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

Bleau LaFave

On behalf of NorthWestern Energy

January 13, 2012

EXHIBIT
NW 1
3-28-12 cw
depobook.com

Table of Contents

Exhibits

Testimony

Introduction and Qualifications

Q: Please state your name and business address.

A: My name is Bleau LaFave. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

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

A: I joined NorthWestern Energy in July 1994 as project engineer, where I was responsible for the design, construction, and customer connections for natural gas expansion in South Dakota. My current position is director of long-term growth. My responsibilities include overseeing the long-term supply growth strategies for NorthWestern, including large project development and acquisitions.

Q: Please summarize your education and employment history.

A: I earned a Bachelor of Science in mechanical engineering from the South Dakota School of Mines and Technology in 1994. After completing my degree, I was employed by NorthWestern Public Service as a project engineer. Working for NorthWestern, I have held several positions, including operations engineer, Huron area engineer, Aberdeen area engineer, maintenance process leader, support services process leader, corporate procurement manager, director of utility services, director of large project development, director of South Dakota and Nebraska supply planning and development, director of long-term growth, and vice president of operations for NorthWestern Services Corporation. During this time period, I served in many operations and administration functions with a focus on operations management, procurement, logistics, contracts, fleet, facilities, utility engineering, measurement, and customer service.

I began my current position in 2011, focusing on long-term growth in supply for Montana, South Dakota, and Nebraska and large project development and acquisitions.

Purpose and Structure of Testimony

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

- Describe the framework for the federal and state regulatory requirements for qualifying facilities;

- Discuss the circumstances of where we are in the process and rebut testimony provided by Mr. Lauckhart concerning adequate negotiation with Oak Tree and a the possible creation of a legally enforceable obligation;
- Introduce NorthWestern's witnesses;
- Describe the process for choosing an appropriate method for calculating the incremental and avoided costs;
- Provide an of NorthWestern's estimated avoided capacity costs;
- Discuss the customer impact of the differences between NorthWestern's actual avoided costs and Oak Tree's demand; and
- Discuss terms that should be included in an agreement with a qualifying facility that were never addressed in Oak Tree's demand.

Q: How is your testimony structured?

A: As this is an issue of first impression for the South Dakota Public Utilities Commision, my testimony starts with the policy framework. The following outlines my testimony:

- Policy Framework: provides a general overview of PURPA, federal regulations, a 1982 South Dakota Order, and a description of a legally enforceable obligation.
- Oak Tree Communications: illustrates the lack of negotiations related to Oak Tree's project.
- Introduction of Witnesses: introduces additional witnesses supporting NorthWestern's incremental costs.
- Possible Rate Methods: discusses possible rate methods for calculating incremental and avoided costs.
- Consequences of "Getting it Wrong": emphasizes the importance of establishing the correct avoided costs.
- Mr. Lauckhart's Estimated Avoided Cost: shows errors in estimating avoided costs by not using NorthWestern's existing supply model.
- Calculating NorthWestern's Avoided Cost: provides high-level overview of how NorthWestern calculated its avoided cost.
- Estimates for Avoided Capacity Cost: provides high-level overview of how NorthWestern calculated its avoided capacity cost.

- Customer impact of Oak Tree Offer: explains the effect on NorthWestern's customers.

Policy Framework

Q: As background for the Commission, what are the requirements for a utility concerning a qualifying facility requesting to provide energy and capacity?

A: Utilities have requirements under the United States Code, 16 U.S.C. § 824(a)-3; Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 C.F.R. pt. 292; and the 1982 South Dakota Public Utilities Commission Order F-3365.

Q: Please describe generally the Public Utility Regulatory Policies Act of 1978.

A: PURPA was passed in response to the Arab oil embargo in 1973 and 1974. The goal of PURPA was to reduce our dependence on foreign oil and to promote efficient production and use of energy.[1] PURPA was a broad act with many provisions. In this proceeding, we are concerned with only one section of PURPA, Section 210. Section 210 requires the Federal Energy Regulatory Commission to adopt rules that impose a purchase obligation to utilities and requires consumer indifference. Generally speaking, Section 210, which is codified as 16 U.S.C. § 824(a)-3, has two primary pillars. First, it requires utilities to purchase electric energy from qualifying facilities or QFs. Second, it requires that the price paid by the utility be set so that the utilities' customers are indifferent to the source of the electric energy. These are sometimes referred to as the "purchase obligation" and "consumer indifference."

Q: Has FERC adopted rules regarding Section 210 of PURPA?

A: Yes. 16 U.S.C. § 824a-3(a), cogeneration and small power production rule, provides, in part:

> [T]he Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to . . . (2) purchase electric energy from such facilities. . . .

16 U.S.C. § 824a-3(b), rates for purchases by electric utilities, provides:

> The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

---

[1] Hon. Richard D. Cudahy, *PURPA: The Intersection of Competition and Regulatory Policy*, 16 ENERGY L.J. 419, 421 (1995).

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

The assumption underlying a utility's purchase obligation provision was that QFs would be able to produce electric energy at a lower cost than the utility. However, to protect against the possibility that QFs could not produce at a lower cost, the consumer indifference provision was included. It is important to note that the price paid to QFs is determined by the utility's costs, not the QFs' costs. Nothing in PURPA requires that utilities pay QFs a rate that makes them financially viable or allows them to obtain financing. Nor is there any provision in PURPA that permits QFs to dictate terms of a contract to the utility.

Q: **What are the requirements for a utility concerning a qualifying facility requesting to provide energy and capacity under PURPA?**

A: Under PURPA, utilities have the obligation to purchase from qualifying facilities in accordance with 18 C.F.R. § 292.304, unless exempted by §§ 292.309 and 292.310, any energy or capacity made available by a qualifying facility. The purchasing rate must be just and reasonable to the electric consumers of the electric utility and in the public interest. The rate must not discriminate against qualifying facilities.

PURPA only requires that a electric utility pay no more than the utility's avoided costs for purchases.

Q: **Has NorthWestern sought an exemption under 18 C.F.R. §§ 292.309 and 292.310 under PURPA for the Oak Tree project?**

A: No. Although NorthWestern believes that the Oak Tree project would have the same access to the markets as any other generator within the Western Area Power Administration (WAPA) services territories connecting the resource to MISO, the current rules and tariffs in WAPA are not established enough to support an exemption under PURPA for a QF smaller than 20 MW.

Q: **Has the South Dakota Public Utilities Commission adopted any rules or orders concerning requirements for QFs?**

A: Yes, Order F-3365.

Q: What are the requirements for a utility concerning a qualifying facility requesting to provide energy and capacity under 1982 South Dakota Public Utilities Commission Order F-3365?

A: Under Order F-3365, the Commission found that rates for purchases from QFs with a design capacity of more than 100 kW should be set by contract negotiations between the QF and the electric utility. The Commission would act as a dispute arbitrator between the parties in accordance with this rule and the PURPA requirements.

The Commission ruled on what constitutes a long-term and a short-term contract. The Commission held that a contract term of fewer than 10 years is classified as a short-term contract, while a term of more than 10 years is a long-term contract. The Commission also decided the basis for short-term and long-term capacity avoided cost.

According to Order F-3365, the Commission held that both short-term and long-term contracts should include an overall energy credit based on the average of the expected hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility.

The Commission's order also states that interconnection costs be assessed to the qualifying facility on a non-discriminatory basis and that the capacity credits be included in any purchase rates. The order specified that—contractual or otherwise—costs of capacity credits should be based on capacity actually avoided; and if the purchase does not enable a utility to avoid capacity costs, capacity credits should not be allowed.

Redacted pursuant to 3/15/2012 SDPUC Order

Redacted pursuant to 3/15/2012 SDPUC Order

Oak Tree Communications

Q: In the complaint, Oak Tree stated that "Oak Tree has attempted for almost a year to engage NWE in contract discussions." Did Oak Tree try to negotiate with NorthWestern for almost a year?

A: As outlined in the next three questions, Oak Tree sent several letters over that time frame, but never engaged NorthWestern in phone calls or meetings to negotiate price and terms for a QF contract. On July 2, 2010, Oak Tree sent a proposal that was significantly above NorthWestern's South Dakota avoided costs which did not include terms and conditions. On January 25, 2011, Oak Tree sent a similar offer—still significantly above NorthWestern's South Dakota avoided cost—and included an executed power purchase agreement (PPA) with terms that wee never discussed.

Q: When were you contacted by Oak Tree and for what reason?

A: In October 2009, Oak Tree contacted NorthWestern for an interconnection request with an initial request to sell the energy to an outside entity, not NorthWestern. Oak Tree continued to work with NorthWestern's transmission department on the interconnection process through the end of June 2010 and made some inquiries for sales of energy and capacity to NorthWestern. On June 25, 2010, Oak Tree notified NorthWestern of a dispute regarding the interconnection. On July 2, 2011, Oak Tree sent an offer to sell energy and capacity output from the wind farm at a levelized price of $69.20/MWh through a PPA. NorthWestern notified Oak Tree that the offer was well above NorthWestern's avoided costs and also let Oak Tree know that NorthWestern would be interested in discussing any terms at or below the avoided costs.

Q: When and why did you start discussing a PPA with Oak Tree, and how were discussions conducted?

A: As described in the question above, discussions with Oak Tree concerning the project near Clark, South Dakota, for interconnection services began in April 2010. The following inquiries and responses were the first discussions that I was involved with as the director of South Dakota supply planning and development:

2010	Date	Topic
From Mike Uda	June 25	Notification of dispute of the type of interconnection study and notes that Oak Tree is waiting until the July avoided cost filing and 10-year plan to decide whether to sell power to NorthWestern. (Compl. Ex. 3 at 3–4.)
NWE Response	July 6	Clarification for interconnection process, public access to filings, and avoided cost rate filed with Commission. (Compl. Ex. 3 at 1–2.)
From Mike Uda	July 2	Notification to sell energy and capacity to NorthWestern with a PPA price of $69.20/MWh. (Compl. Ex. 2.)
NWE Response	July 8	Response extended to July 23 and communication to be routed to Bleau LaFave for NorthWestern.
From Mike Uda	July 13	Acknowledgement of response date of July 23. (Compl. Ex. 4.)
NWE Response	July 15	Clarification — rate needs to be at or below avoided costs, clarification on capacity requirements, and jurisdictional structure and a request to discuss cost effective resources. (Compl. Ex. 5.)
From Mike Uda	July 22	Additional questions for NorthWestern capacity requirements, renewable energy objective (REO), and avoided cost that was filed. (Compl. Ex. 6.)
NWE Response	July 30	Clarification on the detail for the 10-year plan and the South Dakota REO. (Compl. Ex. 7.)

2011	Date	Topic
From Mike Uda	January 25	Offer: PPA price at $54.40/MWh and draft agreement (Compl. Ex. 8.)
NWE Response	February 2	Rejection of offer: above avoided cost and an invite to discuss a renewable resource priced at or below NorthWestern's avoided cost. (Compl. Ex. 9.)
From Mike Uda	February 25	Notification of unwillingness to negotiate and offer with executed agreement at $54.40/MWh (Compl. Ex. 10.)

NWE Response	February 28	Response extended to March 10.
NWE Response	March 10	Affirmed avoided cost, REO and requested discussion concerning cost effective renewable. (Compl. Ex. 12.)
From Mike Uda	March 18	Oak Tree notice to file complaint with Commission.
NWE Response	March 24	Affirmed position and requested discussions to provide costs effective renewable resources.

I have never been contacted by anyone from Oak Tree or by Mr. Uda by phone or email other than the above emails/letters to discuss terms or price for a QF in South Dakota.

Q: Have you had experience in negotiating wind projects?

A: Yes. Over the last year and a half, I have negotiated with several wind developers, successfully negotiating two memorandums of understandings and one asset purchase agreement.

Q: Is your experience with Oak Tree similar to those negotiations?

A: No. Each negotiation was conducted over several months in weekly meetings, including conference calls and face-to-face meetings. With Oak Tree in 2010, requests for additional information and possible intent were communicated in the letters, but there were no discussions to help each party to understand positions, contract terms, feasibility, energy and capacity need, project viability, environmental and wildlife studies, company viability, Midwest Reliability Organization (MRO) process certifications, wind technology verifications, historical wind data, or WAPA connection requirements. In 2011, Oak Tree offered a one-sided agreement to NorthWestern—without any discussions and at a price significantly above NorthWestern's calculated incremental costs.

There are several factors that can adjust avoided cost rates for a particular QF. These factors are set forth in 18 C.F.R. § 292.304 and Commission Order F-3365. These factors were never discussed with Oak Tree. Nor were there discussions regarding the terms and conditions associated with the wind resources to create a just and reasonable rate for NorthWestern's electric customers.

In response to Oak Tree's 2011 proposed PPA, NorthWestern requested additional discussions. No response other than the notification of complaint was ever received.

Introduction of Witnesses

Q: Who will be testifying on NorthWestern's behalf in this docket, and what will they be discussing?

A: NorthWestern will have four additional witnesses:

- Richard Green will provide testimony regarding the methodology for calculating NorthWestern's incremental avoided cost according to PURPA requirements. Mr. Green's testimony will include background costs and baseload costs.
- Dennis Wagner's testimony will provide historical, present, and future capacity needs for NorthWestern.
- Steven Lewis's testimony will discuss the market forecast used in NorthWestern's calculation of its incremental avoided cost. Mr. Lewis's testimony will include the basis for the forecast, including considerations for possible future carbon costs. Mr. Lewis will also rebut the forecast provided by Mr. Lauckhart.
- Finally, Pam Bonrud's testimony will describe the South Dakota Renewable, Recycled and Conserved Energy Objective (REO) as a voluntary objective and will discuss the importance of the precedent that will be established by the South Dakota Public Utilities Commission's decision in this docket.

Possible Rate Methods

Q: What are some possible methods for calculating incremental cost and avoided cost?

A: State regulatory commissions and utilities have used many methods to determine avoided cost. Generally the methods can be classified as:

(1) Proxy Unit or Surrogate Avoided Resource;
(2) Component/Peaker Method;
(3) Differential Revenue Requirement Method;
(4) Market Estimates; or
(5) Bidding Approach.

In some jurisdictions, combinations of two or more of the methods are used.

The Proxy Unit approach calculates avoided cost based on an estimate of the cost associated with the next planned generating unit. The next planned generating unit may be determined from a utility's integrated resource plan, or it may be a generic unit that a regulatory commission requires to be used. Underlying this method is an assumption that the QF will enable a utility to delay its next acquisition.

The Component/Peaker Method calculates avoided costs by combining a capacity payment based on the annual equivalent of a utility's least-cost capacity option and an energy payment based on marginal energy costs. Often the capacity payment is determined by the cost of a peaking unit, and the energy payment is determined by baseload units. Underlying this method is an assumption that a QF will displace the utility's marginal unit at any given time.

The Differential Revenue Requirement Method calculates avoided costs by estimating the utility's total revenue requirement for the term of the contract with the QF at zero cost and without the QF. The difference between the two revenue requirements is the total value of the QF, which is then allocated to capacity and energy over term of the contract. Underlying this method are assumptions that the characteristics of the QF's output meet the needs of the utility and that the necessary planning expansion and financial models can accurately predict the future.

The Market Estimates method calculates avoided cost by estimating future market prices that the utility would pay for energy and capacity and capacity equal to the QF's estimated production. Underlying this method is an assumption that the utility will purchase electric energy in the market and that electric energy is a homogenous commodity.

The Bidding Approach requires QFs to compete in resource solicitations and awards contracts to the lowest cost bidders up to the amount needed by the utility.

Q: What method did NorthWestern use, and why?

A: As described in Mr. Green's testimony, PURPA requires the utility to calculate its avoided costs based on the hourly incremental costs for on-peak, off-peak, and seasonal at a minimum required MW block size. Because NorthWestern's incremental cost for the block sizes from 0 to 30 MW includes a combination of incremental baseload and spot market purchases, NorthWestern utilized a mixture of the Component/Peaker method and the Market Estimates method to reflect the actual cost NorthWestern could avoid by offsetting market purchase or backing down the most expensive baseload unit, depending on NorthWestern's customer load.

Consequences of Getting It Wrong

Q: What are some possible consequences of not estimating a utility's avoided costs correctly?

A: NorthWestern will pay either less or more than it should for the QF's electric energy. If NorthWestern pays more than it should for the QF's energy, NorthWestern's customers will pay more than they would have otherwise. The principle of customer indifference will have been violated.

Q: What if the Commission split the difference between NorthWestern's avoided costs estimate and Oak Tree's offer?

A: NorthWestern's customers would be negatively affected by an overestimation of NorthWestern's actual attainable avoided costs.

Q: Should other methods be considered?

A: The method laid out by Mr. Green in his testimony most closely resembles NorthWestern's current portfolio utilizing mostly baseload generation and occasional spot market purchases to provide cost effective supply to NorthWestern's customers.

Q: Why do you say that history shows that overestimation of avoided costs is more probable?

A: The landscape is littered with train wrecks of overpayments to QFs. In the 1980s , the Montana Public Service Commission (PSC) established avoided costs for long-term contracts based on estimates of escalation in future costs. In the late 1990s, when Montana abandoned electricity deregulation, the Montana PSC ordered the recovery of stranded costs related to out-of-market QF purchase costs through a Competative Transition Charge QF (CTC-QF) charge. Over the life of the CTC-QF charge, NorthWestern's customers will pay an additional $663 million. This represents only a portion of the out-of-market costs. In its 2010 Form 10-K, NorthWestern estimated its unrecoverable QF purchase costs to be an additional $316 million.

Utilities in other states have also reported problems associated with overestimation of avoided costs. In FERC Docket RM87-12-000, Pacific Gas & Electric claimed that its annual overpayments to QFs in 1990 alone would be $857 million, necessitating a 7% increase in retail electric rates. In the same docket, Houston Lighting & Power estimated that its overpayments to QFs from 1987 to 1995 would be between $500 million and $750 million.

It is unlikely that QFs can or will be built if there is an underestimation of avoided costs. Once a QF developer knows what the avoided cost rate will be, it will continue with its project only if it is economical to do so.

Q: What do you advise the Commission to do with respect to long-term estimates of NorthWestern's avoided cost?

A: First, the Commission should recognize that long-term estimates of electricity costs are inherently unreliable. The Energy Information Agency (EIA) publishes a retrospective analysis of its forecasts each year. From the 1982 Annual Energy Outlook to the 2009 Annual Energy Outlook, the absolute difference between its reference case electric price projections and the realized outcomes is 19.7%. This means that EIA estimates miss the actual price by an average of 19.7%.

Second, the Commission should recognize that for projections that extend further into the future, reliability substantially decreases. This is especially true when the projection is based on an escalation factor.

With these facts in mind, the Commission should be skeptical of projections and adopt a conservative approach that protects NorthWestern's customers. Finally, the Commission should approve contracts for the shortest period that is consistent with PURPA to minimize the probability and magnitude of overestimation.

Mr. Lauckhart's Estimated Avoided Cost

Q: Do you agree with Mr. Lauckhart's estimates of NorthWestern's avoided costs listed in Section V of his testimony and referenced throughout his testimony?

A: No. Mr. Lauckhart provided his interpretation of NorthWestern's avoided costs. He did not base his interpretations on NorthWestern's actual costs, markets, and costs drivers, but rather he based his interpretation on general regional market conditions. He also provided an alternative calculation that is a comparison of NorthWestern's constructing its own wind farm. The alternative calculation was based on a misinterpretation that NorthWestern had a requirement to build renewable resources regardless of comparisons to other energy resources. None of Mr. Lauckhart's calculations considered NorthWestern's actual need for energy based on the relationship between baseload and market purchases or NorthWestern's actual needs for capacity, including a wind resources ability or inability to qualify as an accredited capacity resource at a proposed capacity value.

Calculating NorthWestern Energy's Incremental Costs

Q: What would be the appropriate method for calculating NorthWestern's incremental and avoided costs?

A: NorthWestern's actual forecasted incremental cost estimate is based on three factors that include baseload incremental costs, split between market purchases and baseload generation, and market purchase forecasts. Because NorthWestern is a baseload integrated utility, NorthWestern supplies approximately 90% of its energy through owned baseload resources. Because of NorthWestern's heavily weighted baseload portfolio, for over half of the 8760 hours in a year, NorthWestern is not purchasing additional power and instead relies solely on its own generating resources. In order to meet the customers' needs above the baseload capability, NorthWestern utilizes spot market prices, which were needed less than half of the total hours in 2010. In his testimony, Mr. Green will detail the methodology and the drivers for the calculation.

Q: What did NorthWestern use for a market forecast for NorthWestern's South Dakota service territory?

A: NorthWestern purchases spot market energy from WAPA as a part of NorthWestern's balancing agreement. WAPA does not forecast spot market pricing beyond one day. Therefore, NorthWestern contracted Steven Lewis of Lands Energy Consulting to provide a forecast for the spot market pricing. Mr. Lewis will describe the methods used to provide the spot market forecast and will describe the risks associated with longer terms of forecasting.

Q: NorthWestern's incremental costs filed in the avoided costs filing were for the current year plus five more years. How would NorthWestern provide avoided cost estimates for a longer term?

A: NorthWestern would forecast its load duration curve to identify the point in the future NorthWestern estimates that it would be using market purchases 100% of the time due to forecasted load growth. From that point forward, NorthWestern would utilize the forecasted market costs as its incremental costs. For the period between that time and the filed avoided costs, NorthWestern would evenly spread the increase over the gapped years.

As shown in Exhibit BJL-3, NorthWestern estimates that in 2023, NorthWestern will be making at least 1 MW of market purchases on behalf of its customer 100% of the time. Utilizing the market forecast from Lands Energy provided in Mr. Lewis's testimony, NorthWestern could utilize the spot market price forecast for years beyond 2023. For the years between 2023 and the current filed avoided cost which ends in 2016, the average avoided cost increase could be spread between those years.

There are obvious concerns with this method or any other method of estimating longer term avoided costs. The 2023 date is beyond NorthWestern's normal facility planning horizon. Unlike the normal planning process where there is a need identified and NorthWestern is trying to decide the most "just and reasonable" way to fill that need with a long-term investment, this process is trying to offset other existing resources and filling partial needs while attempting to predict when the need will arise in the very distant future and derive a value during the entire term. Each estimate to calculate the final effect increases risk to NorthWestern's customers.

Q: What is the difference between the incremental costs and the avoided cost filings and the appropriate rate for a QF facility?

A: NorthWestern calculates its incremental costs and filed avoided costs based on offsetting market purchases and baseload generation that could be offset by the generation of energy from a QF as described by PURPA. These energy resources to NorthWestern's energy customers are schedulable and dispatchable reacting to NorthWestern's load-serving needs. To provide NorthWestern's consumers with an equitable replacement to determine true avoided costs, each qualifying resource needs to be adjusted according 18 C.F.R. § 292.304 requirements in PURPA for the appropriate rates.

Q: What are the requirements for setting purchase rates under PURPA?

A: Under 18 C.F.R. § 292.304, rates for purchases, PURPA sets how the rates for the purchase of power by the buyer shall be derived:

(a) Rates for Purchases,

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided cost for purchases.

(b) Relationship to avoided cost,

(1) For the purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchases (other than from new capacity) may be less than the avoided costs if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the non-regulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from the avoided costs at the time of delivery.

(c) Standard Rates for Purchases,

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) Standard rates for purchases under this paragraph;

(i) Shall be consistent with paragraphs a) and b) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either;

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation occurred.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data proved pursuant to 292.302(b), (c), or (d), including state review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements and sanctions for non-compliance.

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The cost or savings resulting from variations in line losses from those that would have existed in the absence of purchased from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of the electric energy or capacity.

Q: How should a rate for a specific QF be calculated?

A: As stated in 18 C.F.R. § 292.304(a), "nothing in this subpart requires any electric utility to pay more than the avoided cost for purchases," and the rates "*shall* be just and reasonable to the electric consumer" and "not discriminate" against QFs (emphasis added). Once a true avoided cost reflecting actual costs to consumers is determined, that should be the price that a specific QF pays. As set forth in Mr. Green's testimony, the rate should be adjusted base on the parameters in 18 C.F.R. § 292.304 (e)(2). The QF price should be just and reasonable for electric consumers and keep their costs as neutral as possible for rates of the QF resource.

Q: What are the additional factors for consideration of a final QF price?

A: Some additional factors identified in 18 C.F.R. § 292.304 (e)(2)include:

- The ability of the utility to dispatch the QF;
- The expected or demonstrated reliability of the QF;
- The terms of any contract;
- The usefulness of scheduled outages to the QF;
- The usefulness of energy and capacity during emergencies;
- The individual and aggregate value of energy and capacity of the QF;
- The value of smaller capacity increments and shorter lead times for the addition of a QF;
- The ability for the utility to actually avoid costs; and
- The benefits for possible line losses.

Q: Where any of these factors accounted for in the offered price from Oak Tree?

A: To our knowledge, no discussions were held concerning these factors in the Oak Tree offer, and they were not mentioned as factors as part of the offer to NorthWestern.

Q: How does contract term affect the QF price?

A: The avoided costs are calculated for the current year plus five additional years. As described in Mr. Green's testimony, the avoided cost is based on historic splits between baseload generation and market purchases, historic and forecasted baseload costs, and forecasted energy purchase costs. The short-term predictability of baseload costs and the split between NorthWestern's baseload generation and purchases can be calculated based on historical averages. Longer-term forecasting increases uncertainty because fuel supply contracts do not extend into longer terms and customer growth or loss becomes less predictable. The forecasting of energy costs is volatile even for the short term. Redacted pursuant to 3/15/2012 SDPUC Order Predictability beyond five years becomes more subjective.

Longer-term forecasts also create issues for planning when considering additions to baseload resources. Because adding baseload resources at any time would be based on the economic decisions at that time, rates would need to be adjusted based on that resource at that time. Based on NorthWestern's current growth and planning, any additional baseload resources would be beyond NorthWestern's current 10-year plan[2] on file with the Commission. Without a

[2] *Available at* http://puc.sd.gov/10utilityyearplan/nw.aspx.

need for baseload energy over the next 10 years, setting an avoided cost rate beyond 10 years creates uncertainty for the avoided cost that would be used to set a QF rate. Maintaining rates that are "just and reasonable" beyond that timeframe would be very difficult.

Q: What is NorthWestern's estimated avoided cost levelized for 5, 10, and 20 years compared with Oak Tree's last offer on January 25, 2011?

A: Utilizing the data in Exhibit BJL-3, NorthWestern's 5-year, 10-year, and 20-year estimated levelized incremental cost is $28.30, $31.28, and $35.85, respectively. Oak Tree's offer yielded a 5-year, 10-year, and 20-year levelized incremental cost of $57.08, $60.11, and $65.44, respectively. Exhibit BJL-1 is a graphical comparison for each year's price.

Q: If NorthWestern's estimated avoided cost was calculated in February 25, 2011, what would be the difference from the current forecast?

A: NorthWestern's avoided cost forecast would change very little. The components of the forecast include baseload incremental costs, resources supply mix, and spot market pricing. Each of these components has changed very little over 2011. The only change would have been in the spot market pricing, which again is only part of the calculation less than 50% of the time. Mr. Lewis provides an adjustment of the spot market forecast in his testimony. The spot market forecast from February 2011 to October 2011 is approximately 5% less as presented in Exhibit BJL-4. If NorthWestern were to adjust its filed avoid cost based on the February forecast, the avoided cost would be slightly lower.

Q: Is Oak Tree's offer at or below NorthWestern's avoided costs, and was it at or below NorthWestern's avoided cost at the beginning of 2011 as stated in the Oak Tree complaint?

A: No, Oak Tree's lowest offer is almost two times higher than NorthWestern's avoided cost.

Q: Did NorthWestern have avoided costs filed for QF over 100 kW to communicate with Oak Tree?

A: No. NorthWestern had rates filed for generator under 100 KW and utilized these rates as an estimate of its avoided cost for generators over 100 KW.

Q: Was this a reasonable estimate?

A: Yes. The avoided cost rates were calculated using the weighted average cost of NorthWestern's own generation and the weighted average cost of NorthWestern's purchased power. The total company generation fuel costs were divided by the total company megawatt hours generated to calculate the avoided fuel cost per megawatt hour generated. The total purchased power cost was divided by the total megawatt hours purchased to calculate the purchase cost per megawatt hour. A weighted average, based on megawatt hour generated and purchased, was used to derive the avoided cost per megawatt hour.

The final rate filed June 29, 2010, for the smaller than 100 KW was an average rate \$0.0204/KWh, representing an on-peak cost of \$0.022/KWh and an off-peak cost of \$0.0192/KWh. These costs are similar to the avoided cost rate that was filed in November 13, 2011.

Q: How is this process and rate different from the avoided cost rate that was filed in the fall of 2011?

A: The avoided cost that was filed in the fall of 2011, as described in Mr. Green's testimony, utilized similar inputs to the avoided costs filing for 100 kW and smaller filed in June 2010. The significant differences are an hourly review of baseload resources versus purchases and utilizing the most expensive baseload resource as the baseload input rather than a baseload average. The 2011 fall filing of avoided costs with the more detailed information yielded an average rate of \$0.2497/KWh with an on-peak cost of \$0.02903/KWh and an off-peak cost of \$0.01984/KWh. Although the new method yielded an increase in the estimate incremental costs, the change was not significant and resulted in reasonable estimates for NorthWestern's avoided cost. These costs estimates do not reflect adjustment from 18 C.F.R. § 292.304 and the terms and conditions of the contract that would lower the rate available to Oak Tree to maintain "just and reasonable rates" for NorthWestern's consumers.

Estimates for Avoided Capacity Costs

Q: What is the NorthWestern estimate for avoided capacity costs associated with the Oak Tree project?

A: NorthWestern has and will have all the required capacity represented in internal capacity, capacity contracts, and planned additions through the end of 2015. Therefore, NorthWestern has no ability to avoid capacity costs through the end of 2015. Mr. Wagner's testimony will outline the amount, timing, and requirements of NorthWestern's capacity needs. Mr. Wagner will also outline the requirements for NorthWestern to utilize accredited capacity in NorthWestern's system. As filed in NorthWestern's avoided capacity cost on November 13, 2011, the projected investment costs are \$1,250/KW (Summer) and \$1,083/KW (Winter).

Customer Impact of Oak Tree Offer

Q: What is the impact on NorthWestern's customers comparing Oak Tree's offer to NorthWestern's actual avoided cost.

A: Energy customers on NorthWestern's system will experience a significant negative impact from Oak Tree's current offer. Exhibit BJL-3 shows the difference between Oak Tree's offer and NorthWestern's filed avoided costs and estimated escalator shown in Exhibit BJL-1. Over the term of the avoided cost filing, NorthWestern customers would be paying in excess of \$8.7

million dollars in the first four years at the rates included in Oak Tree's February 2011 offer. This is assuming that the facility is operational for calendar year 2013. The costs to customers escalate as the possible length of the contracts is extended. If the market reacts similarly over the next 10 years as it did in the last 10 years, as reflected in Exhibit BJL-2, the customer risk would even be greater. For a 10- or 20-year term, the estimated cost to consumers would be in excess of $23 million and $52 million respectively.

Q: Other than energy and capacity prices, what other terms should be considered in a QF agreement?

A: Other considerations for terms of a PPA contract are: delay damages; conditions of acceptance; insurance; acceptable engineering certification; operational date; energy and outage forecasts; wind data verification; damages provisions; network resource requirements; not to exceed capacity requirements; mechanical availability requirements; reporting requirements; on-peak, off-peak, and market pricing; maintenance schedule; planning and coordination; energy curtailment; metering, billing, and default remedies. Some of these conditions are identified in Oak Tree's offer, but no specific details were ever addressed.

Q: Do the recommended methods for calculating NorthWestern's avoided cost for capacity and energy and recommendations for negotiating specific terms and conditions provide NorthWestern's customers with rates that are just and reasonable and not discriminate against QFs?

A: Yes. By providing a process that can be repeated based on actual cost drivers and data associated with NorthWestern - South Dakota's electric supply for its customers, the process can establish rates that are just and reasonable while not discriminating against QF resources or future QF applicants.

Q: Does this conclude your testimony?

A: Yes, it does.

Affidavit of Bleau LaFave

STATE OF SOUTH DAKOTA)
: ss
COUNTY OF LINCOLN)

Bleau LaFave, being first duly sworn upon oath, states and alleges as follows:

1) I am the Director of Long-Term Growth 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 Sioux Falls, South Dakota, this 13 day of January, 2012.

Bleau LaFave

SUBSCRIBED AND SWORN to before me this 13 day of January, 2012.

DORI L. QUAM
NOTARY PUBLIC
SOUTH DAKOTA
SEAL

Dori L. Quam
Notary Public, South Dakota
My commission expires: 2/4/2016

Exhibit BJL-1

Incremental Costs

NorthWestern's estimated incremental costs for on-peak and off-peak hours escalated by the calculation described on page 12 of Bleau LaFave's testimony for years beyond the avoided cost filing vs. Oak Tree's most recent offer dated January 25, 2011.

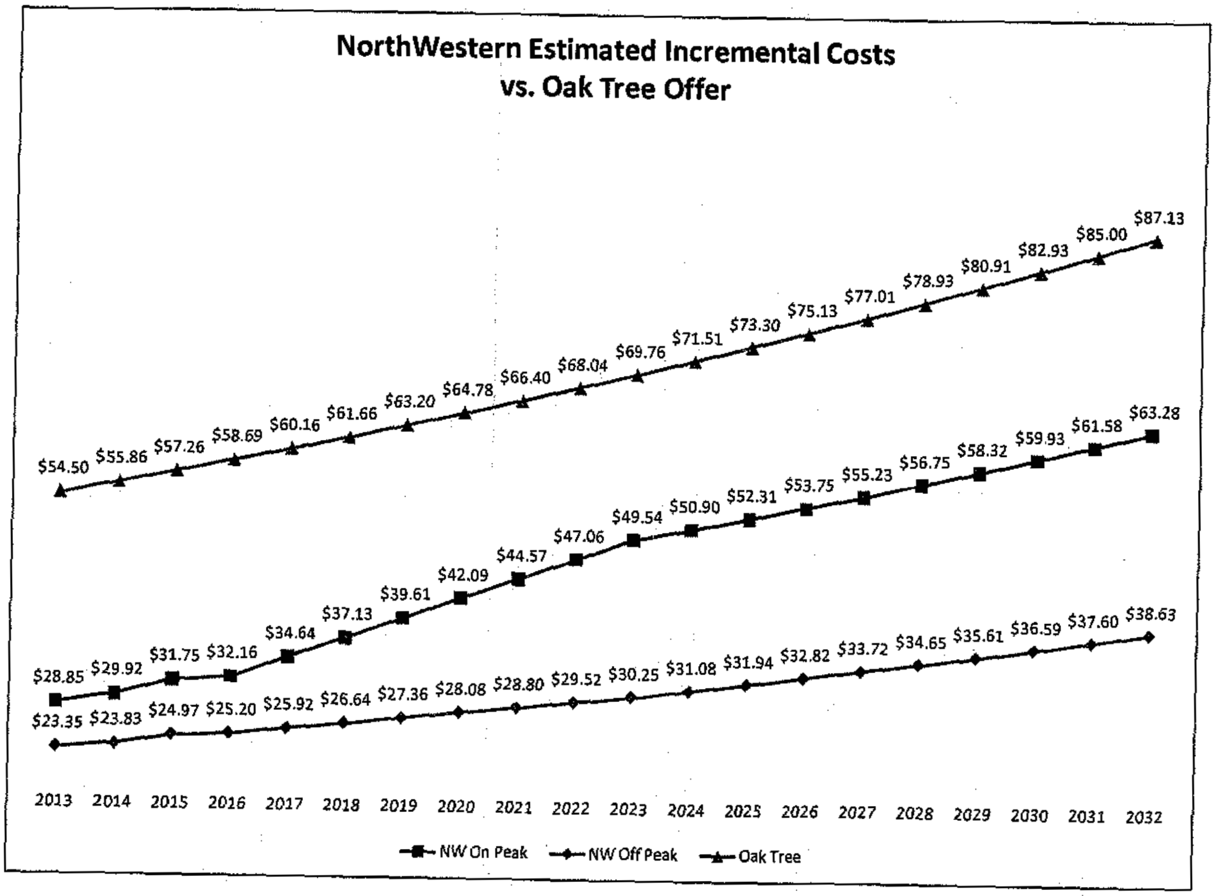
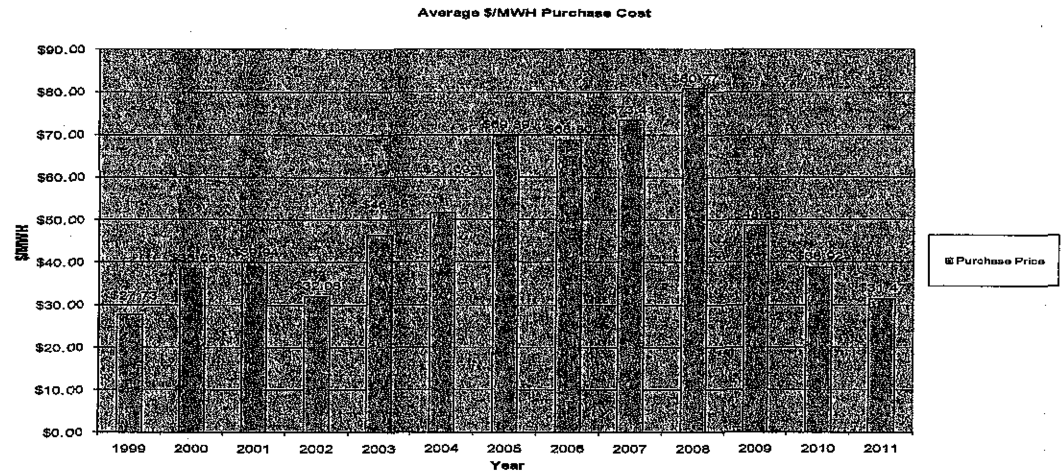


Exhibit BJL-2

Historical Spot Market Pricing

NorthWestern's historical average prices paid for spot market pricing as filed in the FERC Form 1 over the past 12 years.



Customer Impact of Oak Tree's Offer

Customer impact of Oak Tree's February 25, 2011 offer as compared to the actual calculated avoided cost through 2016 and the estimated escalated costs based on the description on page 12 of Bleau LaFave's testimony.

Customer Impact								
NW Incremental Cost vs. Oak Tree Offer								
	Estimated Load							
	Duration Curve	NW On Peak	NW Off Peak	NorthWestern	Oak Tree	Oak Tree	Consumer Impact	
Year	% Market Purchase	Avoided Cost	Avoided Cost	Estimate Cost	Offer	Estimate Cost	Difference	Term of Agreement
2013		$ 28.85	$ 23.35	$ 2,025,622	$ 54.50	$ 4,177,534	$ 2,151,912	
2014		$ 29.92	$ 23.83	$ 2,087,462	$ 55.86	$ 4,281,781	$ 2,194,318	Forecasted
2015		$ 31.75	$ 24.97	$ 2,204,463	$ 57.26	$ 4,389,094	$ 2,184,630	Avoided Cost
2016		$ 32.16	$ 25.20	$ 2,229,767	$ 58.69	$ 4,498,706	$ 2,268,939	$ 8,799,799
2017	74%	$ 34.64	$ 25.92	$ 2,360,499	$ 60.16	$ 4,611,384	$ 2,250,885	
2018	79%	$ 37.13	$ 26.64	$ 2,491,231	$ 61.66	$ 4,726,362	$ 2,235,131	
2019	83%	$ 39.61	$ 27.36	$ 2,621,963	$ 63.20	$ 4,844,406	$ 2,222,444	
2020	88%	$ 42.09	$ 28.08	$ 2,752,694	$ 64.78	$ 4,965,517	$ 2,212,822	
2021	93%	$ 44.57	$ 28.80	$ 2,883,426	$ 66.40	$ 5,089,693	$ 2,206,267	10 term
2022	97%	$ 47.06	$ 29.52	$ 3,014,158	$ 68.04	$ 5,215,402	$ 2,201,244	$ 22,128,592
2023	100%	$ 49.54	$ 30.25	$ 3,144,890	$ 69.76	$ 5,347,244	$ 2,202,354	
2024	100%	$ 50.90	$ 31.08	$ 3,231,591	$ 71.51	$ 5,481,385	$ 2,249,794	
2025	100%	$ 52.31	$ 31.94	$ 3,320,682	$ 73.30	$ 5,618,592	$ 2,297,910	
2026	100%	$ 53.75	$ 32.82	$ 3,412,229	$ 75.13	$ 5,758,865	$ 2,346,636	
2027	100%	$ 55.23	$ 33.72	$ 3,506,300	$ 77.01	$ 5,902,971	$ 2,396,670	
2028	100%	$ 56.75	$ 34.65	$ 3,602,965	$ 78.93	$ 6,050,142	$ 2,447,177	
2029	100%	$ 58.32	$ 35.61	$ 3,702,294	$ 80.91	$ 6,201,913	$ 2,499,619	
2030	100%	$ 59.93	$ 36.59	$ 3,804,362	$ 82.93	$ 6,356,750	$ 2,552,388	
2031	100%	$ 61.58	$ 37.60	$ 3,909,244	$ 85.00	$ 6,515,420	$ 2,606,176	20 Year Term
2032	100%	$ 63.28	$ 38.63	$ 4,017,017	$ 87.13	$ 6,678,689	$ 2,661,671	$ 46,388,986
	Hours per year	4,896	3,864		Oak Tree Estimated Annual Production			
	% split hours/year	56%	44%		76,652	MWh		

Load Duration Curve		Y/Y Change	Forecasted Ave. Market			Levelized Cost	NW	Oak Tree
	Annual	4.60%	Purchase Cost			5	$28.30	$57.08
	Purchases	Generation	HL	LL		10	$31.28	$60.11
2010	42%	58%				20	$35.85	$65.44
2011	47%	53%						
2012	51%	49%						
2013	56%	44%						
2014	60%	40%						
2015	65%	35%						
2016	70%	30%						
2017	74%	26%	$ 42.08	$ 25.69				
2018	79%	21%	$ 43.59	$ 26.40				
2019	83%	17%	$ 44.43	$ 27.13				
2020	88%	12%	$ 45.66	$ 27.88				
2021	93%	7%	$ 46.92	$ 28.64				
2022	97%	3%	$ 48.21	$ 29.43				
2023	100%	0%	$ 49.54	$ 30.25				
2024	100%	0%	$ 50.90	$ 31.08				
2025	100%	0%	$ 52.31	$ 31.94				
2026	100%	0%	$ 53.75	$ 32.82				
2027	100%	0%	$ 55.23	$ 33.72				
2028	100%	0%	$ 56.75	$ 34.65				
2029	100%	0%	$ 58.32	$ 35.61				
2030	100%	0%	$ 59.93	$ 36.59				
2031	100%	0%	$ 61.58	$ 37.60				
2032	100%	0%	$ 63.28	$ 38.63				

Spot Market Forecast Comparison

In the table below are the spot market price comparisons for February 25, 2011, and October 17, 2011. For those two dates, the forward electricity markets for calendar years 2012–2015 were actually about 5% *lower* in February than when we provided the forecast in October.

Forward Price Comparison: February 25 vs. October 17.

	24-Feb-07		16-Oct-07		AMOUNT OCT HIGER THAN FEB			
	Cinergy		Cinergy		$/MWH		PERCENTAGE	
	Peak Price	Off-Peak Price	Peak Price	Off-Peak Price	Peak Price	Off-Peak Price	Peak Price	Off-Peak Price
Win-12	38.90	28.30	42.60	33.00	3.70	4.70	9%	14%
Spr-12	37.00	26.65	37.50	28.95	0.50	2.30	1%	8%
Sum-12	45.75	30.10	46.50	28.85	0.75	-1.25	2%	-4%
Q4-12	36.65	26.65	37.40	28.45	0.75	1.80	2%	6%
Win-13	40.65	29.05	44.10	35.60	3.45	6.55	8%	18%
Cal-12	38.70	27.00	40.20	28.90	1.50	1.90	4%	7%
Cal-13	41.00	28.70	42.90	31.00	1.90	2.30	4%	7%
Cal-14	44.25	31.90	46.55	34.05	2.30	2.15	5%	6%
Cal-15	48.40	35.25	49.45	36.75	1.05	1.50	2%	4%
CAL 12-15	43.09	30.71	44.78	32.68	1.69	1.96	4%	6%