was modified by a settlement agreement dated November 8, 2010, which also resolved issues regarding: (1) margin sales and sales for resale; (2) aircraft; (3) customer deposits; (4) maintenance costs for the Big Stone and Coyote generating facilities; (5) transmission WAPA costs; (6) storm damages; (7) deferred generation costs; (8) treatment of costs associated with refinancing certain debt at lower interest rate; and (9) labor costs. The November 8 agreement also included provisions regarding issues to be addressed by Montana-Dakota prior to its next general rate case including a potential study to be completed by a mutually agreed upon independent consultant regarding Montana-Dakota's accounting system and jurisdictional allocation process, minimum standard rate case filing requirements, and corporate allocations and affiliate transactions. The settlement of these matters reduced the Company's request by $1,220,000. Montana-Dakota's resulting rate request after adjustment for the June 16, 2010 and November 8, 2010 partial settlements was $10,299,000.

Montana-Dakota's rebuttal testimony presented at hearing reflected additional adjustments of investment and expenses related to the wind generation projects as a result of the enactment of the Small Business Jobs Act on September 27, 2010; a reduction in the depreciation rate for the 2010 wind projects from 5.17 percent to 5.0 percent; and the correction of an error in the original filing related to accumulated deferred income taxes. These adjustments lowered the revenue requirement associated with the wind generation projects from $8,582,000 to $7,108,000. The total rate increase request, as effectively reduced by the settlements and adjustments for the wind projects, was $8,825,000 or 7.7 percent.

The Commission held a hearing on the Company's application on November 8-12, 2010, in the Commission Hearing Room. An Administrative Law Judge presided at the hearing. The Commission heard testimony regarding the proposed settlements as well as the remaining contested recommendations of the Staff to exclude from the Company's test year revenue requirement: (1) the investment and expenses associated with the Company's wind generation projects, (2) sixty percent of the Company's employee incentive compensation expenses, and (3) fifty percent of the Company's Board of Director's fees and expenses.

Following the filing of post-hearing briefs, the parties, as well as the Commission Advisory Staff, met for further settlement discussions. During those meetings the Company presented the results of generation resource modeling using the model and inputs that were used for development of the Company's 2009 Integrated Resource Plan ("IRP"). The modeling results presented by the Company provided a net present value comparison over 20 years of the difference between least cost generation resource scenarios, with and without the availability of the Big Stone II coal generation project, and scenarios in which the Diamond Willow and Cedar Hills wind generation projects were considered committed resources, also with and without the availability of the Big Stone II coal generation project. Upon request of the Staff, the Company provided additional modeling results after changing input values for market prices to test the sensitivity of the net present value differences to changes in market prices. The results of the modeling are attached hereto as Attachment 1. In each instance, the delta between the 20 year net present value of the least cost generation resource scenarios without the Big Stone II project (which has been cancelled) and generation resource scenarios with the Diamond Willow and Cedar Hills wind projects as committed resources was less than two percent (less than 3.5 percent with the Big Stone II generation project).

In consideration of the record evidence of this proceeding, the post-hearing arguments and briefs of the parties, the modeling results provided by the Company, and further discussions by the parties, the parties agree to the following subject to approval of this Settlement Agreement by the Commission:

1. Revenue Requirement Increase. The parties agree to final rates in this proceeding providing for an annual test year revenue requirement increase for the Company of $7,614,000 which equals that of the annual interim revenue requirement increase previously approved in this proceeding.

2. Rate Design. The Company shall file revised rates implementing the test year revenue requirement increase based upon the rate design principles and changes proposed by the Company, including the changes to the Thermal Energy Storage Rate 13 presented at the technical hearing and introduced as Exhibit MDU-26. The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement within 10 days after the issuance of a final order by the Commission.

3. Bill Form. Montana-Dakota will implement a new customer bill form with a target implementation date of December 31, 2012. This target date is subject to the

Company's conversion to a new customer information and billing system, currently underway, that meets all necessary metrics for implementation. Updates will be provided to the Commission and Staff as implementation progresses with any known delays reported to the Commission in a timely manner.

4. Time of Day Rate Study. Montana-Dakota will confer with Staff and, following review and approval by Staff, issue a request for proposals ("RFP") for a study on the cost effectiveness of implementing mandatory time of day rates applicable to its North Dakota electric system customers. Montana-Dakota will review the RFP results with the Commission Staff along with the Company's recommendations. Upon approval by the Staff of the scope and cost of a study, Montana-Dakota will commission the time of day rate study. Montana-Dakota will be allowed to recover the cost of the study, as well as the cost of the study provided in the settlement agreement of November 8, 2010, to the extent the Company's 2011 ROE, after considering the cost of the studies, is less than 10.75 percent. The costs shall be recovered as a separate charge included in the Fuel Clause Adjustment Rate 58 over a one-year period. The costs shall be recovered on a per kwh basis and shall be calculated by dividing the appropriate costs by the projected kwh sales volumes for the period the charge shall be in effect.

5. Renewable Energy Credits. Montana-Dakota will allocate the December 31, 2010 renewable energy credit balance and all future generated renewable energy credits (RECs) to each jurisdiction based on the kwh jurisdictional allocation factor. Renewable energy credits allocated to North Dakota will be sold at the

market price for the RECs with any proceeds flowed to customers through the Fuel Cost Adjustment Rate 58.

6. Basis of Settlement Agreement. It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

7. Effect of the Settlement Negotiations. It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

8. Applicability and Scope. This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in the Rate Design section of this Settlement Agreement.

9. Prior Settlements. The prior Settlement Agreements filed in this proceeding between the Company and Staff shall remain in effect and subject to approval by the Commission except to the extent modified by this Settlement Agreement.

10. Modification. If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either the Company or the Staff files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

CONCLUSION

The Settlement Parties have agreed to the foregoing terms to resolve the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Settlement Parties, are in the public interest and will result in reasonable electric issues. For these reasons, the Settlement Parties urge the Commission to approve the Settlement Agreement.

Dated this 11TH day of March 2011.

Montana-Dakota Utilities Co.,
a Division of MDU Resources Group, Inc.

By: [signature]
DAVID L. GOODIN
Title: PRESIDENT & CEO

Dated this 11th day of March 2011.

North Dakota Public Service Commission Staff

By: [signature]
Mike Diller
Dir. of Econ. Reg.

Missouri River Resource Council

By: ______________________

Montana-Dakota Utilities Co.

Additional Wind Investment Analysis

North Dakota Rate Case No. PU-10-124

Overview

This additional analysis will look at the investments Montana-Dakota Utilities Co. (Montana-Dakota) made in Diamond Willow I, Diamond Willow II, and Cedar Hills to quantify the cost differential between resource portfolio additions based strictly on the least cost option and the Company's investment in renewable wind resources, using the 2009 North Dakota Integrated Resource Plan (2009 IRP).

Study Methodology

This analysis utilizes the same computer modeling tool that Montana-Dakota used in the 2009 IRP. This modeling tool was developed by Electric Power Research Institute (EPRI) and is named Electric Generation Expansion Analysis System (EGEAS). EGEAS is a resource planning software package which optimizes future supply-side resource selections based on needs, available resources, and economic criteria.

The 2009 IRP model provides an evaluation of the Company's need and the economic conditions and alternatives that were available to Montana-Dakota at the time of the decision to invest in the Diamond Willow II and Cedar Hills Projects. In the 2009 IRP, Diamond Willow I was already in-service and Diamond Willow II and Cedar Hills were considered as committed resources in Montana-Dakota's least cost plan.

To perform the analysis, the 2009 IRP model was adjusted to remove the Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects as in-service or committed resources. New site specific wind alternatives were created for the EGEAS model that reflected the actual installed costs of Diamond Willow I, Diamond Willow II, and Cedar Hills. Additional generic wind generation projects in 30 MW blocks were available for selection in the model based on original modeling assumptions. The site specific wind alternatives included in the model are contained in the following table.

Site Specific Wind Alternatives	**Size (MW)**	**Capital**	**Capital per kW**	**In-service Available**
Diamond Willow I	19.5	$39.4 Mill	$2,020	Jan. 2009
Diamond Willow II	10.5	$25.4 Mill	$2,419	June 2010
Cedar Hills	19.5	$47.4 Mill	$2,431	June 2010

All other model inputs from the 2009 IRP for existing, committed, and alternative resources remain unchanged and are contained in Attachment A. Midwest ISO energy prices in the EGEAS model used for the 2009 IRP were $60 per MWh on-peak and $40 per MWh off-peak escalated at three percent (3%) per year in 2008 Dollars.

Scenarios

Two different scenarios were modeled as part of this analysis. In the first scenario the EGEAS model developed the least cost plan based on available resources assuming all site specific wind alternatives were available resources to the model and not committed or in-service projects. The second scenario committed any site specific wind alternative projects not selected in the least cost plan to determine the cost differential over the least cost plan associated with the site specific wind alternative projects.

The 2009 IRP included the Big Stone II project as a committed least cost resource based on prior expansion analyses. Each of the two scenarios developed for this analysis were run with and without Big Stone II in the model to recognize that the Big Stone II resource is no longer available to Montana-Dakota's customers.

The EGEAS model optimizes investment and production costs over the study period and determines a net present value (NPV) for the model solution. For the 2009 IRP, a fifty (50) year study period was used to develop the least cost scenario. For this analysis the timeframe was reduced to a twenty (20) year period to reflect the life expectancy of the wind generation investments.

Results

- First Scenario
    - With Big Stone II - no wind projects selected
    - Without Big Stone II - Diamond Willow I selected

Case	Net Present Value*
With Big Stone II	$1,439.82 Mill
Without Big Stone II	$1,370.48 Mill

- Second Scenario
    - With Big Stone II – Diamond Willow I, Diamond Willow II, and Cedar Hills were committed resources to the least cost plan
    - Without Big Stone II – Diamond Willow II and Cedar Hills were committed to the least cost plan

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,481.72 Mill	2.9 %
Without Big Stone II	$1,386.85 Mill	1.2 %

*Net Present Value calculated over 20 years in 2008 Dollars.

A summary table of selected resources for both the First Scenario and Second Scenario is contained in Attachment B.

Analysis

The NPV numbers referenced in the results correspond to the entire Montana-Dakota integrated system and are not state specific. The NPV of production costs includes future operations and maintenance charges for all resources, fuel costs, market purchases, and recovery of future capital investments associated with the supply side resources.

As discussed in more detail in the Company's current North Dakota rate case; the Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects are currently in-service and are used and useful in providing electric service to Montana-Dakota's North Dakota customers. The purpose of this analysis is to show if there is a cost adder for renewable wind generation above Montana-Dakota's least cost resource plan.

With the Big Stone II project, none of the three site specific wind alternatives were picked in the least cost plan. It should be noted that under the normal fifty (50) year modeling period the NPV of the With Big Stone II case is less than the NPV of the Without Big Stone II case. The reason for this is that the investment benefit of a baseload coal-fired plant is received over the entire forty (40) plus year life of the asset which is not adequately reflected in a twenty (20) year study timeframe.

Montana-Dakota was ultimately unsuccessful in its attempts to develop the Big Stone II project and the Without Big Stone II scenario is the appropriate case to focus on for the additional cost of wind generation.

Under the Without Big Stone II modeling runs, the resource expansion model selects the Diamond Willow I project in the least cost plan. The incremental NPV cost to all state jurisdictions with the inclusion of Cedar Hills and Diamond Willow II in the Without Big Stone II runs is $16.37 million over the twenty (20) year life of the projects. This represents an increase of 1.2 percent over the least cost plan.

North Dakota's state jurisdictional share of the Cedar Hills and Diamond Willow II investments is approximately sixty-five percent (65%) which allocates $10.64 million of the NPV increase to North Dakota customers. The Cedar Hills project received a Certificate of Public Convenience and Necessity (CPCN) from the North Dakota Public Service Commission based upon estimated completion costs presented in the Company's application. The Cedar Hills project came in on budget and on schedule. The Cedar Hills wind project is rated at 19.5 MW and the Diamond Willow II project is rated at 10.5 MW for a total of 30 MW. Cedar Hills represents sixty-five percent (65%) of the total wind investment in the Cedar Hills and the Diamond Willow II projects. Therefore only thirty-five percent (35%) of North Dakota's share of the incremental NPV for wind generation should be considered a cost adder above the Without Big Stone II least cost plan which represents a NPV of $3.72 million. Using an eight percent (8%) discount rate and a twenty (20) year term, the annual levelized cost impact to North Dakota customers for Diamond Willow II is $379,000 per year.

This analysis does not include any benefit to North Dakota customers for the North Dakota earned investment tax credit for Cedar Hills or the additional bonus tax depreciation that was available in 2010 for Diamond Willow II or Cedar Hills.

Conclusion

The Diamond Willow I, Diamond Willow II, and Cedar Hills wind projects are used and useful in providing electric service to Montana-Dakota's customers and provide numerous benefits including: reduced dependency on market purchases, reduced exposure to market price fluctuations, zero marginal cost generation resources, and a fuel diversified generation fleet. The cost differential between resource portfolio additions based strictly on the least cost option and the Company's investment in renewable wind resources is 1.2 percent.

Additional Modeling Runs

Additional modeling sensitivity runs requested by the North Dakota Public Service Commission Advocacy Staff are included in Attachment C. Additional sensitive runs looked at lower forecasted Midwest ISO energy market prices of $40 per MWh on-peak and $20 per MWh off-peak; and $50 per MWh on-peak and $30 per MWh off-peak. Also included in Attachment C are summaries of modeling runs to show the affects of using a 25 year depreciation life for the wind turbine investments versus the Company proposed 20 year depreciation life.

Attachment 1

Attachment A

Following tables are referenced from the 2009 IRP

Table A-1

Montana-Dakota's Existing Coal-Fired Units

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Coyote[2]	106.75	20.20	2.25	1.14
Big Stone Unit I[3]	107.50	19.89	1.50	1.57
Heskett 1	27.96	50.57	5.98	1.59
Heskett 2	74.17	44.71	7.07	1.59
Lewis & Clark	52.30	43.55	2.47	1.13

1. Based on July URGE rating (1/1/08-10/31/09)
2. Montana-Dakota's 22.7% ownership share
3. Montana-Dakota's 25% ownership share

Table A-2

Montana-Dakota's Existing Natural Gas Combustion Turbines

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Glendive 1	36.0	9.48	2.35	6.90
Glendive 2	41.6	5.58	2.35	6.90
Miles City	24.5	9.06	2.35	6.90
Williston	9.6	3.08	2.35	6.90

1 – Based on July URGE rating (11/1/08-10/31/09)

Table A-3

Montana-Dakota's Existing Contracts, Variable Generation, and Diesel Unit

Unit	Summer Accredited Capacity (MW)[1]	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU)
Diamond Willow[1]	4.37	10.16	-27.23	-
Glendive Diesel	2.01	4.00	2.35	16.57
Glen Ullin Station 6	4.50	31.33	6.5	-
NSP contract[2]	95.00	17.70	84.30	-
NSP contract[3]	10.00	17.70	184.30	-
WAPA contract[4]	2.80	-	16.84	-

1. Summer Accredited Capacity is based on 22.43% capacity factor. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2. Increase to 100 MW in 2010 with option years in 2011-12.
3. Expires in 2010
4. Expires in 2020

Table A-4

Montana-Dakota's Committed Resources

Unit	In-Service Date	Summer Accredited Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel ($/MBTU
Big Stone Unit II	2015	131.00	2938.59	29.84	1.80	1.66
WE Energies Contract	2012-2014	110-120	-	34.80	111.50	-
NSP Contract Extension	2011	105.00	-	21.00	77.50	-
Diamond Willow Addition[1]	2010	2.24	2400.00	10.16	-27.23	-
Cedar Hills Wind[1]	2010	4.37	2400.00	10.16	-28.77	-

1 - Summer Accredited Capacity is based on 22.43% capacity factor. Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.

Table A-5

Resources Alternatives Available to Montana-Dakota

Unit	Size (MW)	Available Date	Capital Cost ($/kW)[2]	Fixed O&M ($/kW-year)[3]	Variable O&M ($/MWh)[3]	Fuel Cost ($/MBTU)
Combustion Turbine	43	2010	850	$11.63	$2.00	$6.90
Combustion Turbine	75	2010	750	$8.67	$2.00	$6.90
Combined Cycle	140	2010	1150	$12.50	$6.00	$6.90
Coal	blocks of 30	2013	3900	$48.00	$2.50	$1.50
Wind	blocks of 30	2009	2400	$23.33	$2.00	-
Wind before 2014[1]	blocks of 30	2013	2400	$23.33	-$27.23	-
Purchased Capacity	blocks of 10	2012	-	$34.80	$111.50	-

1 - Variable O&M cost includes the Production Tax Credit, which is represented by a negative $/MWh cost value.
2 - In 2008 dollars escalated at 7%
3- In 2008 dollars escalated at 4%

Attachment B

Summary Results for Additional Wind Analysis

Year	Scenario 1		Scenario 2	
	With Big Stone II	**Without Big Stone II**	**With Big Stone II**	**Without Big Stone II**
2009	Glen Ullin	Glen Ullin & DW I	Glen Ullin & DW I	Glen Ullin & DW I
2010			DW II & CH	DW II & CH
2011	20 MW Purchase	20 MW Purchase	10 MW Purchase	10 MW Purchase
2012	140 MW Purchase	130 MW Purchase	120 MW Purchase	120 MW Purchase
2013	150 MW Purchase	140 MW Purchase	130 MW Purchase	130 MW Purchase
2014	150 MW Purchase	150 MW Purchase	140 MW Purchase	140 MW Purchase
2015	BSP II & CT75	2-CT75 & CT43	CT75	2-CT75 & CT43
2016				
2017				
2018				
2019	CT43	CT43		CT43
2020				
2021			CT43	
2022				
2023		CT43		
2024	CT43			CT43
2025			CT43	
2026				
2027		CT43		
2028	CT43			CT43
NPV*	1,439.82	1,370.48	1,481.72	1,386.85

*Net Present Value (NPV) in millions of Dollars over 20 year study period
CT43 – 43 MW Combustion Turbine
CT75 – 75 MW Combustion Turbine
DWI – Diamond Willow I
DWII – Diamond Willow II
CH – Cedar Hills
Purchase – Purchased Capacity

Attachment C

$20 & $40/MWh Market Prices

Results

On-Peak: $40/MWh in 2008 dollars escalated at 3%
Off-peak: $20/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - No wind selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,410.12 Mill
Without Big Stone II	$1,314.64 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,458.68 Mill	3.4 %
Without Big Stone II	$1,337.89 Mill	1.8 %

*Net Present Value based over 20 years

$30 & $50/MWh Market Prices

On-Peak: $50/MWh in 2008 dollars escalated at 3%
Off-peak: $30/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,427.35 Mill
Without Big Stone II	$1,345.79 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,472.34 Mill	3.2 %
Without Big Stone II	$1,364.87 Mill	1.4 %

*Net Present Value based over 20 years

25 Year Book Life

$40 & $60/MWh Market Prices

Results

On-Peak: $60/MWh in 2008 dollars escalated at 3%
Off-peak: $40/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,648.70 Mill
Without Big Stone II	$1,593.51 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,675.67 Mill	1.6 %
Without Big Stone II	$1,599.57 Mill	0.4 %

*Net Present Value based over 25 years

25 Year Book Life

$20 & $40/MWh Market Prices

Results

On-Peak: $40/MWh in 2008 dollars escalated at 3%
Off-peak: $20/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,614.40 Mill
Without Big Stone II	$1,529.05 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,648.99 Mill	2.1 %
Without Big Stone II	$1,541.03 Mill	0.8 %

*Net Present Value based over 25 years

25 Year Book Life

$30 & $50/MWh Market Prices

On-Peak: $50/MWh in 2008 dollars escalated at 3%
Off-peak: $30/MWh in 2008 dollars escalated at 3%

- First Scenario
  - No wind selected with Big Stone II
  - Diamond Willow I selected without Big Stone II

Case	Net Present Value*
With Big Stone II	$1,634.17 Mill
Without Big Stone II	$1,563.93 Mill

- Second Scenario
  - This Scenario committed all wind not selected in the first scenario.

Case	Net Present Value*	Percent Increase Over First Scenario
With Big Stone II	$1,664.70 Mill	1.9 %
Without Big Stone II	$1,572.99 Mill	0.6 %

*Net Present Value based over 25 years

Summary Results for 25 year book life

Year	Scenario 1		Scenario 2	
	Big Stone II	No Big Stone II	Big Stone II	No Big Stone II
2009	Glen Ullin	Glen Ullin & DW I	Glen Ullin & DW I	Glen Ullin & DW I
2010			DW II & CH	DW II & CH
2011	20 MW Purchase	20 MW Purchase	10 MW Purchase	10 MW Purchase
2012	140 MW Purchase	130 MW Purchase	120 MW Purchase	120 MW Purchase
2013	150 MW Purchase	140 MW Purchase	130 MW Purchase	130 MW Purchase
2014	150 MW Purchase	150 MW Purchase	140 MW Purchase	140 MW Purchase
2015	BSP II & CT43	2-CT75 & CT43	BSP II & CT75	2-CT43 & CT75
2016	CT43			
2017				
2018				
2019		CT43		
2020				CT43
2021	CT43		CT43	
2022				
2023		CT75		
2024				
2025	CT43		CT43	CT43
2026				
2027				
2028				

CT43 – 43 MW Combustion Turbine
CT75 – 75 MW Combustion Turbine
DW I – Diamond Willow
DW II – Diamond Willow
CH – Cedar Hills
Purchase – Purchased Capacity

MDU EXHIBIT 3

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., Electric Rate Increase Application	Case No. PU-10-124

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 8th day of November, 2010, by and between the North Dakota Public Service Commission Advocacy Staff ("Staff"), Montana Dakota Utilities Co., a Division of MDU Resources Group, Inc., ("Montana-Dakota" or "Montana-Dakota"). Montana-Dakota and Staff were not able to complete this Settlement Agreement timely, such that other parties were able to consider it. This Settlement Agreement resolves certain outstanding issues in the above-captioned proceedings in a manner consistent with the public interest.

BACKGROUND

This proceeding involves Montana-Dakota's request to increase its retail rates to allow it to earn a reasonable return on equity.

Montana-Dakota sought to increase retail rates by $11,519,000, reflecting the Settlement Agreement dated June 16, 2010 or 10 percent. An interim rate increase of $7.6 million or 7 percent was approved effective June 18, 2010.

Montana-Dakota's electric operations in North Dakota were revenue deficient and earnings were below a reasonable return on equity ("ROE"). Montana-Dakota's last North Dakota general electric rate case was in 2003 with final rates effective January 2004.

In this current rate case, Montana-Dakota identified primary drivers for the need to request a rate increase as increased investment in facilities, including the expansion of wind generation in the Cedar Hills and Diamond Willow projects and the associated expenses and the significant loss of wholesale sales margin.

Montana-Dakota and Advocacy staff previously settled Cost of Debt, Return on Equity and overall Rate of Return, which are modified in this Settlement Agreement. Issues that remain disputed include handling of investments in wind generation and handling of incentive compensation and Board of Directors expenses.

Terms

The Parties agree to the provisions as defined below.

I. Rate Base and Revenue Requirements in the Rate Case.

The Parties agree with respect to the items discussed below. The agreement is made relative to the revised request amount of $11,519,000 and is net of Rate Base, ROR and Expense adjustments proposed by Staff. With respect to the settled items below, Staff proposed adjustment of $2,354,000, the Parties agree that Staff's proposed adjustment should be reduced to $1,220,000. This $1,220,000 will reduce the total request amount of $11,519,000. The parties do not agree how much of a reduction is necessary for Wind or Incentive Compensation and Board of Directors costs.

A) Rate of Return.

The Parties agree to a return on equity of 10.75 percent, with the capital structure and cost set forth in the table below:

Long Term Debt	41.084%	6.845%	2.812%
Short Term Debt	3.199%	2.535%	0.081%
Preferred Stock	2.380%	4.590%	0.109%
Common Equity	53.337%	10.750%	5.734%
Total	100.000%		8.736%

Montana-Dakota agrees to share any earnings above 10.75 percent with customers (see Other Terms and Conditions for a full discussion of this sharing mechanism).

The Parties also agree that an overall rate of return of 8.736 percent will be used for purposes of determining interim rates in Montana-Dakota's next electric rate case.

B) Resolved Issues.

Advocacy Staff's responsive testimony raised several issues of concern. As set forth below, the parties resolve all of the issues, with the exception of bonus and incentive compensation, Board of Directors expense and recovery of wind generation investment and related expenses. As stated above, the total agreed upon adjustment on agreed upon issues, net of Rate Base, ROR and expense items is $1,220,000. The parties have not agreed to an exact allocation of which issues are assigned specific adjustments, rather the parties agree to the reasonableness of the overall adjustment without allocation to specific items.

The non-monetary adjustments which have been agreed upon are covered herein, below.

Advocacy Staff's adjustment proposals included concerns and the Advocacy Staff requested adjustments on the following issues:

(1) Margin Sales and Sales for Resale. Advocacy Staff believed these were separate issues and requested a fixed amount be placed into the cost of service, based on 2009 actual wholesale sales margin. Montana-Dakota proposed to remove all wholesale sales margins from base rates and pass

through 85% of the margins to customers via the Fuel and Purchased Power Adjustment Clause (FCA).

(2) *Aircraft*. Montana-Dakota sought recovery for its ownership in certain aircraft used for travel to service territory locations that are not provided with adequate commercial travel. Advocacy Staff challenged inclusion of the aircraft in rate base, as well as applicable expense items in Montana-Dakota's income statement. Montana-Dakota believes its investment is prudent and a legitimate cost of doing business.

(3) *Customer Deposits*. Advocacy Staff had concerns regarding MDU not using Customer Deposits as a reduction to rate base. Staff requested the jurisdictional amount, instead MDU provided both electric and gas combined balance. Montana-Dakota argues that customer deposits were not included as a reduction to rate base because interest is paid on customer deposits. Staff and Montana-Dakota agreed to include the Customer Deposits applicable to Electric service in the rate base and related interest expense in the cost of service.

(4) *Maintenance Costs for Big Stone and Coyote Generating Facilities*. Advocacy Staff had concerns about the unusually high maintenance costs included in the test year for the Big Stone and Coyote generating facilities. Montana-Dakota believes that if maintenance expenses are adjusted, the corresponding operation expenses should be treated the same way.

(5) *Transmission – WAPA Costs.* Advocacy Staff believed there was too high of a charge included for transmission and WAPA charges. Montana-Dakota did not object to the adjustment.

(6) *Storm Damages.* Advocacy Staff proposed Montana-Dakota be entitled to recovery for storm damages. Advocacy Staff requested that Major Storm Damages be tracked and accounted by the Company, so that from rate case to rate case it can be tracked and properly recovered. Advocacy Staff believes Montana-Dakota should be entitled to a normalized amount to cover costs of major storm damages. Montana-Dakota did not object to the adjustment.

(7) *Deferred Generation Costs.* Advocacy Staff believed Montana-Dakota should not be entitled to recover deferred generation costs that fall outside of the rate case. Montana-Dakota believes the deferred generation costs were prudently incurred and should be recovered. The Company applied for a deferred accounting order for these generation development costs.

(8) *Treatment of Costs Associated with Refinancing Certain Debt at Lower Interest Rates.* Advocacy Staff was supportive of recovery, but proposed modification as to how the Company recovered costs associated with refinancing debt. Montana-Dakota believes its treatment of the unamortized loss on debt and associated debt costs is in compliance with FERC accounting.

(9) *Labor Costs.* Advocacy Staff had concerns regarding the level of labor costs and compensation being included in the rate case, along with the

methodology being used to calculate those costs for the test year. Montana-Dakota does not believe that Staff reflected current (2010) wage and salary levels in its adjustment.

C) <u>Wholesale Sales margins</u>

For purposes of determining the overall revenue requirement, the Parties agree to credit to customers through the FCA 100 percent of North Dakota's portion of asset-based margins received by Montana-Dakota. Passing these credits directly through the FCA as they are realized ensures that neither customers nor Montana-Dakota will be disadvantaged by a non-representative margin forecast in the test year. Montana-Dakota will, starting with the month final rates go in place, include in its fuel clause adjustment calculation, the actual amount of wholesale sales margins for the applicable month. Any balance of unrecovered Margin Sharing Adjustment (MSA) amount remaining at time final rates become effective will be recovered over a twelve month period based on forecasted kWh sales volumes and included in the FCA until fully recovered.

II. Issues to be Addressed before Montana-Dakota's Next Rate Case.

Montana-Dakota will meet with the Staff to discuss a potential study to be completed by the filing of the Company's next general rate case and to be conducted by a mutually agreeable independent consultant. The Company agrees to fund up to $125,000, or such other mutually agreeable amount, for such study. The scope of the study shall be agreed to by the parties but may include all or any of the following three major issues raised by the Staff in this proceeding:

1. Review Montana Dakota's Accounting System and the jurisdictional allocation process. One of the goals is, to determine if a better process can be developed to create an easier audit trail and a more transparent reporting process.
2. Develop an appropriate Minimum Standard Filing Requirements to facilitate a better review of Rate Case components in future cases. Staff will take the lead in identifying the standard information to be filed when requesting for a rate increase.
3. Review the corporate allocation process and the affiliate transactions used to allocate costs associated with MDU Resources and other affiliates to Montana-Dakota's gas and electric operations.

III. Allocations and Rate Design for the Rate Case.

The rate design shall be as Montana-Dakota proposed in its request, modified to reflect adjustments to the revenue requirement and class allocations described in this Agreement.

Montana-Dakota shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement at least thirty (30) days prior to the effective date of final rates.

IV. Other Terms and Conditions

A) Customer Refunds for Earnings Above Authorized ROE.

Per the settlement in Attachment A, the Parties agree to an earnings-sharing mechanism that will result in customer refunds if the Company's net income exceeds a 10.75 percent ROE for its North Dakota electric operations.

If the Company earns in excess of 10.75 percent ROE as reflected in the annual report of jurisdictional regulated electric earnings for any fiscal year prior to either: (i) January 1, 2013; or (ii) the base period included in the Company's next electric general rate case (whichever occurs sooner); the Company will refund to customers revenues corresponding to 50 percent of earnings above 10.75 percent ROE.

Earnings sharing credits will be applied to customer accounts as soon as practical after July 1, following the annual report of electric earnings for the given fiscal year has been filed with the Commission (typically on April 15). A refund would be administered as a one-time bill credit.

B) <u>Deferred Generation Costs.</u>

The Company shall be entitled to recover, outside of rate base, a $172,000 expense, for ten years. The parties agree that this amount will be included in expenses of future rate cases for ten years from the filing of this rate case. This amount is included in and not in addition to the settled amount discussed above.

C) <u>Basis of Settlement Agreement</u>

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates in the Company's next electric general rate case, as required in tracking adjustment mechanisms that may be approved by the Commission, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

D) Effect of the Settlement Negotiations.

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

E) Applicability and Scope.

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

F) Effective Date.

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve some of the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Parties, are in the public interest and will result in reasonable electric rates.

For these reasons, the Parties urge the Commission to approve the Settlement Agreement.

Dated this 8th day of November, 2010.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc

By:_______________________
Name and title
DAVID L. GOODIN
PRESIDENT + CEO

Dated this 8th day of November, 2010.

North Dakota Public Service Commission Staff

By:_______________________
Name and title
Attorney for
Commission Staff