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March 11, 2005

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South Public Utilities Commission
Capitol Building
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Pierre, SD 57501

RECEIVED
MAR 15 2005
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Re: Superior Renewable Energy LLC v. Montana Dakota Utilities Co.

Greetings:

Enclosed please find the original and ten copies of Superior Renewable Energy, LLC's Responses to Commission Staff's Second Set of Interrogatories and Requests for Production, Rebuttal Testimony of John E. Calaway, Rebuttal Testimony of Kenneth J. Slater, and Rebuttal Testimony of Jeff Ferguson.

Sincerely yours,

Mark V. Meierhenry

Mark V. Meierhenry

MM/lk

cc: Bradford Moody

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

RECEIVED
MAR 15 2005
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMPLAINT FILED BY SUPERIOR RENEWABLE ENERGY LLC ET AL. AGAINST MONTANA DAKOTA UTILITIES CO. REGARDING THE JAVA WIND PROJECT	)	Docket No. EL04-016

REBUTTAL TESTIMONY OF JOHN E. CALAWAY ON BEHALF OF SUPERIOR RENEWABLE ENERGY LLC AND JAVA LLC

Q. MR. CALAWAY HAVE YOU REVIEWED THE TESTIMONY SUBMITTED BY MONTANA-DAKOTA UTILITIES COMPANY IN THIS PROCEEDING?

A. Yes I have. I have reviewed the testimony of Donald R. Ball, Andrea L. Stomberg, and Edward B. Kee.

Q. DOES THAT INCLUDE THE SUPPLEMENTAL TESTIMONY OF MR. KEE?

A. Yes it does.

Q. HAVE YOU LIKEWISE REVIEWED THE TESTIMONY SUBMITTED BY THE SDPUC STAFF EXPERT IN THIS PROCEEDING?

A. Yes, I have. I have reviewed the testimony of Timothy Woolf.

Q. WOULD YOU LIKE TO OFFER ANY REBUTTAL IN RESPONSE TO THIS TESTIMONY?

A. Yes I would. I have several general responses regarding the testimony and then specific comments about the testimony offered by each of the individual witnesses.

Q. WHAT EXHIBITS HAVE YOU ATTACHED TO YOUR REBUTTAL TESTIMONY?

A. I have included three exhibits to my rebuttal testimony. They are numbered as a continuation of the exhibits submitted with my direct testimony. The exhibits are:

Exhibit 12—Otter Tail Power Company Press Release

Exhibit 13—Otter Tail Website Pages

Exhibit 14—Excerpts from most recent MDU Resources Group, Inc. 10-K

Q. WHAT WAS YOUR REACTION GENERALLY TO TESTIMONY SUBMITTED BY MDU?

A. In general I was struck by how neither Mr. Ball nor Ms. Stomberg responded in any detail to Superior's testimony regarding MDU's unwillingness to negotiate a power purchase agreement with Superior pursuant to the Commission's Decision and Order implementing PURPA. I also discussed how difficult it has been to determine MDU's avoided costs, in part because MDU keeps changing its story and in part because MDU has never provided the Commission and Superior with the information required by PURPA and by the Commission's rules of discovery.

Mr. Ball suggests that MDU has complied with PURPA's information reporting requirements by filing with the Commission a tariff for small generators under PURPA, an obligation totally separate from the information reporting requirements set out in section 292.302(b)(1)-(3) of the FERC regulations. He never addressed why his company's submission to the Commission on October 20, 2004 regarding avoided costs is totally different than the avoided costs represented by his counsel when this controversy first arose, and also the avoided cost calculations submitted by his expert Mr. Kee.

Ms. Stomberg implies that MDU would not negotiate with Superior because there were other, less expensive wind power projects that MDU was considering. Other than the failed Dakota I project, however, she fails to identify any of these projects and further fails to describe the extent to which MDU has encouraged these projects by negotiating power purchase agreements. The plain fact is that no new wind power projects have been commissioned in South Dakota that will deliver power to MDU since this proceeding began. I think this fact speaks volumes about the viability of these allegedly lower cost projects as well as MDU's desire and interest in accepting power from Qualified Facilities under PURPA.

Q. WHAT ABOUT MS. STOMBERG'S AND MR. BALL'S TESTIMONY REGARDING AVOIDED COSTS?

A. Neither Mr. Ball nor Ms. Stomberg provides any testimony regarding avoided costs. All of this information comes from MDU's expert witness Mr. Kee. As a result, I still cannot determine MDU's position with respect to its avoided costs. On the one hand, I have letters from MDU's counsel stating that MDU is not short of capacity and therefore not willing or required to pay Superior anything for avoided costs of capacity. On the other hand, I have a document prepared by MDU on October 20, 2004 in which MDU calculates its avoided costs of capacity based on a combination of certain short term power purchase agreements and MDU's planned Lignite Vision 21 coal plant scheduled to begin construction in 2006. Finally, I have Mr. Kee's testimony in which he appears to rely on Ms. Stomberg's representations about two other coal fired units that MDU has apparently discussed with several utilities. Mr. Kee uses only the most preliminary (and therefore uncertain) data about one of the plants as a basis to perform a new avoided cost calculation.

Q. WHAT IS WRONG WITH MR. KEE'S USE OF GENERALIZED COST DATA?

A. In the first place, there has been no disclosure to the Commission or to Superior about the details of these plants. None of us can tell in any meaningful way the extent to which MDU is committed to these plants. We also cannot tell what the actual plant costs are going to be both because of the paucity of the disclosure made by MDU and because of the preliminary nature of the cost estimates available. When you compare the nature and amount of information disclosed by MDU for the Lignite Vision 21 Unit relative to the nature and amount of information disclosed by MDU and Mr. Kee for the Big Stone II and Resource Coalition units, I think you can quickly see that the latter two units are more talk than reality, at least as far as MDU's participation is concerned. If you look at MDU's responses to the Commission Staff's most recent set of interrogatories, you will see that MDU's cost information for Big Stone II is from a web site for Otter Tail Power Company. There is no cost information for the Resource Coalition unit, as best as I can tell from reviewing MDU's testimony.

Q. WHAT DOES THE OTTER TAIL WEB SITE SAY?

A. For one thing, it does not identify MDU as a participant. MDU's unregulated parent, MDU Resources Group, is identified elsewhere on the Otter Tail web site as having participated in the engineering studies for the plant but the site specifically says "the utilities will determine their participation after the studies are complete." To make MDU's participation even cloudier, there is a press release from Otter Tail dated October 11, 2004 headlined "Six Utilities Announce Feasibility Study for Second Plant at Big Stone." Neither MDU nor MDU Resources Group is listed as one of those six utilities. Of course, the plant is not listed in MDU's most recent Integrated Resource Plan. I have attached a copy of the October 11, 2004 press release as Exhibit "12" to my testimony. I have attached the pages from the Otter Tail web site that I quote hereafter as Exhibit "13."

Q. WHAT ELSE DOES THE WEB SITE SAY ABOUT BIG STONE II?

A: It says that the cost of the plant, including engineering and administration would be $1 billion. In addition, the web page says that transmission upgrades would be required at an additional cost of up to an additional $100 million. I also note that MDU's expert says that the cost of transmission is going to be $150 million.

Q. ACCORDING TO THE OTTER TAIL WEB SITE, WHAT IS THE STATUS OF THE PERMITTING FOR THE BIG STONE II PLANT?

A. Permits are not going to be applied for until "the first half of 2005." The permits that Otter Tail says must be obtained include the following:

Federal

- Federal Environmental Impact Statement

South Dakota

- Plant site
- Air permit
- Water appropriations
- Ash disposal
- Possible transmission line route permit

Minnesota

- IRP approval
- Certificate of Need for the transmission line
- Transmission line route permit

Clearly, those permits represent significant regulatory hurdles for whomever it is that intends to participate in the construction of the facility. At least with MDU's Lignite Vision 21 unit, MDU has already applied for the air permit and included it within its Integrated Resource Plan.

Q. WHAT DOES THE OTTER TAIL WEB SITE SAY ABOUT THE IMPACT ON RATES PAID BY THE CUSTOMERS OF THE BIG STONE II PLANT OWNERS?

A: The web site only discusses the rate impact with respect to two companies. For Otter Tail Power Company, the web site says only that "the impact on rates would be determined as part of the resource planning process." It goes on to admit, however, that "Big Stone II would be more expensive than Otter Tail Power Company's other plants because the company hasn't built a base load plant since 1981. Construction costs have gone up in the last 25 years. And new environmental standards will require expensive controls." For Missouri River Power, the web site says "[i]t is premature to make any cost projections with any level of confidence until the project details are more defined." Clearly, even if MDU is actually going to participate in the ownership of this plant, there is much work to be done in terms of identifying and analyzing all of the costs to be incurred. From that standpoint, the plant does not seem to be a reliable source of avoided cost information.

Q. WHAT ABOUT THE RESOURCE COALITION PLANT REFERENCED IN MS. STOMBERG'S TESTIMONY?

A: There is no information provided in any of the MDU witnesses' testimony about this Resource Coalition plant, other than its name, size and approximate location. If you look at MDU's 15th and 16th responses to Commission Staff interrogatories dated February 10, 2005, it appears that the only plant costs relied upon by Mr. Kee are the Big Stone II plant costs estimated on the Otter Tail Power Company web site. There is no reference to the plant costs for the Resource Coalition plant.

Q. WHAT HAS MDU TOLD ITS INVESTORS ABOUT THE BIG STONE II AND RESOURCE COALITION PLANTS?

A. In its most recent 10-K filed with the Securities and Exchange Commission just a few weeks ago on February 23, 2005, MDU specifically addresses only the Lignite Vision 21 Unit. In reference to its need for additional baseload capacity, the company says, "As part of the North Dakota Industrial Commission's Lignite Vision 21 project, Montana-Dakota submitted an air quality permit application in May 2004 to construct a 175-megawatt coal-fired plant at Gascoyne, North Dakota. The air permit application is under review at the North Dakota Department of Health (North Dakota Health Department)." Although there is also a vague statement about MDU's "review of other potential projects to replace capacity associated with expiring purchased power contracts and to provide for future growth," I would think that MDU would want to let its shareholders know if it was committed to a $1 billion coal plant. I have attached a copy of excerpts quoted in my testimony from MDU's most recent 10-K to my testimony as Exhibit "14."

Q: HAVE YOU BEEN GIVEN THE OPPORTUNITY THROUGH DISCOVERY TO DETERMINE ALL OF THOSE RELEVANT FACTS REGARDING THESE TWO UNITS?

A. No, not at all. If you go back and review the various discovery requests served on MDU by both Superior and Commission Staff, I think you would agree that most of those questions are designed to elicit as much information as possible about MDU's avoided costs of energy and capacity. In none of those responses did MDU ever provide Superior or the Commission Staff with any information relative to the Big Stone or Resource Coalition units. The first time that any of us heard about these units and their alleged impact on avoided costs was the day that we received copies of MDU's pre-trial testimony.

Q. HAS MDU SUPPLEMENTED ITS DISCOVERY RESPONSES RELATIVE TO AVOIDED COSTS?

A. No, it has not.

Q. WHAT IMPACT HAS MDU'S FAILURE TO SUPPLEMENT HAD ON SUPERIOR'S POSITION IN THIS PROCEEDING?

A. It has put Superior and the Commission at a significant disadvantage because we have no effective way to determine the significance of these plants relative to MDU's avoided costs. As I understand the rules applicable to this proceeding, each party is supposed to provide full, fair and accurate answers to any relevant discovery requests made to them. The rules recognize that facts and circumstances change by requiring parties to supplement their answers as soon as the changed facts and circumstances are known. The ultimate objective of the rules is to allow all sides to understand each other's positions going into the hearing so that each may properly prepare its case and avoid surprise. In this case, after almost a year of significant time, effort and expense to obtain full discovery from MDU, Superior finds itself on the eve of the hearing finding out for the first time that there are two base load generating units that MDU claims have an impact on its avoided cost. Coming on the heels of MDU's inaccurate and misleading responses regarding the short term power purchase agreements with Omaha Public Power District previously used by MDU to determine its avoided costs, these last minute disclosures certainly seem to be inconsistent with the rules.

Q. IS THERE ENOUGH INFORMATION DISCLOSED BY MDU FOR THE COMMISSION TO DETERMINE MDU'S AVOIDED COSTS, AND THEREFORE THE PRICE OF ENERGY AND CAPACITY PAYABLE TO SUPERIOR UNDER PURPA?

A. No, not quite. I think that MDU's avoided cost of energy has been pretty well determined as a result of the most recent PROSYM modeling work performed by MDU's

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expert, Mr. Kee. The results of that modeling work are attached to Mr. Kee's testimony as Exhibit EDK-5 (revised 14 Feb 05). In this revised exhibit, Mr. Kee corrects the previous PROSYM modeling work done by MDU with a new PROSYM model run by Mr. Kee. It uses the "QF-in QF-Out" approach originally recommended by Jeff Ferguson and Ken Slater. The only problem with this testimony is that Mr. Kee failed to run the model beyond a ten-year time horizon. If the Commission agrees that a longer time period for a power purchase agreement is more appropriate, then the model will have to be re-run to include this additional time period.

Q. WHAT ABOUT MDU'S AVOIDED COST OF CAPACITY?

A. Yes, I think that the Commission can determine MDU's avoided cost of capacity. In his supplemental testimony, Superior's expert Ken Slater has calculated MDU's avoided cost of capacity on a levelized basis and summarized those results in his exhibit KJS-8. He presents in that exhibit two different results. The first result, \$401.78 / kW-Yr, assumes that the Commission will decide that Superior should receive capacity credit beginning at the expected in-service date for the Lignite Vision 21 unit. The second result, \$369.01 / kW-Yr, assumes that the Commission will decide that Superior should receive capacity credit beginning at the expected in-service date for the Java Wind Facility.

Q. WHAT IF THE COMMISSION DECIDES TO ADOPT THE METHOD FOR CALCULATING MDU'S AVOIDED COSTS RECOMMENDED BY THE COMMISSION STAFF EXPERT TIMOTHY WOOLF?

A. In that case, some additional calculations will be necessary, although I understand that MDU is attempting to make at least some of those calculations right now. If they are not completed before the hearing or if they are completed in a manner that the

Commission finds is inconsistent with PURPA, then this Commission can direct MDU to perform correct calculations as part of any relief granted in this proceeding. Any such calculations must be careful to include the correct cost of the Lignite Vision 21 unit and not the cost originally used by MDU in its first submission to the parties on October 20, 2004. As Ken Slater testified, MDU may have seriously under-accounted for the costs of the Lignite Vision 21 unit. Mr. Slater included in his testimony a proper accounting of the Lignite Vision 21 unit costs that includes the items omitted by MDU. That accounting is shown in Exhibits KJS-6 and KJS-7. In his rebuttal testimony, he outlines how he believes MDU should calculate MDU's avoided costs using Mr. Woolf's methodology.

Q. SHOULD THIS COMMISSION CONTINUE THE HEARING UNTIL MDU HAS BEEN GIVEN TIME TO PERFORM THESE CALCULATIONS?

A. No, I believe that any further delay would materially prejudice Superior's ability to construct the Java Wind Facility and could significantly increase its costs. As I testified previously, there is a production tax credit from the federal government available for wind energy projects. The credit expires, however, at the end of this year. Moreover, Superior (and I am sure MDU as well) is experiencing significant inflationary pressures on all costs associated with the construction of power production facilities. For these reasons, I believe that each week is critical in terms of being able to successfully develop this project. Finally, I read that the Commission Staff's expert witness, Mr. Woolf, agrees with Superior that the burden of demonstrating its avoided costs rest squarely with MDU. If MDU failed to meet that burden by not performing certain calculations regarding avoided costs or failing to disclose the avoided cost information required by the FERC, then MDU – not Superior – should suffer the consequences for this failure.

Q. DO YOU AGREE WITH THE TESTIMONY OF MR. BALL REGARDING WHAT HE CALLS THE "JURISDICTIONAL COST ALLOCATION MATTER?"

A. No I do not. First, I am advised by my counsel that there is nothing in the PURPA statute that requires or even suggests that a utility's obligation to accept and pay for power produced from a Qualified Facility is limited to the utility's market within the state where the Qualified Facility is located. Second, there is nothing in PURPA that conditions a utility's obligation to take power from a Qualified Facility based on such utility's ability to recover power purchase costs under state law. To the extent that MDU desires to obtain such cost recovery, it should do so under its existing tariff and applicable state law in the jurisdictions where MDU is subject to rate regulation. PURPA's requirement that the avoided cost price paid be "just and reasonable" should help MDU meet any burden it faces to obtain cost recovery in the different states where MDU is regulated. *See* 18 C.F.R. § 292.304(a) (2004).

Q. WHAT DOES MDU SAY ABOUT ITS ABILITY TO RECOVER COSTS OF PURCHASED ENERGY AND CAPACITY?

A. In its most recent 10-K, MDU states, "Fuel adjustment clauses contained in North Dakota and South Dakota jurisdictional electric rate schedules allow Montana-Dakota to reflect increases or decreases in fuel and purchased power costs (excluding demand charges) on a timely basis. Expedited rate filing procedures in Wyoming allow Montana-Dakota to timely reflect increases or decreases in fuel and purchased power costs. In Montana (24 percent of electric revenues) such cost changes are includable in general rate filings." There is nothing in the 10-K that says a power purchase agreement executed pursuant to PURPA would or should be treated any differently.

Q. LET US TURN NOW TO THE TESTIMONY OF MS. STOMBERG. WHAT WAS YOUR REACTION TO HER TESTIMONY IN GENERAL?

A. I found her testimony to be inconsistent with MDU's prior representations to the Commission and to Superior. On the one hand, she says that MDU has considered participating in the Resource Coalition base load generating project "since 2003" and with "early proposals for the Big Stone II Plant since 2001." On the other hand, Ms Stomberg claims that "only more recently have they seriously considered involvement with the Big Stone II Project." If MDU has been seriously considering the Resource Coalition and the Big Stone II projects for so long, why did MDU not disclose this fact to the Commission and Superior when it first disclosed its avoided costs? Similarly, why were these projects not included in MDU's most recent Integrated Resource Plan like the Lignite Vision 21 unit?

Q. HOW ELSE DID MS. STOMBERG'S TESTIMONY SEEM INCONSISTENT OR CONTRADICTORY?

A. Ms. Stomberg's testimony regarding MDU's plans to address the rising cost and uncertainty of using natural gas for combustion turbines contradicts MDU's prior calculation of avoided costs as well as the testimony of MDU's expert Mr. Kee. On pages 3 and 4 of her testimony, Ms. Stomberg says, "MDU is moving away from its 2003 Integrated Resource Plan ("IRP") which she characterized as being "heavily dependent on gas." See Stomberg testimony, p. 3, line 25; p. 4, line l. She says that as a result of "the Plan's reliance on gas fired generation expos[ing] our customers to considerable price and reliability issues associated with fuel costs and availability . . .," MDU began to consider "construction of another base load coal plant . . ." See Stomberg testimony on pp. 3-4. If true, I do not understand why the cost of gas fired combustion turbine generators should be used to determine MDU's avoided cost of capacity, regardless of whether those generators are designed to be peak or base load capacity. In essence, Ms. Stomberg says that gas fired units are not the units that MDU will avoid as a result of the capacity contribution from the Java Wind Facility. This testimony is inconsistent with the testimony of MDU's expert, Mr. Kee to the extent that Mr. Kee relies on gas fired combustion turbines to determine avoided capacity during the period 2008-2010.

Q. DO YOU HAVE COMMENTS CONCERNING MS. STOMBERG'S TESTIMONY REGARDING THE EXPENSE OF POWER PRODUCED FROM THE JAVA WIND FACILITY RELATIVE TO OTHER WIND RESOURCES?

A. First, Ms. Stomberg provides no support for that assertion. Second, I'm not sure that it matters in the context of an avoided cost dispute. The fact that some other wind power developer might be willing to accept less than an avoided cost price does not mean that the capacity from the Java Wind Facility can be ignored. Of course, the one specific contract she referenced was for the Dakota I Power Partners project. This project never got off the ground, I believe in large measure because the price specified in that contract was much lower than the avoided costs being discussed in this proceeding.

Q. IS THERE ANYTHING ELSE ABOUT MS. STOMBERG'S TESTIMONY UPON WHICH YOU WOULD LIKE TO COMMENT?

A. Yes, Ms. Stomberg wants this Commission to believe that MDU's failure to move forward in negotiations with Superior for a power purchase agreement on the Java Wind Facility is not the result of a deliberate attempt to frustrate the development of the project, but instead the result of careful deliberative thinking about both renewable and non-renewable capacity options. I think if the Commission looks carefully at the situation, it is hard to understand MDU's reluctance to bring on new generating capacity from the Java Wind Facility. If you look back at MDU's efforts to plan and build the Lignite Vision 21 unit together with MDU's efforts to obtain additional capacity through the Request for Proposal ("RFP") process together with MDU's efforts to contract for capacity from the Omaha Public Power District and others, I think the inescapable conclusion is that MDU has been short of capacity for quite some time now. This shortage will be even more acute when the Basin Electric Power Purchase Contract expires next year. Rather than acknowledge that capacity from the Java Wind Facility could be at least part of MDU's solution, the company has done just about everything it knows how to do to avoid contracting with Superior for the Java Wind Facility.

First, MDU tried to discourage Superior by representing consistently that the company was not short of capacity when we now know that this situation was not the case. Next, MDU refused to engage in good faith negotiations for a power purchase agreement, in part to give itself time to enter into various power purchase agreements with conventional generators that could provide capacity otherwise provided by the Java Wind Facility. Moreover, MDU has yet to provide Superior with a credible and consistent calculation of its avoided costs. If MDU was trying in good faith to evaluate its options to obtain future capacity and energy, it would not have ignored one of its better options during this evaluation period.

Q. LET US TURN NOW TO THE TESTIMONY OF MDU'S EXPERT WITNESS, EDWARD KEE. IN GENERAL, WHAT DID YOU THINK ABOUT THE POINTS RAISED BY MR. KEE?

A. In general, I think Mr. Kee tried to take a relatively simple situation and make it as complicated and confusing as possible.

Q. HOW HAS HE MADE IT CONFUSING?

A. I believe that the Commission Staff's expert Mr. Timothy Woolf does a very good job of explaining the problems with Mr. Kee's testimony. Although Superior's expert Ken Slater disagrees with Mr. Woolf in a few places, Superior agrees with most of what Mr. Woolf has to say about why Mr. Kee's testimony misses the mark on avoided costs.

Q. IS THERE ANYTHING THAT YOU WOULD LIKE TO ADD TO WHAT MR. WOOLF HAS ALREADY SAID ABOUT MR. KEE'S TESTIMONY?

A. Yes, just a few points. First, I agree with Mr. Woolf that Mr. Kee improperly determined MDU's avoided cost from the present until June 15, 2007. Mr. Woolf's testimony makes the somewhat theoretical point that "assuming that avoidable capacity costs are $0.00--in any year – is likely to understate the value of avoided capacity." I would like to make the practical point that MDU has sought to obtain additional capacity for this exact same time period largely without success. First, it signed contracts with the Omaha Public Power District but was unable to take delivery because of transmission issues. Second, MDU executed power purchase agreements with NorthPoint Energy Solutions. Finally, MDU has solicited additional energy and capacity for this time period through an RFP process. As Ms. Stomberg has testified, the RFP process was completely unsuccessful in obtaining the requested energy and capacity. Knowing these facts, it seems hard to find credible Mr. Kee's testimony that "Montana Dakota has no need for capacity, so there is no avoidable unit." See testimony of Edward D. Kee, p. 24,61, ll.12-13.

Q. WHAT ABOUT MR. KEE'S CRITICISMS OF THE COMMISSION'S DECISION AND ORDER IMPLEMENTING PURPA?

A. Again, I believe that Mr. Woolf does a good job of explaining the technical problems with Mr. Kee's recommended changes to the Commission's implementation of PURPA. My practical reaction is that the Commission should not change the rules of the game in mid-stream. When Superior first began planning the Java Wind Facility, it studied the Commission's Decision and Order implementing PURPA very carefully. The actions that Superior has taken since then filing this Complaint and preparing its case have largely relied on the findings of the Commission in that Decision and Order. Likewise, I assume that MDU has relied on the Decision and Order in responding to Superior with respect to issues related to the Java Wind Facility. As a matter of fairness, I believe that if the Commission believes that it should modify the Decision and Order, it should only come at the conclusion of this proceeding. Modifying the decision and order and creating a new PURPA implementation as recommended by Mr. Kee I believe would create regulatory and legal risks that would make future wind power development in South Dakota much more difficult.

Q. MR. KEE ATTACHED A TERM SHEET DESCRIBING KEY PROVISIONS FOR HIS RECOMMENDED POWER PURCHASE AGREEMENT. ARE YOU FAMILIAR TERM SHEET?

A. Yes, I am. Mr. Kee attached it to his testimony as Exhibit EDK-8.

Q. ARE THE TERMS AND CONDITIONS SET OUT IN THIS EXHIBIT APPROPRIATE FOR INCLUSION IN A POWER PURCHASE AGREEMENT BETWEEN JAVA AND MDU?

A. No, they are not. These terms are incredibly one-sided in favor of MDU and conform neither to standards set in the Commission's Decision and Order or to standards for long term power purchase agreements for wind generated electricity.

Q. IN WHAT WAY DO THESE TERMS NOT CONFORM TO THE COMMISSION'S DECISION AND ORDER?

A. The term is too short and the price is not constant over the life of the contract, to name the most important places where the contract deviates from the Commission's findings in its Decision and Order.

Q. WHAT OTHER POINTS IN THE TERM SHEET ARE TROUBLESOME TO SUPERIOR?

A. The term sheet requires Superior to obtain firm transmission rights as a condition of any sales to MDU. This requirement makes no sense to me because Superior will not need any transmission rights in order to complete the sale of energy and capacity to MDU. The sale will be complete when Superior delivers the contract requirements at the point of interconnection with MDU's system. Once the Java Wind Facility delivers the contractual amounts of energy and capacity to MDU's system, it is MDU's responsibility to transmit and sell that power wherever on MDU's integrated system that MDU sees fit. If firm transmission is necessary in order to make such a sale, it is MDU's responsibility to obtain such transmission. In the same manner, any deduction for transmission loss factor is inappropriate because there are no transmission losses between where the Java Wind Facility produces the electricity and where it is metered for sale at the point of interconnection.

Q. WHAT ABOUT THE CURTAILMENT PROVISIONS OF THE CONTRACT?

A. Kee's term sheet proposes that MDU be given the right "from time to time to curtail (*i.e.*, order the reduction and output of the project) at any time for any reason." There are no limits on this curtailment power, giving in effect MDU an absolute right to negate its obligation under PURPA to accept power produced from the Java Wind facility.

Q. LET'S GO THROUGH THE TERMS PROPOSED BY MR. KEE FOR THE POWER PURCHASE AGREEMENT ONE BY ONE. WHAT IS WRONG WITH THE LENGTH OF THE CONTRACT PROPOSED BY MR. KEE?

A. I think that the Commission Staff's expert witness Mr. Woolf did a good job of explaining why ten years is not an appropriate length for the power purchase agreement. I would add, however, that the life of a wind energy facility is very similar to the life of a coal-fired baseload generating unit. Although Mr. Kee wants the Commission to believe that there is an unacceptably high risk to MDU's ratepayers associated with a power purchase agreement greater than ten years, I think that there is not much difference from a risk standpoint between a twenty year power purchase agreement and a twenty year plus design life coal fired plant. In both cases, MDU would face many of the same risks that can materialize over the long term. Nevertheless, MDU routinely expects to be able to obtain regulatory approval to construct and operate long life coal-fired plants. From this standpoint, I do not see why wind generation should be treated any differently.

Q. WHAT ABOUT THE PAYMENT PROVISIONS SUGGESTED BY MR. KEE?

A. Again, I believe that Mr. Woolf explains very well why a capacity payment based on only seven megawatts drastically understates the amount of capacity that will be avoided and therefore should be paid for by MDU. Mr. Woolf and I likewise agree that using market based prices as a surrogate for MDU's actual avoided cost of energy is inconsistent with the Commissioner's Decision and Order. It seems particularly inappropriate given the absence of any true, open and competitive market in South Dakota for either wholesale or retail energy markets. Finally, I agree with Mr. Woolf that deducting $4.60 per megawatt hour from the avoided cost price otherwise due from MDU is simply not supported by any useful testimony or evidence. The one article cited by Mr. Kee relates to the integration of wind resources on a much larger scale on a much different system than MDU's system.

Q. WHAT ABOUT THE VARIOUS PERFORMANCE PROVISIONS SUGGESTED MR. KEE?

A. In general, I agree that some performance provisions are necessary for a power purchase agreement in a situation like this one where the Java Wind Facility has yet to be constructed.

Q. IS THE END OF 2005 A REALISTIC DATE FOR REQUIRING THAT THE JAVA WIND PROJECT TO BE OPERATIONAL?

A. No, Superior would like to construct and begin operations at the Java Wind Facility before the end of 2005. There are many things beyond Superior's control, however, that could frustrate that objective. Most importantly, Mr. Kee makes no provision for continued legal disputes with MDU regarding the Java Wind Facility. For example, if MDU appeals any decision rendered by the PUC in this proceeding, such appeal could take longer than the time proposed by Mr. Kee for first operation. Also, I note that even the one-sided Dakota I Power Partners power purchase agreement gave the seller approximately 20 months to complete construction of the project after execution of its power purchase agreement.

Q. LET US CONTINUE WITH THE POWER PURCHASE AGREEMENT TERMS PROPOSED BY MR. KEE. WHAT ABOUT MR. KEE'S REQUIREMENT FOR CAPACITY PAYMENTS?

A. Mr. Kee agrees with Superior, Superior's expert, Ken Slater, and Mr. Woolf that MAPP accreditation methods should be used to determine the amount of capacity for which Superior should be paid by MDU. As discussed by Mr. Woolf in much greater detail, however, confining that accreditation to the lowest amount of capacity delivered during MDU's summer peak months drastically understates the amount of capacity avoided by MDU as a result of deliveries from the Java Wind Facility. Mr. Slater also has some testimony on this point confirming that the 7 MW capacity figure proposed by Mr. Kee is inappropriate.

Q. WHAT ABOUT MR. KEE'S TESTIMONY REGARDING ENERGY PAYMENTS?

A. I agree that the output from the Java Wind project needs to be metered so that the appropriate energy payments can be made based on the real time output from the Java Wind Facility. Mr. Woolf and I agree about why use of MISO Day 2 electricity market prices is not appropriate as a substitute for MDU's actual avoided energy costs. I have also testified about why a $4.60 per megawatt hour deduction for the costs of integrating the Java Wind Facility into MDU's system is inappropriate. Mr. Kee also suggests that there should be a reduction of payments for "other identifiable costs" without specifying what costs, if any, Montana Dakota has identified that are appropriate for reducing amounts otherwise payable to Superior. That sort of open-ended term I do not believe would ever survive an arms length negotiation for a power purchase agreement.

Q. MR. KEE INCLUDED A PARAGRAPH IN HIS TERM SHEET THAT GIVES MDU THE RIGHT TO WHATEVER GREEN TAG OR RENEWABLE ENERGY CREDITS THAT ARE PRODUCED FROM THE JAVA WIND FACILITY. CAN YOU COMMENT ON THAT PROPOSAL?

A. Yes, this term is typical of the "Heads, I win; tails you lose" approach taken by Mr. Kee in this term sheet. On the one hand, he clearly recognizes that there is some value to the renewable energy credits or else he would not have proposed that they be delivered to MDU. On the other hand, he requires Superior to deliver them to MDU for free. I think Mr. Woolf provides some useful testimony about how these credits might be valued but I disagree with him regarding his treatment of them in the power purchase agreement.

Q. WHAT IS WRONG WITH MR. WOOLF'S APPROACH?

A. Mr. Woolf shows how the European Union's carbon emissions trading system has placed a value on avoided carbon dioxide and other greenhouse gas emissions, but he never proposes that this value be recognized in the contract. Instead, he proposes only that the parties be allowed to enter into new contract negotiations at the end of ten years that would presumably take into account the value of avoided greenhouse gas. He never addresses who should be entitled to the renewable energy credits during the first ten years of the contract.

Q. HOW WOULD YOU TREAT RENEWABLE ENERGY CREDITS IN THE POWER PURCHASE AGREEEMENT?

A. I think that the power purchase agreement should require MDU to pay Superior for the value of the credits, using the EU emissions market valuation suggested by Mr. Woolf. If the Commission believes that such valuation is too speculative, then I believe that the power purchase agreement should expressly provide that MDU does not have to pay Superior anything for the avoided future environmental costs but concomitantly that Superior should retain all of the value from whatever "green tags," renewable energy credits or other similar benefits are generated by the Java Wind Facility.

Q. WHAT ABOUT MR. KEE'S TESTIMONY REGARDING THE POSTING OF SECURITY TO ENSURE THAT THE JAVA WIND PROJECT MEETS ITS DELIVERY OBLIGATIONS UNDER THE AGREEMENT?

A. I agree that some security is appropriate to guarantee both parties' obligations under the power purchase agreement. In my previous testimony and in interrogatory responses made by Superior in this proceeding, Superior has stated that it will provide an investment grade letter of credit or similar security as part of its power purchase agreement obligation. I do not know what type of security MDU is prepared to offer to secure its very substantial payment obligations to Superior but I would expect it to be comparable.

Q. WHAT ABOUT THE RISK MANAGEMENT PROVISIONS THAT MR. KEE PROPOSED FOR MONTANA DAKOTA?

A. I wish that Superior could include a similar set of risk management provisions for the benefit of the Java Wind Facility but I know that they would be no more commercially reasonable for Superior than they are for MDU. Moreover, such provisions completely undercut the price and contract length certainty that are at the heart of the Commission's Decision and Order implementing PURPA. Superior could not obtain financing for the Java Wind Facility with such terms in the power purchase agreement.

Q. GIVE US EXAMPLES OF PERFORMANCE TERMS THAT ARE INCONSISTENT WITH PURPA, AS IMPLEMENTED BY THE COMMISSION'S DECISION AND ORDER.

A. I have read nothing in PURPA or the Commission's Decision and Order implementing PURPA that conditions MDU's obligation to take and pay for power purchased from the Java Wind Facility based on whether or not such purchased power costs are recoverable by MDU under state utility law.

Similarly, an agreed-upon buyout price giving MDU the right to terminate the contract might be an appropriate term if the parties could agree on such a price but I have not heard of such an arrangement in other long-term wind power purchase agreements and I am not aware of anything in PURPA that requires such a term to be included in the power purchase agreement. To the extent that Mr. Kee is suggesting with the use of the word "buyout" that MDU should have the right to purchase the Java Wind Facility from Superior outright, I would say that Superior intends to own and operate the Java Wind Facility for a very long time and therefore has no interest in such a provision. It does not seem to have much to do with the intent of PURPA.

The curtailment provisions suggested by Mr. Kee seem so vague and open-ended that I have a difficult time commenting on them with specificity. I do note that the curtailment provision he suggests seems to allow Montana Dakota to negate its PURPA obligations by not paying for power produced from the Java Wind Facility whenever MDU experiences "significant scheduling or balancing problems." I do not know what scheduling or balancing problems could arise with respect to the Java Wind Facility but I expect that if the Commission believes that such a provision is appropriate, this concept would have to be considerably refined.

Finally, if there is an investment grade letter of credit in place to support the performance of the Java Wind Facility under a power purchase agreement, I do not understand why MDU should be given the right to control "the financial structure of the proposed Java Wind Project" or otherwise have the kind of limits on transferability suggested by Mr. Kee.

Q. IN HIS TESTIMONY, MR KEE SUGGESTS THAT THERE IS SOME ISSUE REGARDING THE SIZE OF THE JAVA WIND FACILITY. CAN YOU COMMENT ABOUT THAT?

A. Yes I can. The Java Wind Facility is self-certified at the Federal Energy Regulatory Commission as a Qualified Facility under PURPA to be a 31.5 megawatt facility. This amount represents an increase of 6 megawatts over the original self-certification project size filed with the FERC. Superior based this new self-certification on the use of 21 1.5 GE wind turbines. Superior increased the size of the Java Wind Facility after it began studying interconnection issues and determined that MDU's system could easily handle the additional capacity. The Java Wind Facility has never been self-certified to be 50.4 megawatts. This figure comes from the interconnection work that Superior has done with MISO. When Superior commenced this interconnection work, it wanted to plan for the largest amount of capacity that it believed could be accommodated by MDU's system. All of that interconnection work has confirmed that MDU system can handle a wind energy facility with 50.4 megawatts of nameplate capacity.

Q. IS THE JAVA WIND FACILITY IDENTIFIED AS HAVING 31.5 MW OF NAMEPLATE CAPACITY IN THE POWER PURCHASE AGREEMENT?

A. No the power purchase agreement provides for MDU to purchase the energy and capacity produced from turbines with a total of 30.6 MW of nameplate capacity. This slightly lower amount of nameplate capacity results from a change in the incumbent turbines identified for the project, from the 20 1.5 MW GE turbines I identified previously to 17 1.8 MW turbines manufactured by Vestas. Jeff Ferguson discussed these turbines in his direct testimony. Superior will of course file any required QF re-certification with the FERC advising it of the final nameplate capacity of the Java Wind Facility.

Q. WOULD YOU AGREE THAT THE POWER PURCHASE AGREEMENT SHOULD INCORPORATE A GOOD DESCRIPTION OF THE JAVA WIND FACILITY AND THE TYPE AND NUMBER OF WIND TURBINES TO BE INCLUDED?

A. Yes I do. The power purchase agreement that Jeff Ferguson has submitted with his testimony provides for such a description.

Q. DOES THIS ANSWER CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE COMPLAINT FILED BY SUPERIOR RENEWABLE ENERGY LLC ET AL. AGAINST MONTANA DAKOTA UTILITIES CO. REGARDING THE JAVA WIND PROJECT	)	Docket No. EL04-016

AFFIDAVIT

County of Harris
State of Texas

John E. Calaway, Managing Member, Superior Renewable Energy LLC (Superior), being first duly sworn, deposes and says that the Rebuttal Testimony of John E. Calaway on Behalf of Superior and Java LLC submitted in the above-captioned proceeding was prepared by him, with the assistance of others working under his direction and supervision, that he is familiar with the contents thereof, and that the statements set forth therein are true and correct to the best of his knowledge, information and belief.

John E. Calaway

Subscribed and sworn before me

this 8th day of March 2005.

Notary Public

My Commission Expires: 3/12/2008

NATALIE G. McCUE
NOTARY PUBLIC
STATE OF TEXAS
My Commission Expires 03/12/2008

News release

OTTER TAIL POWER COMPANY

For further information call

Steve Schultz
Office 701-253-4709
Cell 701-320-1406

215 South Cascade
Fergus Falls, MN 56537
800-434-5015

For release:
October 11, 2004

Exhibit 12
To The
Testimony of John E. Calaway

Six utilities announce feasibility study for second plant at Big Stone

Increasing electric demand cited as reason new generation is needed

In a joint announcement today officials from Otter Tail Power Company, Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Hutchinson Utilities Commission, and Missouri River Energy Services reported that the companies are investigating the feasibility of another electric generating plant on the site of the existing Big Stone Plant near Milbank, South Dakota.

"Based on studies that point to a potential energy shortfall in the Mid-Continent Area Power Pool by 2007 and our long-standing commitment to meet our customers' energy needs in a low-cost, environmentally responsible manner," said Otter Tail Power Company President Chuck MacFarlane, "studying the potential of a second unit at Big Stone is prudent."

In making the announcement, MacFarlane said that area power pool and independent market analysts estimate that energy consumption in the region will increase by 15 percent to 25 percent during the next decade. "We think it's essential to respond to that knowledge," he said.

The group is exploring the feasibility of building an approximately 600-megawatt coal-based generating unit designed with the best available emissions technology as prescribed by federal and state environmental regulations. The decision whether to proceed with construction of the plant is expected by early next summer. If built, Big Stone II is projected to come online in 2011 and serve the utilities' native customer loads. It would be the largest investment of private and public capital in the state, employing an average of 625 construction workers during its four-year construction period, with a peak work force of 1500. Once online the plant likely would require 30 to 40 operational workers in addition to those already employed at the combined Big Stone Plant and Big Stone II site.

Tom Heller, CEO of Missouri River Energy Services, added that necessary transmission studies are being conducted through the Midwest Independent System Operator. "And we intend to continue our discussions with government officials, the local public, and other stakeholders as the study results become available," he said. "We still are in the early phases of the project, but we think it is important to get timely information to interested parties."

MacFarlane agrees. "Otter Tail Power Company has been operating the existing Big Stone Plant since 1975. We always appreciate the relationship we've had with the local residents and town, county, and state officials," he said.

"We also appreciate the unique relationship this project has developed among our companies, which include investor-owned utilities, municipal electric utilities, and electric cooperatives," added Heller. "We're working together to resolve our potential mutual need for baseload energy."

In their joint statement, company officials pointed out that, during its more than 25 years of operation, Big Stone Plant has proven that a well-designed, well-maintained coal-fired plant can be a reliable, efficient, low-cost energy source and an environmentally friendly neighbor. "Big Stone II, which would use state-of-the-art coal-burning and environmental-control technologies, would offer further proof," said MacFarlane.

Otter Tail Power Company, a division of Otter Tail Corporation (Nasdaq: OTTR), is headquartered in Fergus Falls, Minnesota. It provides electricity and energy services to more than a quarter million people in Minnesota, North Dakota, and South Dakota. To learn more about Otter Tail Power Company visit www.otpco.com. To learn more about Otter Tail Corporation visit www.ottertail.com.

Central Minnesota Municipal Power Agency, headquartered at Blue Earth, Minnesota, is a nonprofit municipal corporation and political subdivision of the State of Minnesota created in 1987. It is composed of 16 member municipals located in south central Minnesota. The majority own and operate an electric generation and distribution system. CMMPA provides members and nonmembers with low-cost, reliable electric energy and related services.

Great River Energy is a not-for-profit generation and transmission cooperative headquartered in Elk River, Minnesota. It provides energy and related services to 28 distribution cooperatives in Minnesota and Wisconsin, serving approximately 1.2 million people. Great River Energy is the second largest power supplier in Minnesota. To learn more, visit www.gre.com.

Heartland Consumers Power District, headquartered in Madison, South Dakota, is a nonprofit public corporation and political subdivision of the State of South Dakota created in 1969. The District's purpose is to supply electric energy and to encourage and extend its use. Heartland is currently supplying wholesale supplemental electric power and energy from a diverse mix of resources to 15 municipal electric systems and 1 cooperative in South Dakota, 2 municipal electric systems in Minnesota, and 1 municipal system in Iowa. For more information about Heartland, visit www.hcpd.com.

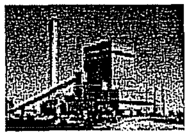
Hutchinson Utilities Commission, headquartered in Hutchinson, Minnesota, is a nonprofit corporation and political subdivision of the City of Hutchinson. The commission's purpose is to supply electric energy and natural gas to the City of Hutchinson, Minnesota, and its residents.

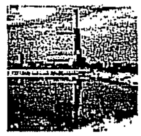
Missouri River Energy Services, headquartered in Sioux Falls, South Dakota, is a not-for-profit joint-action agency governed by the members it serves. Municipal electric utilities from 58 communities in Iowa, Minnesota, North Dakota, and South Dakota compose the MRES membership. MRES members have allocations of hydroelectricity from the Western Area Power Administration, accounting for an average of approximately 50 percent of their power needs. MRES provides the balance of its member power needs from other resources. For more information about MRES, visit www.mrenergy.com.

Otter Tail Power Company contact: Steve Schultz Public Relations Specialist Phone: 701-253-4709 sschultz@otpco.com	**Heartland Consumers Power District contact:** Tim Mullenberg, Manager, Customer Relations Phone: 605-256-6536 timmuell@hcpd.com
Central Minnesota Municipal Power Agency contact: Steve Thompson Director, Operations Phone: 507-526-2193 stevet@utplus.com	**Hutchinson Utilities Commission contact:** Missouri River Energy Services is serving as Hutchinson's agent on the project at this time. See contact information below.
Great River Energy contact: Kandace Olsen Manager, Communications Phone: 763-241-2293 Kolsen@GREnergy.com	**Missouri River Energy Services contact:** Bill Radio Director, Member and Public Relations Phone: 605-338-4042 bradio@mrenergy.com

Exhibit 13
To The
Testimony of John E. Calaway

OTTER TAIL POWER COMPANY





Proposed Big Stone II project

Fact sheet

What is Big Stone II?

Eight local utilities are studying the feasibility of a second electric generating unit, tentatively named Big Stone II, on the site of the existing Big Stone Plant near Milbank, South Dakota. If built, Big Stone II would come online in 2011 and serve the investing utilities' customer loads. Big Stone II would be:

- Approximately 600 megawatts.
- Coal-based.
- Designed with the best available emission-control technology as prescribed by EPA requirements.

What companies are involved in the studies?

The following local utilities are funding the studies and have engaged Kansas City-based engineering firm Burns and McDonnell. The utilities will determine their participation after the studies are complete.

- Otter Tail Power Company, lead developer
- Central Minnesota Municipal Power Agency
- Great River Energy
- Heartland Consumers Power District
- Hutchinson Utilities Commission
- Missouri River Energy Services
- MDU Resources Group
- Southern Minnesota Municipal Power Agency

What is being studied?

Burns and McDonnell is conducting studies in the following areas:

- A cost and performance comparison of state-of-the-art coal combustion and emissions technologies in various size ranges.
- Estimates of air emission rates.
- An evaluation of designs to provide a reliable quantity of cooling water from Big Stone Lake while minimizing impacts and costs.

What transmission upgrades or new construction are being investigated?

Transmission capability studies are underway at the Midwest Independent Transmission System Operator (MISO); however, we would expect transmission upgrades and additions. Every effort will be made to focus on upgrades in existing rights-of-way and to make any additions with the least environmental impact. Results from these studies will be available to the utilities early in 2005, which is when they will make their decisions whether to participate in the project.

How many jobs would this project provide?

Big Stone II would employ an average of 625 construction workers during its four-year construction period, with a peak workforce of 1500. Once online, the plant likely would employ 30 - 40 operational workers at the site.

Related pages

Related pages

Proposed Big Stone II project

Proposed Big Stone II Questions and answers

Proposed Big Stone II Proposed location

Proposed Big Stone II News releases

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You are here: About the company › Generating electricity › Proposed Big Stone II project › **Questions and answers**

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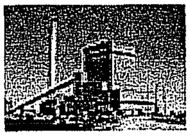
OTTER TAIL POWER COMPANY

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Proposed Big Stone II project

Questions and answers

Project

- Why is this project necessary?
- What have the individual utilities' integrated resource plans shown?
- How many customers do the participants serve?
- What would this plant cost to build?
- What's the estimated service life of the plant?
- How would this plant fit in to Minnesota Renewable Energy Objective strategies, given that the state wants 10 percent renewables by 2015?
- What major regulatory approvals are necessary?
- What fuel source are you proposing for this project?
- Will the route to bring fuel to the plant have adequate rail?
- What is the design and technology for burning the coal?
- How would constructing this plant benefit Minnesota customers and Minnesota energy policy?
- How would building this plant improve reliability?

Environment

- What air emissions controls would this plant use?
- What technology would be used to control mercury?
- Are you using any externality values in your evaluation process?
- What impact would this project have on Big Stone Lake?
- Will this project require an environmental impact study?
- Does this project have potential to back down less efficient plants so there would be fewer emissions overall?
- What are you doing to minimize environmental controversy?

Alternatives

- What alternative generation possibilities are you considering?
- What about IGCC (integrated gas combined cycle)?

Transmission

- How are the transmission studies being conducted?
- When will the studies be completed?
- What transmission alternatives are you studying?
- How much transmission might be in Minnesota?
- What might be the cost of transmission?
- How would the transmission costs be paid/allocated?
- Will upgraded or new transmission for Big Stone II also be able to carry

Economics

South Dakota

Why is this project necessary? Conservative estimates by the Mid-Continent Area Power Pool indicate that electricity consumption in our region will increase by as much as 15 percent over the next decade. Estimates by some independent market analysts indicate that energy consumption may increase by as much as 25 percent. Resource Data International estimates that meeting the increased consumption will require adding more than 9,300 megawatts of capacity in the MAPP region by 2012.

For many years, MAPP has been one of the nation's most reliable systems. However, according to RDI, MAPP had less than 2,700 megawatts scheduled to come on line within the next several years. That's 6,300 megawatts less than the region will require. Because it takes four to six years to plan, site, and build a base-load generating plant, we need to act soon to prevent a supply problem.

The Federal Regulatory Energy Commission has been working for a number of years to develop a competitive wholesale market by opening up access on the bulk transmission system. MAPP historically has been a low-cost region in the country. The competitive wholesale market has allowed higher cost areas outside of MAPP to access the generating facilities within MAPP. This has driven up prices and reduced the available supply. If we do not build, we can expect that relying on purchases from others will become increasingly more expensive.
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What have the individual utilities' integrated resource plans shown? Not every participant files an integrated resource plan. Here is information for those that do.

• **Otter Tail Power Company's** 2002 integrated resource plan filing indicated a need for base load resources. The company now is in the process of developing its newest resource plan, which will identify preferred resources for meeting customer load. Planners are updating the company's load forecast and all other inputs to the planning process. Although the company is obligated to file by July 1, 2005, planners may ask to file early if the planning results indicate that filing early is desirable.

• **Missouri River Energy Services.** In its 2002-2016 integrated resource plan, MRES did not project a need for additional base-load resources during the 2002-2016 planning horizon, but did project a need for intermediate natural gas-fired resources. Since that time, however, the volatile and rising natural gas prices, as well as more recent projections of load growth, indicate a need for additional baseload resources beginning as early as 2009. MRES planners are in the process of updating the various components of resource plan, including projected load data. The next MRES integrated resource plan will be filed with the Minnesota Public Utilities Commission on or before July 1, 2005.
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How many customers do the participants serve?

1,087,000
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What would this plant cost to build? The construction contract would be about $850 million. Including engineering and administration the plant would cost about $1 billion. Transmission upgrades would be an additional cost.
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What's the estimated service life of the plant? 40 years or longer.
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How would this plant fit in to Minnesota Renewable Energy Objective strategies, given that the state wants 10 percent renewables by 2015? Otter Tail Power Company expects to comply with the Minnesota REO across its entire system but still will need some baseload resources to serve its load. Other participants who are subject to the Minnesota REO also expect to comply.
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What major regulatory approvals are necessary? We'll begin applying for the following permits the first half of 2005 if the project goes ahead.

- Federal Environmental Impact Statement

South Dakota
- Plant site
- Air permit
- Water appropriations
- Ash disposal
- Possible transmission line route permit

Minnesota
- IRP approval
- Certificate of Need for the transmission line
- Transmission line route permit

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What fuel source are you proposing for this project? The primary fuel source would be Powder River Basin coal. We also are investigating biomass.
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Will the route to bring fuel to the plant have adequate rail? Yes.
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What is the design and technology for burning the coal? The Phase I engineering studies for the plant portion of the project were completed in May 2004. Results indicated that a 600 megawatt pulverized coal supercritical boiler would be the best and most economical for the site.
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How would constructing this plant benefit Minnesota customers and Minnesota energy policy? This plant would provide an economical, increasingly clean, reliable source of power. And it's possible that the required transmission upgrades could provide opportunities for the development of renewables.
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How would building this plant improve reliability? The plant itself would provide another source of dispatchable base-load energy. In addition, the transmission system would be strengthened.
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Environment

What air emissions controls would this plant use? Big Stone II air emissions would be controlled with highly effective control technologies. As a general comparison, Big Stone II would emit less of the following than existing coal-fired resources that meet current permitting levels:

- Particulate (PM 10) - Bag house technology would control fine particles.
- Sulfur dioxide (SO_2) - 10% that of existing plants
- Nitrous oxide (NO_x) - 5% that of existing plants
- Carbon dioxide (CO_2) - This project proposes using a pulverized coal super critical boiler, which reduces CO_2 emissions on a per kwh basis as compared with conventional boiler technologies.

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What technology would be used to control mercury? Mercury emissions control technology research is continuing. At this time, it appears that activated carbon injection likely would be used to control mercury, but we certainly will not rule out other more cost-effective technologies.
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Are you using any externality values in your evaluation process? Yes. We are using the most current environmental externality values prescribed in Minnesota.
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What impact would this project have on Big Stone Lake? Big Stone II should have a minimal impact on Big Stone Lake because it would use water from the lake only if the lake level were above normal standards. If the lake level were below normal standards, the plant would use stored water or wells. Neither city nor rural water systems would be used as back up.
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Will this project require an environmental impact study? Most likely.
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Does this project have potential to back down less efficient plants so there would be fewer emissions overall? The potential exists because the plant's highly efficient design would make it a low-cost generating station. This means that the electricity it would generate would be dispatched before that from older, less environmentally friendly plants.
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What are you doing to minimize environmental controversy? Because the environment is a primary concern, we are involving stakeholders as early as possible in

the study effort. We intend to ensure that, if built, the plant would be equipped with state-of-the-art mercury, sulfur dioxide, nitrogen oxides, and particulate emissions controls. From a transmission site perspective, once the studies are complete we'll make efforts to minimize the impact to the environment by optimizing the use of existing corridors.
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Alternatives

What alternative generation possibilities are you considering? Remember, this is a project that may be part of eight utilities' plans. You may have to ask each utility about its plans. Here is a brief review of Otter Tail Power Company's and Missouri River Energy Services' plans:

Otter Tail Power Company personnel are considering the following for the next integrated resource plan:

- Purchases from Excelsior Energy.
- Building new base load.
  - IGCC-integrated gasification combined cycle
  - Natural-gas fired—both peaking and combined cycle
  - Different coal technologies
    Circulating fluidized bed
    Pulverized coal
      Sub critical
      Super critical—More environmentally friendly, more efficient (use less coal/kwh)
- Renewables, including biomass and wind.
- Purchases from Manitoba Hydro and other neighboring utilities.
- More energy conservation.
- More load management.

Missouri River Energy Services. In its continuing efforts toward economical, reliable and responsible resource planning, MRES is considering additional power supply options, including:

- Construction of additional fossil-based resources, including participation in a separate coal-fired plant, as well as construction of natural gas-fired peaking units
- Construction of additional renewable energy, including wind, biomass, and compressed air storage
- Short-term or long-term purchases from neighboring utilities
- Upgrades to existing coal unit (LRS)
- Additional efforts to encourage consumer conservation
- Additional efforts to encourage load management

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What about IGCC (integrated gas combined cycle)? We have investigated integrated gas combined cycle generation for this project and determined that it is not a commercially viable option. IGCC plants that have been built have been much smaller than this Big Stone II proposal and have required government funding.
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Transmission

How are the transmission studies being conducted? Transmission studies are being conducted through the Midwest Independent System Operator. Otter Tail Power Company is doing the work as a contractor to MISO. We also will hold meetings with utilities and other interested stakeholders as the study results become available.
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When will the studies be completed? Our target for identifying the major transmission facilities is early 2005. Detailed studies likely will continue for another year.
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What transmission alternatives are you studying? The primary option we're reviewing at this time is to upgrade existing 115-kv lines in west central Minnesota to 230-kv operation by rebuilding in existing corridors. Other upgrades likely will be identified through the study process. We also are investigating new transmission.
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How much transmission might be in Minnesota? We anticipate that the majority of the transmission requirements for this project will be in Minnesota because of the characteristics of the power system and because a good portion of the output of Big Stone II would be used to serve Minnesota customers.
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What might be the cost of transmission? Options range from $60 to $100 million.
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How would the transmission costs be paid/allocated? Because of the uncertainty of federal policy regarding transmission cost recovery and cost allocation, it's difficult to determine the exact way this would occur. However, we would expect that the project participants' customers would bear the majority of the costs over time.
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Will upgraded or new transmission for Big Stone II also be able to carry

[illegible] **renewable energy?** The transmission studies will determine first what is needed for the plant and then what would be available for renewable or other generation. In addition, although Big Stone II's primary fuel source would be Powder River Basin coal, we also are investigating biomass.
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What would the EMF exposure be with these transmission facilities? Although links between power lines and health problems haven't been proven, we'll take precautions in the line design and placement of the conductors to minimize EMF exposure.
Back to the top

Economics

What's the cost of electricity from this plant? The output cost depends on financing costs, which are different for each participating company. Nevertheless, this plant should result in the most cost-effective baseload resource. The estimated capital cost at the time the unit is in service is $1,666 per kilowatt. This cost may seem high, but it includes estimates for anticipated environmental requirements that include very aggressive mercury control and greatly increased cost for SO 2 allowances, as well as mercury and nitrogen oxide allowances. When these are considered, the cost is at the same level that has been projected in all the previous studies.
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How would the cost of this plant per kwh compare with alternatives? A cost per kwh comparison doesn't tell the whole story. Various generating alternatives provide different services beyond just kilowatt-hours. The question should be: How well does the resource fit in with your other resources and what it the total cost to the customer. Only our pending integrated resource plans can answer that.
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How would Big Stone II impact on rates?

- **For Otter Tail Power Company** the impact on rates would be determined as part of the resource planning process. Big Stone II would be more expensive than Otter Tail Power Company's other plants because the company hasn't built a base load plant since 1981. Construction costs have gone up in the last 25 years. And new environmental standards will require expensive controls.

- **Missouri River Energy Services.** It is premature to make any cost projections with any level of confidence until the project details are more defined. MRES has long held the belief that owning our own resources has a much greater stabilizing impact on our rates than if we were dependent on the volatile fluctuations of the market. Having a new, state of the art generating resource, should provide greater efficiencies to the MRES generating mix and support our projected load growth.

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South Dakota

Why build at this location?

- To take advantage of this brown field (existing) site that has existing infrastructure for a second unit. This keeps the cost down and minimizes the environmental disruption. Building on this site also will result in cost decreases to the existing facility through the sharing of resources

- The location is closer to the loads of the current potential co-owners than other sites in North Dakota. This minimizes the transmission line requirements.

Back to the top

What concessions might we ask for from the state of South Dakota? Taxing large developments such as Big Stone II at existing rates may create difficulties. We would like to discuss reductions in:

- Contractors excise tax - 2 percent on any bill from a contractor. Other large projects have had this tax collected and then refunded.
- Property tax - We certainly want to pay taxes and need to determine a fair and reasonable amount.
- Sales tax (currently 4 percent) - a reduction would be helpful.

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How will project sponsors get local government and landowners involved? The personnel and companies connected with the existing Big Stone Plant have a long history of working with local communities through economic development (helping to develop Northern Lights Ethanol, for example) and working with Big Stone restoration groups on lake quality and lake level issues. They have discussed the concept of a Big Stone II with local community members in the past and the idea was well received.

Because our experience has shown that the more we communicate with others the more successful we will be, we will begin working with the Big Stone City and Milbank school district, city commissioners, county commissioners, and other local public officials and community members as soon as possible. Regarding transmission, Minnesota has a defined public meeting process that we will follow in addition to our other outreach efforts.

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Related pages

Proposed Big Stone II project

Proposed Big Stone II Fact sheet

Proposed Big Stone II Proposed location

Proposed Big Stone II News releases

Proposed Big Stone II Timeline

Your electric account | Products and services | Save energy and money | Electric rates | Safety | News and information | About the company | Wholesale marketing | Privacy Policy |

Exhibit 14
To The
Testimony of John E. Calaway

<DOCUMENT>
<TYPE>10-K
<SEQUENCE>1
<FILENAME>mdu10k2004.txt
<DESCRIPTION>MDU RESOURCES GROUP, INC. 2004 10-K
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2004

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number 1-3480

MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

Delaware	41-0423660
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Schuchart Building
918 East Divide Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 222-7900
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00 and Preference Share Purchase Rights	New York Stock Exchange Pacific Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Preferred Stock, par value $100
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X . No __.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes X . No __.

State the aggregate market value of the voting stock held by nonaffiliates of the registrant as of June 30, 2004: $2,822,813,000.

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of February 17, 2005: 118,292,354 shares.

DOCUMENTS INCORPORATED BY REFERENCE.
Portions of the Registrant's 2005 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12 and 14 of this Report.

CONTENTS

PART I

PART I

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are all statements other than statements of historical fact, including without limitation, those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions. In addition to the risk factors and cautionary statements included in this Form 10-K at Item 7 -- Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) - Risk Factors and Cautionary Statements that May Affect Future Results, the following are some other factors that should be considered for a better understanding of the financial condition of MDU Resources Group, Inc. (Company). These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, and/or available supplies of, energy

products and services
- Cyclical nature of large construction projects at certain operations
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- Inability of the various contract counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology
- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations of acquired companies
- Fluctuations in natural gas and crude oil prices
- Decline in general economic environment
- Changes in governmental regulation
- Changes in currency exchange rates
- Unanticipated increases in competition
- Variations in weather

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

GENERAL

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at the Schuchart Building, 918 East Divide Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 222-7900.

Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of the Company, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in the northern Great Plains. Great Plains Natural Gas Co. (Great Plains), another public utility division of the Company, distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added products and services in the northern Great Plains.

The Company, through its wholly owned subsidiary, Centennial Energy Holdings, Inc. (Centennial), owns WBI Holdings, Inc. (WBI Holdings), Knife River Corporation (Knife River), Utility Services, Inc. (Utility Services), Centennial Energy Resources LLC (Centennial Resources) and Centennial Holdings Capital LLC (Centennial Capital).

WBI Holdings is comprised of the pipeline and energy services and the natural gas and oil production segments. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services, including cable and pipeline magnetization and locating. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities, primarily in the Rocky Mountain region of the United States and in and around the Gulf of Mexico.

Knife River mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performs integrated construction services, in the central and western United States and in the states of Alaska and Hawaii.

Utility Services specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling, and the manufacture and distribution of specialty equipment.

Centennial Resources owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

Centennial Capital insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property and contract rights. These activities are reflected in the

Other category.

As of December 31, 2004, the Company had 8,058 full-time employees with 100 employed at MDU Resources Group, Inc., 903 at Montana-Dakota, 55 at Great Plains, 478 at WBI Holdings, 4,015 at Knife River, 2,414 at Utility Services and 93 at Centennial Resources. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

At Montana-Dakota and Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of WBI Holdings, 433 and 75 employees, respectively, are represented by the International Brotherhood of Electrical Workers (IBEW). Labor contracts with such employees are in effect through April 30, 2007 and March 31, 2005, for Montana-Dakota and Williston Basin, respectively. Williston Basin is currently in negotiations with the IBEW relative to its contract.

Knife River has 41 labor contracts that represent 662 of its construction materials employees. Knife River is currently in negotiations on one of its labor contracts.

Utility Services has 69 labor contracts representing the majority of its employees. The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are believed to be generally in good condition, are well maintained, and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments as well as their financing requirements are set forth in Item 7 - MD&A and Item 8 -- Financial Statements and Supplementary Data - Note 13 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site, which is discussed under Items 1 and 2 -- Business and Properties - Construction Materials and Mining - Environmental Matters and in Item 8 -- Financial Statements and Supplementary Data - Note 18. There are no pending Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site.

Governmental regulations establishing environmental protection standards are continuously evolving and, therefore, the character, scope, cost and availability of the measures that will permit compliance with these laws or regulations cannot be accurately predicted. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description below.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q, the Company's current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available through the Company's Web site as soon as reasonably practicable after the Company has filed such reports with the Securities and Exchange Commission (SEC). The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.

ELECTRIC

General --

Montana-Dakota provides electric service at retail, serving over 117,000 residential, commercial, industrial and municipal customers located in 177 communities and adjacent rural areas as of December 31, 2004. The principal properties owned by Montana-Dakota for use in its electric operations include interests in seven electric generating stations, as further described under System Supply and System Demand, and approximately 3,100 and 4,200 miles of transmission and distribution lines, respectively. Montana-Dakota has obtained and holds valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. For additional information regarding Montana-Dakota's franchises, see Item 7 -- MD&A - Prospective Information - Electric. As of December 31, 2004, Montana-Dakota's net electric plant investment approximated $292.9 million.

All of Montana-Dakota's electric properties, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustees, and are subject to the junior lien of the Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee.

The electric operations of Montana-Dakota are subject to regulation by the Federal Energy Regulatory Commission (FERC) under provisions of the Federal Power Act with respect to the transmission and sale of power at wholesale in interstate commerce, interconnections with other utilities, the issuance of securities, accounting and other matters. Retail rates, service, accounting and, in certain instances, security issuances are also subject to regulation by the North Dakota Public Service Commission (NDPSC), Montana Public Service Commission (MTPSC), South Dakota Public Utilities Commission (SDPUC) and Wyoming Public Service Commission (WYPSC). The percentage of Montana-Dakota's 2004 electric utility operating revenues by jurisdiction is as follows: North Dakota -- 59 percent; Montana -- 24 percent; South Dakota -- 7 percent and Wyoming -- 10 percent.

System Supply and System Demand --

Through an interconnected electric system, Montana-Dakota serves markets in portions of the following states and major communities -- western North Dakota, including Bismarck, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South Dakota, including Mobridge. The interconnected system consists of seven on-line electric generating stations, which have an aggregate turbine nameplate rating attributable to Montana-Dakota's interest of 434,230 kilowatts (kW) and a total summer net capability of 475,000 kW. Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station aggregating 22.7 percent and 25.0 percent, respectively) is 327,758 kW. Three combustion turbine peaking stations supply the balance of Montana-Dakota's interconnected system electric generating capability. Additionally, Montana-Dakota has contracted to purchase through October 31, 2006, 66,400 kW of participation power annually from Basin Electric Power Cooperative for its interconnected system. Montana-Dakota also has an agreement through December 31, 2020, with the Western Area Power Administration (WAPA) to provide federal hydroelectric power to eligible Native American customers on the Fort Peck Indian Reservation. The program provides a credit to the customers for the portion of their power received from the federal hydroelectric system. The associated summer monthly capability from the WAPA agreement is 2,819 kW.

On January 9, 2004, Montana-Dakota entered into a firm capacity contract with a Midwest utility to purchase capacity during certain months of 2004 to 2006. In addition, on January 9, 2004, Montana-Dakota entered into a firm power contract with the Midwest utility to purchase power during certain months of 2006 to 2010. All capacity and power purchases from these contracts were contingent upon the parties securing transmission service for the delivery of capacity and power to Montana-Dakota's customer load. Transmission service was not secured and no capacity or energy was delivered under this contract in 2004. These agreements expired on December 31, 2004.

On July 15, 2004, Montana-Dakota entered into a firm capacity contract to purchase 15 megawatts of capacity and associated energy for the summer of 2005 and 25 megawatts of capacity and associated energy for the summer of 2006 from a neighboring utility.

On October 25, 2004, Montana-Dakota issued a request for proposal for 70 megawatts to 100 megawatts of firm capacity and associated energy for the period of November 1, 2006 through December 31, 2010. Montana-Dakota is currently in the process of evaluating the responses.

The following table sets forth details applicable to the Company's electric generating stations:

Generating	Nameplate Rating	Summer Capability	2004 Net Generation (kilowatt-hours in

Station	Type	(kW)	(kW)	thousands)
North Dakota --				
Coyote*	Steam	103,647	106,750	809,267
Heskett	Steam	86,000	103,780	613,145
Williston	Combustion Turbine	7,800	9,600	(75)**
South Dakota --				
Big Stone*	Steam	94,111	103,240	771,679
Montana --				
Lewis & Clark	Steam	44,000	52,300	345,857
Glendive	Combustion Turbine	75,522	75,500	9,689
Miles City	Combustion Turbine	23,150	23,830	3,311
		434,230	475,000	2,552,873

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* Reflects Montana-Dakota's ownership interest.

** Station use, to meet Mid-Continent Area Power Pool's (MAPP) accreditation requirements, exceeded generation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company (Westmoreland). Contracts with Westmoreland for the Coyote, Heskett and Lewis & Clark stations expire in May 2016, December 2005, and December 2007, respectively. The majority of the Big Stone Station's fuel requirements were met with coal supplied by RAG Coal West, Inc. under a contract that expired on December 31, 2004. On July 14, 2004 and July 22, 2004, Montana-Dakota entered into a three-year coal supply agreement with Kennecott Coal Sale Company (Kennecott) and Arch Coal Sales Company (Arch), respectively, to meet the majority of the Big Stone Station's fuel requirements for the years 2005 to 2007, at contracted pricing. The Kennecott and Arch agreements provide for the purchase during 2005, 2006 and 2007 of 500,000, 1.5 million and 1.3 million tons of coal, respectively, from Kennecott and 1.3 million, 500,000 and 500,000 tons of coal, respectively, from Arch.

The Coyote coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The maximum quantity of coal during the term of the agreement, and any extension, is 75 million tons. The Heskett coal supply agreement allows for the purchase of coal necessary to supply the coal requirements of the Heskett Station at contracted pricing. The anticipated fuel supply requirement for 2005 is 400,000 tons. The Lewis & Clark coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Lewis & Clark Station, at contracted pricing. Montana-Dakota estimates the coal requirement to be in the range of 250,000 to 325,000 tons per contract year.

During the years ended December 31, 2000, through December 31, 2004, the average cost of coal purchased, including freight, per million British thermal units (Btu) at Montana-Dakota's electric generating stations (including the Big Stone and Coyote stations) in the interconnected system and the average cost per ton, including freight, of the coal purchased was as follows:

Years Ended December 31,	2004	2003	2002	2001	2000
Average cost of coal per million Btu	$ 1.08	$ 1.04	$ .98	$ .92	$ .94
Average cost of coal per ton	$15.96	$15.22	$14.39	$13.43	$13.68

The maximum electric peak demand experienced to date attributable to sales to retail customers on the interconnected system was 470,000 kW in August 2003. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the peak demand growth rate through 2010 will approximate 1.2 percent annually. Montana-Dakota's latest forecast indicates that its kilowatt-hour (kWh) sales growth rate, on a normalized basis, through 2010 will approximate 1.5 percent annually.

Montana-Dakota currently estimates that it has adequate capacity available through existing baseload generating stations, turbine peaking stations and long-term firm purchase contracts to meet the peak demand requirements of its customers through the year 2006. Additional capacity that is needed in 2007, or after, to replace expiring contracts and meet system growth requirements is expected to be met through power contracts and/or building or acquiring an additional 175 megawatts to 200 megawatts of capacity. As part of the North Dakota Industrial Commission's

Lignite Vision 21 project, Montana-Dakota submitted an air quality permit application in May 2004 to construct a 175-megawatt coal-fired plant at Gascoyne, North Dakota. The air permit application is under review at the North Dakota Department of Health (North Dakota Health Department). Montana-Dakota also is involved in the review of other potential projects to replace capacity associated with expiring purchased power contracts and to provide for future growth. The costs of building and/or acquiring the additional generating capacity are expected to be recovered in rates.

Montana-Dakota has major interconnections with its neighboring utilities, all of which are MAPP members. Montana-Dakota considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Through a separate electric system (Sheridan System), Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date and attributable to Montana-Dakota sales to retail consumers on that system was approximately 52,300 kW and occurred in August 2003.

The Sheridan System is supplied through an interconnection with the PacifiCorp transmission system, under an agreement with Black Hills Power and Light Company (Black Hills Power), as part of a power supply contract through December 31, 2006, which allows for the purchase of up to 55,000 kW of capacity annually. On December 30, 2004, Montana-Dakota entered into a power supply contract with Black Hills Power to purchase up to 74,000 kW of capacity annually during the period January 1, 2007 to December 31, 2016.

Regulation and Competition --

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas. The restructuring of the electric industry has been slowed due to certain events in the industry. In addition, as a result of competition in electric generation, wholesale power markets have become increasingly competitive and evaluations are ongoing concerning retail competition.

Montana-Dakota is a member of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). The Midwest ISO is responsible for operational control of the transmission systems of its members. The Midwest ISO agreement permits Montana-Dakota to be a separate transmission pricing zone. The Midwest ISO also provides security center operations and tariff administration.

The Montana legislature passed an electric industry restructuring bill, effective May 2, 1997. The bill provided for full customer choice of electric supplier by July 1, 2002, stranded cost recovery and other provisions. Based on the provisions of such restructuring bill, because Montana-Dakota operates in more than one state, the Company had the option of deferring its transition to full customer choice until 2006. In March 2001, legislation was passed in Montana that delays the restructuring and transition to full customer choice until a time when Montana-Dakota can reasonably implement customer choice in the state of its primary service territory.

In its 1997 legislative session, the North Dakota legislature established an Electric Industry Competition Committee to study over a six-year period the impact of competition on the generation, transmission and distribution of electric energy in North Dakota. In 2003, the committee was expanded and the study was extended for an additional four years. To date, the Committee has made no recommendation regarding restructuring. In 1997, the WYPSC selected a consultant to perform a study on the impact of electric restructuring in Wyoming. The study found no material economic benefits. No further action is pending at this time. The SDPUC has not initiated any proceedings to date concerning retail competition or electric industry restructuring. Federal legislation addressing this issue continues to be discussed.

Although Montana-Dakota is unable to predict the outcome of such regulatory proceedings or legislation, or the extent to which retail competition may occur, Montana-Dakota is continuing to take steps to effectively operate in an increasingly competitive environment. For additional information regarding retail competition, see Item 7 - MD&A - Prospective Information - Electric.

Fuel adjustment clauses contained in North Dakota and South Dakota jurisdictional electric rate schedules allow

Montana-Dakota to reflect increases or decreases in fuel and purchased power costs (excluding demand charges) on a timely basis. Expedited rate filing procedures in Wyoming allow Montana-Dakota to timely reflect increases or decreases in fuel and purchased power costs. In Montana (24 percent of electric revenues) such cost changes are includable in general rate filings.

Environmental Matters --

Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

The U.S. Environmental Protection Agency (EPA) may authorize a state to manage federal programs such as the Federal Clean Air Act (Clean Air Act) and Federal Clean Water Act (Clean Water Act), under approved state programs. This is the case in all the states where Montana-Dakota operates.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which it operates. Each of these permits has a five-year life. Three permits have expired with a fourth expiring on April 1, 2005. Montana-Dakota has submitted applications for renewal on all four permits within the required time frames, and as a result, all the expired permits remain valid. State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities located on the Yellowstone and Missouri Rivers. These permits also have a five-year life with the first permit expiring on November 30, 2005. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and U.S. Army Corps of Engineers (Army Corps) permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary, and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the Resource Conservation and Recovery Act (RCRA). Montana-Dakota routinely handles polychlorinated biphenyls (PCBs) from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007. For matters involving Montana-Dakota and the North Dakota Health Department and a related matter involving the Dakota Resource Council, see Item 3 -- Legal Proceedings.

NATURAL GAS DISTRIBUTION

General --

Montana-Dakota sells natural gas at retail, serving over 223,000 residential, commercial and industrial customers located in 142 communities and adjacent rural areas as of December 31, 2004, and provides natural gas transportation services to certain customers on its system. Great Plains sells natural gas at retail, serving over 22,000 residential, commercial and industrial customers located in 19 communities and adjacent rural areas as of December 31, 2004, and provides natural gas transportation services to certain customers on its system. These services for the two public utility divisions are provided through distribution systems aggregating approximately 5,200 miles. Montana-Dakota and Great Plains have obtained and hold valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. For additional information regarding Montana-Dakota's and Great Plains' franchises, see Item 7 - MD&A - Prospective Information - Natural gas distribution. As of December 31, 2004, Montana-Dakota's and Great Plains' net natural gas distribution plant investment approximated $151.6 million.

All of Montana-Dakota's natural gas distribution properties, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustees, and are subject to the junior lien

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

RECEIVED
MAR 15 2005
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMPLAINT FILED BY SUPERIOR RENEWABLE ENERGY LLC ET AL. AGAINST MONTANA DAKOTA UTILITIES CO. REGARDING THE JAVA WIND PROJECT	) Docket No. EL04-016

CERTIFICATE OF SERVICE

This is to certify that on March 11, 2005, a copy Superior Renewable Energy LLC's Rebuttal Testimony of John E. Calaway was forwarded to the following electronically and United States mail, in accordance with South Dakota Codified Law:

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