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November 15, 2011

Patricia VanGerpen
Executive Director
SD Public Utilities Commission
500 E. Capitol Ave.
Pierre, SD 57501

RE: 18 C.F.R. § 292.302(b) Informational Compliance Filing

Dear Patty:

NorthWestern Corporation, d.b.a. NorthWestern Energy, hereby submits its informational filing in compliance with 18 C.F.R. 292.302(b).

This report includes NorthWestern Energy's estimated electric avoided cost information for its South Dakota operations as filed biannually with state regulatory authorities.

If you, or any of your staff, have additional questions, please do not hesitate to contact me.

Sincerely,

Pamela A. Bonrud

Pamela A. Bonrud
Director – Government and Regulatory Affairs

Cc: Bleau LaFave, NorthWestern Energy
Jeff Decker, NorthWestern Energy
Sara Dannen, NorthWestern Energy

NorthWestern Energy

Informational Compliance Filing

As required by 18 C.F.R. § 292.302(b)

Submitted to the South Dakota Public Utilities Commission
November 15, 2011

18 C.F.R. § 292.302(b)(1)

The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1,000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems 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.

The estimated avoided energy cost calculations were made for the summer and winter seasons for each year and for the daily on- and off-peak periods within those seasons. 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 6 A.M. through 10 P.M. All other hours during those days are off-peak as well as all hours on Sundays and NERC-prescribed holidays.

NorthWestern Energy estimated its avoided energy costs for various levels of purchase from qualifying facilities based on the average historical patterns of owned generation and market purchases for each megawatt level of purchase for every hour throughout the periods in question. The historical patterns were combined with forecast incremental production costs and forecast market prices to develop the costs.

For summer periods, the average historical pattern was 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 weather cycles and major maintenance outage cycles.

Due to more consistent patterns exhibited during winter periods, the average historical pattern used for the winter periods was based on the two-year period of 2010 and 2011 (through May 2011). Tables of estimated avoided costs by block for the 0-megawatt level through the 30-megawatt level for 2011 through 2016 are included in Exhibit A.

NOTE: "*Avoided Costs* means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility generated itself or purchased from another source." 18 C.F.R. § 292.101(b)(6).
NOTE: "Nothing in this subpart requires any electric utility to pay more than the avoided cost for purchases." 18 C.F.R. 292.304(a)(2).

18 C.F.R. § 292.302(b)(2)

The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years.

Capacity Additions, Firm Capacity Purchases & Firm Energy Purchases

2012

Capacity Additions:

None planned. Capacity reserve forecast remains positive (+39.3 MW).

Firm Capacity Purchases:

80 MW (June – Sept) from MidAmerican Energy (MEC) through a three-year System Participation Power Agreement. 2012 is the final year of that agreement.

5 MW (May – October) from Basin Electric Power Cooperative (BEPC) through a four-year System Participation Power Agreement. 2012 is the first year of that agreement. No capacity is needed or planned to be purchased for November of the preceding year through April of this year.

Firm Energy Purchases:

NorthWestern's South Dakota annual system energy requirements are supplied through a portfolio of resources, including owned shares of three coal-fired baseload units, a long-term non-firm energy supply agreement with WAPA, and a wind farm PPA. Other firm energy resources available to be scheduled as needed, when economics and/or operational conditions warrant, are owned peaking units (natural gas and/or diesel) and the energy portion of the MEC and/or BEPC System Participation Agreements discussed above. For 2012, it is forecasted that 88.3% of the annual system energy requirement will be from baseload units and the wind PPA. The remaining 11.7% is expected to be purchased, at market-based rates, through the WAPA non-firm energy agreement.

2013

Capacity Additions:

A 52-MW (summer rating) simple-cycle combustion turbine begins commercial operation (construction began in October 2011). Capacity reserve forecast remains positive (+8.3 MW).

Firm Capacity Purchases:

11 MW (May – October) from Basin Electric Power Cooperative (BEPC) through a four-year System Participation Power Agreement. 2013 is the second year of that agreement. No

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capacity is needed or planned to be purchased for November of the preceding year through April of this year.

Firm Energy Purchases:

Same as 2012 with the following exceptions:

(a) The MEC System Participation Agreement will have expired, making that energy unavailable.

(b) For 2013, it is forecasted that 87.2% of the annual system energy requirement will be supplied by baseload units and the wind PPA. The remaining 12.8% is expected to be purchased, at market-based rates, through the WAPA non-firm energy agreement.

2014

Capacity Additions:

None planned. Capacity reserve forecast remains positive (+8.4 MW). In anticipation of expected capacity deficits for 2016 – 2021, it is planned to issue Requests for Proposal(s) ("RFP(s)") for capacity and energy supplies for the 2016 – 2021 time period or beyond as conditions then warrant. Evaluation of responses to RFP(s) will guide capacity additions and/or purchases for the 2016 – 2021 (or beyond) time frame, including consideration of converting the 2012 combustion turbine from simple- to combined-cycle operation. That conversion would add approximately 95 MW (summer rating).

Firm Capacity Purchases:

15 MW (May – October) from Basin Electric Power Cooperative (BEPC) through a four-year System Participation Power Agreement. 2013 is the third year of that agreement. No capacity is needed or planned to be purchased for November of the preceding year through April of this year.

Firm Energy Purchases:

Same as 2013 with the following exception: for 2014, it is forecasted that 89.4% of the annual system energy requirement will be supplied by baseload units and the wind PPA. The remaining 10.6% is expected to be purchased, at market-based rates, through the WAPA non-firm energy agreement.

2015

Capacity Additions:

None planned. Capacity reserve forecast remains positive (+8.5 MW)

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Firm Capacity Purchases:

19 MW (May – October) from Basin Electric Power Cooperative (BEPC) through a four-year System Participation Power Agreement. 2015 is the fourth and final year of that agreement. No capacity is needed or planned to be purchased for November of the preceding year through April of this year.

Firm Energy Purchases:

Same as 2014 with the following exception: for 2015, it is forecasted that 78.5% of the annual system energy requirement will be supplied by baseload units and the wind PPA. This notable reduction from historic levels in baseload energy for 2015 is the result of a planned outage of one of NorthWestern's baseload units (Big Stone) in order to bring new emission control equipment on line. The remaining 21.5% is expected to be purchased, at market-based rates, through the WAPA non-firm energy agreement and, if and when needed, through the BEPC System Participation Agreement.

2016

Capacity Additions:

To be determined. As discussed in the 2014 section, additions and/or purchases will be guided by actions prescribed by evaluations of the 2014 RFP(s). Otherwise, without action, forecasted capacity reserves would become increasingly negative (-14.5 MW to -35 MW) throughout the period. No capacity is needed or planned to be purchased for November of the preceding year through April of this year.

Firm Capacity Purchases:

See comment immediately above regarding RFP evaluations.

Firm Energy Purchases:

Same as 2015 with the following exceptions: for 2016, it is forecasted that 90.1% of the annual system energy requirement will be supplied by baseload units and the wind PPA following the "return to normal" annual availability of the Big Stone Plant. The remaining 9.9% is expected to be purchased, at market-based rates, through the WAPA non-firm energy agreement and, if economically feasible, yet-to-be determined sources that will be the result of the 2014 RFP(s).

2017 - 2021

Firm Capacity Purchases:

See comment for 2016 regarding RFP evaluations.

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Firm Energy Purchases:

Information regarding baseload power plant planned maintenance outage schedules during this time frame is not yet available. However, historic plant availability patterns are expected to prevail, which would result in the owned baseload plants and the wind PPA continuing to supply the vast majority of system energy requirements. However, with normal system load growth, the percentage of system energy requirements supplied by the baseload and the wind PPA resources will slowly decline from the lower 90th percentile range to the lower 80th percentile range during the period.

The remaining annual energy balances are expected to be purchased, at market-based rates, through the WAPA non-firm energy agreement and, if economically feasible, yet-to-be determined sources that will be the result of the 2014 RFP(s). *Note*: The current WAPA non-firm energy agreement expires at the end of 2020. During the 2017 – 2019 time frame, efforts will be undertaken to renew this contract for 2021 and beyond. If those efforts are unsuccessful, other energy resources will be pursued, including, but not limited to, conversion of the 2013 combustion turbine from simple- to combined-cycle (if not already done as discussed in the 2014 section), system participation agreements with other utilities, and/or off-system market purchases with marketing entities other than WAPA.

Planned Retirements: 2012 – 2021

There are no planned generating unit retirements throughout the 2012 – 2021 planning period. However, six small diesel engine-driven peaking generators totaling 8.3 MW at two locations will be reclassified as “emergency only” beginning in 2013. As “emergency only” units, they can no longer be deemed to be accredited capacity in the MRO. This action is thought to be necessary and appropriate in order to comply with provisions of the EPA Reciprocating Internal Combustion Engines (RICE) NESHAP rules that become effective in 2013. While these units could be retrofitted with appropriate emission controls, that action is deemed uneconomic for these units due to their small individual size (as small as 0.5 MW), age (as old as 63 years), and high-cost fuel type (diesel fuel only). With the “emergency only” classification (as defined in EPA rules), these units will be allowed to continue to provide system reliability in the event of local area transmission or distribution outages.

The effect of this reduction of 8.3 MW of accredited capacity in 2013 was included in developing the Capacity Additions plan discussed above.

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18 C.F.R. § 292.302(b)(3)

The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

NorthWestern continually reviews its capacity needs. As discussed throughout section 18 C.F.R. § 292.302(b)(2) above, NorthWestern's capacity needs are planned to be met through a combination of capacity additions and capacity purchases.

Only one capacity addition is expected to occur during the 2012 – 2021 time frame. That addition is in the form of a peaking-duty dual-fuel (natural gas- or diesel fuel-fired) simple-cycle combustion turbine unit near Aberdeen, South Dakota. This addition is technically no longer a "planned" capacity addition inasmuch as construction of this facility began in October 2011. The expected capacity rating is 52 MW summer/60 MW winter. The unit is scheduled to begin commercial operation in late 2012 or early 2013.

The currently projected cost for construction of this unit is approximately $65,000,000. The projected costs result in a cost per kilowatt of $1,250/kW (summer) and $1083/kW (winter). This cost data is provided for informational purposes only to serve as a guidepost relative to current construction costs of this type of firm capacity addition. As this project is under construction, this cost cannot be avoided by purchases of capacity from qualifying facilities.

The energy costs for this peaking unit (at rated baseload output) for the year 2012 are forecast to be 4.13 cents/ kWh (summer) and 4.38 cents kWh (winter) escalating through the next ten years to 6.11 cents/ kWh (summer) and /6.12 cents/ kWh (winter) by 2021. NorthWestern will incur these energy costs only if the market price exceeds these costs.

No other capacity additions are currently planned for the 2012 – 2021 timeframe.

If future capacity addition(s) and/or capacity purchases are deemed appropriate during the 2012 – 2021 time frame as determined through evaluation of the capacity RFP(s) discussed in section 18 C.F.R. § 202.302(b)(2) above, the costs of such addition(s) or purchases will become known at that time.

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Exhibit A

		AVOIDED COST SUMMARY				
NorthWestern Energy - South Dakota						
Avoided Energy Costs for Various Levels of Purchase from Qualifying Facilities						
Dollars Per MWH						
LEVEL OF	Year	2011	ACTUAL		2011 YTD	ACTUAL
PURCHASE		SUMMER (JUN-SEPT)			WINTER (JAN-MAY)	
MW	On-Peak	Off-Peak	Season	On-Peak	Off-Peak	Season
0	$33.88	$17.72	$27.43	$26.60	$20.90	$24.12
5	$33.69	$17.83	$27.37	$26.39	$20.85	$23.97
10	$33.51	$17.92	$27.29	$26.16	$20.82	$23.81
15	$33.32	$18.00	$27.21	$25.92	$20.81	$23.66
20	$33.14	$18.10	$27.13	$25.69	$20.81	$23.52
25	$32.95	$18.21	$27.05	$25.45	$20.83	$23.39
30	$32.75	$18.36	$26.99	$25.22	$20.85	$23.27
LEVEL OF	Year	2012	ESTIMATED		2012	ESTIMATEI
PURCHASE		SUMMER (JUN-SEPT)			WINTER (JAN-MAY,OCT-DEC)	
MW	On-Peak	Off-Peak	Season	On-Peak	Off-Peak	Season
0	$27.60	$21.57	$24.58	$27.08	$21.69	$24.39
5	$27.46	$21.61	$24.53	$26.87	$21.76	$24.31
10	$27.28	$21.67	$24.47	$26.62	$21.84	$24.23
15	$27.10	$21.72	$24.41	$26.38	$21.92	$24.15
20	$26.93	$21.78	$24.35	$26.15	$21.99	$24.07
25	$26.77	$21.83	$24.30	$25.94	$22.06	$24.00
30	$26.60	$21.88	$24.24	$25.74	$22.12	$23.93
LEVEL OF	Year	2013	ESTIMATED		2013	ESTIMATEI
PURCHASE		SUMMER (JUN-SEPT)			WINTER (JAN-MAY,OCT-DEC)	
MW	On-Peak	Off-Peak	Season	On-Peak	Off-Peak	Season
0	$30.12	$23.36	$26.74	$28.97	$23.19	$26.08
5	$29.93	$23.39	$26.66	$28.72	$23.25	$25.98
10	$29.71	$23.42	$26.57	$28.43	$23.31	$25.87
15	$29.48	$23.46	$26.47	$28.15	$23.38	$25.76
20	$29.26	$23.49	$26.38	$27.89	$23.43	$25.66
25	$29.05	$23.52	$26.29	$27.64	$23.49	$25.57
30	$28.84	$23.55	$26.20	$27.42	$23.54	$25.48

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LEVEL OF	Year	2014	ESTIMATED		2014	ESTIMATEI
PURCHASE		SUMMER (JUN-SEPT)			WINTER (JAN-MAY,OCT-DEC)	
MW	On-Peak	Off-Peak	Season	On-Peak	Off-Peak	Season
0	$31.27	$24.06	$27.66	$30.16	$23.64	$26.90
5	$31.05	$24.06	$27.56	$29.86	$23.67	$26.76
10	$30.78	$24.07	$27.43	$29.49	$23.71	$26.60
15	$30.51	$24.08	$27.29	$29.14	$23.75	$26.44
20	$30.25	$24.09	$27.17	$28.81	$23.78	$26.30
25	$29.99	$24.09	$27.04	$28.50	$23.81	$26.16
30	$29.75	$24.10	$26.92	$28.22	$23.84	$26.03

LEVEL OF	Year	2015	ESTIMATED		2015	ESTIMATEI
PURCHASE		SUMMER (JUN-SEPT)			WINTER (JAN-MAY,OCT-DEC)	
MW	On-Peak	Off-Peak	Season	On-Peak	Off-Peak	Season
0	$33.55	$25.46	$29.51	$32.05	$24.83	$28.44
5	$33.27	$25.43	$29.35	$31.65	$24.80	$28.22
10	$32.91	$25.38	$29.15	$31.17	$24.77	$27.97
15	$32.55	$25.34	$28.95	$30.71	$24.74	$27.72
20	$32.21	$25.30	$28.75	$30.28	$24.71	$27.50
25	$31.87	$25.26	$28.56	$29.88	$24.69	$27.28
30	$31.55	$25.21	$28.38	$29.51	$24.66	$27.09

LEVEL OF	Year	2016	ESTIMATED		2016	ESTIMATEI
PURCHASE		SUMMER (JUN-SEPT)			WINTER (JAN-MAY,OCT-DEC)	
MW	On-Peak	Off-Peak	Season	On-Peak	Off-Peak	Season
0	$34.05	$25.75	$29.90	$32.50	$25.07	$28.78
5	$33.75	$25.71	$29.73	$32.07	$25.02	$28.55
10	$33.37	$25.65	$29.51	$31.55	$24.97	$28.26
15	$32.99	$25.59	$29.29	$31.07	$24.93	$28.00
20	$32.63	$25.54	$29.08	$30.61	$24.88	$27.75
25	$32.27	$25.48	$28.88	$30.18	$24.84	$27.51
30	$31.93	$25.43	$28.68	$29.79	$24.80	$27.30

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