BEFORE THE PUBLIC UTILTIES 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

EL11-006

Prefiled Direct and Rebuttal Testimony of

Richard J. Green

On behalf of NorthWestern Energy

January 12, 2012

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Testimony

Introduction and Qualifications

Q: Please state your name and business address.

A: My name is Richard J. Green. I am an independent operations consultant contracted to provide services for NorthWestern Energy. My business address is 165 S. Circle Drive in Huron, South Dakota 57350.

Q: Briefly describe your education and business experience.

A: I hold a Bachelor of Science degree in mechanical engineering from the South Dakota School of Mines and Technology in Rapid City. I graduated in 1969. Following graduation, I began work as an engineer for Chevrolet Engineering in Detroit followed by a three-year service period as a maintenance officer in the U.S. Army Corps of Engineers in Europe. I started working in the electric utility business as a results engineer for Northwestern Public Service (NWPS) in 1973. During my full-time employment with NWPS/NorthWestern Energy from 1973 thru 2000, I held various positions including superintendent - Electric Production, manager - Production, manager - Production and Environmental Affairs, manager - Huron Division (with continued responsibilities as manager - Production), and manager - System Control. Since 2000, I have been working for NorthWestern as an independent operations consultant providing consulting services related primarily to coal-fired steam plant operations, oil- and gas-fired peaking plants, power plant fuel supply, electric energy supply, electric transmission, system control, and planning related to those areas of interest.

Purpose and Summary of Testimony

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to provide information related to the development of NorthWestern's avoided cost filing (energy component only) in South Dakota as prescribed by PURPA and the South Dakota Public Utilities Commission and to rebut certain portions of Mr. J. Richard Lauckhart's direct testimony.

Q: Please summarize your testimony.

A: My testimony includes:

- A review of the development of the methodology used to calculate the avoided costs for the energy component of NorthWestern's avoided cost filing of November 2011; and

- ♦ Information and discussion that refutes Mr. Lauckhart's, assertion, on behalf of Oak Tree Energy, that avoided costs should be based solely on spot market prices.

Avoided Cost Methodology Development for NorthWestern Energy in South Dakota

Q . **What is the definition of "avoided cost"?**

A: FERC issued regulations implementing PURPA in February 1980. FERC's rules provide that the just and reasonable rate for purchases from a QF should be equal to the utility's full avoided cost, which FERC defines at 18 C.F.R. § 292.101(6):

> *Avoided Costs* means the incremental costs to an electric utility of electric energy, capacity, or both, which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

Q: **Please describe the volumes of QF purchases and periods of time that were considered in developing the energy component of avoided costs on NorthWestern's system.**

A: 18 C.F.R. § 292.302(b)(1) provides rules related to developing"[t]he estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities." In the case of NorthWestern Energy – South Dakota, the applicable ensuing portion of that section states:

> Such levels of purchases shall be stated . . . in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years; . . .

In NorthWestern's case, the highest, on record, hourly "system peak demand" was established on August 11, 2011, during the hour ending 1700, at a level of approximately 341 megawatt-hours (MWh) per hour. Therefore, the largest "block" that could be considered is 34.1 MWh.

In the present filing, NorthWestern has chosen to develop avoided costs for block sizes, or volumes, of 0, 5, 10, 15, 20, 25, and 30 MWh per hour. For each of those blocks, separate and unique average avoided cost values were developed which represent the costs during winter seasons, summer seasons and on- and off-peak periods within those seasons.

The period of time for which estimated avoided costs were developed was the then current calendar year of 2011 and the ensuing years of 2012 through 2016.

Q: What is the most important issue that must be considered in developing a methodology to calculate the estimated avoided costs on NorthWestern's South Dakota system?

A: From my review of NorthWestern's historic hourly cost data, I believe that the most important issue to be considered is the dynamic nature, in terms of both price and volume, of the individual components that make up the hourly incremental energy cost. In its 1982 Decision and Order (F-3365) regarding the implementation of PURPA QF rules, at page 12, the South Dakota Public Utilities Commission recognized the dynamic nature, stating:

> The Commission finds, as Mr. Bernal testified, that such a basis of calculation [referring to the process of averaging hourly incremental avoided costs over the period in question] recognizes that the avoided energy cost to the utility's system changes constantly. Hourly incremental costs vary greatly depending on which unit of generation is being added in the next increment.

Generating unit incremental costs continue to be the most important component of avoided costs for NorthWestern Energy - South Dakota. However, an additional important cost component has evolved since the time of the 1982 order. In the mid-1990s, federal legislation was enacted to encourage open, non-discriminatory access to the bulk electric transmission system. This encouraged a major expansion of the wholesale electric energy market across the Mid-Continent Area Power Pool (MAPP) area, and elsewhere, and made available to NorthWestern Energy - South Dakota an additional important supply component in the form of cost-based, economic wholesale market energy.

Q: To help understand the importance of both the generating unit and wholesale market components to NorthWestern's South Dakota system, what are their respective contributions to the overall annual electric energy supply portfolio?

A: The following table shows the relative volumes, in megawatt-watt hours, of generation and wholesale market purchases that have made up NorthWestern's annual total electric supply during recent years. This data indicates three-year averages of 7.3% for wholesale market purchases and 92.7% for baseload generation. Year-to-year fluctuations are generally the result of multi-year cycles in major maintenance outages that affect generating unit availability. Cyclical extreme weather (hot or cold) events also play a role in the overall annual requirement.

	2008		2009		2010	
	MWh	%	MWh	%	MWh	%
GENERATION - STEAM & WIND	1601236	92.38%	1553577	91.40%	1694986	94.22%
PURCHASES - WHOLESALE ENERGY MARKET	132104	7.62%	146108	8.60%	104007	5.78%
SUPPLY TOTAL	1733340	100.00%	1699685	100.00%	1798993	100.00%

SOURCE: FERC FORM 1 and NorthWestern Energy - South Dakota System Control Records

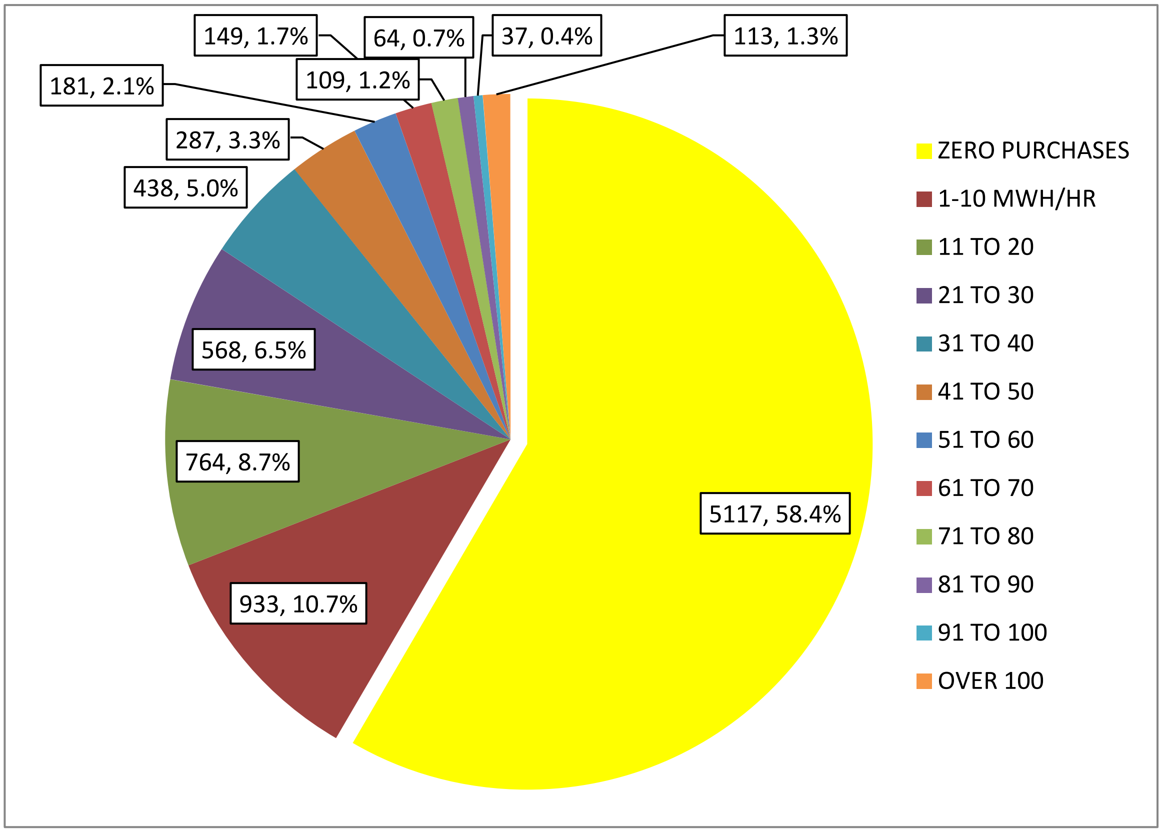
Q: How do system load and supply conditions influence the treatment of generating unit and wholesale market components in the calculation of NorthWestern's avoided costs?

A: The need to purchase supplemental wholesale market energy occurs, in varying amounts per hour, during the higher load hours of the year when baseload generation alone is insufficient. As illustrated in the pie chart shown below, baseload generation was sufficient, with no purchases needed, during 5117 hours or 58.4% of the hours during 2010. During the remaining 3643 hours or 41.6% of the hours of 2010, at least some level (1 MWh or more) of market purchase was necessary. Thus, two general system conditions occur that dictate how the generating unit and market purchase components are to be treated in the avoided cost calculation. Condition #1 occurs, as evidenced in the chart, during the majority of the hours of the year when no purchases are necessary. Under condition #1, the hourly avoided cost calculation must be based solely on the incremental cost of generation because that is the only cost component present and, thus, the only cost that could possibly be avoided.

Condition #2 occurs during the balance of the hours in the year when some level of market purchases are necessary to supplement generation and, thus, the hourly avoided costs must be based on a blend of both generation and market components. The specific hourly blend rate will depend on each component's respective proportional volume contribution to the hourly QF purchase level.

Normally, daily changes in system load cause the system to transition between conditions #1 and #2 with condition #1 predominant during off-peak hours and condition #2 predominant during on-peak hours. The fundamental conclusion that I draw from the preceding discussion is that both incremental generating costs and wholesale market costs must be considered in the calculation of avoided costs.

2010 ELECTRIC WHOLESALE PURCHASES
ANNUAL PROFILE OF MWh PER HR (HOURS AND PERCENT)



Q: How does your conclusion that NorthWestern's avoided cost calculations must consider both generation costs and market costs differ from the opinion expressed by Mr. Lauckhart on behalf of Oak Tree energy?

A: The difference between my opinion and that of Mr. Lauckhart's is that I believe that both generation costs and market costs should be represented in any calculation of avoided energy costs, while Mr. Lauckhart apparently believes that only market costs should be included. I believe this to be his opinion based on the fifth bullet point under Oak Tree's Summary of Testimony, wherein it states:

> Historical data shows that NorthWestern both buys spot market power and sells spot market power. As such, a brown value avoided energy cost is appropriately based on a forecast of hourly spot market energy prices.

Mr. Lauckhart's opinion that only market prices should be considered completely ignores the key cost element of *self-generation that <u>is</u> included* in the FERC definition of avoided costs but then goes on to introduce an unrelated element in the form of *sales of market power* that *is <u>not</u> included* in the FERC definition. Please refer to the FERC definition, 18 C.F.R. § 292.101(6), repeated here:

> *Avoided Costs* means the incremental costs to an electric utility of electric energy, capacity, or both, which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

The exclusion of the self-generation cost component from the calculation of real avoided costs on NorthWestern's system would lead to grossly inaccurate avoided costs due to the nearly 60% of annual hours, as discussed in the previous answer, during which that component is the one and only cost that could possibly be avoided. Further inaccuracy would be introduced by including the unrelated element of off-system sales.

Q: In his testimony on pages 8 and 9, Mr. Lauckhart provided data for August 11, 2010, as a heavy load day and September 25, 2010, as a light load day and concluded that NorthWestern "must be selling spot power in light load and buying spot market power in heavy load hours." Do you agree that August 11, 2010, and September 25, 2010, are days that are representative of NorthWestern's system on heavy load days and light load days?

A: No. August 11, 2010, was an exceptional heavy load day rather than a typical heavy load day. NorthWestern had its highest peak load of the entire year on August 11, 2010. September 25, 2010, was not a typical light load day. September 25, 2010, was a Saturday. Unlike most light load days, the Coyote generating plant, which is a coal-fired plant that normally produces about 40 megawatts for NorthWestern, was shut down for scheduled maintenance.

Q: Do you agree that NorthWestern must be "buying spot market power in heavy load hours?"

A: No. NorthWestern only buys spot market power when its load exceeds the production of its base load generation and the output of Titan Wind. There are many on-peak or heavy load hours during the year in which NorthWestern does not purchase any spot market power.

Q: Please describe the basic technique that you used in developing the estimated avoided costs on NorthWestern's South Dakota system?

A: The estimated avoided energy costs for various levels of purchase from qualifying facilities were based on the average historical trends, or patterns, of the proportional contributions made by (1) baseload generation and (2) wholesale market purchases to the total makeup of each megawatt level of purchase.

Hourly proportional contribution factors, expressed in per cent, were calculated for each and every hour during the multi-year historic study periods.

Then, arithmetic averages of the hourly contribution factors were computed for the winter and summer seasons and for the on- and off-peak periods within those seasons.

Finally, the average proportional contribution factors were combined with forecast incremental baseload production costs and forecast wholesale market prices to develop the estimated avoided costs, in dollars per megawatt-hour, for 2012 through 2016.

Study Periods:

For summer periods, the average proportional factors were based on the four-year period of 2008 through 2011 in order to capture the inherent year-to-year fluctuations caused by events such as extreme hot weather cycles and major maintenance outage cycles average proportional contribution factors used for the winter periods was based on a more limited two-year period of 2010 and 2011 (through May 2011).

For the purposes of these estimated avoided energy cost calculations, the summer season is June through September, with all other months in each year in the winter season.

The on-peak periods are Monday through Saturday from Hour Ending 7:00 A.M. through 10:00 P.M. All other hours during those days are off-peak as well as all hours on Sundays and NERC-prescribed holidays.

Q: Can your provide an illustrative example showing how the historical hourly data was analyzed to determine the percentage contributions of baseload generation and market purchases to a particular level of QF purchase?

A: Yes. During any given hour, there are three possible scenarios that determine how baseload generation and market purchases each contribute to the overall makeup of the particular QF level of purchase under consideration.

Hourly Scenario #1: During any hour that baseload generation is sufficient to supply system load with no market purchases necessary, the market purchase MWh contribution will be equal to 0% and the baseload generation MWh contribution will be equal to 100%.

Hourly Scenario #2: During any hour that market purchases are necessary to supplement baseload generation to supply system load and the market *purchase volume is <u>greater than or equal</u> to the MWh block size of the QF purchase* under consideration, the market purchase MWh contribution will be equal to 100% and the baseload generation MWh contribution will be equal to 0%.

Hourly Scenario #3: During any hour that market purchases are necessary to supplement baseload generation to supply system load but the market *purchase volume is <u>less than</u> the MWh block size of the QF purchase* under consideration, the market purchase MWh contribution will be equal to (purchase volume ÷ QF block size) × 100% and the baseload MWh contribution will be the remainder or (1 – (purchase volume ÷ QF block size)) × 100%.

Exhibit RJG-1 is an example of how the proportional contributions of baseload generation MWh and market purchase MWh to a given QF level were calculated over a 24-hour period. The day used for the example was June 28, 2010, and the assumed QF purchase level (or block size) was 10 MWh per hour. That day was chosen for this example because it contains hours representative of all three of the types of hourly scenarios described above, and it also was a day when generating unit conditions and system load conditions were what could be considered "normal." In other words, the three baseload steam units were on-line and the average hourly load of 192 MWh per hour differed only slightly (+4%) from the 2010 annual average of 184 MWh per hour. During 14 hours of that day, no market purchases were needed to supplement baseload generation, while during the remaining 10 hours, from 6 to 27 MWh per hour were needed.

Following is the daily summary (taken from Exhibit RJG-1) of hourly calculations made in accordance with the appropriate hourly scenarios described above to produce the period average proportional contribution factors for each of the supply elements (baseload generation and market purchases).

DAILY SUMMARY : 6/28/2010	BASELOAD		MARKET PURCHASE			
QF LEVEL: 10 MWh PER HR	CONTRIBUTION		CONTRIBUTION		TOTALS	
	MWh	PER CENT	MWh	PER CENT	MWh	PER CENT
ALL HOURS:	148	61.7%	92	38.3%	240	100.0%
ON-PEAK HOURS:	68	42.5%	92	57.5%	160	100.0%
OFF-PEAK HRS:	80	100.0%	0	0.0%	80	100.0%

For the real-life, actual avoided cost filing, the same calculation process was used as in the above example but greatly expanded to include all the many more hours contained in the study periods described in the previous answer.

Q: How are the proportional contribution factors, in per cent, then used to calculate the Avoided Costs, in dollars per MWh for future periods?

A: The process is fairly straightforward. For each QF level of purchase and period (seasonal, on- and off-peak) and for each year (2012 through 2016) considered in the Avoided Cost filing, the calculated average contribution percentage for the baseload component is multiplied by the forecast incremental baseload generating cost for the future year in question. The result is the average cost, in dollars, that the baseload supply component contributes to 1 MWh of the QF purchase.

In like fashion, the average contribution percentage for the market purchase component is multiplied by the appropriate forecast market price. The result is the average cost, in dollars, that the market supply component contributes to 1 MWh of the QF purchase.

Finally, these two results are added together to create the total cost, in dollars, for 1 MWh of QF purchase.

Incremental baseload generating costs, as forecast by Ottertail Power Company (the operating agent for the owners), for the Big Stone Plant, in dollars per MWh for 2012–2016, are expected to be:

	2012	2013	2014	2015	2016
BIG STONE $ PER MWh	$23.00	$24.25	$24.25	$24.32	$24.25

Further, expected wholesale market purchase prices for 2012 are shown below. These values were taken from Exhibit RJG-2, which is a summary of Lands Energy's South Dakota Price Forecast prepared for NorthWestern during the summer of 2011 and used in NorthWestern's avoided cost filing in November of 2011:

	2012 SUMMER		
	ON-PEAK	OFF PEAK	SEASON
0	$32.78	$19.95	$26.36
5	$32.78	$19.95	$26.36
10	$32.78	$19.95	$26.36
15	$32.78	$19.95	$26.36
20	$32.78	$19.95	$26.36
25	$32.78	$19.95	$26.36
30	$32.78	$19.95	$26.36

Following is a illustrative calculation showing the mathematical process used to combine the average historical proportional contribution factors, in percent, with forecast generation and market costs. For this example, the proportional contribution factors were taken from the 6/28/2010 example shown above and the forecast prices were taken from the tables above with 2012 values used.

For the "All Hours" period:

Generation contribution factor (61.7%) × forecast generating cost ($23) = $14.19, which is the generation portion of 1 MWh of the avoided cost.

Market contribution factor (38.3%) × forecast market price ($32.78) = $12.55, which is the market portion of 1 MWh of the avoided cost.

Then, adding the two portions, $14.19 + $12.55 = $26.74, which is the total average avoided cost for the "All Hours" period.

In like fashion, for the On- and Off-Peak periods:

On-Peak: (42.5%) × ($23) = $9.78 (generation portion of 1 MWh)
(57.5%) × ($32.78) = $18.85 (market portion of 1 MWh)
Adding $9.78 + $18.85 = $28.63 total average avoided cost for "On-Peak" period.

Off-Peak: (100.0%) × ($23) = $23.00 (generation portion of 1 MWh)
(0.0%) × ($32.78) = $00.00 (market portion of 1 MWh)
Adding $23.00 + $00.00 = $23.00 total average avoided cost for "Off-Peak" period.

Again, for the real-life, actual avoided cost filing, the same calculation process was used as in the above example but expanded to include the appropriate forecast costs, along with the historical study period average proportional contribution factors, to compute the avoided costs for each of the years of 2012 through 2016.

Q: Do you believe that the energy component of NorthWestern's Avoided Cost filing, based on the methodology summarized by your testimony, is a fair and reasonable estimate of expected avoided energy costs for the period 2012 through 2016?

A: Yes, I do.

Q: Does that conclude your testimony?

A: Yes, it does.

Affidavit of Richard J. Green

STATE OF SOUTH DAKOTA)
: ss
COUNTY OF BEADLE)

Richard J. Green, being first duly sworn upon oath, states and alleges as follows:

1) I am an independent operations consultant contracted to provide services for NorthWestern Corporation d/b/a NorthWestern Energy.

2) I have read this document and am familiar with its contents, and the same are true to the best of my knowledge and belief.

Further affiant sayeth naught.

Dated at Huron, South Dakota, this 12th day of January, 2012.

Richard J. Green

Richard J. Green

SUBSCRIBED AND SWORN to before me this 12th day of January, 2012.

JoAnne H Peterson

Notary Public, South Dakota
My commission expires: June 10, 2016

JOANNE H. PETERSON
Notary Public
SEAL
South Dakota