Michael J. Uda
UDA LAW FIRM, P.C.
7 W. 6th Avenue, Suite 4E
Helena, MT 59601
(406) 457-5311
(406) 447-4255 fax
muda@mthelena.com

Yvette K. Lafrentz
DONEY CROWLEY PAYNE BLOOMQUIST P.C.
220 South Pacific Street
P.O. Box 1418
Dillon, MT 59725
(406) 683-8795
(406) 683-8796 fax
ylafrentz@doneylaw.com

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF The Complaint By Oak Tree Energy LLC Against NorthWestern Energy For Refusing To Enter Into A Purchase Power Agreement	**DOCKET NO. EL11-006**

OAK TREE ENERGY, LLC'S ADDITIONAL TESTIMONY OF J. RICHARD LAUCKHART

I. INTRODUCTION

Q. Please state your name and employment.

A. My name is J. Richard Lauckhart. I am an energy consultant.

Q. Are you the same J. Richard Lauckhart who provided Direct and Rebuttal Testimony in this proceeding?

A. Yes.

Q. What is the purpose of this Additional testimony in this case?

A. On May 15, 2012, the South Dakota PUC (SD PUC) issued an Interim Order; Order For and Notice of Further Hearing in this proceeding. That Order called for additional testimony of the parties to be filed on or before June 6, 2012. On May 31, 2012, the SD PUC issued an Order Cancelling Procedural Schedule and Hearing which canceled the June 6, 2012 date for submission of additional prefiled testimony. On October 11, 2012, the SD PUC issued an Order Granting Part and Denying in Part Motion Partial Reconsideration and Application for Reconsideration in Docket EL11-006. On October 15, 2012 the SD PUC issued a Procedural Order; Order for and Notice for Hearing for filing of additional testimony and hearing to address the issues outstanding following the Interim Order as modified by the Reconsideration Order. This testimony is being filed as a result of that Order. In this testimony I not only address avoided cost issues, but I also respond to a statement made by NorthWestern lawyer Al Brogan in his oral argument related to the motions for reconsideration on October 2, 2012. I feel that Mr. Brogan's advocacy was somewhat misleading in claiming that the Montana Public Service Commission made a "mistake" in approving QF contracts that Montana ratepayers are now paying for in an amount of roughly $600 million dollars.

II. SUMMARY OF TESTIMONY

Q. Please summarize your Additional Testimony in this case.

A. The comments made by Mr. Brogan during his oral argument on October 2, 2012, on the parties' motions for reconsideration were misleading and should be given no weight by the SD PUC. Mr. Brogan implied that the Commission should guard against "mistakes" in deciding the value of the Oak Tree project, and further implied that wind projects have a negative value that would result in potential long-term harm to NorthWestern's South Dakota ratepayers. My testimony will amply demonstrate that wind projects such as Oak Tree have a tremendous positive value and will provide considerable benefits to NorthWestern's ratepayers. I also calculate the avoided cost of the wind projects (exclusive of externality benefits such as (a) no harmful emissions, (b) avoidance of burning limited supplies of fossil fuels, and (c) the economic development benefits to South Dakota) and testify that NorthWestern's avoided costs lie in the range between $56/MWh to $89/MWh. The SD PUC should choose an average of the avoided costs I have calculated to factor in all of the forecasts I have reviewed. That value is $69.3/MWh.

III. COMMENTS MADE BY NORTHWESTERN COUNSEL AL BROGAN

Q. What comments were made by Mr. Brogan that you take issue with?

A. In his initial arguments at the October 2, 2012 hearing Mr. Brogan stated: "I fervently hope that South Dakota does not repeat the mistakes that Montana made 30 years ago with respect to setting avoided cost and promoting qualifying facilities, mistakes that are costing NorthWestern's Montana consumers over $600 million." Although this statement seemed like little more than hyperbole, Oak Tree was unclear as to the basis for Mr. Brogan's statement that the Montana PSC made a $600 million dollar mistake in approving QF contracts. In order to verify the accuracy of Mr. Brogan's comment to the SD PUC, Oak Tree contacted Mr. Brogan regarding the origins and basis for his statement. Although Mr. Brogan did not provide a specific calculation to us, he did identify a January 31, 2002 Final Order issued by the Montana PSC in regards to the combined Montana proceedings dealing with Montana Power's proposed Electric Utility Restructuring Transition Plan and its application for Sale of Montana Power to NorthWestern Corporation. *See* Final Orders 5986w in Docket D97.7.90; 6353c in Docket D2001.1.5 (appended as Attachment 1).

Q. Did that Order state that avoided cost rate setting in Montana was costing Montana consumers over $600 million?

A. No. First, it is important to understand the context of the Montana PSC's order in the combined dockets. D97.7.90 was commenced as part of Montana Power Company's effort to implement restructuring and a transition to being a transmission and distribution entity that did not own or operate generation. Initially, Montana Power proposed to create a new generation company that would own its generating assets. Ultimately, however, Montana Power Company decided to sell its generation assets. A significant issue for the parties in that proceeding was how much, if any, "stranded costs" would be assigned to ratepayers. "Stranded costs" was essentially the difference between the net book value carried forward on Montana Power Company's books and the value of those assets in a competitive environment. The debate in

D97.7.90 included a discussion of the net outstanding obligations owing to QFs who had signed contracts with Montana Power Company years earlier. Some four years later, Montana Power Company decided, in the midst of the D97.7.90 proceeding, that it wished to sell its electric and natural gas operations and assets to NorthWestern. Montana Power Company's application to sell its electric and natural gas business to NorthWestern commenced Docket D2001.1.5. Thus, the amount of stranded costs became an issue for NorthWestern as the buyer of Montana Power Company, and the Commission combined consideration of both cases (e.g., resolving the net amount of stranded costs and the potential sale to NorthWestern). At a point prior to the hearing on both of these cases, most of the parties entered settlement discussions on the stranded costs and NorthWestern vigorously participated in those discussions. Ultimately, those discussions produced a Stipulation that resolved the stranded cost issue. Montana Power Company and NorthWestern both supported the stipulation at the hearing and the Commission considered only whether to approve the Stipulation at hearing. The Order itself approved a Settlement and associated Stipulation agreed to by parties in the Dockets. The Order included a copy of the "Stipulation" by the parties dealing with all issues in the combined proceedings. The Stipulation included a statement that the many paragraphs of the Stipulation were inseparable from the whole of the agreement and that the reasonableness of the proposed settlement is critically dependent upon its adoption, in its entirety, by the Commission. In approving the Stipulation, which fixed the net amount of stranded costs owing by Montana Power Company ratepayers (and future NorthWestern ratepayers) and the sale to NorthWestern, the Commission stated:

> It is reasonable to conclude that a fully litigated Tier II proceeding would take several more months at a minimum. Given the substantial interests involved, the Commission's decision could be followed by protracted litigation with an uncertain outcome. Under these conditions the sale might not occur for years, if ever. Approving the Stipulation produces benefits for consumers, including the $30 million fund and a company that desires to serve utility customers; rejecting the Stipulation risks losing those benefits and creating a very uncertain outcome. However, as discussed already, the level of transition costs in the Stipulation falls within a range of reasonableness, and off-setting benefits are not obvious given the large transactions costs associated with the fully litigated contested case scenario.

Final Orders 5986w, Docket D97.7.90, and 6353c, Docket D2001.1.5, at p. 15, ¶ 47.

The implication of this is that the Montana PSC did not simply pass on a "mistake" to NorthWestern's ratepayers. It carefully considered the Stipulation and concluded that ratepayers would not be harmed. Including the continued payment by NorthWestern of QF contracts for the generation sold to NorthWestern on behalf of its future ratepayers.

Q. Did one of the paragraphs of the Stipulation discuss the cost of QF contracts?

A. Yes. Paragraph 25 of the Stipulation referred to an Appendix D to the stipulation that included a calculation of "Hybrid Annual QF Out-of-Market Payment Amounts" of $662,623,824.

Q. How was this amount calculated?

A. The Order did not describe the calculation and, as I understand it, there was no testimony or discovery or cross examination on the calculation of this number in that proceeding since Paragraph 25 was part of a total settlement package associated with those two proceedings.

Q. Have you attempted to determine how the calculation may have been made?

A. Yes. Although Mr. Brogan does not know the details of the calculation, I have attempted to determine how the calculation was made back in the year 2002.

Q. What have you learned?

A. Apparently, an estimate was made of the going forward costs of the QF contracts that were in existence as of the year 2002. The two biggest such contracts were the Colstrip Energy Limited Partnership (CELP) and Yellowstone Energy Limited Partnership (YELP). CELP is a coal fired electrical generation facility. Coal for the facility comes from the Western Energy mine or other nearby mines. The coal used is called culm, which is a refuse coal whose uses are somewhat limited. The fact that the fuel is a "refuse" coal allows CELP to be a "renewable" QF under PURPA. YELP is a petroleum coke-fired electrical/steam co-generation facility south of the Exxon Refinery in Billings. The YELP facility generates electrical power, which is sold to the Montana Power Company. The fact that the facility is a co-generation facility allows YELP to be a QF. The CELP and YELP QF contracts were signed in the 1980's and were 35-year contracts. These contracts were thus in place as of the date of the Stipulation in 2002. The estimated levelized going forward costs of those contracts was about \$80/MWh since at the time the contracts were signed the avoided cost was based on the estimated costs of building and operating Colstrip 3 and 4. This \$80/MWh estimated "going-forward" cost of the YELP and CELP contracts was compared to a 20 year levelized price of \$32.75/MWh, a number that was calculated based on an estimate of future electricity prices going out 20 years. NorthWestern and the other settling parties apparently believed that NorthWestern's 20 year avoided cost as of 2002 was \$32.75/MWh. The difference between the cost of the YELP and CELP power at \$80/MWh and the cost of the YELP and CELP power if it were priced at \$32.75/MWh is roughly \$600 Million.

Q. Does such a calculation of \$600 million indicate that the Montana commission made a mistake in the early 1980's when they set the price to be paid to YELP and CELP?

A. No. Clearly Colstrip 3 and 4 were avoidable in the early 1980's and that set the avoided cost. There was no \$32.75/MWh option identified in the 1980's. Further, if the Montana PSC made a \$600 million mistake on the YELP and CELP contracts, they made even a larger mistake when they let parts of Colstrip 3 and 4 go into ratebase in the late 1980s. And they made a similar mistake when they approved NorthWestern's purchase of another share of Colstrip 4 a few years ago. In point of fact, under NorthWestern's argument that the Montana PSC made a "mistake" in approving the \$600 million in QF transition charges for NorthWestern's customers, any utility investment that proved to be above market based on estimates at any given time would be a similar "mistake." But PURPA contemplated that QF contracts may vary from the estimates of energy markets at any given time, and it is clear that the stipulated 20-year estimate of market prices in 2002 substantially understated electricity prices over that 20-year term. Valuation of utility assets is not done that way, otherwise it would open utilities to substantial second guessing regarding the prudence of utility investments. Again, this is simply another way NorthWestern subjects the valuation of its own assets to a very different position than it does for QFs. NorthWestern would not agree that if its own generation investments were predicted to be substantially above market that it should forfeit any right to recover its investment from those ratepayers on the grounds that, in hindsight, it was a mistake. QFs should be entitled to the same treatment.

Q. Using the same logic as that applied by Mr. Brogan, would the SD PUC be making a mistake if they approved the Big Stone application by Otter Tail?

A. Yes. Otter Tail has said that the Big Stone modification would result in an incremental cost of power of $74/MWh excluding any potential new environmental costs in the future. If the avoided cost is in the $40/MWh to $50/MWh range as NorthWestern indicates in this proceeding, then the SD PUC would be making a huge mistake in approving the Big Stone modifications, a mistake that would cost South Dakota ratepayers somewhere in the range of $400 million to $600 million. However, I don't think that's a fair way to look at the Big Stone replacement cost, nor do I believe it is fair way to evaluate QF investments.

Q. In light of the foregoing, do you believe it would be a bigger mistake to encourage QF generation (as PURPA requires the Commission to do) with full avoided cost rates, or for South Dakota to hinder the development of wind with artificially low avoided costs?

A. There is no question that encouraging wind generation is good public policy for South Dakota. Not only is it required by PURPA, there are practical long-term ramifications for South Dakota of not going forward with PURPA contracts such as Oak Tree. Just as an example, every day the Oak Tree project is delayed, South Dakota ratepayers are causing out of state natural gas owners of gas to be compensated for gas (to be burned in power plants) when they could have supported in-state economic development by paying in state owners of a wind plant for power. This is a substantial economic benefit. In addition, every day the Oak Tree project is delayed, there are harmful emissions being put into the environment and there is a burning of limited fossil fuels that will not be useable for more important services in the future. Finally, every day that the Oak Tree project is delayed NorthWestern's South Dakota ratepayers are deprived of the generation from a clean, renewable resource that will provide a reliable hedge against future increases in electricity prices – increases that are, in my opinion, substantially likely to occur.

IV. REVISED CALCULATION OF AVOIDED COSTS

Q. Have you prepared an alternative estimate of avoided costs as of February 2011 in a manner that takes into account the SDPUC Orders of this year?

A. Yes. The SD PUC has determined that it did not agree with Oak Tree's avoided cost calculations that I prepared in my Direct Testimony in this docket, Docket EL11-006, and that there was a need for further testimony and supporting calculations. For example, the SD PUC felt that the natural gas price forecast I used in the Black & Veatch forecast (dated November 2010) should be modified in certain respects. The most accurate way to forecast avoided costs using different drivers (such as different natural gas price forecasts) would be to modify the different input drivers in the models used by Black & Veatch and then re-run those models. Unfortunately, to reach agreement on which alternate input drivers to use and then to rerun all of these models would take an exceedingly long time. Therefore, it is not efficient given the limited time frame to use those detailed models. To comply with the Commission's orders, Oak Tree was required to utilize a different approach.

Q. How do you go about forecasting avoided cost in this proceeding given that a different approach needs to be taken?

A. In this testimony I approach the avoided cost calculation using forecasts prepared by others in the February 2011 timeframe. These forecasts, prepared by others, sometimes provide a direct forecast of avoided electricity cost. When using forecasts of natural gas prices developed by others (rather than a forecast of avoided electricity cost), I derived the energy avoided cost forecast by using, in part, the Steve Lewis spreadsheet model provided in response to RFP-022 and the spreadsheet model that developed Exhibit BJL-3 since that model reflects the hybrid methodology that the SD PUC has directed me to use. I am somewhat reluctant to use the Steve Lewis spreadsheet methodology because it locks in a very low "market heat rate" for the entire 20 years of the forecast, but it is one way to compute a forecast. The "market heat rate" utilized by Mr. Lewis assumes that the relationship between natural gas prices and electricity prices will remain fixed over time, whereas the reality is that that relationship varies over time according to different economic and market conditions. Nonetheless, I did use both Mr. Lewis and Mr. LaFave's approach. After developing the energy avoided cost utilizing natural gas price inputs, I then added the capacity avoided cost to develop a full avoided cost electricity forecast.

Q. Please describe one of the direct forecasts of electricity avoided cost that was prepared in the Feb. 2011 timeframe.

A. The owners of the Big Stone coal plant have recently indicated that the cost of the needed environmental retrofits of the Big Stone coal plant are in the range of $74/MWh to $78/MWh. While this forecast was recently filed with the SD PUC, it was prepared prior to Feb. 2011 and Otter Tail Energy apparently believes it is still valid. Otter Tail's analysis indicates that all other available alternatives to retrofitting Big Stone will cost more than retrofitting Big Stone. As a result, it can be reasonably concluded that $74/MWh is a floor for avoided cost. The cost of retrofitting Big Stone I utilize here does not include any estimate of possible future carbon costs and I have not added any since the SD PUC has directed me not to do so. In order to reflect the fact that Oak Tree only counts 20% toward peak needs while Big Stone counts 100% toward peak needs, I have reduced the cost of Big Stone by 80% of its fixed costs (Depreciation, Return, Interest, Income taxes). Thus the $74.38 is reduced to $57.09/MWh in my analysis. Further, the Big Stone analysis contains an estimate of the cost of power if the future power need is met with a new Combined Cycle Combustion Turbine (CCCT). NorthWestern will need both the power equivalent to the Big Stone plant plus additional power in the future. The SD PUC could use the cost of the Combined Cycle Combustion Turbine as set forth in the Otter Tail recent filing with the SDPUC as the avoidable cost. That cost is $103.38/MWh. In order to reflect the fact that Oak Tree only counts 20% toward peak needs while the CCCT counts 100% toward peak needs, I have reduced the cost of Big Stone by 80% of its fixed costs (Depreciation, Return, Interest, Income taxes). Thus the $103.38 is reduced to $81.47/MWh in my analysis.

Q. *Are there other forecasts of avoided costs for wind that the SD PUC could look to that were prepared in the February 2011 timeframe?*

A. Yes. NorthWestern itself made a forecast of avoided cost for a wind plant in that same timeframe in Montana. The method used by NorthWestern at that time was the "differential revenue requirement" method. Such a method looks at the 20 year revenue requirement of the utility without the new wind plant and then recalculates the 20 year revenue requirement of the utility with the new wind plant in place. The difference in revenue requirement is then divided by the wind plant output to get the avoided cost of the wind plant. It would be very desirable to use this Differential Revenue Requirement method in South Dakota. Unfortunately, only NorthWestern possesses the information that would permit such a calculation to be made and NorthWestern has chosen not to use that method. However, the differences between Montana and South Dakota are not so great that the calculations made by NorthWestern in Montana could not be used as a proxy for avoided costs in South Dakota. The cost avoided through acquisition of a wind plant in Montana as calculated by NorthWestern in Montana PSC Docket D2011.5.41 was $75.52/MWh.

Q, As an alternative to a direct forecast of electricity avoided costs, have you searched for a forecast of natural gas prices to be used in a forecast of avoided energy costs?

A. Yes, I have first looked to the EIA forecasts of natural gas prices in the Feb. 2011 timeframe.

Q. Please describe what the EIA has said about long term natural gas price forecasts in the Feb. 2011 timeframe.

A. The EIA typically puts out a series of possible forecasts of natural gas prices each year. EIA provides a single initial "Early Release" at the beginning of a year that provides preliminary insight into what EIA might ultimately forecast. Later in the same year, EIA will then complete a more exhaustive analysis and provide that with EIA's final Reference Case for the year along with a large number of alternative cases to the EIA final Reference Case. The Reference Case is described by EIA as a case that might occur if no laws were adopted and if no new regulations consistent with recently passed laws were ever implemented. The EIA suggests that the Reference Case should not be considered EIA's best forecast and that decision makers should look at the alternative cases to see which seems to represent assumptions most consistent with that decision maker's view of the future. The EIA also publishes a forecast of natural gas prices that power plants will experience in each of several different regions of the United States. For this testimony, I have focused on the EIA forecast of natural gas prices for power plants in the West North-Central area of the United States, which includes South Dakota and is generally the region that impacts South Dakota.

Q. In February of 2011, the EIA's most recent full forecast would have been the forecast it put out for the year 2010. What did that forecast show?

A. The EIA forecast of gas prices for power plants in the West North-Central area of the United States can be viewed at the EIA-AEO Tablebrowser web site.

http://www.eia.gov/oiaf/aeo/tablebrowser/

Once at that website, one enters Publication of the forecast of interest (in this case, Annual Energy Outlook 2010), then filter on the information of interest (in this case Energy Prices), select the Table of information desired (in this case Energy Prices by Sector and Source), and select the region of interest (in this case West North Central). Finally, one must select the Case/Scenario of interest. There are 30 total cases/scenarios. Up to 5 different cases/scenarios can be selected at a time. When "Display Table" is chosen, the table of results appears on the screen. On the results look for a line entitled "Prices in Nominal Dollars," then locate the line titled "Electric Power." Then locate the line labeled "Natural Gas." For purposes of this testimony I chose 5 cases/scenarios for the year 2010. Those 5 were "Reference Case", "High Growth", "Low Technology", "High Renewable Cost", and "No Shale Gas." Other cases can be selected, but I have not done that for this testimony. Other parties may want to select and view the gas price forecasts in the remaining 25 cases/scenarios. Attachment 2 to this testimony is an Excel Workbook I used in developing avoided cost prices in this testimony. Sheet 1 in Attachment 2 to this testimony provides the yearly gas prices for these 5 cases.

Q. In February of 2011, the EIA would also have had a new "Early Bird" forecast for the year 2011. That forecast assumed no new future environmental laws being passed and no regulations that would be put in place to implement any recent new laws. What did that forecast show?

A. The same EIA-AEO Tablebrowser web site also has the gas price forecast for power plants in the West North Central region for the 2011 Early Bird forecast. That forecast is also shown in Attachment 2 to this testimony. I am reluctant to rely on the 2011 Early Bird Forecast because it contained a shockingly high increase in the assumption about Technically Recoverable Shale Gas reserves. It is not clear that that shockingly increased assumption was not in error as evidenced by the fact that a year later the EIA adjusted that number down by a large amount. Further, the 2011 Early Bird Forecast assumed no new environmental laws would be passed in the future and assumed that no new regulations would be written under existing environmental laws. Both of these assumptions would cause the avoided cost forecast to be artificially low and, in my opinion, below NorthWestern's full avoided cost.

Q. Which of all these natural gas price forecasts developed by the EIA do you believe is the best to be used in the Feb 2011 timeframe?

A. In my view, the SD PUC should look at avoided cost forecasts resulting from all six EIA-AEO cases I have selected and examine the results of that analysis in concert with viewing the other forecasts I include in this testimony. With regard to the avoided cost forecasts based on EIA gas prices, the EIA-AEO 2010 forecasts were clearly subject to much more detailed analysis and show a series of possible futures. The 2011 Early Bird would be the most recent, but it is somewhat problematic because (a) it was not subject to the detailed analysis, (b) it only reflects a single case where no new future environmental laws are passed and no regulations would be put in place in the future to implement recent environmental laws, and (c) it reflects a shockingly large increase in the estimate of technically recoverable shale gas reserves, an increase that has not been carried through in more recent EIA-AEO forecasts. The other more carefully studied cases/scenarios reflected in the 2011 EIA-AEO were not available until June of 2011.

Q. Is there any other natural gas price forecast you found in the Feb. 2011 timeframe that should be reviewed by the SD PUC?

A. Yes. The Big Stone analysis that I mentioned above also looked at gas fired alternatives to the Big Stone environmental retrofit project. That analysis included a forecast of natural gas prices. It appears that the gas price forecast may have been made somewhat before the Feb.

2011 timeframe. However, the sponsors of the Big Stone study have continued to use that natural gas price forecast in recent filings with regulatory bodies including the SD PUC.

Q. Having found seven forecasts of natural gas prices that the SD PUC could reasonably use for this avoided cost forecast, please describe how you turned these seven gas price forecasts into seven forecasts of avoided energy avoided costs and what those forecasts are.

A. I used the Steve Lewis model to turn these gas price forecasts into forecasts of spot market electricity price forecasts. As mentioned earlier, I am uncomfortable using the Steve Lewis model because of its assumption that "market heat rates" start quite low and remain so throughout the 20 year forecast period. I then used the spreadsheet model that developed Exhibit BJL-3 in this Docket to represent the "hybrid" approach as directed by the SD PUC. In order to use the "hybrid" approach, I also needed to have a forecast of coal incremental operating costs in the future. I note that the Otter Tail filing with the SD PUC on Big Stone has significant discussion of how recent environmental legislation and regulation would adjust the incremental cost of coal plants (e.g. by 2016). So I have added those specific increases to a general inflation increase in the incremental cost of the coal plants.

Q. You indicate that you have used a combination of the Steve Lewis model and the model used to develop Exhibit BJL-3 in this Docket. Please indicate with more specificity what you did.

A. In this testimony I approach the avoided cost calculation using an Excel Workbook model. I used the Steve Lewis spreadsheet model provided in response to RFP-022 and the spreadsheet model that developed Exhibit BJL-3 as the starting point for developing an appropriate Excel Workbook based Avoided Cost methodology model. In developing my avoided cost calculation workbook I adopted the market heat rates developed by Steve Lewis for the year 2012 based on market forwards. I assumed those market heat rates would continue to apply in the future if there is no carbon price. With these adjustments I am able to calculate estimated monthly on-peak and off-peak spot market prices under a range of possible input assumptions that can be used in an avoided cost calculation. The Excel workbook needs input gas prices and input carbon prices to calculate the spot market prices. I set the carbon prices at zero as directed by the SDPUC.

Q. *What did you do to convert those spot market prices to a calculation of avoided cost?*

A. I started with the Excel workbook that developed Mr. LaFave's Exhibit BJL-3. That workbook takes as an input the spot market prices developed by Mr. Lewis. I modified the Excel workbook that developed Mr. LaFave's Exhibit BJL-3 so the Avoided Cost calculation workbook (Attachment 2 to this testimony) uses the spot market price calculation that I described above. The BJL-3 spreadsheet makes a calculation for the year 2012 and a calculation for the year 2023 and then develops a straight line between the two numbers. This method does not take into account the yearly change in gas prices. My workbook makes a specific calculation for all years of the forecast. In addition, my workbook was designed so that the user can choose to develop Avoided Costs that reflects (a) market prices in all hours, (b) avoided incremental cost in all hours (e.g. no market exists), or (c) the hybrid approach that uses market prices in hours when NorthWestern does not have sufficient coal generation to cover its load but uses coal variable cost (ignoring the market) when NorthWestern does have sufficient coal generation to cover its load. I ran the model only with the hybrid approach as directed by the SD PUC. I needed to adjust the variable cost of coal as discussed above. I then ran that model with the different gas price inputs in order to calculate a range of possible avoided costs. I believe that an avoided capacity cost should then be added to the avoided energy cost set forth therein. Since the SDPUC has declined to accept the Black & Veatch forecast, I have used the more traditional capital cost of a natural gas peaker to indicate the avoided capacity cost. This method is consistent with NorthWestern's indicated plan to build a new natural gas peaker in South Dakota when new capacity is needed. Finally, this avoided cost calculation is for avoiding "brown" power (i.e. power that does not have renewable attributes). If the SD PUC wants Oak Tree to provide its Renewable Energy attributes to NorthWestern, then there needs to be added a forecast of Renewable Energy Credit or "REC" value to the avoided cost. Otherwise, the avoided cost is as I calculated it assumes Oak Tree will own the RECs. NorthWestern has indicated in other forums that the value of the REC is $7.5/MWh. If the SD PUC wants NorthWestern to own the RECs from the Oak Tree project, then the SD PUC should add this $7.5/MWh to the avoided cost rate that I calculate.

V. RESULTS OF VARIOUS APPROACHES USED TO DEVELOP AVOIDED COSTS ESTIMATES AS OF FEB. 2011

Q. What gas prices have you run through the Excel Workbook Avoided Cost Model?

A. I have run the model with the seven gas price assumptions indicated in the above methods. I then added the capacity value and the REC value to get the total avoided cost for these seven possible gas price futures. Those results are shown in the table below.

Q. How do these forecasts compare with the more direct forecast of avoided cost that have discussed in this testimony?

A. I have added the direct approach based avoided costs to the table below.

Q. What are your results?

A. The results appear in the table below.

	2010	2010	2010	2010	2010	2011	Otter Tail	Otter Tail	Otter Tail	NorthWestern
	Ref Case	High Growth	Low Tech	Hi Renew Cost	No Shale	EarlyRelease	Gas	Big Stone	CCCT	Spion Kop
	MHR method	MHR method	MHR method	MHR method	MHR method	MHR method	MHR method	Direct	Direct	Direct
Energy	50.21	48.95	52.1	50.54	56.63	41.38	60.72	57.09	81.47	75.52
REC	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	0
Capacity	7.3	7.3	7.3	7.3	7.3	7.3	7.3	0	0	0
Total Avoided Cost	65.01	63.75	66.9	65.34	71.43	56.18	75.52	64.59	88.97	75.52

Q. These results show a range of avoided costs from $56/MWh to $89/MWh. What do you believe is a reasonable value to use for Oak Tree?

A. Clearly there is uncertainty in a 20 year forecast of avoided cost. However, as I mention in the beginning of this testimony, it would make little sense for the SDPUC to pick the lowest number for an avoided cost for Oak Tree. The lowest number would be the number based on the EIA-AEO 2011 Early Release. As indicated earlier in this testimony, this number is problematic from the standpoint that: (a) it relies on the Steve Lewis assumption that Market Heat Rates will not increase in the future; (b) it does not reflect any possible future environmental laws, (c) it does not reflect any of the cost associated with possible future new regulations under existing environmental laws; and (d) it reflects a shocking large jump in the assumption of Technically

Recoverable shale gas reserve…an assumption that the EIA reduced substantially in the following year's EIA-AEO. The Big Stone modification would clearly appear to be an avoidable cost and that cost has been carefully analyzed. Therefore, I believe an avoided cost of $64.9/MWh may be the legally supportable avoided cost. But since NorthWestern needs both Big Stone and additional supply in the future, the Otter Tail filing with Big Stone suggests that the CCCT may also be an avoidable resource. Therefore, I believe the $89/MWh estimated cost of a new CCCT is another legally supportable avoided cost. With the understanding that the SD PUC has not yet approved the Big Stone modification plan, a sensible conservative approach for the SD PUC to take would be to average the 10 possible avoided costs. Averaging those 10 possible avoided cost estimates results in $69.3/MWh.

Q. Does that conclude your Additional testimony?

A. *Yes.*