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March 10, 2008

VIA FEDERAL EXPRESS & EMAIL

Illona Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol
Bismarck, ND 58505

**Re: Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station
Case Nos. PU-06-481 and PU-06-482**

Dear Ms. Jeffcoat-Sacco:

On behalf of Applicants Otter Tail Corporation and Montana-Dakota Utilities Co., enclosed for filing in the above matter please find the following supplemental direct testimony and attached exhibits of Applicants:

Ward Uggerud (OTP Exhibit 112);
Bryan Morlock (OTP Exhibit 117);
Andrea Stomberg (MDU Exhibit 213);
James Heidell (MDU Exhibit 214);
Mark Rolfes (OTP/MDU Exhibit 324);
Tim Rogelstad (OTP/MDU Exhibit 325);
Jeffrey Grieg (OTP/MDU Exhibit 326); and
Thomas Crowley (OTP/MDU Exhibit 328).

Please direct any questions to Montana-Dakota's Mr. Daniel Kuntz (701-530-1016), Otter Tail's Mr. Mark Bring (218-998-7152), or to the undersigned.

Thank you for your consideration.

Very truly yours,

/s/ Todd J. Guerrero

TJG/kas
cc: Attached Service List (w/encl.)

Doc# 2570973\1

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Supplemental Direct Testimony and Attached Exhibits of Applicants
Lindquist & Vennum
Todd Guerrero

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF

MARK ROLFES

PROJECT MANAGER

OTTER TAIL POWER COMPANY

MARCH 10, 2008

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF MARK ROLFES

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF MARK ROLFES

I. INTRODUCTION

Q: Please state your name and business address.

A: Mark Rolfes, 48450 144th Street, Big Stone City, SD 57216

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted testimony as OTP/MDU Exhibits 301 and 302.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to address the current schedule for the Big Stone II Project given the withdrawal by Great River Energy (GRE) and Southern Minnesota Municipal Power Agency (SMMPA). My testimony also covers the downsized plant size options being used by the Applicants in their revised planning because of the recent changes of ownership, the cost projections for these different unit sizes, and the basis for these cost projections.

Q: Please summarize your testimony?

A: The planned Commercial Operation Date (COD) for the Big Stone II project is now summer 2013. The Applicants chose to examine two plant sizes as part of their updated analyis – a nominal 500 MW facility and a nominal 580 MW facility.

Costs for these plant size alternatives were developed based on project data gathered to-date, commonly-used industry methods, and other factors including expert judgment. A 500 MW plant is estimated to cost $1.272 billion. A 580 MW plant is estimated to cost $1.411 billion. The plant efficiency and emissions rates for this range of plant sizes will not be appreciably different from the 630 MW plant size contemplated earlier.

III. BIG STONE II PROJECT SCHEDULE

Q: Please describe the current schedule for construction of Big Stone II.

A: Given the delays to the project, the schedule we are currently operating under for commercial operation of a second unit at Big Stone is summer 2013. This schedule is approximately thirteen months later than I testified to at the hearings in June of 2007. Tim Rogelstad will provide testimony on the schedule for the proposed transmission facilities.

When I last testified, the Big Stone II owners anticipated a decision on all public service commission regulatory approvals (North Dakota Public Service Commission, South Dakota Public Utilities Commission, and Minnesota Public Utilities Commission) no later than mid-year 2007. Because of the delay primarily in the Minnesota Certificate of Need matter, and the decision by the owners not to enter into large procurement contracts until the permitting is completed, the owners have been required to readjust the schedule. Given that we now expect a decision in this case at the end of May 2008, the most likely in-service date for the unit is the summer of 2013, or roughly 62 months from the time the final permits are obtained. Any additional delays in governmental authorizations will result in a commensurate delay in commercial operation.

IV. PROJECT COST ESTIMATES

Q: What size plant did the Applicants use in their updated analysis?

A: The Applicants examined two different project sizes: a 580 MW supercritical pulverized coal plant and a 500 MW supercritical pulverized coal plant. The original plant was a planned nominal 630 MW supercritical pulverized coal unit.

Q: Why were these sizes selected?

A: With the withdrawal by GRE and SMMPA from the project, and in light of the practical inability to expedite the process of admitting new participants to the project without drastically protracting the regulatory review process, the remaining five utilities understood they had to downsize the plant to optimally fit their anticipated resource needs and take advantage of the economies of scale.

A 500 MW unit is representative of a number of units that have been constructed recently, or are in the planning stage, so there is current, relevant information available on plants of this size. An example is the Weston 4 project in Wisconsin, a 500 MW supercritical pulverized coal plant being constructed by Wisconsin Public Service. Another reason for selecting 500 MW is that this size is consistent with the South Dakota tax legislation that placed a cap on property evaluation for units 500 MW and larger. Also, 500 MW is essentially the anticipated aggregate basic needs of the partners.

580 MW was chosen as the upper limit for a couple of reasons. First, it provides some economies of scale that a 500 MW plant does not present, so it offers a different cost analysis. Second, it affords more room for the owners to obtain additional generating capacity, and more likely, some capacity to accommodate the needs of additional partners if that should develop. Finally, construction of a 580 MW plant was considered to be a realistic option for the five owners so it was important to examine a plant in that size range.

Q: What are the cost estimates for these two different size plants?

A: The cost estimate used for a 500 MW nominal unit is **$1.272 billion** dollars (or $2,545/kW). The cost estimate being used by the companies in their analysis for a 580 MW nominal unit entering into service in June of 2013 is **$1.411 billion** dollars (or $2,434/kW). These cost estimates are for the plant only and do not include costs for transmission. These are in actual dollars, and represent what the owners would need to expend in the aggregate between the beginning of construction through summer of 2013. These numbers could be discounted back to present (2007) value using an assumed discount rate. We did not do so in order to avoid introducing inapt cost figures that could contribute to confusion in the record.

These costs do not include Interest During Construction (IDC) or Allowances for Funds Used During Construction (AFUDC).

Q: How did you determine these estimates?

A: The process to determine these estimates was based on the cost estimates that were provided last year with some adjustments as explained below. Using the work conducted by Black & Veatch for a 630 MW facility to be in-service in May 2011, we used information from the Electric Power Research Institute (EPRI) for scaling plant costs from a known size to a different size unit, either larger or smaller. We then used escalation factors to estimate the cost based on an in-service date two years later.

Q: Is using the EPRI formula something that can be relied on with any certainty?

A: Absolutely. Using the EPRI formula is a standard way to adjust the costs for differences in size. The formula came from a report that EPRI issued in March 2007 and it is based on current data. It is common practice in the industry to use a formula like this when one size of plant is known and an estimated cost is needed for a slightly different size unit. The sizes that we are considering are well within the accuracy range of this formula.

Q: How did you account for the delay in bringing Big Stone II into commercial operation?

A: Delay is by far the biggest component in the price change. In our previous testimony, we testified that the project is using an approximate 6% per year escalation factor. This escalation is also based on the original Black & Veatch analysis.

Q: Are you confident that a 6% escalation rate is reasonable?

A: Yes. While it is difficult to find exact information given the competitive nature of comparable projects, our research of public record literature and periodicals on published cost expectations indicates that our price estimates are well within the range of what other projects are experiencing and what others are using in their projects.

We have also examined published indices with respect to commodities such as steel, pipe, wire, etc. The majority of these indices have been at or below the escalation rate that we have been using for commodity pricing in our project. Thus, we feel that the cost estimate for delay is very reasonable. Again, it must be emphasized that delay is by far a bigger contributor to the cost exposure of a project than the change in plant size for the project within the range of sizes we are considering.

Q: Did the Applicants perform any sensitivity analysis around its estimates?

A: Yes. The Applicants are highly sensitized to the possibility of increased costs. As discussed above, that is why, in part, the Applicants elected not to reduce cost estimates for key commodity inputs, despite a moderation in the prices of those commodities over the past year. The project has employed other methods that factor in the possibility of increased costs, without referring to them as sensitivity analyses. One example is the work that the Applicants' resource planners performed, as described in the testimonies of Bryan Morlock and James Heidell.

The Applicants' consideration of two different plant sizes is also a form of sensitivity analysis. The cost of a 500 MW unit is slightly under 5% more than for a 580 MW unit on a cost per MW basis. Even with the 5% higher cost, the Applicants still have the same level of need. In addition, within our price estimate we have included a contingency of approximately 13.5%. During more predictable times, this contingency level would be lower. This is another way that we have built sensitivity to higher costs into the analysis. We have also used a number of conservative estimates on design and labor costs to try to build-in some cushion for possible upward price deviations.

Q: Can you provide any other information regarding the reasonableness of your cost estimates for Big Stone II?

A: Yes. In the Minnesota CON proceeding, intervenors pointed to Duke Energy's recently approved 800 MW Cliffside project as an example of how much a super-critical baseload plant is likely to cost. As we pointed out in Minnesota, if you take the Duke cost number and adjust it for economies of scale (because the proposed Duke facility is a larger project than Big Stone II), you would find that the Big Stone II cost estimate and the Duke cost estimate are almost exactly the same number on a per kW basis. The percentages of increase are immaterial. The final cost is the more important number. A comparison of Big Stone II with the Duke Cliffside plant actually lends credence to the fact that our estimate is in line with what the rest of the industry is seeing.

Q: Why did you decide not to engage Black & Veatch to prepare an update of the costs estimates for you?

A: We did not think that a second in-depth cost estimate was necessary because we had a very good base case to work from and we had standard industry practices to adjust for different size plants and the cost due to escalation. These are standard engineering practices. We did check with Black & Veatch to make sure our methodology was proper and followed acceptable practices. They confirmed that what we were doing was normal practice. It must be remembered that the biggest variable in the cost for the new unit is delay. This is more of a factor than the engineering work and that is the factor in the calculation that we have the least amount of control over. That's why it did not make sense to expend significant resources and time to come up with a cost number that is no more accurate than the one we have today.

The accuracy of our cost estimates cannot be sharpened until we achieve greater permitting certainty. Repeated delays have created the risk of the project being viewed by key vendors as the proverbial "boy who cried wolf." We would face the potential of not being taken seriously if we were to continually ask our prospective vendors for updated price bids. We know that the vendors will not go through the time consuming, expensive process of developing bids based on detailed cost estimates until there is greater permitting certainty than exists now.

It is simply unrealistic to assume vendors will spend a great deal of time and effort to "sharpen their pencils" until they have a more definitive timeframe and more assurances on the permitting side. If they know specific timeframes based on permitting certainty, they can prepare "firm" bids. We could spend large sums of money to have Black & Veatch or another engineering firm provide a new estimate, but without any more permit certainty this would be a waste of time and resources.

Q: Will costs increase for other kinds of technology also?

A: Yes, certainly. Most of the cost increase is due to ongoing escalation for construction labor and materials. These same cost escalation factors affect all other resource options as well.

Q: Some people have indicated that though all power generation projects use the same commodities, a coal-fired project is more adversely affected by cost increases than a natural gas project. Do you agree with this statement?

A: Depending upon what happens, a natural gas project could be more adversely affected by future developments than coal-fired projects. As coal-fired projects are being cancelled, many of them are now turning to natural gas projects. In the past we have seen huge run-ups in the cost of gas turbines in response to an increase in demand for them.

The manufacturing capability for gas turbines is quite limited, and the manufacturers have increased their prices greatly in the past when demand has increased. In addition, this is a time when other uses of gas turbines, principally for airplane propulsion, is also at a peak. The two largest manufacturers, Boeing and Airbus, are having record sales, with a huge backlog. The likely run-up in cost for gas turbines could far exceed the cost increases for other components. In addition, if there is a softening in the labor markets, a coal-fired plant could have a relative advantage, as the amount of labor needed to construct a coal-fired plant is a much larger percentage of the overall cost than it is for a natural gas fired unit.

The bottom line is that a utility must plan prudently. All power projects are going to see cost increases going forward, assuming the predicted demand for these resources continues to increase. A blanket statement that a coal-fired plant is going to fare worse than other types of resources is simplistic and is readily subject to dispute.

V. OTHER FACTORS

Q: Are there other cost considerations that should be kept in mind when looking at the cost to build Big Stone II and other resources?

A: Yes. By the nature of our business, the process that leads to the addition of supply-side resources tends to drive up the prices of power and generation equipment. Due to the industry philosophy under which we operate, utilities do not build plants when it is most economical. Because we as an industry all routinely share and trade resources to equalize generation surpluses and deficits, we all tend to go deficit together around the same time. This is what is happening in our region right now. In effect, utilities must consider their needs and only build new plants as a last resort. Utilities are not allowed to build plants when they are, in effect, "relatively cheap."

We must have overwhelming proof of a material need for a plant before we can construct one. Because we operate in a market where utilities share resources, this tends to require all utilities to build at the same time. Thus, the industry tends to cause, by the very nature of its business, construction peaks and valleys.

When any utility sets about solving the problem of acquiring needed resources, there has to be an underlying assumption that competition will exist for the material and labor required to build those generation resources. This is a fundamental aspect of our industry. We will see increases in costs for new electric generation as we defer construction until the point where neither the utilities nor their customers can afford to wait any longer, a situation the Applicants and their customers are fast approaching. This is a fundamental condition within which we must operate.

Q: With the change in plant size to 500 MW or 580 MW, will there be a decrease in the plant's overall efficiency?

A: No. The overall plant efficiency, or heat rate as it is referred to, will not be adversely affected in either a 500 MW or 580 MW plant as compared to the 630 MW unit. The final heat rate is dependent upon the particular equipment manufacturers and models of their equipment selected, and that is independent of size. In the size range of alternatives we are considering, size does not have an effect on unit efficiency.

Q: Does the change in size have any effect on the carbon dioxide or other emissions information previously provided?

A: Because the overall plant efficiency, or heat rate, does not change for a 500 MW or 580 MW unit, the rate of carbon dioxide and regulated emissions does not change on a per MWh basis. Of course, the smaller unit will have fewer total emissions because it produces fewer total MWh; but on a per MWh emissions rate basis there will be no change.

There will be a slight change in the cost of these controls because of the loss of economies of scale. For instance, it takes approximately the same number of people to operate the pollution control equipment on a 500 MW unit as it does on a 580 MW unit. Thus, there is some increase in the operating and maintenance cost per MWh given the smaller size. These costs were considered, however, by the companies' resource planning experts. The other costs associated with control for allowances and capital costs will be unaffected.

Q: What is the current status of the permitting for the Big Stone plant?

A: Prior to the hearings in June last year, the project had in place a Solid Waste permit, a Surface Water Appropriations permit, and a Energy Conversion Facility Permit, each from the state of South Dakota. Since then, the project has obtained a South Dakota Transmission Routing permit and a Groundwater Appropriations permit. Two other South Dakota Air permits remain in process - the Prevention of Significant Deterioration and Title V permits - and the Federal Environmental Impact Statement (EIS) (which is not really a permit, *per se*) has not been finalized. We expect to receive the PSD permit in the second quarter of 2008. The supplemental draft EIS was published on October 26, 2007 and we expect the final report/record of decision will be published in the third quarter 2008. We anticipate a decision by the Minnesota Public

Utilities Commission on the Certificate of Need and Route Permits for the transmission lines in April or May this year.

Q: Does this conclude your testimony?

A: Yes

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF

TIMOTHY J. ROGELSTAD

Manager of Delivery Planning

OTTER TAIL POWER COMPANY

MARCH 10, 2008

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF TIMOTHY J. ROGELSTAD

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL TESTIMONY OF TIMOTHY J. ROGELSTAD, P.E.

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Timothy J. Rogelstad. My business address is 215 South Cascade Street, Fergus Falls, Minnesota 56537.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted direct testimony on December 1, 2006 and rebuttal testimony on June 21, 2007, OPT/MDU Exhibits 312 and 318 respectively, along with other exhibits.

II. THE BIG STONE II TRANSMISSION PROJECT

Q: What is the proposed in-service date for the transmission lines?

A: Right now we are anticipating that the transmission facilities will be in service in early 2013. This is several months prior to the commercial operation of the Big Stone Unit II generating plant. The previous schedule called for the Big Stone II Transmission project to be completed in 2011. However, because of delays in obtaining final regulatory approvals, the completion of the interconnection facilities of the Big Stone II Transmission project has been delayed by approximately a year and a half.

Q: What is the current estimated cost for the transmission facilities necessary for adding Big Stone II generation?

A: The total estimated cost of the transmission facilities necessary for interconnecting and delivering the generation to the project participants' load is $249 million. This compares to a cost of $238 million that I reported in December 2006. The major reason for the cost increase is inflation resulting from a delay in the in-service date.

Q: Has the change in ownership had any impact on the facilities proposed to interconnect the Big Stone Unit II?

A: No, as I testified last time, interconnection studies determine what facilities are required to interconnect a proposed generator to the transmission grid regardless of where the power from the generator is going to be delivered. How the generation is delivered from the generating plant to the load is addressed in a delivery service study. Therefore, a change in ownership of the project will not have an impact on the interconnection facilities.

Q: Does the change in the size of the Big Stone Unit II facility affect the need for the proposed transmission interconnection lines?

A: No. Essentially any generation facility larger than 150 MW at the Big Stone site would require more than a 115 kV system. The proposed lines to Morris and to Granite Falls remain the best choice for interconnecting a 500 MW facility at Big Stone.

Q: Does a change in the size of the Big Stone Unit II unit affect the Applicants' position in the MISO queue for access to the transmission system?

A: No, not at all. Keeping the proposed transmission lines the same allows the Applicants to retain their position in the MISO queue and not require additional studies.

Q: How might the change in ownership impact the transmission delivery service study results?

A: Because SMMPA and GRE's loads are further east than the remaining participants, their withdrawal from the project may actually result in some of the facilities that are further away being removed from the list of facilities impacted by Big Stone II. Further study will determine whether that is the case.

Q: Would a change in the Big Stone Transmission project have an impact on other generation projects that are in the interconnection queue after Big Stone?

A: Yes. If the Big Stone Transmission project does not go forward, it will have a significant impact on the generation projects that are queued after Big Stone II in the region. Almost all of the transmission studies for projects queued after Big Stone II would need to be restudied because they assumed Big Stone II and its associated transmission would be in-service. MISO has indicated that it will take up to an additional year to perform a restudy of those projects that had assumed the Big Stone II Transmission project in their base case. Not only will the projects after Big Stone II be subject to restudy, they will likely be subject to additional costs associated with transmission upgrades.

To put this into perspective, there are more than 50,000 MW of interconnection requests in the MISO queue in the tri-state region that were filed after Big Stone II. There are 59 projects, accounting for nearly 11,000 MW, in North Dakota. Of these 59 projects, there are nine that would have to be restudied because they assumed that the Big Stone II Transmission lines were constructed. Of these nine, two are already in service. Even those projects that are already in-service are at risk if Big Stone II Transmission lines are not constructed, because they would still have to do additional studies. If the additional studies (without the Big Stone transmission facilities) identify the need for additional facility additions, those projects would be on the hook for cost-sharing those additional upgrades

Q: Does this conclude your testimony?

A: Yes.

OTP/MDU Exhibit 326

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF

JEFFREY J. GREIG

General Manager, Business & Technology Services

BURNS & MCDONNELL ENGINEERING COMPANY

MARCH 10, 2008

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF JEFFREY J. GREIG

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL PREFILED DIRECTTESTIMONY OF JEFFREY J. GREIG

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Jeffrey (Jeff) J. Greig. My business address is Burns & McDonnell Engineering Co., 9400 Ward Parkway, Kansas City, MO, 64114.

Q: By whom are you employed, and in what capacity?

A: I am employed by Burns & McDonnell Engineering Company. I am the General Manager of the Business & Technology Services Division of the company.

Q: Did you previously provide any prefiled written testimony in this matter?

A: Yes, I did. I prepared Rebuttal Testimony dated June 21, 2007, that was entered into the record as OTP/MDU Exhibit 309.

Q: Did you testify at the previous hearing held in June 2007?

A: Yes, I did. I testified before the Commission on June 26, 2007.

II. PURPOSE AND SUMMARY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to report on the work that Burns & McDonnell recently completed to compare the economics of various baseload generation technologies, using a number of updated assumptions from the earlier analysis that I reported on during the last round of hearings in 2007. In particular, we provided revised cost estimates for a downsized Big Stone Unit II from a nominal 630 MW facility to either a 580 MW nominal or a 500 MW nominal facility, based on the fact that two partners withdrew from the project last fall.

Q: Please summarize your testimony.

A: Burns & McDonnell evaluated several sizes for a supercritical pulverized coal (PC) plant (630 MW, 580 MW, and 500 MW) and compared the busbar costs of energy from those facilities with the busbar cost of a 500 MW combined cycle natural gas (CCGT) facility. Burns & McDonnell also evaluated the busbar costs of a combination 500 MW CCGT facility with market purchases of wind, both with and without the extension of a Production Tax Credit (PTC) for wind. We determined that the Big Stone Unit II supercritical PC plant still has the lowest busbar costs on a $/MWh basis of all the baseload alternatives considered, for both Otter Tail Power and Montana-Dakota Utilities, at all threes plant sizes that were considered, namely 630 MW, 580 MW, and 500 MW.

III. UPDATED ANALYSIS

Q: Please describe the analysis that Burns & McDonnell recently completed.

A: In the fall of 2007 we were requested by the Big Stone participants to update the economic evaluation we performed in 2006 to reflect the fact that two of the utilities had withdrawn from the Big Stone Project and that the remaining five utilities were considering the possibility of downsizing Big Stone Unit II. We estimated the relative busbar costs of energy from the different types of facilities under consideration, relying on the most recent and pertinent assumptions available.

Q: What assumptions did you update from your 2006 analysis?

A: One assumption that we updated was the current cost estimates of the various options under review compared to earlier planning estimates. Another assumption was that the size of the proposed Big Stone Unit II project was decreased to either 580 MW or 500 MW. We also updated the fuel cost forecasts based on recent information.

Q: Did you make any assumptions regarding potential costs for carbon dioxide regulation?

A: Yes, we included a carbon dioxide cost evaluation required by Minnesota Public Utilities Commission for filings before that state's commission. We analyzed the effect of a $9/ton carbon dioxide cost on the busbar costs of energy from the various technologies considered. This $9/ton assumption was applied to all tons of carbon that would be emitted by Big Stone II, which is conservative. According to leading climate change bills in Congress, new efficient units like Big Stone II could be allocated a large quantity of no-cost carbon allowances. This issue was also addressed in detail in the Minnesota proceeding. This means that $9/ton applied to all tons of carbon is equivalent in annual costs to a much higher allowance cost per ton as it would be applied to only a portion of Big Stone II's carbon emissions.

Further, after Burns & McDonnell completed this analysis in November 2007, we went back again and re-examined some additional higher carbon dioxide costs that the Minnesota PUC adopted in December 2007 and presented those results in the Minnesota proceeding.

Q: Are you including carbon dioxide costs in your North Dakota testimony?

A: No, I am not because North Dakota law precludes a utility from incorporating possible future environmental costs into consideration and because the Commission has already ruled that evidence related to this matter is irrelevant. However, I do want to point out that I have not drafted a separate report specifically for North Dakota, so there is discussion of the impact of carbon dioxide costs on Big Stone in the November 2007 Report.

Q: Did you compare the busbar costs for both investor-owned utilities and publicly-owned utilities?

A: Yes, because in the overall project there are three publicly-owned utilities involved. We prepared two different economic models – one to reflect public power entities and a second to apply to investor-owned utilities (IOU). Investor-owned and publicly-owned utilities have different financing and capital structures, and have different revenue requirements. For the investor-owned model, a 50 percent debt / 50 percent equity financing structure was assumed, and an income tax liability component was estimated. The revenue requirements of each ownership structure were also determined differently. The public power model was intended to capture economic results that would be expected for a cooperative, municipal utility, or joint action agency. The public power model assumed tax-exempt debt financing through bond issuance for 100 percent of the project capital costs. Also, no income tax liability was estimated.

Q: Are you including testimony about publicly-owned utilities in your testimony?

A: No, because the three publicly-owned utilities involved in the Big Stone II project have no customers in North Dakota and are not involved in this advance prudence determination proceeding. However, my November 2007 Report does include the results of my analysis for the publicly-owned utilities.

Q: Did Burns & McDonnell prepare a written report of its updated economic evaluation of different generation alternatives?

A: Yes, we did. Burns & McDonnell presented its results in a written report entitled "Updated Economic Evaluation of Baseload Generation Alternatives" dated November 2007. This updated summary is included as OTP/MDU Exhibit 327.

Q: What was your role in preparing the update?

A: As with the prior "Updated Economic Evaluation of Baseload Generation Alternatives" prepared in September 2006, I was the overall project manager for the 2007 study update.

IV. METHODOLOGY

Q: What methodology did Burns & McDonnell follow in performing its economic analysis?

A: First, the capital cost, performance, and operations & maintenance (O&M) costs for the different baseload generation alternatives were estimated. These estimates were used as the key inputs into a pro forma economic model that determined the annual busbar cost of power for each alternative on a revenue requirements basis over a 20-year planning period. The technical inputs were combined with economic, financing, and fuel cost assumptions to develop the overall busbar power costs. Two different economic models were prepared to reflect the different potential ownership structures.

Q: What is meant by the busbar cost?

A: Busbar refers to the cost of power without transmission, distribution, and ancillary service charges. Effectively the busbar cost is the cost of the power at the plant substation.

Q: Explain the term revenue requirements.

A: Revenue requirements are the total costs that need to be recovered on an annual basis, both operating costs and capital costs. For the investor-owned utility model, the revenue requirements are defined as fuel costs, fixed and variable O&M costs, interest on debt, depreciation expense, return on invested equity, and a tax liability component.

Q: What were the specific financing assumptions used in the economic analysis for the IOUs?

A: For the investor-owned model, a 50 percent debt / 50 percent equity financing structure was assumed for capital cost financing. The debt component was assumed as 20 years with a 7.5

percent interest rate. The return on equity was assumed to be 12.0 percent. These financing assumptions were used for each of the baseload generation alternatives.

Q: Explain the term levelized.

A: Generally, costs increase over time due to inflation impacts on operating costs and fuel costs. Over a long-term planning period, a levelized busbar cost represents a single, all-in power cost that captures measures of both cost escalation and the time value of money. For the selected discount rate, the utility would be indifferent to the levelized busbar cost throughout the planning period or a power cost that started lower but escalated annually. A levelized busbar cost is a useful summary measure for comparing alternatives.

Q: What specific alternatives were considered in your latest analysis?

A: We evaluated six different generation options that are capable of providing reliable, dispatchable capacity and energy to meet baseload requirements. These included the following:

- 630 MW Big Stone Unit II supercritical PC plant
- 580 MW Big Stone Unit II supercritical PC plant
- 500 MW Big Stone Unit II supercritical PC plant
- 500 MW combined cycle gas turbine (CCGT) plant
- 500 MW CCGT plant plus market purchases of wind energy with an extension of the Production Tax Credit
- 500 MW CCGT plant plus market purchases of wind energy without an extension of the Production Tax Credit.

V. COST ESTIMATES

Q: What were the current cost assumptions provided to Burns & McDonnell for the Big Stone Unit II project?

A: The current capital cost estimate provided to Burns & McDonnell by Otter Tail for a 630 MW alternative is $1.496 billion excluding transmission construction for the 630 MW project size. This reflects a deferred on-line date of 2013 and is approximately 9.5 percent higher than the cost estimate used in the September 2006 analysis. The cost estimates for the 580 MW alternative and 500 MW alternative were scaled by Otter Tail Power Company and were $1.412 billion (580 MW alternative) and $1.272 billion (500 MW alternative). The cost estimates reflect an appropriate increase in $/kW based on a decline in the economy of scale that the 630 MW unit provides.

Q: What were the current cost and performance assumptions provided to Burns & McDonnell for the CCGT project?

A: The Applicants' construction and engineering firm Black & Veatch prepared a report entitled, "Supply-Side Technology Study" dated August 2006. The capital cost estimate for a generic 2 x 1 GE 7FA CCGT project was estimated in 2006$ at $281 million ($562/kW) plus $56.2 million of Owner's costs ($674.4/kW total). This cost was used again and escalated 5.0 percent annually until the proposed commercial operation date.

Q: What was the basis for the cost of wind resources used in the Updated Economic Evaluation?

A: For the CCGT plus market purchase of wind energy alternative, it was assumed that non-firm wind energy would be purchased. These wind energy purchases would displace an equivalent amount of energy and would offset the need for a portion of the higher cost gas-fired energy generation by the CCGT. Burns & McDonnell estimated in the earlier study that new wind farm development in the Midwest region costs $40/MWh in 2006$ with the federal production tax credit (PTC) in place. The price of wind turbines has subsequently increased significantly within the last two years due to market factors and material costs such as steel and copper, and many Burns & McDonnell clients are currently pricing new wind farm developments at $50/MWh or higher; however the $40/MWh cost assumption was maintained as a conservative assumption. The 2006$ cost estimate was escalated 5.0 percent annually until the proposed commercial operation date.

The current PTC expires at the end of 2008 and may not be available in 2013 as a subsidy to lower the cost of wind energy. A second scenario was prepared using a cost of purchased wind that is $20/MWh higher under the assumption that the PTC is not available at that time.

VI. WIND ASSUMPTIONS

Q: What was the purpose of including the wind resource with the CCGT alternative?

A: For the CCGT project plus wind case, the 500 MW CCGT plant is the baseload alternative being compared to the supercritical PC plant alternatives. Both are reliable, dispatchable generation resources that can be operated to meet baseload capacity and energy requirements. Wind is not a baseload resource because it does not produce dependable generation year-round at high capacity factors. Hence, our analysis did not assume construction of a wind resource, but market purchases of non-firm wind energy. The wind component was added to the CCGT project alternative to enhance its economic performance by displacing higher cost gas-fired energy production with non-firm wind energy when available. The evaluation was focused on comparing baseload project alternatives, not developing combinations of resources on a system basis as a substitute for utility resource planning efforts.

Q: What was the assumption regarding the capacity factor of the wind resource?

A: The evaluation assumed that non-firm wind energy would be available to displace the equivalent of a 40 percent capacity factor for the CCGT plant. In this regard, the assumption was optimistic for typical wind farm production. Nevertheless, we utilized the 40 percent estimate to be conservative in testing Big Stone Unit II economics against alternatives.

Q: Did you make any assumptions with regard to transmission that might be required for new wind projects?

A: No, since we are only calculating a busbar cost, we excluded transmission costs for all of the alternatives. In reality, however, new wind farms in the hundreds of megawatts that are being considered here would require substantial new transmission infrastructure. This is another conservative assumption that favors wind.

VII. OTHER ASSUMPTIONS

Q: Were the financing assumptions the same as used in the prior studies?

A: Yes.

Q: Were the other key operating and economic assumptions the same?

A: Yes, with the exception that the fuel cost forecasts were updated based on 2007 information.

Q: What was the basis for the fuel cost forecasts used in the Updated Economic Evaluation?

A. The Powder River Basin (PRB) fuel cost forecast was provided by Otter Tail Power Company. In the September 2006 analysis, we used a cost of $1.71/MMBtu in 2010 and an overall escalation rate of approximately 2.9 percent. In this round of examination, we used a cost of $1.74/MMBtu in 2010 for the overall delivered cost for PRB coal and an escalation rate of approximately 3.5 percent.

For natural gas, in September 2006, the New York Mercantile Exchange (NYMEX) futures price for Henry Hub natural gas commodity supply in 2011 was $7.20/MMBtu. A conservative transportation cost of $0.40/MMBtu was added to this supply cost for a delivered cost of $7.60/MMBtu in 2011 in the prior analysis. In October 2007, the NYMEX futures price for Henry Hub natural gas commodity supply in 2012 was $7.91/MMBtu. The same conservative transportation cost of $0.40/MMBtu was added to this supply cost for a delivered cost of $8.31/MMBtu in 2012 in the updated analysis. Note that the U.S. Energy Information Administration published that the average differential in wellhead and delivered natural gas fuel costs for electric utilities was $0.67/MMBtu in 2006. The use of $0.40/MMBtu for gas transportation and balancing services for an upper Midwest generic location is conservative, and gives the benefit of the doubt in favor of the CCGT alternative.

Q: Were any additional sensitivity analyses prepared in the Updated Economic Evaluation with regard to future costs of natural gas?

A: Yes. As noted before, the assumption for gas transportation costs of $0.40/MMBtu is conservative. In addition, if a federal carbon tax or CO_2 allowance structure is implemented in the US, basic economics indicate that the demand for natural gas used in power generation will increase, further exacerbating the current natural gas supply situation and increasing costs further. To evaluate the potential that delivered natural gas costs are understated in the analysis due to these factors, a sensitivity assuming a $0.50/MMBtu and a $1.00/MMBtu increase were evaluated.

Q: What were the results of this sensitivity analysis?

A: Under an investor-owned utility ownership structure, if the price of natural gas increased by $0.50/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $91.04/MWh. If the price of natural gas increased by $1.00/MMBtu the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $93.55/MWh.

VIII. CONCLUSIONS

Q: What was the conclusion of your 2007 updated analysis?

A: This 2007 update confirmed that the Big Stone Unit II project represents the lowest cost baseload generation alternative of those evaluated on a life-cycle basis considering capital and operating costs for Otter Tail Power and Montana-Dakota Utilities. This conclusion was reaffirmed for the 630 MW project size and remained for the smaller 580 MW or 500 MW plant sizes considered. The proposed Big Stone Unit II has been consistently verified as a least-cost baseload generation alternative on a life-cycle basis, with or without the extension of the PTC for wind under capital, operation, performance, and fuel cost estimates that have been periodically updated over time.

Q: What were the specific results reported in your updated analysis?

A: For the investor-owned utility ownership model, the lowest cost generation alternative was the 630 MW supercritical Big Stone Unit II project with an estimated levelized busbar cost of $73.98/MWh over the 2013 to 2032 planning period. The 580 MW and 500 MW Big Stone Unit II project alternatives followed at $75.26/MWh and $77.65/MWh, respectively. The CCGT plus market purchases of wind energy alternative was $86.55/MWh (with PTC), which is 17 percent higher than the 630 MW Big Stone Unit II project and 11 percent higher than the 500 MW Big Stone Unit II project.

Q: Did the results changes from your earlier analysis?

A: No, they didn't. Some economies of scale are lost when the plant is downsized but supercritical PC remains the lowest cost option. A comparison of the results from the September 2006 study with the 2007 update is shown in the table below.

TABLE 1. ESTIMATED LEVELIZED BUSBAR COSTS ($/MWH)

	Alternatives Study 2006	Updated Evaluation 2007
	Investor Owned	Investor Owned
630 MW Supercritical	$69.62	$73.98
580 MW Supercritical	N/A	$75.26
500 MW Supercritical	N/A	$77.65
500 MW CCGT	$81.89	$92.68
CCGT plus wind energy purchases	$80.78	$86.55

Q: Would you advocate that a utility should rely on the kind of economic analysis Burns & McDonnell performed as the primary basis for deciding on which type of generation facility to construct?

A: No. The purpose of our work was to compare alternative baseload generation technologies capable of providing reliable, dispatchable capacity and energy to meet baseload requirements. Burns & McDonnell has never portrayed the evaluations as an assessment of need or an integrated evaluation of supply and demand-side alternatives. The evaluation compares baseload generation alternatives only and demonstrates that the supercritical Big Stone Unit II pulverized coal plant is a least-cost baseload generation alternative on a life-cycle basis considering capital and operating costs compared to numerous other baseload generation alternatives. A prudent utility would rely on detailed resource planning analyses to make a final conclusion, and that is what I understand the Applicants have completed.

Q: Does this conclude your testimony?

A: Yes, it does.

UPDATED ECONOMIC EVALUATION OF BASELOAD GENERATION ALTERNATIVES

prepared for

Otter Tail Power Company
Fergus Falls, Minnesota

November 2007

Project No. 41451

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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UPDATED ECONOMIC EVALUATION OF BASELOAD GENERATION ALTERNATIVES

1.1 INTRODUCTION

Burns and McDonnell (B&McD) previously prepared a number of pro forma economic analyses of baseload generation technology alternatives for the Otter Tail Power Company (OTPCo) Big Stone Unit II (BSII or Project). A twenty-year economic model analysis was prepared based on the estimated capital costs, performance, fuel costs, emissions, and operating costs of each baseload generation alternative. The economic model analyses of each baseload generation alternative resulted in a levelized busbar cost that could be compared against the other alternatives.

Recently, several inputs to the economic models were updated, and the models were rerun. This evaluation presents the changes to the inputs and the new pro forma model results.

In addition, the BSII participant group is considering downsizing the Project size as an alternative to remarketing available capacity to new participants. Supercritical pulverized coal (PC) units of 580 MW and 500 MW have been added to this updated analysis.

1.2 UPDATED ECONOMIC ANALYSIS ASSUMPTIONS

The following provides the economic analysis assumptions utilized in the original economic model analysis compared to the assumptions utilized in the updated economic model analysis.

Commercial Online Date	Updated Input	2006 Input
• Project COD (all options)	2013	2012

Coal Unit Capital Costs [1]	Updated Input	2006 Input
• 630 MW Supercritical PC (BSII)	$1.496 billion	$1.366 billion
• 580 MW Supercritical PC	$1.412 billion	Not Modeled
• 500 MW Supercritical PC	$1.272 billion	Not Modeled

[1] PC unit costs are presented in time of construction (nominal) dollars.

Gas Unit Costs[2]	Updated Input	2006 Input
• 500 MW CCGT Plant (2006$)	$674.4/kW	$674.4/kW

[2] 2x1 GE 7FA CCGT capital cost estimated by B&V and escalated to COD at 5.0%.

Fuel Cost Forecast	Updated Input	2006 Input
• PRB Coal Cost (2010$)	$1.74/MMBtu	$1.71/MMBtu
• PRB Coal Escalation Rate	3.5% per annum	2.9% per annum
• Natural Gas Cost	$8.31/MMBtu (2012$)	$7.60/MMBtu (2011$)
• Natural Gas Escalation Rate	Unchanged	3.0% per annum

Purchased Wind Power Cost [3]	Updated Input	2006 Input
• Levelized Cost – With PTC (2006 $)	$40.00/MWh	$40.00/MWh
• Levelized Cost – No PTC	+$20.00/MWh	$60.00/MWh

[3] Purchase cost of non-firm wind estimated by B&McD and escalated to COD at 5.0%.

CO_2 Emissions Environmental Costs	Updated Input	2006 Input
• CO_2 Emissions Cost	$9.00/ton (2007$)	$3.64/ton (2006$)
• CO_2 Emissions Escalation Rate	Levelized	2.5% per annum

Operating Assumptions	Updated Input	2006 Input
• Overall Capacity Factor	Unchanged	88.0%

1.3 CAPITAL STRUCTURE AND ECONOMIC ASSUMPTIONS

The following financing and economic assumptions were utilized in the initial economic model analysis and remain unchanged. They are listed again herein for a comprehensive description of assumptions. The economic model analyses were prepared under two distinct ownership and cost of capital structures: investor owned utility (IOU) and public power utility (PPU).

Note that each of the BSII participating utilities will have its own financing plan, capital structure, rate of return, tax rate, and depreciation schedule for its share of the BSPII Project, and the specific cost of capital assumptions will vary. The following assumptions are used to represent the relative difference in capital cost financing for the different ownership structures.

Financing Assumptions (Investor Owned Utility)

• Interest Rate	7.5%
• Term	20 years
• Debt/Equity Percentage	50%/50%
• Return on Equity	12.0%
• Construction Financing	48 months for PC
	24 months for CCGT

Financing Assumptions (Public Power Utility)

• Interest Rate	6.0%
• Term	30 years
• Debt/Equity Percentage	100%/0%
• Return on Equity	N/A
• Construction Financing	48 months for PC and IGCC
• 24 months for CCGT	

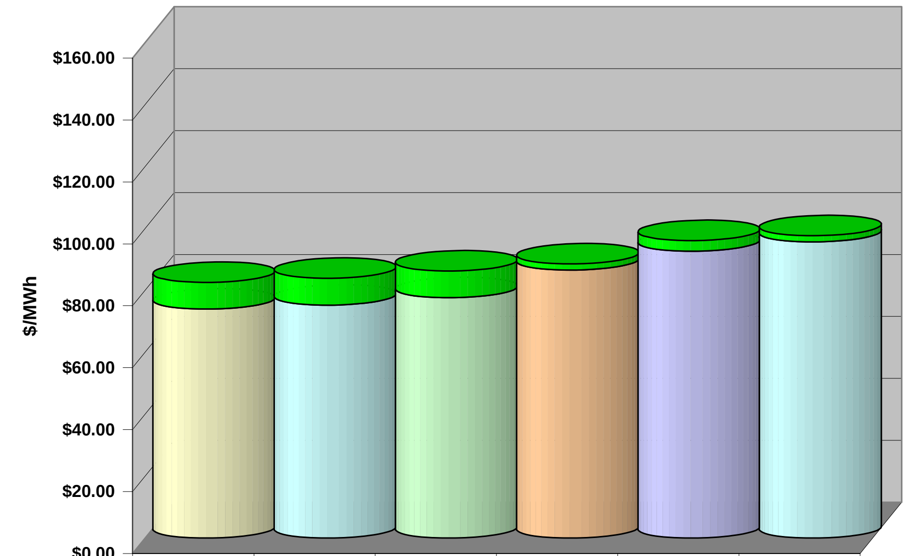
Economic Assumptions

• Discount Rate (Investor Owned Utility)	9.75%
• Discount Rate (Public Power)	6.0%
• Effective Tax Rate (IOU only)	40.0%
• Book Depreciation	30 years
• Tax Depreciation (IOU only)	20 years

1.4 SUMMARY OF ECONOMIC ANALYSIS

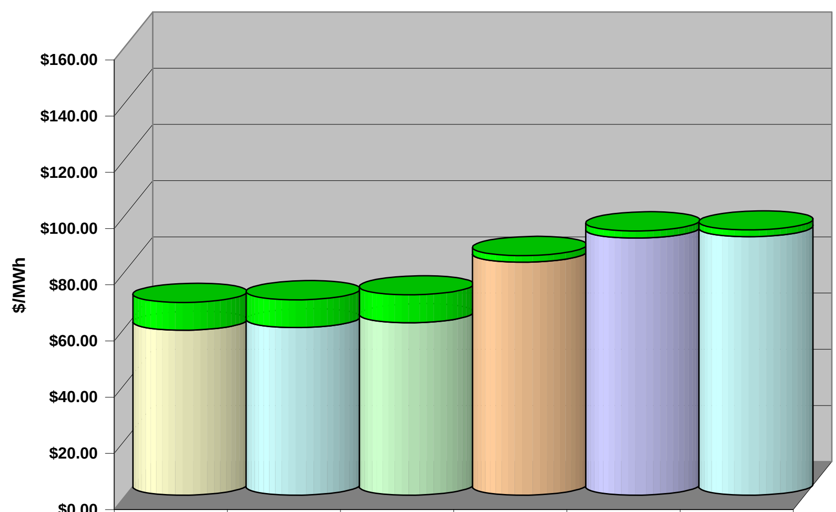
B&McD prepared an updated economic model analysis for each of the baseload generation alternatives based on the updated inputs presented in the previous sections. A 20-year economic analysis was prepared and the levelized busbar cost of each alternative was determined under two ownership structures: investor-owned utility (IOU) and public power utility (PPU). Figures 1 and 2 present graphs showing the 20-year levelized busbar power costs in 2013$ for each of the baseload generation alternatives under both investor owned utility and public power utility ownership.

Figure 1: Levelized Busbar Costs (2013$) – Investor Owned Utility



	630 MW BSII	580 MW BSII	500 MW BSII	CCGT +Wind - With PTC	500 MW CCGT	CCGT +Wind - No PTC
Total Busbar Cost	$82.61	$83.89	$86.27	$88.55	$96.09	$97.64
Carbon Tax	$8.63	$8.63	$8.63	$2.00	$3.41	$2.00
Busbar Cost w/o Carbon Tax	$73.98	$75.26	$77.65	$86.55	$92.68	$95.64

Figure 2: Levelized Busbar Costs (2013$) – Public Power Utility



	630 MW BSII	580 MW BSII	500 MW BSII	CCGT +Wind - With PTC	500 MW CCGT	CCGT +Wind - No PTC
Total Busbar Cost	$68.62	$69.55	$71.30	$85.29	$94.03	$94.38
Carbon Tax	$9.92	$9.92	$9.92	$2.37	$2.54	$2.37
Busbar Cost w/o Carbon Tax	$58.70	$59.63	$61.38	$82.92	$91.49	$92.01

As indicated in Figures 1 and 2, the inclusion of a carbon environmental cost levelized value of $9.00/ton increases the levelized busbar costs of all the alternatives, but does not change the relative economics of the baseload alternatives.

The three supercritical PC units remain cost-effective, even accounting for higher costs associated with declining economy of scale on the unit size from 630 MW to 500 MW.

1.4.1 Investor Owned Utility Results

The break-even carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately $12.10/ton for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $89.25/MWh, which is an increase of 15 percent compared to the base case 500 MW BSII cost of $77.65/MWh for an IOU participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately $15.30/ton for the IOU structure. This would increase the levelized busbar cost of both alternatives to approximately $89.95/MWh, which is an increase of 20 percent compared to the base case 580 MW BSII cost of $77.65/MWh for an IOU participant.

The break-even carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately $24.40/ton for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $101.05/MWh, which is an increase of 30 percent compared to the base case 500 MW BSII cost of $77.65/MWh for an IOU participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately $27.70/ton for the IOU ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $101.80/MWh, which is an increase of 35 percent compared to the base case 580 MW BSII cost of $77.65/MWh for an IOU participant.

1.4.2 Public Power Utility Results

The break-even carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately

$25.70/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $89.70/MWh, which is an increase of 46 percent compared to the base case 500 MW BSII cost of $61.38/MWh for a public power participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately $27.80/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $90.27/MWh, which is an increase of 51 percent compared to the base case 580 MW BSII cost of $61.38/MWh for a public power participant.

The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately $36.60/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $101.70/MWh, which is an increase of 66 percent compared to the base case 500 MW BSII cost of $61.38/MWh for a public power participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately $38.70/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $102.28/MWh, which is an increase of 71 percent compared to the base case 580 MW BSII cost of $61.38/MWh for a public power participant.

Overall, inclusion of a $9.00/ton CO_2 environmental cost value in the evaluation did not impact the baseload generation economic results irrespective of whether the PTC is extended, or whether the BSII unit size is decreased by moderate levels.

Further, the analysis relies on a conservative assumption regarding the purchase price of non-firm wind energy. The estimated 2006 purchase price of $40.00/MWh (with PTC) has been escalated 5.0% annually, implying a 2007 purchase price of $42.50/MWh. However, due to significant cost increases in wind turbine-generator units and general construction and commodity cost escalation that has impacted all generation resources, B&McD’s clients are currently pricing new wind farm developments at $50/MWh or higher.

1.5 NATURAL GAS COST SENSITIVITY

The primary driver for these updated results is the increase in natural gas costs. In the analysis prepared in September 2006, NYMEX futures for natural gas supply were $7.20/MMBtu in 2011. In October 2007, the MYMEX futures price for natural gas supply in 2012 had increased to $7.91/MMBtu. In both cases, a conservative transportation cost of $0.40/MMBtu was added.

Natural gas prices remain high and highly volatile. Therefore, it is appropriate to test the results against the potential that natural gas prices will prove to be higher than predicted. As an example, Attachment A from a recent Energy Information Administration report outlines the delivered cost of natural gas to electric utilities relative to wellhead prices. As indicated, the average differential in the US in 2006 was $0.67/MMBtu ($7.09/MMBtu - $6.42/MMBtu). Year- to-date 2007 indicates a differential of $1.25/MMBtu. B&McD is reflecting a conservative $0.40/MMBtu transportation component for a northern Midwest generic location. Actual transportation and balancing costs could be significantly higher.

In addition, if a carbon tax or CO_2 allowance program were to be implemented in the United States, there would likely be an increase in natural gas based power generation. This would increase the demand for natural gas, and potentially further drive up the price of natural gas relative to coal resources. As a sensitivity analysis, levelized busbar costs were calculated for the CCGT plus Wind cases assuming a $0.50/MMBtu and a $1.00/MMBtu increase in natural gas costs.

Under an investor owned utility ownership structure, if the price of natural gas increased by $0.50/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $91.04/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $15.40/ton for the investor owned utility ownership structure. If the price of natural gas increased by $1.00/MMBtu the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $93.55/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $18.80/ton for the investor owned utility ownership structure.

Under a public power utility ownership structure, if the price of natural gas increased by $0.50/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $87.78/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $28.70/ton for the public power utility ownership structure. If the price of natural gas increased by $1.00/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $90.43/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $31.60/ton for the public power utility ownership structure.

1.6 CONCLUSIONS

This Updated Analysis of Baseload Generation Alternatives supports the following conclusions:

- The Big Stone II unit alternative remains a low cost baseload resource alternative for the participating utilities and their customers.
- Although the CCGT alternative has lower capital costs, the high and volatile cost of natural gas fuel makes it uneconomical for baseload dispatch.
- The CCGT plus Wind case reflects the next lowest cost baseload energy resource combination, but is 12 percent higher cost for the IOU utilities and 35 percent higher cost for the public power utilities compared to the 500 MW Big Stone II alternative, if the PTC is renewed. Plus, the CCGT resource is not renewable.
- If the PTC is not renewed, The CCGT plus Wind case is 23 percent higher cost for the IOU utilities and 50 percent higher cost for the public power utilities compared to the 500 MW Big Stone II alternative.
- Inclusion of a carbon environmental cost value in the evaluation of $9.00/ton did not change the results and was primarily offset by continued escalation in natural gas costs. In addition, the transportation component assumed for natural gas is conservative, as is the purchase cost for non-firm wind energy utilized in the analysis.
- If a carbon tax or CO_2 allowance program were imposed, the price of natural gas would likely increase, therefore, further increasing the levelized busbar cost of natural gas based alternatives.

1.7 STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of a new power generating facilities. While we believe the use of these assumptions is reasonable for the purposes of this Study, B&McD makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, fuel costs, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in the Study will vary.

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Table 3. Selected National Average Natural Gas Prices, 2002-2007
(Dollars per Thousand Cubic Feet)

Year and Month	Wellhead Price[a]	City Gate Price	Delivered to Consumers					Electric Power Price[c]
			Residential Price	Commercial		Industrial		
				Price	% of Total[b]	Price	% of Total[b]	
2002 Annual Average	**2.95**	**4.12**	**7.89**	**6.63**	**77.38**	**4.02**	**22.70**	**3.68**
2003 Annual Average	**4.88**	**5.85**	**9.63**	**8.40**	**78.24**	**5.89**	**22.12**	**5.57**
2004 Annual Average	**5.46**	**6.65**	**10.75**	**9.43**	**77.97**	**6.53**	**23.66**	**6.11**
2005								
January	5.80	7.05	11.03	10.23	85.22	7.05	24.67	6.72
February	5.74	7.09	11.02	10.08	85.48	7.14	24.11	6.42
March	5.95	7.24	11.00	10.16	84.96	7.11	24.37	6.84
April	6.58	7.79	12.02	10.49	83.21	7.71	23.71	7.27
May	6.24	7.51	12.88	10.55	80.14	7.19	23.97	6.83
June	6.09	7.30	13.92	10.41	78.98	6.92	23.44	7.08
July	6.71	7.68	14.99	10.73	76.59	7.40	24.21	7.58
August	6.48	8.20	15.66	11.19	77.19	7.99	24.31	8.67
September	8.96	10.26	16.70	12.82	75.78	10.19	22.95	11.01
October	10.35	12.16	16.56	14.62	79.59	12.07	22.97	11.85
November	9.91	11.57	15.78	15.11	81.83	12.13	23.20	9.87
December	9.08	10.77	14.75	14.32	84.48	11.17	23.44	11.28
Annual Average	**7.33**	**8.67**	**12.84**	**11.59**	**82.71**	**8.56**	**23.81**	**8.48**
2006								
January	[E]8.66	10.75	14.94	14.11	83.79	10.85	[R]22.33	9.09
February	[E]7.28	9.27	14.00	13.00	84.03	9.31	[R]22.15	7.99
March	[E]6.52	8.74	13.20	12.01	83.87	8.24	[R]22.30	7.35
April	[E]6.59	8.28	13.28	11.51	80.84	7.94	[R]21.91	7.31
May	[E]6.19	7.94	14.40	11.54	78.37	7.65	[R]22.32	6.87
June	[E]5.80	7.29	15.03	11.03	75.65	6.91	[R]21.85	6.67
July	[E]5.82	7.27	15.69	10.92	74.35	6.80	22.03	6.67
August	[E]6.51	7.96	16.17	11.14	72.12	7.39	[R]22.36	7.52
September	[E]5.51	7.58	15.69	11.10	74.30	7.23	[R]20.58	6.32
October	[E]5.03	6.34	12.57	10.05	77.05	5.63	[R]21.24	5.75
November	[E]6.43	8.39	12.47	11.05	80.06	7.79	[R]21.32	7.48
December	[E]6.65	8.66	12.53	11.57	82.35	8.26	[R]21.88	7.56
Annual Average	**[E]6.42**	**8.54**	**13.75**	**11.97**	**80.57**	**7.89**	**[R]21.86**	**7.09**
2007								
January	[E]5.92	7.86	12.08	11.12	82.99	7.36	22.24	7.04
February	[E]6.66	8.60	12.13	11.23	83.68	8.27	21.99	8.17
March	[E]6.56	8.81	12.85	11.82	83.25	8.47	21.22	7.64
April	[RE]6.84	8.17	13.28	11.54	80.88	8.17	21.43	7.76
May	[E]6.98	8.33	14.59	11.58	77.83	8.14	22.43	7.96
June	[E]6.86	8.39	16.22	11.91	73.52	8.01	22.96	[R]7.80
July	[E]6.19	7.94	16.65	11.63	73.83	7.58	22.03	NA
August	[E]5.90	7.45	16.85	11.16	72.00	6.58	22.26	NA
2007 YTD[d]	**[E]6.49**	**8.25**	**13.05**	**11.44**	**80.67**	**7.82**	**22.06**	**7.74**
2006 YTD[d]	**[E]6.67**	**8.86**	**14.19**	**12.39**	**81.10**	**8.19**	**22.16**	**7.38**
2005 YTD[d]	**6.20**	**7.36**	**11.70**	**10.33**	**83.13**	**7.31**	**24.12**	**6.89**

[a] See Appendix A, Explanatory Note 9, for discussion of wellhead prices.

[b] Percentage of total deliveries represented by onsystem sales (see Figure 6). See Table 23 for State data.

[c] The electric power sector comprises electricity-only and combined-heat-and-power plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public. Beginning in 2002, data include nonregulated members of the electric power sector.

[d] Year-to-date price represents months for which price information is available in the current year. The electric power sector year-to-date price is two months behind those of wellhead, city gate, residential, commercial and industrial.

[E] Estimated data.

[NA] Not available.

[RE] Revised estimated data.

Notes: Data for 2002 through 2005 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 States and the District of Columbia.

Sources: 2002-2005: Energy Information Administration (EIA), *Natural Gas Annual 2005*. January 2006 through current month: Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"; Form EIA-910, "Monthly Natural Gas Marketer Survey"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Federal Energy Regulatory Commission (FERC), Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; and EIA estimates.

OTP/MDU Exhibit 328

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF

THOMAS CROWLEY

L.E. PEABODY & ASSOCIATES, INC.

MARCH 10, 2008

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF THOMAS CROWLEY

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BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF THOMAS CROWLEY

I. INTRODUCTION

Q: Would you state your name, background, and present position.

A: My name is Thomas D. Crowley. I am an economist and President of the economic consulting firm of L. E. Peabody & Associates, Inc. The firm's offices are located at 1501 Duke Street, Suite 200, Alexandria, VA 22314; 5901 Cicero Avenue, Suite 504, Chicago, IL 60646; and 10445 N. Oracle Road, Suite 151, Tucson, Arizona 85737. I have been employed by L. E. Peabody & Associates, Inc. since 1971.

Q: What is your educational background?

A: I received a Bachelor of Science degree in Economics from the University of Maine. I have also taken graduate courses in transportation at George Washington University in Washington DC.

Q: What previous experience do you have?

A: The firm of L.E. Peabody & Associates, Inc. specializes in solving economic, marketing and transportation problems. As an economic consultant, I have organized and directed economic studies and prepared reports for railroads, freight forwarders and other carriers, for shippers, for associations and for state governments and other public bodies dealing with transportation and related economic problems. Examples of studies I have participated in include organizing and directing traffic, operational and cost analyses in connection with multiple car movements, unit train operations for coal and other commodities, freight forwarder facilities, TOFC/COFC rail facilities, divisions of through rail rates, operating commuter passenger service, and other studies dealing with markets and the transportation by different modes of various commodities from both eastern and western origins to various destinations in the United States. The nature of these studies enabled me to become familiar with the operating practices and accounting procedures utilized by railroads in the normal course of business.

Additionally, I have inspected and studied both railroad terminal and line-haul facilities used in handling various commodities, and in particular unit train coal movements from the Powder River Basin ("PRB") of Wyoming and Montana to various utility destinations in the midwestern and western portions of the United States. These operational reviews and studies were used as a basis for the determination of the traffic and operating characteristics for specific movements of coal, both inbound raw materials and outbound paper products to and from paper mills, crude and pelletized iron ore, crushed stone, soda ash, aluminum, fresh fruits and vegetables, TOFC/COFC traffic and numerous other commodities handled by rail.

I have frequently been called upon to develop and coordinate economic and operational studies relative to the acquisition of coal and the rail transportation of coal on behalf of electric utility companies. My responsibilities in these undertakings included the analyses of rail routes, rail operations and an assessment of the relative efficiency and costs of railroad operations over those routes. I have also analyzed and made recommendations regarding the acquisition of railcars according to the specific needs of various coal shippers. The results of these analyses have been employed in order to assist shippers in the development and negotiation of rail transportation contracts which optimize operational efficiency and cost effectiveness.

Since the implementation of the Staggers Rail Act of 1980, which clarified that rail carriers could enter into transportation contracts with shippers, I have been actively involved in negotiating transportation contracts on behalf of coal shippers. Specifically, I have advised utilities concerning coal transportation rates based on market conditions and carrier competition, movement specific service commitments, specific cost-based rate adjustment provisions, contract reopeners that recognize changes in productivity and cost-based ancillary charges.

I have also been actively engaged in negotiating coal supply contracts for various users throughout the United States. In addition, I have analyzed the economic impact of buying out, brokering, and modifying existing coal supply agreements. My coal supply assignments have encompassed analyzing alternative coals to determine the impact on the delivered price of operating and maintenance costs, unloading costs, shrinkage factor and by-product savings.[1]

I have developed different economic analyses for over sixty (60) electric utility companies located in all parts of the United States, and for major associations, including American Paper Institute, American Petroleum Institute, Chemical Manufacturers Association, Coal Exporters Association, Edison Electric Institute, Mail Order Association of America, National Coal Association, National Industrial Transportation League, the Fertilizer Institute and Western Coal Traffic League. In addition, I have assisted numerous government agencies, major industries and major railroad companies in solving various economic problems.

Q: You indicated earlier that you have performed economic analyses for numerous government agencies. Have you ever been retained by the State of North Dakota?

A: Yes, in 2005 and 2006 L. E. Peabody & Associates, Inc. was retained by the State of North Dakota Public Service Commission to evaluate the likely outcome of pursuing a complaint proceeding before the Surface Transportation Board ("STB") related to the level of rail rates charged by BNSF for the movement for grain from origins in the State of North Dakota to

[1] Shrinkage factors vary by coal characteristics such as moisture content and size. By-products of gypsum and fly ash are created by burning coal in an electric generation station and different coals produce varying quantities and qualities of these by-products, thereby creating varying by-product savings.

various destinations. Our preliminary analyses estimated maximum reasonable rates using both the STB's stand-alone cost methodology and its maximum rate procedures for small shipper complaints.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Otter Tail Corporation and Montana-Dakota Utilities Co., hereinafter referred to as "Applicants".

Q: Have you testified in prior North Dakota or other state or federal utility regulatory proceedings?

A: Yes. I have presented evidence before the Interstate Commerce Commission ("ICC") in Ex Parte No. 347 (Sub-No. 1), <u>Coal Rate Guidelines - Nationwide</u> which is the proceeding that established the methodology for developing a maximum rail rate based on stand-alone costs. I have submitted evidence applying the ICC's stand-alone cost procedures in every proceeding filed before the ICC and its successor the STB where these procedures have been used. I have frequently presented both oral and written testimony before the ICC, STB, Federal Energy Regulatory Commission, Railroad Accounting Principles Board, Postal Rate Commission and numerous state regulatory commissions, federal courts and state courts. This testimony was generally related to the development of variable cost of service calculations, rail traffic and operating patterns, fuel supply economics, contract interpretations, economic principles concerning the maximum level of rates, implementation of maximum rate principles, and calculation of reparations or damages, including interest. I presented testimony before the Congress of the United States, Committee on Transportation and Infrastructure on the status of rail competition in the western United States. I have also presented testimony in a number of court and arbitration proceedings concerning the level of rates, rate adjustment procedures, rail operating procedures and other economic components of specific contracts.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: My testimony will address forecasts of coal fuel prices and coal transportation prices.

Q: Are you sponsoring any documents and exhibits in the filing?

A: Yes, I am sponsoring six exhibits. OTP/MDU Exhibit 329 is a summary of our forecast of the delivered price of fuel to the Big Stone II generation station. OTP/MDU Exhibit 330 is our forecast of the cost of transportation of coal from the Powder River Basin of Wyoming ("PRB") to the Big Stone II Generating Station. OTP/MDU Exhibit 331 is our forecast of fuel prices for the Big Stone II Generating Station. OTP/MDU Exhibit 332 is a graphical illustration of the change in PRB spot coal prices from 1997 to today. OTP/MDU Exhibits 333 and 334 illustrate in graphical and tabular form the differences between my forecast and the forecasts used by the Applicants in 2006 and 2007.

Q: Please summarize your testimony.

A: I have independently prepared a delivered coal price forecast for the Big Stone II plant. Comparing my forecast to those of the Applicants, I find that my forecast is very similar to the Applicants' 2006 forecast. My forecast is lower than the Applicants' 2007 forecast used in this proceeding, with the greatest divergence occurring during the time period 2019 to 2025. This indicates that the Applicants' 2007 forecast used in his proceeding is conservative with regard to its potential effects on the amount of Big Stone II that is needed relative to other alternatives.

III. FORECAST SUMMARY

Q: Please explain what is displayed in OTP/MDU Exhibit 329.

A: OTP/MDU Exhibit 329 is a summary of our forecast of the delivered price of fuel to the Big Stone II Generation Station though 2038. Page 1 of OTP/MDU Exhibit 329 shows our forecast of the delivered price on a per ton basis and Page 2 of OTP/MDU Exhibit 329 shows our forecast of delivered prices on a price per million British Thermal Units ("MMBTU") basis.[2]

Q: OTP/MDU Exhibit 329 shows a Rail Transportation Forecast, a PRB Coal Forecast and a Total Delivered Cost Forecast. Please describe the differences in these forecasts.

A: The Rail Transportation forecast shown in Column (2) of OTP/MDU Exhibit 329 is our rail freight rate forecast for moving PRB coal to the Big Stone II Generating Station for the period 2012 through 2038. The PRB Coal Forecast shown in Columns (3), (4) and (5) of OTP/MDU Exhibit 329 is our forecast of the price that the Applicants will pay for PRB coal over the same 30 year period. Finally, Columns (6), (7) and (8) show our forecast of the delivered price of PRB coal to the Big Stone II Generating Station assuming "Low Case," Base Case" and "High Case" scenarios. I explain the differences between the "Cases" later in my testimony. The delivered price forecast is the combination of the transportation forecast and the coal price forecast.

Q: OTP/MDU Exhibit 329 shows a "Low Case," "Base Case" and "High Case" forecast for PRB coal prices, but only shows one forecast for Rail Transportation. Why is that?

A: The Big Stone Generating Station is served only by one rail carrier, the Burlington Northern Santa Fe Railway Company ("BNSF"), and is therefore considered a "captive" shipper. As BNSF faces no effective competition for delivery of coal to Big Stone II, it has no incentive to lower its transportation rates for delivery of coal to Big Stone and therefore no "Low Case"

[2] A British Thermal Unit ("BTU") is a standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

scenario exists for rail rates. Further, as the rates currently charged by BNSF for coal shipments to Big Stone I reflect captive shipper rates, they already reflect a "High Case" scenario.

Q: Are you suggesting that BNSF has no incentive to raise the rates to Big Stone above the current tariff levels?

A: BNSF's economic incentive is to raise rates on all of its shipments to the extent the marketplace will allow such increases. As Big Stone is captive to BNSF, the only pricing constraint on BNSF is the maximum rate guidelines promulgated by the STB. The current tariff rates reflect this level of maximum rate and therefore if BNSF attempted to unreasonably increase these transportation rates, Applicants could ask the STB for relief.

Q: But didn't Otter Tail lose its maximum rate challenge before the STB which would suggest that the BNSF can increase the rate level?

A: Yes, Otter Tail did lose its maximum rate challenge before the STB. Since the issuance of its January 2006 decision, the STB has altered its regulation of maximum reasonable rail rates for moving coal, which would affect the rate level BNSF could charge for the shipment of coal from the PRB to Big Stone II. The change in the regulations would have both positive and negative effects on the maximum rate levels BNSF could charge for this movement.[3] In my opinion, these regulatory changes, combined with the changes in the rates and fuel surcharges BNSF currently charges to shippers which would be included in an analysis of the maximum rate

[3] The STB determines maximum reasonable rates a rail carrier can charge for moving coal for captive rail shippers base on the rates that would be charged by a least cost, most efficient, hypothetical competitor, which earns a return on its investment equal to the STB's determination of the rail industry's cost of capital, (i.e. stand-alone costs). Since the issuance of the STB's January 2006 decision in the Otter Tail case, the STB has changed the maximum rate regulation methodology and outcome: 1) by adopting a revised method for determining the industry's cost of capital; and 2) has adopted a revised maximum rate methodology, adopted an average total cost approach for allocating revenues for cross over traffic, shortened the discounted cash flow period to 10 years, included a hybrid productivity approach for indexing operating expenses, required the use of unadjusted Uniform Rail Costing System Phase III cost program for jurisdictional threshold determinations and created new standards for reopening a rate case.

to Big Stone II, would result in the existing or marginally lower rates than the rates currently charged for shipments to Big Stone I.

IV. TRANSPORTATION FORECAST

Q: Please explain what is shown in OTP/MDU Exhibit 330.

A: OTP/MDU Exhibit 330 is the source for the rail transportation rates shown in Column (2) of OTP/MDU Exhibit 329. OTP/MDU Exhibit 330 shows the various components of our rail transportation forecast.

Q: How did you develop the various rail transportation forecast components shown in OTP/MDU Exhibit 330?

A: A rail freight rate forecast depends upon the characteristics of each utility's position in the marketplace. For example, a utility may be procuring coal from different origin regions, and may be served by different modes and different carriers. In addition, each situation will be affected by different market forces. In the case of Big Stone II, we know that Big Stone II will procure coal from the PRB, that the coal will be delivered by rail and that Big Stone is captive to BNSF. In addition, we know that the Applicants intend to provide the railcars necessary to move the coal to Big Stone II. As a result, we developed a forecast for each of the components that will comprise the rail transportation cost for moving PRB coal to Big Stone II. These components include the rail rate itself, the fuel surcharge that we assume BNSF will apply to the rail rate, and the costs of acquiring and maintaining rail cars for this movement.

Q: What is the basis for your rail freight transportation forecast shown in Column (2) on page 1 of OTP/MDU Exhibit 330?

A: We develop rail transportation forecasts for moving coal from several different origin regions to destinations that are captive to a single rail carrier and to destinations that enjoy competitive alternatives from other modes or more than one rail carrier. Column (2) of OTP/MDU Exhibit 330 shows the rate of change in rail transportation rates based on our forecast of transportation rates for PRB coal moving to destinations captive to a single rail carrier. Our forecasted rate of change was applied to the rail tariff rates currently paid by Otter Tail for shipment of coal to the Big Stone I Generating Station. Stated differently, I applied our forecast of the rate of change in transportation charges for coal moving from PRB origins to destinations captive to one rail carrier.

Q: How was your forecast developed?

A: First, the historic rate of change for rail rates for moving coal in captive markets was developed. Next the historic and projected economic trends and factors that affect the change in captive rates, including items such as the overall economic output as measured by the Gross Domestic Product ("GDP"), and the impact of regulations on coal transportation were estimated. Using these trends and my experience in rail transportation, I then examined the expected changes in these same factors and estimated the impact of future inflation, rail productivity and demand will have on captive rail rates for moving coal.

Q: What is the basis for your Fuel Surcharge Forecast?

A: BNSF and all Class I railroads currently charge a fuel surcharge to shippers where not prohibited by contract. The fuel surcharge for coal is dependent on the change in fuel prices and the distance traveled by the individual shipment. To develop our forecast of the fuel surcharge to be charged by BNSF to the Applicants, I adopted the Energy Information Agency's forecast of highway diesel fuel prices and applied BNSF's fuel surcharge formula to the characteristics of the Big Stone II movement. The results of this analysis are shown in Column (3) on page 1 and page 2 of OTP/MDU Exhibit 330.

Q: What is the basis of your Railcar Maintenance Forecast?

A: Our Firm has developed a proprietary model for estimating rail car maintenance costs. The model takes into account expected wear by component for aluminum coal cars (like those used by Applicants) in normal use conditions, combined with Association of American Railroad ("AAR") material and labor prices. As the Applicants anticipate supplying the railcars for this movement, I assumed that 80 percent of the railcar repairs will occur in a private rail car shop on a scheduled basis and 20 percent of repairs will be performed by BNSF on a non-scheduled basis. The difference between private shop and BNSF repairs costs are related to the labor rates charged for the repair service. Labor rates and material prices are both increased by 2 percent annually to reflect inflation.

Q: What is the basis for your Railcar Lease forecast?

A: The railcar lease expense is based on a quote provided to Otter Tail Power Company by Trinity Railcar, one of the country's largest railcar manufacturers. The quote is for a 15 year net lease rate of $645 per month per railcar. We increased the Trinity quote to reflect inflation and Ad Valorem taxes paid by the rail car user. Our rate of inflation of 2.5 percent per year is based on the average annual change in coal rail car prices over the 1996 to 2007 period.

The Ad Valorem taxes are based on those charged by the State of Wyoming and are a mileage base user fee for miles traveled in Wyoming. PRB coal moving to Big Stone II will also travel through the states of Montana, South Dakota and North Dakota, however, these states do not charge Ad Valorem taxes to utility companies which provide rail cars for shipping coal.

Q: What is represented in Columns (6) and (7) of OTP/MDU Exhibit 330?

A: Column (6) of OTP/MDU Exhibit 330 provides our forecast of total transportation costs per ton for each year 2012 through 2038 to move coal from the PRB to the Big Stone II generation station and is a combination of the numbers shown in Columns (2) through (5), Column (7) of OTP/MDU Exhibit 330 shows the year over year percent change in the Column (6) transportation costs per ton.

V. FUEL PRICE FORECAST

Q: Please explain what is shown in OTP/MDU Exhibit 331.

A: OTP/MDU Exhibit 331 is the source for the coal price forecasts shown in Columns (3), (4) and (5) of OTP/MDU Exhibit 329. OTP/MDU Exhibit 331 shows the various components of our coal price forecast.

Q: What is the basis for your PRB Coal Forecast shown in OTP/MDU Exhibit 331?

A: The PRB coal forecast shown in OTP/MDU Exhibit 331 is based on my experience in pricing in coal markets. In addition, the forecast takes into account the view of the future demand for coal, as well as the impact on demand for PRB coal vis-à-vis anticipated Clean Air Act, mercury and likely carbon dioxide regulation. This forecast also considers PRB capacity and production limitations, employment growth and inflation. Forecasts were developed for spot and contract coal and for 8,400 BTU coal and 8,800 BTU coal, the two most common heat rate levels of coal in the PRB.

Q: What is the difference between the "Base," "Low" and "High" forecasts shown on Pages 1, 2 and 3, respectively of OTP/MDU Exhibit 331?

A: The Base case shown on Page 1 of OTP/MDU Exhibit 331 is our estimation of the prices that are most likely to occur for PRB coal over the 2012 to 2038 period. The Low case assumes the same demand, capacity, production, employment and inflation factors included in the Base case and will affect the change in prices of the forecast period.

Similarly, the High case assumes the same factors included in the Base case and will change the future price forecast, but stronger demand will increase the base price by as much as $3.00 per ton. For example, the market is currently experiencing an increase in demand for export coal from Northern Appalachia and Central Appalachia moving to the European Markets. The demand in Europe for coal is steady, although demand in China has increased. South African coal which historically moved to Europe is now moving to China, causing the increase in demand for Appalachia coal. In the short run, western coal and primarily PRB coal is filling the void in domestic markets left by the export of Appalachia coal moving to Europe.

Q: Current coal prices on the PRB spot market are high. How do you view these prices in the context of a long-range forecast?

A: To address this question, I have attached as OTP/MDU Exhibit 332 a graphic display of the historical change in PRB spot coal prices for both 8,400 BTU and 8,800 BTU coal. OTP/MDU Exhibit 332 shows that in specific historical periods the PRB coal market prices have been volatile. This is due to several factors, including historically high natural gas prices and consolidation among the PRB producers.

By early 2006, spot PRB coal prices reached approximately $18 per ton for 8,800 BTU coal and $14 per ton for 8,400 BTU coal before retreating steadily down to between $7.50 and $9.00 ton in mid 2007. Even with this decline in prices from their historic highs in 2006, prices did not decline back to the levels realized prior to the price spike. However, using the change in PRB coal prices over the past ten years as a guide, plus the short-term actions by coal suppliers and western coal railroads, and the continued volatility in the natural gas markets, it is our belief that periodic price "spikes" will occur. These spikes will drive spot prices up in the short run before declining. As in previous short-term price increases, the decline in coal prices after the market highs will probably not drop back to levels seen directly prior to the price increases, but will instead stabilize at price levels higher than before. This pricing scenario will continue until demand for PRB coal moderates.

Q: What is the difference between the coal forecasts shown in OTP/MDU Exhibit 331 and Columns (6), (7) and (8) of OTP/MDU Exhibit 329?

A: As stated above, the coal forecasts shown in OTP/MDU Exhibit 331 are developed for spot and contract coals and for 8,400 BTU coal and 8,800 BTU coal. In addition, each of these combinations is forecast for the Base, Low and High cases in OTP/MDU Exhibit 331. In contrast, the coal forecast for the base, low and high case shown in OTP/MDU Exhibit 329 reflects a procurement strategy which I anticipated would be implemented by the Applicants.

First, based on the current burn characteristics of Big Stone I coal, I expect that Big Stone II will consume 8,400 BTU coal. Second, Applicants like most other utilities purchase the majority of its coal through contracts, rather than the spot market. Due to the volatility in today's markets, many utilities are purchasing coal through a series of contracts whereby every year they are in the market for a portion of their coal supply. In this instance, I have assumed that Applicants will procure 90 percent of their coal through three-year contracts and 10 percent of their coal through the spot market. Further, I have assumed that Applicants will, at any given time, have three 3-year coal contracts, with one of the contracts expiring each year. This approach reduces the risk of drastic changes in delivered coal prices over time.

VI. COMPARISON OF FORECASTS

Q: Are you familiar with the forecasts of coal and transportation prices that Applicants have submitted in the proceeding previously?

A: Yes. Applicants submitted a forecast of both coal prices and transportation rates in December 2006 and again in November 2007 and I have reviewed both of these forecasts.

Q: How do Applicants' 2006 and 2007 forecasts compare with those which you have prepared for this testimony?

A: OTP/MDU Exhibit 333 is a graphical comparison of the three forecasts of the delivered price of coal from 2012 to 2025, and OTP/MDU Exhibit 334 provides a year-by-year comparison of the three forecasts on both a dollar per ton basis and an annual percent change bases.

As shown in these two exhibits, all three forecasts produce similar results. The geometric average annual percent change in the delivered price of fuel for Applicants' 2006 and 2007 forecast over the 13 year period are 3.01% and 3.64%, respectively. The geometric annual average percent change in my forecast for this same period is 3.00% or nearly the same result as Applicants' 2006 forecast.

Q: What are the major differences in your forecast and Applicants' 2007 forecast?

A: The most significant difference in these two forecasts is our approach to the period 2019 through 2025. During this period Applicants' forecast assumes a constant annual percent increase of 4.03% for both its fuel price component and transportation rate component. In contrast, my forecast in this period does not rely on a default constant year over year change but instead continues to consider the various economic factors discussed above that will specifically impact both the price of PRB coal and transportation of that coal.

As shown in OTP/MDU Exhibit 333, it is during this period that the greatest divergence occurs between Applicant's 2007 forecast and my forecast. During this time period, the Applicants' 2007 forecast is higher than mine.

Q: What are included in these 2019 through 2025 factors?

A: During this period, my forecast continues to consider the effects of demand for PRB coal, production capacity and the coal producers' expansions to meet this demand and its cyclical effects on pricing. My forecast also considers the continuing effects on demand for PRB coal which will result from both the anticipated Clean Air Mercury regulations and Carbon Dioxide regulations, both of which will have a dampening effect on the demand for PRB coal relative to other domestically produced coal.

Q: Are there other significant differences in these two forecasts?

A: No. While the components comprising the two forecasts change in both upward and downward directions over the 2012 to 2025 period, these annual variations do not significantly impact the difference in the forecasts.

Q: What do you conclude from the comparison of your forecast and the Applicants' 2006 and 2007 forecasts?

A: The forecast that I independently developed is very similar to the Applicants' 2006 forecast. My forecast is somewhat lower than the Applicants' 2007 forecast during the time period 2019 to 2025, for the reasons I described earlier. This indicates that the Applicants' 2007 forecast that they are using in this proceeding is conservative with regard to its potential effects on the amount of Big Stone II that is needed relative to other alternatives.

Q: Does this conclude your testimony?

A: Yes.

Forecast of PRB Coal and Transportation Prices To Ottertail Power's Big Stone Plant

(In Dollars Per Ton)

	Year	Rail Transportation Forecast ($/Ton) 1/	PRB Coal Forecast 2/ LOW ($/Ton)	PRB Coal Forecast 2/ BASE ($/Ton)	PRB Coal Forecast 2/ HIGH ($/Ton)	Total Delivered Cost Forecast LOW ($/Ton) 3/	Total Delivered Cost Forecast BASE ($/Ton) 4/	Total Delivered Cost Forecast HIGH ($/Ton) 5/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	2012	$20.38	$7.70	$9.29	$12.47	$28.08	$29.67	$32.84
2.	2013	$20.42	$8.06	$9.74	$13.07	$28.48	$30.16	$33.50
3.	2014	$20.41	$8.65	$10.51	$14.18	$29.06	$30.91	$34.58
4.	2015	$21.21	$9.12	$11.15	$15.13	$30.33	$32.35	$36.33
5.	2016	$22.11	$9.17	$11.29	$15.41	$31.28	$33.40	$37.52
6.	2017	$22.56	$9.05	$11.22	$15.43	$31.61	$33.78	$38.00
7.	2018	$24.55	$8.96	$11.19	$15.48	$33.51	$35.74	$40.03
8.	2019	$23.81	$9.20	$11.55	$16.04	$33.01	$35.36	$39.85
9.	2020	$24.40	$9.87	$12.42	$17.30	$34.27	$36.83	$41.70
10.	2021	$26.55	$10.41	$13.15	$18.36	$36.96	$39.70	$44.92
11.	2022	$25.74	$10.84	$13.77	$19.31	$36.58	$39.51	$45.05
12.	2023	$26.49	$10.82	$13.82	$19.48	$37.31	$40.31	$45.97
13.	2024	$27.30	$10.77	$13.85	$19.63	$38.07	$41.15	$46.93
14.	2025	$29.64	$10.76	$13.92	$19.82	$40.40	$43.56	$49.46
15.	2026	$28.95	$11.06	$14.36	$20.52	$40.01	$43.31	$49.47
16.	2027	$29.73	$11.86	$15.46	$22.16	$41.58	$45.18	$51.89
17.	2028	$30.38	$12.46	$16.34	$23.54	$42.84	$46.72	$53.92
18.	2029	$31.03	$12.54	$16.55	$23.99	$43.57	$47.57	$55.01
19.	2030	$31.78	$12.36	$16.45	$24.02	$44.14	$48.22	$55.79
20.	2031	$32.30	$12.25	$16.40	$24.10	$44.54	$48.70	$56.40
21.	2032	$36.05	$12.58	$16.93	$24.96	$48.63	$52.98	$61.01
22.	2033	$32.83	$13.48	$18.21	$26.92	$46.31	$51.03	$59.75
23.	2034	$33.45	$14.22	$19.27	$28.58	$47.67	$52.72	$62.03
24.	2035	$34.09	$14.82	$20.18	$30.06	$48.91	$54.26	$64.14
25.	2036	$34.73	$14.79	$20.26	$30.32	$49.52	$54.98	$65.05
26.	2037	$35.31	$14.72	$20.31	$30.56	$50.03	$55.61	$65.87
27.	2038	$35.97	$14.70	$20.40	$30.85	$50.67	$56.36	$66.81

1/ Based on L. E. Peabody & Associates, Inc. forecast of captive PRB rail transportation rates, assuming a 904 mile loaded move. Maintenance and railcar lease expenses have been included.

2/ Based on 90% contract and 10% spot 8400 Btu PRB coal. The contract prices are based on a series of 3 year 8400 Btu contracts with one expiring each year. A 4% annual sales tax has been included.

3/ Column (2) + Column (3)

4/ Column (2) + Column (4)

5/ Column (2) + Column (5)

Forecast of PRB Coal and
Transportation Prices To Ottertail Power's Big Stone Plant

(In Dollars Per MMBtu[1/])

		Rail Transportation	PRB Coal Forecast			Total Delivered Cost Forecast		
	Year	Forecast ($/MMBtu)	LOW ($/MMBtu)	BASE ($/MMBtu)	HIGH ($/MMBtu)	LOW ($/MMBtu)	BASE ($/MMBtu)	HIGH ($/MMBtu)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	2012	$1.2130	$0.4585	$0.5533	$0.7420	$1.6715	$1.7662	$1.9550
2.	2013	$1.2158	$0.4796	$0.5796	$0.7780	$1.6954	$1.7953	$1.9938
3.	2014	$1.2147	$0.5148	$0.6254	$0.8439	$1.7295	$1.8401	$2.0585
4.	2015	$1.2623	$0.5429	$0.6635	$0.9005	$1.8052	$1.9258	$2.1628
5.	2016	$1.3160	$0.5460	$0.6719	$0.9173	$1.8621	$1.9879	$2.2333
6.	2017	$1.3431	$0.5385	$0.6679	$0.9185	$1.8816	$2.0110	$2.2616
7.	2018	$1.4611	$0.5333	$0.6661	$0.9217	$1.9944	$2.1272	$2.3828
8.	2019	$1.4172	$0.5478	$0.6873	$0.9545	$1.9651	$2.1046	$2.3718
9.	2020	$1.4526	$0.5873	$0.7394	$1.0296	$2.0399	$2.1920	$2.4822
10.	2021	$1.5806	$0.6195	$0.7826	$1.0929	$2.2001	$2.3632	$2.6735
11.	2022	$1.5322	$0.6454	$0.8194	$1.1495	$2.1776	$2.3516	$2.6817
12.	2023	$1.5768	$0.6441	$0.8226	$1.1595	$2.2210	$2.3994	$2.7364
13.	2024	$1.6249	$0.6413	$0.8245	$1.1687	$2.2662	$2.4495	$2.7937
14.	2025	$1.7644	$0.6402	$0.8283	$1.1797	$2.4047	$2.5927	$2.9441
15.	2026	$1.7231	$0.6586	$0.8550	$1.2214	$2.3818	$2.5782	$2.9445
16.	2027	$1.7694	$0.7057	$0.9200	$1.3192	$2.4751	$2.6894	$3.0886
17.	2028	$1.8083	$0.7420	$0.9726	$1.4015	$2.5502	$2.7808	$3.2097
18.	2029	$1.8469	$0.7463	$0.9849	$1.4277	$2.5932	$2.8318	$3.2746
19.	2030	$1.8915	$0.7360	$0.9790	$1.4296	$2.6275	$2.8705	$3.3211
20.	2031	$1.9224	$0.7289	$0.9764	$1.4345	$2.6513	$2.8988	$3.3569
21.	2032	$2.1460	$0.7487	$1.0075	$1.4857	$2.8947	$3.1535	$3.6316
22.	2033	$1.9540	$0.8026	$1.0838	$1.6024	$2.7566	$3.0378	$3.5564
23.	2034	$1.9910	$0.8466	$1.1471	$1.7010	$2.8376	$3.1381	$3.6920
24.	2035	$2.0290	$0.8821	$1.2010	$1.7890	$2.9111	$3.2300	$3.8180
25.	2036	$2.0671	$0.8803	$1.2058	$1.8047	$2.9474	$3.2729	$3.8718
26.	2037	$2.1016	$0.8764	$1.2086	$1.8191	$2.9780	$3.3103	$3.9207
27.	2038	$2.1408	$0.8750	$1.2141	$1.8361	$3.0158	$3.3550	$3.9769

1/ Cost per ton on Page 1 of Exhibit TDC-1 converted to cost per MMBtu based on 8,400 Btu/lb coal.

Forecast of Transportation Rates
To OtterTail Power's Big Stone Plant

	Year	Rail Transportation Forecast ($/Ton) 1/	Fuel Surcharge Forecast ($/Ton) 2/	Railcar Maintenance Forecast ($/Ton) 3/	Railcar Lease Forecast ($/Ton) 4/	Total Transportation Price Forecast ($/Ton) 5/	Percent Change In Forecasted Price 6/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1.	2012	$17.21	$1.98	$0.04	$1.15	$20.38	xxx
2.	2013	$17.20	$1.98	$0.07	$1.17	$20.42	0.2%
3.	2014	$17.18	$1.98	$0.05	$1.20	$20.41	-0.1%
4.	2015	$17.94	$1.98	$0.06	$1.23	$21.21	3.9%
5.	2016	$18.72	$1.98	$0.15	$1.26	$22.11	4.3%
6.	2017	$19.17	$2.05	$0.05	$1.29	$22.56	2.1%
7.	2018	$19.62	$2.20	$1.39	$1.33	$24.55	8.8%
8.	2019	$20.10	$2.28	$0.07	$1.36	$23.81	-3.0%
9.	2020	$20.59	$2.35	$0.07	$1.39	$24.40	2.5%
10.	2021	$21.09	$2.43	$1.60	$1.43	$26.55	8.8%
11.	2022	$21.63	$2.58	$0.06	$1.46	$25.74	-3.1%
12.	2023	$22.20	$2.73	$0.05	$1.50	$26.49	2.9%
13.	2024	$22.80	$2.89	$0.08	$1.54	$27.30	3.0%
14.	2025	$23.42	$3.04	$1.61	$1.58	$29.64	8.6%
15.	2026	$24.06	$3.11	$0.16	$1.62	$28.95	-2.3%
16.	2027	$24.71	$3.27	$0.09	$1.66	$29.73	2.7%
17.	2028	$25.20	$3.42	$0.06	$1.70	$30.38	2.2%
18.	2029	$25.70	$3.49	$0.10	$1.74	$31.03	2.1%
19.	2030	$26.20	$3.72	$0.07	$1.78	$31.78	2.4%
20.	2031	$26.72	$3.57	$0.17	$1.83	$32.30	1.6%
21.	2032	$27.26	$3.27	$3.65	$1.87	$36.05	11.6%
22.	2033	$27.80	$3.04	$0.07	$1.92	$32.83	-8.9%
23.	2034	$28.36	$3.04	$0.08	$1.97	$33.45	1.9%
24.	2035	$28.93	$3.04	$0.11	$2.02	$34.09	1.9%
25.	2036	$29.51	$3.04	$0.12	$2.07	$34.73	1.9%
26.	2037	$30.10	$3.04	$0.06	$2.12	$35.31	1.7%
27.	2038	$30.70	$3.04	$0.06	$2.17	$35.97	1.9%

1/ Based on L. E. Peabody & Associates, Inc. forecast of captive PRB rail transportation rates, assuming a 904 mile loaded move.

2/ Fuel surcharge based on BNSF's existing mileage based fuel surcharge, assuming a 904 mile loaded move, 119 net tons per car and on highway diesel fuel prices as forecasted by the Energy Information Administration.

3/ LEPA Maintenance Forecast based on 80% private shop maintenance and 20% railroad shop maintenanc

4/ Otter Tail Power's railcar lease estimate provided in "BSP II price forecastfor LE Peabody.xls" ["Rail lease cost based on budgetary estimate by Trinity Rail (375 cars @ 645/month lease)"] increased by LEPA's estimate annual railcar price inflation of 2.5%. Ad Valorem Taxes for Wyoming have been included.

5/ Sum of Columns (2) through (5)

6/ [(Current Year Price in Col. (6) ÷ Prior Year Price in Col. (6)) -1] x 100

SUMMARY OF FORECAST OF
POWDER RIVER BASIN, WYOMING COAL PRICES -- BASE

		Spot Prices per Ton		Contract Prices per Ton		OTP Forecast 1/		
	Year	8400 BTU	8800 BTU	8400 BTU	8800 BTU	8400 BTU	Sales Tax 2/	Total 3/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	2012	$8.13	$9.44	$9.24	$10.92	$8.94	$0.36	$9.29
2.	2013	$8.85	$10.19	$9.99	$11.71	$9.36	$0.37	$9.74
3.	2014	$10.83	$12.41	$10.83	$12.62	$10.10	$0.40	$10.51
4.	2015	$11.18	$12.81	$11.18	$13.03	$10.72	$0.43	$11.15
5.	2016	$9.68	$11.16	$10.94	$12.83	$10.85	$0.43	$11.29
6.	2017	$9.42	$10.94	$10.71	$12.65	$10.79	$0.43	$11.22
7.	2018	$9.68	$11.24	$11.00	$12.99	$10.76	$0.43	$11.19
8.	2019	$10.46	$12.06	$11.82	$13.87	$11.10	$0.44	$11.55
9.	2020	$12.74	$14.63	$12.75	$14.89	$11.94	$0.48	$12.42
10.	2021	$13.18	$15.13	$13.18	$15.40	$12.64	$0.51	$13.15
11.	2022	$13.64	$15.67	$13.64	$15.94	$13.24	$0.53	$13.77
12.	2023	$11.93	$13.77	$13.49	$15.85	$13.29	$0.53	$13.82
13.	2024	$11.74	$13.64	$13.35	$15.77	$13.32	$0.53	$13.85
14.	2025	$12.08	$14.03	$13.73	$16.22	$13.38	$0.54	$13.92
15.	2026	$12.94	$14.95	$14.64	$17.21	$13.81	$0.55	$14.36
16.	2027	$15.84	$18.20	$15.88	$18.55	$14.86	$0.59	$15.46
17.	2028	$16.35	$18.79	$16.39	$19.15	$15.71	$0.63	$16.34
18.	2029	$14.17	$16.37	$16.04	$18.86	$15.91	$0.64	$16.55
19.	2030	$13.78	$16.04	$15.70	$18.58	$15.82	$0.63	$16.45
20.	2031	$14.16	$16.48	$16.13	$19.09	$15.77	$0.63	$16.40
21.	2032	$15.30	$17.69	$17.33	$20.39	$16.27	$0.65	$16.93
22.	2033	$18.64	$21.46	$18.69	$21.87	$17.51	$0.70	$18.21
23.	2034	$19.28	$22.20	$19.33	$22.63	$18.53	$0.74	$19.27
24.	2035	$19.95	$22.98	$20.00	$23.43	$19.40	$0.78	$20.18
25.	2036	$17.45	$20.20	$19.78	$23.29	$19.48	$0.78	$20.26
26.	2037	$17.18	$20.00	$19.57	$23.17	$19.52	$0.78	$20.31
27.	2038	$17.68	$20.58	$20.13	$23.84	$19.61	$0.78	$20.40

1/ Each year of the forecast consists of three 3-year contracts of equal vloumes ending in consecutive years plus 10% from tl spot market.

2/ OTP Sales Tax on Coal is 4%

3/ Column (6) + Column (7)

SUMMARY OF FORECAST OF
POWDER RIVER BASIN, WYOMING COAL PRICES -- LOW

		Spot Prices per Ton		Contract Prices per Ton		OTP Forecast 1/		
	Year	8400 BTU	8800 BTU	8400 BTU	8800 BTU	8400 BTU	Sales Tax 2/	Total 3/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	2012	$6.57	$7.87	$7.67	$9.34	$7.41	$0.30	$7.70
2.	2013	$7.13	$8.47	$8.26	$9.99	$7.75	$0.31	$8.06
3.	2014	$8.67	$10.24	$8.90	$10.70	$8.32	$0.33	$8.65
4.	2015	$8.87	$10.49	$9.11	$10.95	$8.77	$0.35	$9.12
5.	2016	$7.62	$9.07	$8.84	$10.70	$8.82	$0.35	$9.17
6.	2017	$7.36	$8.82	$8.59	$10.46	$8.70	$0.35	$9.05
7.	2018	$7.52	$9.01	$8.78	$10.69	$8.62	$0.34	$8.96
8.	2019	$8.12	$9.66	$9.42	$11.40	$8.85	$0.35	$9.20
9.	2020	$9.86	$11.68	$10.13	$12.19	$9.49	$0.38	$9.87
10.	2021	$10.14	$12.01	$10.42	$12.54	$10.01	$0.40	$10.41
11.	2022	$10.44	$12.37	$10.72	$12.91	$10.43	$0.42	$10.84
12.	2023	$9.06	$10.79	$10.52	$12.74	$10.40	$0.42	$10.82
13.	2024	$8.85	$10.61	$10.34	$12.59	$10.36	$0.41	$10.77
14.	2025	$9.07	$10.88	$10.59	$12.90	$10.34	$0.41	$10.76
15.	2026	$9.72	$11.58	$11.29	$13.68	$10.64	$0.43	$11.06
16.	2027	$11.82	$14.01	$12.17	$14.65	$11.40	$0.46	$11.86
17.	2028	$12.10	$14.34	$12.45	$15.00	$11.99	$0.48	$12.46
18.	2029	$10.40	$12.40	$12.09	$14.65	$12.06	$0.48	$12.54
19.	2030	$10.04	$12.06	$11.74	$14.33	$11.89	$0.48	$12.36
20.	2031	$10.26	$12.32	$12.00	$14.65	$11.77	$0.47	$12.25
21.	2032	$11.08	$13.21	$12.88	$15.62	$12.09	$0.48	$12.58
22.	2033	$13.45	$15.97	$13.85	$16.70	$12.96	$0.52	$13.48
23.	2034	$13.84	$16.43	$14.24	$17.18	$13.68	$0.55	$14.22
24.	2035	$14.24	$16.91	$14.66	$17.68	$14.25	$0.57	$14.82
25.	2036	$12.36	$14.75	$14.38	$17.45	$14.22	$0.57	$14.79
26.	2037	$12.08	$14.51	$14.13	$17.25	$14.16	$0.57	$14.72
27.	2038	$12.38	$14.87	$14.48	$17.68	$14.13	$0.57	$14.70

1/ Each year of the forecast consists of three 3-year contracts of equal vloumes ending in consecutive years plus 10% from tl spot market.

2/ OTP Sales Tax on Coal is 4%

3/ Column (6) + Column (7)

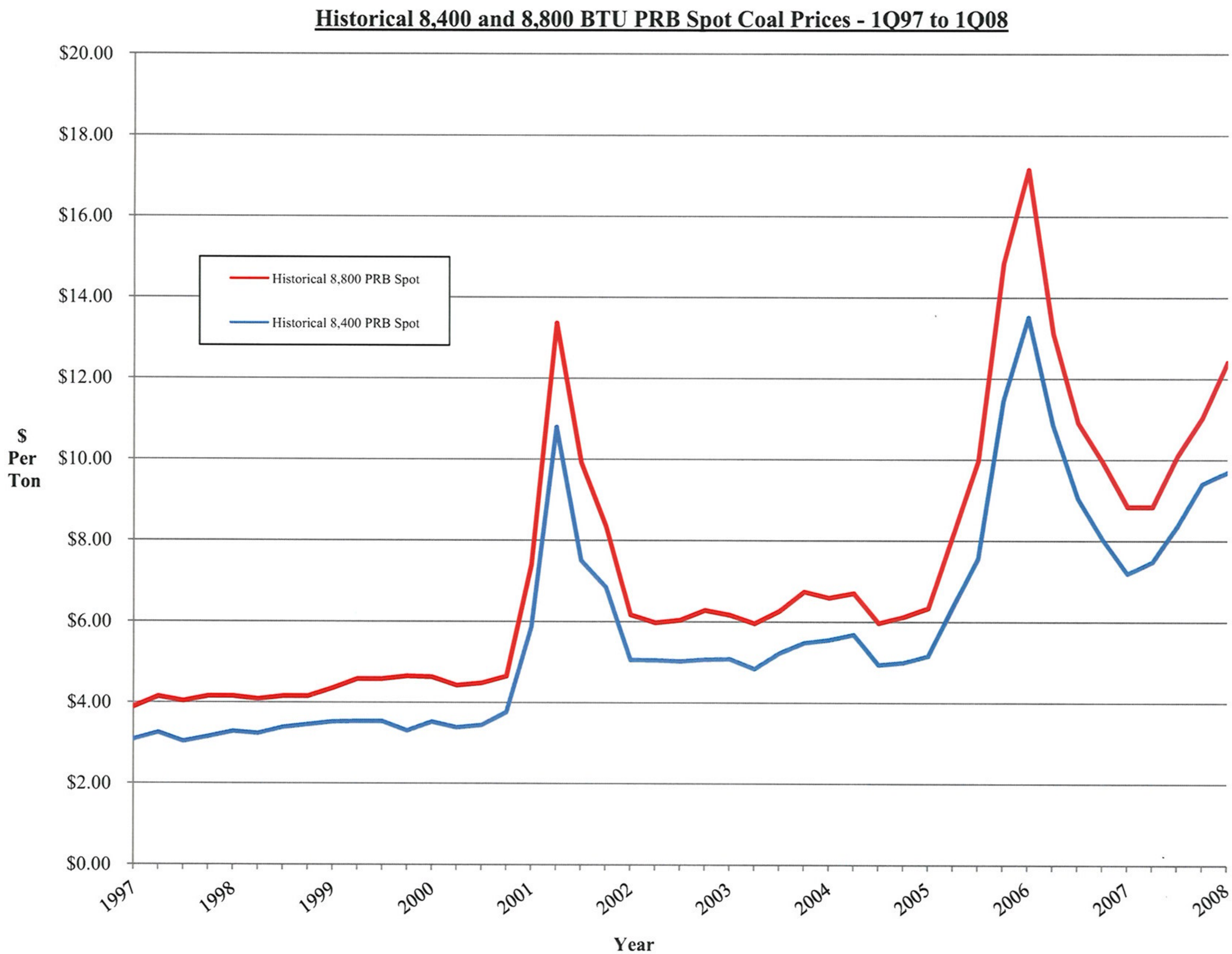
SUMMARY OF FORECAST OF
POWDER RIVER BASIN, WYOMING COAL PRICES -- HIGH

		Spot Prices per Ton		Contract Prices per Ton		OTP Forecast 1/		
	Year	8400 BTU	8800 BTU	8400 BTU	8800 BTU	8400 BTU	Sales Tax 2/	Total 3/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	2012	$11.26	$12.58	$12.37	$14.06	$11.99	$0.48	$12.47
2.	2013	$12.29	$13.61	$13.41	$15.13	$12.57	$0.50	$13.07
3.	2014	$15.12	$16.67	$14.62	$16.40	$13.63	$0.55	$14.18
4.	2015	$15.73	$17.35	$15.21	$17.07	$14.55	$0.58	$15.13
5.	2016	$13.72	$15.22	$14.98	$16.92	$14.82	$0.59	$15.41
6.	2017	$13.45	$15.02	$14.78	$16.79	$14.84	$0.59	$15.43
7.	2018	$13.87	$15.49	$15.24	$17.32	$14.89	$0.60	$15.48
8.	2019	$14.99	$16.64	$16.38	$18.51	$15.42	$0.62	$16.04
9.	2020	$18.32	$20.24	$17.71	$19.91	$16.63	$0.67	$17.30
10.	2021	$19.04	$21.05	$18.41	$20.71	$17.66	$0.71	$18.36
11.	2022	$19.82	$21.92	$19.16	$21.56	$18.57	$0.74	$19.31
12.	2023	$17.42	$19.35	$19.05	$21.54	$18.73	$0.75	$19.48
13.	2024	$17.26	$19.28	$18.96	$21.55	$18.88	$0.76	$19.63
14.	2025	$17.81	$19.90	$19.57	$22.24	$19.06	$0.76	$19.82
15.	2026	$19.08	$21.20	$20.87	$23.61	$19.73	$0.79	$20.52
16.	2027	$23.48	$25.96	$22.76	$25.60	$21.31	$0.85	$22.16
17.	2028	$24.44	$27.03	$23.68	$26.65	$22.64	$0.91	$23.54
18.	2029	$21.31	$23.70	$23.33	$26.41	$23.06	$0.92	$23.99
19.	2030	$20.89	$23.40	$23.01	$26.21	$23.09	$0.92	$24.02
20.	2031	$21.54	$24.13	$23.73	$27.03	$23.17	$0.93	$24.10
21.	2032	$23.28	$25.91	$25.50	$28.89	$24.00	$0.96	$24.96
22.	2033	$28.45	$31.52	$27.57	$31.07	$25.88	$1.04	$26.92
23.	2034	$29.57	$32.78	$28.66	$32.32	$27.48	$1.10	$28.58
24.	2035	$30.78	$34.14	$29.84	$33.65	$28.90	$1.16	$30.06
25.	2036	$27.06	$30.14	$29.66	$33.62	$29.15	$1.17	$30.32
26.	2037	$26.80	$30.03	$29.52	$33.64	$29.39	$1.18	$30.56
27.	2038	$27.66	$30.99	$30.47	$34.71	$29.66	$1.19	$30.85

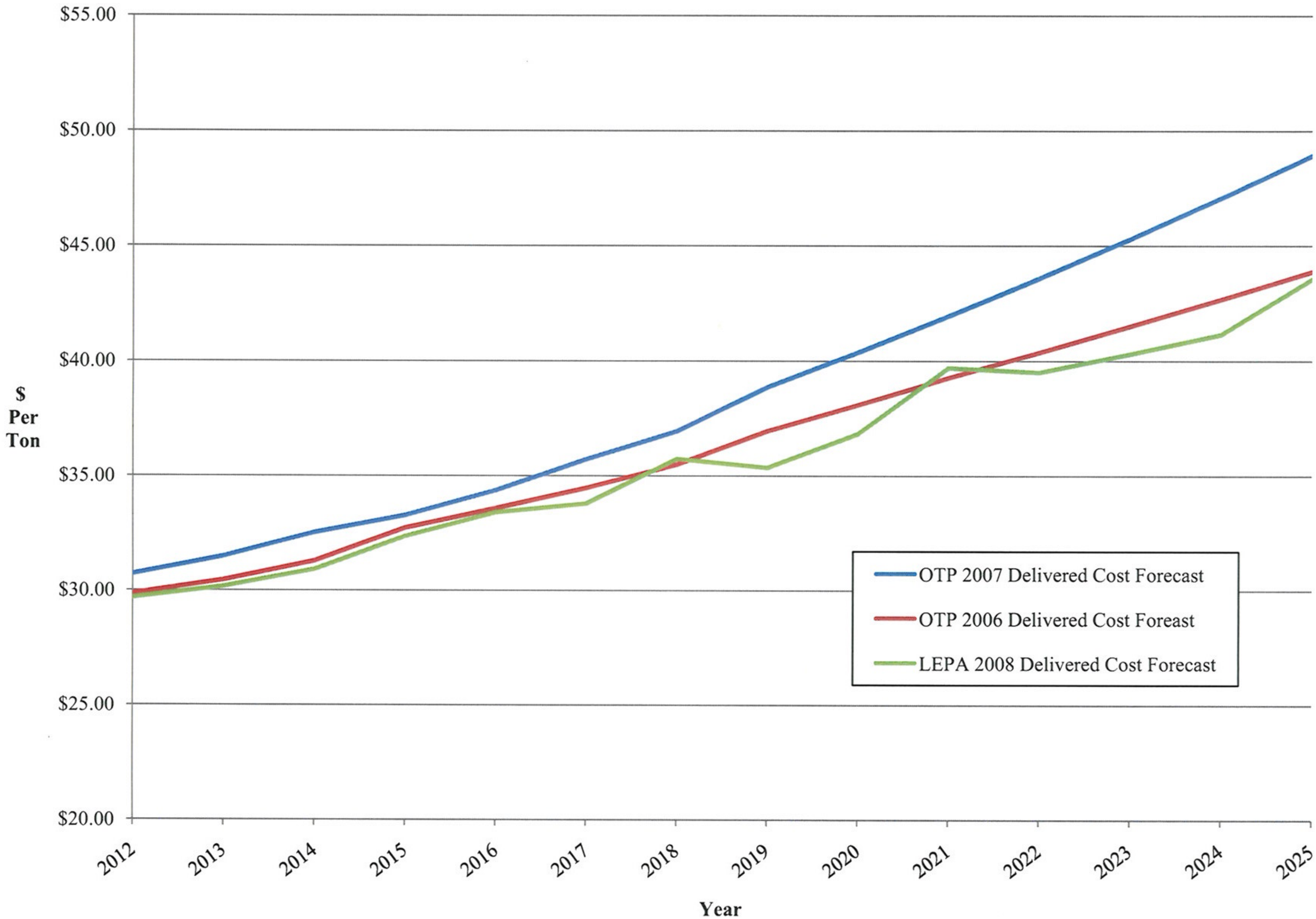
1/ Each year of the forecast consists of three 3-year contracts of equal vloumes ending in consecutive years plus 10% from tl spot market.

2/ OTP Sales Tax on Coal is 4%

3/ Column (6) + Column (7)


Historical 8,400 and 8,800 BTU PRB Spot Coal Prices - 1Q97 to 1Q08
Historical 8,800 PRB Spot
Historical 8,400 PRB Spot
$ Per Ton
$20.00
$18.00
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year

Comparison of Delivered Cost Forecasts - OTP 2006, OTP 2007 and LEPA



Comparison of OTP and LEPA Delivered Cost Forecasts

(In Dollars Per Ton)

		Delivered Cost Forecast			Difference	
	Year	OTP '06 ($/Ton) 1/	OTP '07 ($/Ton) 2/	LEPA ($/Ton) 3/	OTP '06 - LEPA 4/	OTP '07 - LEPA 5/
	(1)	(2)	(3)	(4)	(5)	(6)
1.	2012	$29.85	$30.71	$29.67	$0.18	$1.04
2.	2013	$30.45	$31.49	$30.16	$0.29	$1.33
3.	2014	$31.29	$32.52	$30.91	$0.37	$1.61
4.	2015	$32.72	$33.27	$32.35	$0.37	$0.92
5.	2016	$33.58	$34.36	$33.40	$0.18	$0.96
6.	2017	$34.46	$35.71	$33.78	$0.68	$1.93
7.	2018	$35.49	$36.93	$35.74	($0.25)	$1.20
8.	2019	$36.95	$38.86	$35.36	$1.59	$3.50
9.	2020	$38.08	$40.37	$36.83	$1.26	$3.55
10.	2021	$39.27	$41.95	$39.70	($0.44)	$2.25
11.	2022	$40.37	$43.59	$39.51	$0.86	$4.08
12.	2023	$41.51	$45.30	$40.31	$1.20	$4.98
13.	2024	$42.68	$47.07	$41.15	$1.53	$5.92
14.	2025	$43.88	$48.91	$43.56	$0.32	$5.36

1/ Otter Tail Power's 2006 delivered cost forecast, including fuel surcharge, provided in "BSP II price forecast graph for Todd.xls".

2/ Otter Tail Power's 2007 delivered cost forecast, including fuel surcharge, provided in "BSP II price forecast graph for Todd.xls".

3/ L. E. Peabody & Associates, Inc. forecast of PRB coal and rail transportation prices to Otter Tail Power's Big Stone plant.

4/ Column (2) - Column (4)

5/ Column (3) - Column (4)

Comparison of OTP and
LEPA Delivered Cost Forecasts

(Annual Percent Change[1/])

		Delivered Cost Forecast		
		OTP '06	OTP '07	LEPA
	Year	(% Change)	(% Change)	(% Change)
	(1)	(2)	(3)	(4)
1.	2012	xxx	xxx	xxx
2.	2013	2.00%	2.53%	1.65%
3.	2014	2.75%	3.28%	2.49%
4.	2015	4.59%	2.31%	4.66%
5.	2016	2.61%	3.26%	3.23%
6.	2017	2.64%	3.95%	1.16%
7.	2018	2.97%	3.42%	5.78%
8.	2019	4.12%	5.21%	-1.07%
9.	2020	3.07%	3.90%	4.15%
10.	2021	3.11%	3.90%	7.81%
11.	2022	2.81%	3.91%	-0.49%
12.	2023	2.82%	3.91%	2.03%
13.	2024	2.82%	3.92%	2.09%
14.	2025	2.82%	3.92%	5.85%
Geometric Average Annual Change				
15.		3.01%	3.64%	3.00%

1/ Annual percent change of values appearing on Page 1 of Exhibit TDC-6.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Application	**AFFIDAVIT OF SERVICE**
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application	Case Nos. PU-06-481, PU 06-482

Kristen A. Swenson, of the City of Minneapolis, County of Hennepin, in the State of North Dakota, being duly sworn on oath says: that on the 10th day of March, 2008, she served the following:

Ward Uggerud (OTP Exhibit 112);
Bryan Morlock (OTP Exhibit 117);
Andrea Stomberg (MDU Exhibit 213);
James Heidell (MDU Exhibit 214);
Mark Rolfes (OTP/MDU Exhibit 324);
Tim Rogelstad (OTP/MDU Exhibit 325);
Jeffrey Grieg (OTP/MDU Exhibit 326);
Thomas Crowley (OTP/MDU Exhibit 328); and
An Affidavit of Service.

A copy has also been served upon the attached service list via electronic mail and U.S. Mail.

Kristen A. Swenson

Subscribed and sworn to before me
this 10th day of March, 2008.

Donna a LeClair

Notary Public

DONNA A LECLAIR
Notary Public-Minnesota
My Commission Expires Jan 31, 2010

Doc# 2487093\1

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation, Advance Determination of Prudence Application

SERVICE LIST

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc., Advance Determination of Prudence Application

Case Nos. PU-06-481, PU 06-482

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