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

Testimony and Exhibits of

Brian P. Rounds

On Behalf of Commission Staff

Public Version

November 21, 2012

EXHIBIT
Staff 2

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and employment.

A. My name is Brian P. Rounds. I am a utility analyst at the South Dakota Public Utilities Commission (PUC or Commission).

Q. Are you the same Brian P. Rounds who earlier filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The Commission's May 15, 2012 and October 11, 2012 Orders requested the parties file additional analyses to enable the Commission to determine the following:

1. The proper application of the hybrid method.
2. The proper natural gas input(s) to use in the hybrid method based on market conditions and projections as of the date of the Legally Enforceable Obligation (LEO), February 25, 2011.
3. The proper electric market rates that the parties may deem warranted to reflect market conditions and projections as of the date of the LEO.
4. The proper capacity contribution and resulting capacity credits to be included in the avoided cost and added into the hybrid method under the Titan I method.
5. NorthWestern Energy's (NWE's) avoided cost levelized over a 20 year period.

My testimony will provide and explain Staff's analyses for each of the requested points above, eventually recommending the proper avoided cost. Section II will directly answer each of the above questions. Section III will then describe the hybrid method with proper inputs to determine a specific avoided cost recommendation.

II. SUMMARY CONCLUSIONS

Q. What is the proper application of the hybrid method?

A. I believe the proper application of the hybrid method would be to evaluate each hour of the year and compare NWE's load, NWE's baseload generation, and the QF's output. That comparison then sets the avoided cost for each hour as follows:

1. During hours in which NWE's baseload generation exceeds its load, the avoided cost should be set at the cost of NWE's most expensive baseload generator.
2. During hours in which NWE's load exceeds its baseload generation by at least the QF's output, the avoided cost should be set at the market price.
3. During hours in which NWE's load exceeds its baseload, but not by as much as the QF's output level, the avoided cost should be split. The market price should be paid for the difference in capacity between NWE's load and its baseload generation, and the most expensive baseload generator should set the price for the remaining QF output.

Assuming NWE has baseload generation of 210 MW, consider the following examples:

#	NWE's load	QF output	Baseload	Avoided Energy Cost
~~1~~	~~190 MW~~	~~10 MW~~	~~210 MW~~	~~10 MW @ baseload cost~~
2	230 MW	10 MW	210 MW	10 MW @ market price
3	216 MW	10 MW	210 MW	6 MW @ market, 4 MW @ baseload

Q. What is the proper natural gas input to use in the hybrid method based on market conditions and projections as of the date of the LEO?

A. I believe the best forecast available as of February 25, 2011 was the natural gas forecast from the EIA's Annual Energy Outlook (AEO) 2011 Early Release Reference Case, released on December 16, 2010[1]. The forecast is timely and relevant. The reference case does not include potential carbon legislation, as requested by the Commission, and was released only a couple of months prior to the LEO. This projection was also unanimously chosen by the Eastern Interconnection States Planning Council[2] (EISPC) and eventually the Eastern Interstate Planning Collaborative (EIPC) for the reference case in their modeling in January of 2011.

Besides being what I think is a reputable projection, it is also convenient. It was used in the AEO 2011 Early Release reference case as well as EIPC's Business As Usual (BAU) case, both of which I utilized in my analyses.

Q. What are the proper electric market rates to reflect conditions and projects as of the LEO?

A. Again, I believe the best electric market rate forecast comes from the AEO 2011 Early Release Reference case. The AEO provides an annual electric generation cost for the US through 2035. As you will see in Section III, I used that data along with other AEO and EIPC data to calculate an hourly price forecast for 2012 through 2035.

Q. What is the proper capacity contribution to the avoided cost?

A. I believe the proper capacity contribution should be 12.9% of nameplate capacity at an annual cost of $20/kW-year. OTE originally assumed a credit of 20% of nameplate capacity at an annual cost of $17/kW-year. In light of the testimony received during the hearing this spring, I believe OTE's original capacity contribution estimate price was reasonable, but I did not find evidence to support a 20% accreditation. In MISO's 2011-2012 LOLE Study Report[3], MISO calculated a 12.9% system wide wind capacity credit for its 2011 planning year. NWE, by entering into a capacity contract in 2011 for summer capacity beginning in 2012, proved that it was short on capacity beginning in 2012. **BEGIN CONFIDENTIAL**

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[1] Available at http://www.eia.gov/forecasts/archive/aeo11/er/

[2] EISPC is a committee consisting of two representatives of each of the 39 states in the Eastern Interconnection as well as the City of New Orleans and the District of Columbia.

[3] https://www.midwestiso.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf released in December of 2010.

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Q. ~~**What is NWE's avoided cost levelized over a 20 year period?**~~

A. According to my analysis, NWE's levelized cost over a 20 year period is $54.32, beginning in 2013 or $55.78, beginning in 2014. However, using a levelized cost places a lot of risk on NWE. They pay in excess of the avoided costs for the first 10 years and make up for it over the last 10 years. If OTE were unable to provide energy throughout the contract, for some reason, NWE ratepayers could be left holding the bill. Thus, I would advise using the annual avoided costs calculated in Exhibit BPR-1:

Year	$/MWh
2014	$42.81
2015	$43.62
2016	$44.86
2017	$45.57
2018	$47.04
2019	$48.06
2020	$49.72
2021	$51.62
2022	$53.42
2023	$55.18
2024	$56.47
2025	$57.69
2026	$59.31
2027	$60.71
2028	$62.34
2029	$64.07
2030	$65.72
2031	$67.21
2032	$69.36
2033	$70.91

III. CALCULATIONS

Q. Describe how you calculated NWE's avoided cost.

A: In order to calculate NWE's avoided cost, I first needed to determine the following components:

1. NWE's hourly load over the 20-year duration of the contract;
2. OTE's hourly output over the 20-year duration of the contract;
3. the hourly cost of NWE's most expensive baseload generation over the 20-year duration of the contract;

4. the hourly market price forecast over the 20-year duration of the contract; and
5. NWE's cost of capacity.

Employing the methods I will explain below, I determined the necessary components above for the years 2013 through 2033. With those, I was able to calculate an avoided cost for two potential contract periods, 2013-2032 or 2014-2033, depending on when the project would go into service.

Once I had determined all necessary components, I examined each hour of the year. In cases where NWE's load was less than their baseload generation (204.742 MW), I multiplied OTE's output by NWE's baseload cost. In cases where NWE's load was more than baseload generation by at least OTE's output, I multiplied OTE's output by the market price. Finally, in cases where NWE's load was more than baseload but by less than OTE's output, I multiplied the difference between load and baseload by the market price, and the remainder of OTE's output was multiplied by NWE's baseload cost.

EXAMPLE - For one hour, assume the baseload cost is $30 and the market price is $50:

#	NWE's load	OTE output	Baseload	Avoided Energy Cost
1	190 MW	10 MW	210 MW	10 MW x $30 = $300
2	230 MW	10 MW	210 MW	10 MW x $50 = $500
3	216 MW	10 MW	210 MW	6 MW x $50 + 4 MW x $30 = $420

Once the annual avoided energy cost was determined in Exhibit BPR-2, the avoided capacity cost was added. The resulting figure was divided by the number of hours in a year in order to produce an annual price per MWh as shown in Exhibit BPR-1.

Q. What modeling did you use to determine the components above?

A: Due to a lack of financial resources, I was unable to run my own model to determine the components above, so I had to rely on other models. I used the results from EIPC's macroeconomic analyses[4] of the Eastern Interconnection and the EIA's AEO 2011 Early Release reference case. As one of South Dakota's representatives on EISPC, I participated in the selection of the inputs to EIPC's analyses (coincidentally) just prior to February of 2011. In that process, we used many of the AEO 2011 Early Release reference case inputs for our Business As Usual future. Those inputs include what I believe to be the most reasonable natural gas price forecast and no carbon legislation. As a result, I feel those two analyses are well suited for determining an avoided cost in this case.

Q. Did you really look at every hour over the next 20 years?

[4] The results from EIPC's Phase I modeling are available on its website at http://www.eipconline.com. However, I've included all the spreadsheets I used within my exhibits.

A: No. I looked at 20 different blocks of hours for each year. To simplify the analyses, EIPC broke each year into 20 different "load blocks", where each block represents a number of hours that exhibits similar load characteristics each season. The blocks used are listed below.

#	Season	Hours
1	Summer	10
2	Summer	25
3	Summer	75
4	Summer	100
5	Summer	200
6	Summer	300
7	Summer	400
8	Summer	500
9	Summer	800
10	Summer	1,262
11	Shoulder	25
12	Shoulder	200
13	Shoulder	600
14	Shoulder	900
15	Shoulder	1,203
16	Winter	25
17	Winter	100
18	Winter	400
19	Winter	700
20	Winter	935

Q. How did you determine NWE's hourly load forecast?

A: To determine the load forecast I first referenced the biannual plan NWE submitted in 2010. In that plan, NWE included a load forecast going out 10 years. However, the forecast contradicted itself. It listed an annual growth factor of 1%, but the resulting demand was showing a growth rate of closer to 0.5%. As a result, I decided the forecast was unreliable and instead used EIPC's growth rates for this region. The resulting growth rates were 0.89% for 2011-2020 and 0.78% for 2020-2050, as shown in Exhibit BPR-3.

Once I had calculated an annual demand forecast as shown in Exhibit BPR-4, I plugged the forecast into EIPC's load shapes for NWE's region, shown in Exhibit BPR-5. This produced an hourly load forecast for NWE as calculated in Exhibit BPR-6.

Q. How did you determine OTE's hourly output?

A: Although I would have rather used the hourly data given by OTE earlier in this proceeding, it was incompatible with the load block format I used for NWE's load forecast. Thus, I started by using EIPC's regional "wind shapes" as shown in Exhibit BPR-7. For each of the 20 load blocks, EIPC determined a regional wind shape consisting of expected wind generation during each block. Because EIPC's wind shape for OTE's region had an expected annual capacity factor of 40% and OTE had an expected annual capacity factor of **BEGIN CONFIDENTIAL END CONFIDENTIAL**, I scaled the entire wind shape to match OTE's annual capacity factor as shown in CONFIDENTIAL Exhibit BPR-8.

Q. **How did you determine the hourly cost of NWE's most expensive baseload generation?**

A: I used the "NW Off Peak Avoided Cost" given by Mr. LaFave in his Exhibit BJL-3. Because it didn't include data for 2033-2035, I extrapolated my own estimates for those years as shown in Exhibit BPR-9. For each year, I assumed the price was static across all hours.

Q. **How did you calculate an hourly market price forecast?**

A: I used both the AEO 2011 Early Release reference case (AEO) and EIPC's results. EIPC's results included regional prices for each of the 20 load blocks in 2015, 2020, 2025, 2030, and 2040 as shown in Exhibit BPR-10. I began by extrapolating these prices to the years between, as shown in Exhibit BPR-9.

Once I had extrapolated the hourly market price forecast from EIPC, I should have been finished. Unfortunately, because EIPC is most interested in comparing results across model runs and not determining a true price forecast, EIPC's results are of mixed dollar values. That is, the inputs were not all converted to the same time value. Some may be in 2010 dollars, some may be in nominal dollars. The result is a forecast without identical units. We know that the forecast lies somewhere between 2010 dollars and nominal dollars, but not the specific values. However, the relationship of the prices across load blocks should be accurate and instructive.

As to the foundation of the market price forecast, I started with the AEO's average annual generation price in the United States as shown in Exhibit BPR-11. Next, I looked at the AEO's average price of electricity to all consumers (Exhibits BPR-12 and BPR-13) and determined a relationship between the price in NWE's region and the price across all regions in the United States. I used this relationship to scale the AEO's average annual generation price as shown in Exhibit BPR-9. I then compared the new regional generation price to the average annual EIPC price to determine how to scale the hourly EIPC prices I had originally derived. My final market price forecast is in nominal dollars and includes prices for the 20 load blocks of each year from 2012 through 2035.

Q. **How did you calculate NWE's cost of capacity?**

A: As shown in Exhibit BPR-14, I multiplied the total nameplate capacity of 19.5 MW times by an accredited capacity of 12.9%, and then multiplied by a cost of $20/kW-year. This calculation produces an annual cost of $50,310 or approximately $0.66/kWh.

Q. **Are your formulas and calculations available in digital format for review?**

A. Yes. Attached to this testimony is a CONFIDENTIAL Microsoft Excel workbook that includes all spreadsheets I have referenced as exhibits.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.