BEFORE THE PUBLIC UTILITIES COMMISSION OF
THE STATE OF SOUTH DAKOTA

In the Matter of the Complaint by Juhl Energy, Inc. Against Northwestern Corporation DBA Northwestern Energy For Establishing a Purchase Power Agreement	))))	Docket EL16-021

DIRECT TESTIMONY AND EXHIBITS OF JON THURBER
ON BEHALF OF
THE COMMISSION STAFF

January 10, 2017

EXHIBIT
Staff
1

TABLE OF CONTENTS

I.	INTRODUCTION AND QUALIFICATIONS	1
II.	PURPOSE OF TESTIMONY	1
III.	INTRODUCTION OF WITNESSES	2
IV.	REGULATORY FRAMEWORK FOR QUALIFIED FACILITIES UNDER PURPA	2
V.	OVERVIEW OF AVOIDED ENERGY COST METHODOLOGIES	7
VI.	LEO ESTABLISHMENT	12
VII.	CARBON COMPLIANCE COSTS	18

EXHIBITS

EXHIBIT_JPT-1 FERC ORDER 69

EXHIBIT_JPT-2 DOCKET F-3365 ORDER

EXHIBIT_JPT-3 DOCKET EL11-006 ORDER

EXHIBIT_JPT-4 JUHL'S RESPONSE TO COMMISSION STAFF DR 1-9

EXHIBIT_JPT-5 DOCKET RM13-002 DRAFT RULES

EXHIBIT_JPT-6 DOCKET RM13-002 JUHL REPLY COMMENTS

EXHIBIT_JPT-7 JUHL'S RESPONSE TO COMMISSION STAFF DR 3-1

EXHIBIT_JPT-8 JUHL'S RESPONSE TO COMMISSION STAFF DR 3-2

EXHIBIT_JPT-9 JUHL'S RESPONSE TO COMMISSION STAFF DR 2-2

EXHIBIT_JPT-10 JUHL'S RESPONSE TO COMMISSION STAFF DR 2-5

EXHIBIT_JPT-11 NORTHWESTERN'S RESPONSE TO COMMISSION STAFF DR 2-1

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. Jon Thurber, Public Utilities Commission, State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota, 57501.

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

A. I am a utility analyst for the South Dakota Public Utilities Commission ("Commission"). I am responsible for analyzing and presenting recommendations on utility dockets filed with the Commission that best serves the public interest.

Q. Please describe your educational and business background.

A. I graduated summa cum laude from the University of Wisconsin – Stevens Point in December of 2006, with a Bachelors of Science Degree in Managerial Accounting, Computer Information Systems, Business Administration, and Mathematics. My regulated utility work experience began in 2008 as a utility analyst for the Commission. At the Commission, my responsibilities included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric and natural gas utilities. In 2013, I joined Black Hills Corporation as Manager of Rates. During my time at Black Hills Corporation, I held various regulatory management roles and was responsible for the oversight of electric and natural gas filings in Wyoming, Montana, and South Dakota. In July of 2016, I returned to the Commission as a utility analyst. I have provided written and oral testimony on the following topics: the appropriate test year, rate base, revenues, expenses, taxes, cost allocation, rate design, power cost adjustments, capital investment trackers, and PURPA standards.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide and explain Commission Staff's position regarding the complaint by Juhl against NorthWestern (collectively referred to as the "Parties") with respect to establishing a proper avoided cost for three purchase power agreements ("PPA"). Commission Staff will address the following issues presented by the Parties and provide a recommendation to the Commission to resolve this contractual dispute:

- Whether Juhl is currently bound by a legally enforceable obligation ("LEO"), and if so, when that LEO commenced and what impact that has on the avoided cost calculation?
- What is the appropriate methodology to calculate NorthWestern's avoided cost that will determine the basis for the rate NorthWestern must pay Juhl for its electricity made available from qualifying facilities?

First, I will introduce the other Commission Staff witness, Kavita Maini, and identify the topics she will discuss. Second, I will discuss the regulatory framework for qualifying facilities under the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Third, I will provide an overview of the Parties' avoided energy cost methodologies within the context of FERC and Commission policy. Fourth, I will discuss whether Juhl has established a LEO, and if so, when that LEO commenced. Finally, I will discuss the proper carbon compliance costs to include in the avoided cost.

III. INTRODUCTION OF WITNESSES

Q. Who will be testifying on behalf of Commission Staff in this docket and what will they be discussing?

A. Commission Staff will have Ms. Kavita Maini discuss the appropriate methodology to calculate NorthWestern's avoided energy, capacity, and interconnection costs. Ms. Maini also discusses the incremental wind integration costs the Juhl projects will impose, and presents an alternative avoided cost methodology for Commission consideration.

IV. REGULATORY FRAMEWORK FOR QUALIFIED FACILITIES UNDER PURPA

Q. Please provide some background regarding the relevant Sections of PURPA for this docket.

A. PURPA was passed as part of the legislation known as the National Energy Policy Act. Under Sections 201 and 210, PURPA encouraged development of certain small power production and cogeneration facilities known as qualifying facilities ("QF"). Section 210 requires electric utilities to (1) purchase from qualifying facilities any energy and capacity which is made available, (2) to sell to any qualifying facility, and (3) to interconnect with the qualifying facility. The Federal Energy Regulatory Commission ("FERC") issued regulations implementing PURPA Sections 201 and 210, including 18 CFR 292.304 (a) regarding the rates for purchase:

(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 costs* for purchases. (*emphasis added*)

Avoided costs are defined by the FERC as the incremental costs of electric energy, capacity, or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source.[1] The primary point of contention in this docket is the determination of the cost NorthWestern can avoid by obtaining energy and capacity from Juhl's projects.

Q. Which FERC Order adopts regulations that implement Section 210 of PURPA?

A. FERC Order 69[2] adopts regulations that implement Section 210 of PURPA.

Q. Does the FERC provide an interpretation of an electric utility's obligation to purchase all electric energy and capacity made available from qualified facilities with which the electric utility is directly or indirectly connected under PURPA in Order 69?

A. Yes. Except under certain specific circumstances, the FERC reiterates this purchase obligation mandated by PURPA. However, the FERC does provide some clarifying comments on how much utilities should pay for energy and capacity if the power is not required to meet its total system load:

[1] 18 CFR 292.101(b)(6)
[2] See Exhibit_JPT-1 for FERC Order 69.

"A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale."[3]

I will reference this interpretation by the FERC in other areas of my testimony as I believe this guidance will help the Commission resolve some areas of contention.

Q. Did the Commission initiate an investigation of the implementation of the FERC's PURPA rules?

A. Yes. While the FERC issued regulations adopting PURPA sections 201 and 210, the state regulatory commissions are responsible for implementing PURPA QF regulations consistent with FERC regulations. The FERC rules require state public utility commissions to set rates for the host utility to purchase power from a QF.

In Docket F-3365,[4] the Commission investigated how the FERC rules should be implemented in South Dakota. I have listed some of the relevant findings that relate to this docket below:

- The rates for purchases from a QF with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility. The Commission agrees with the recommendations of all parties that the Commission should play a minimal role in the negotiation of such contracts, a role limited to resolving any contract disputes which arise between the parties.

- Distinguishing between rates for purchases fixed by contract with a duration of less than 10 years ("short-term contract") and rates for purchases set by contract with a duration of 10 years or more ("long-term contract").

- The capacity credits included in long-term contracts should be made constant over the duration of the contract.

- Both short-term and long-term contracts should include an energy credit based on the average hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility.

[3] Federal Register Vol. 45 No. 38, page 12219.
[4] See Exhibit_JPT-2 for the Order from Docket F-3365.

- The Commission finds that 18 C.F.R Section 292.306 requires each QF to pay "any interconnection costs which the State regulatory authority ... may assess against the qualifying facility on a non-discriminatory basis with respect to other customers with similar load characteristics". The Commission finds that an assessment of interconnection costs can only be made on a case by case basis.

- The interconnection costs should be levelized over the life of the facility. To require a QF to pay the entire cost of interconnection up front might present too great a financial obstacle, and tend to discourage development of cogeneration and small power production.

- The capacity credits to be included in any purchase rates, whether contractual or otherwise, should be based on capacity <u>actually</u> avoided, and if the purchase does not enable a utility to avoid capacity costs, capacity credits should not be allowed. (<u>emphasis added</u>)

- The Commission does not read the FERC's rules to permit a utility to pay capacity costs where none are avoided. To do so would have the effect of requiring the utility to pay twice for the same capacity and would thus impose added and unnecessary costs on the utility's other customers, contrary to clear congressional and FERC intent.

Q. Are there any other past Commission decisions that provide guidance on implementing PURPA and determining an appropriate avoided cost?

A. In Docket EL11-006, In the Matter of the Complaint by Oak Tree Energy, LLC against NorthWestern Energy for Refusing to Enter into a Purchase Power Agreement, the Commission issued findings[5] in 2013 on many of the same PURPA issues that are present in this docket. While the facts and circumstances of this docket may be slightly different than Docket EL11-006, I believe the following rulings are instructive:

- Given NorthWestern's status as a vertically integrated utility with predominant reliance on its own internal generation at this time, the hybrid method employed by NorthWestern is the proper method to calculate avoided costs for NorthWestern's South Dakota system.

- The appropriate contract term for the Project is 20 years.

- Levelized avoided cost values are the appropriate values to use because they will produce a stable price that will better enable Oak Tree to finance the project.

[5] See Exhibit_JPT-3 for the Amended Final Decision and Order for Docket EL11-006.

- The renewable energy credits associated with the Project should remain with Oak Tree. Oak Tree will have access to the REC markets, and Oak Tree can market its RECs as it deems in its best interest.

- The inclusion of carbon costs in the avoided cost calculations is not justified at this time due to the absence of any legislation that seems likely to pass that would establish such costs and is therefore too speculative to warrant inclusion in the avoided cost.

- The proper natural gas and electric market rates to use in the hybrid method reflect market conditions and projections as of February 25, 2011, the date on which a LEO was created.

- Oak Tree is entitled to a capacity credit for the facility's output commencing with the Project's coming online with the capacity value equal to 20% of the Project's after-losses capacity of 18.915 MW. The 20% value is the appropriate percentage since NorthWestern is a member of the Midwest Reliability Organization (MRO), and as of the LEO date of February 25, 2011, the MRO accredited wind energy facilities at 20% of their rated capacity.

Q. Why is it difficult for Parties to agree on a proper avoided cost?

A. The definition of avoided cost is straightforward, but it can be difficult for Parties to agree on the costs an electric utility will avoid over a long period of time because it is an estimate based on forecasts. The estimate of future avoided energy costs over a long-term contract is primarily dependent on underlying assumptions about fuel and electricity market cost forecasts, and there are many different forecasts that stakeholders can use that yield significantly different avoided energy cost forecasts.

Q. Why is it important to establish a rate for purchase that does not exceed NorthWestern's actual avoided cost?

A. NorthWestern's customers will ultimately be responsible for paying the rate for purchase ordered by the Commission. A fixed-price, long-term PPA effectively transfers much of the financial risk of the QF project from the developer to NorthWestern's customers. NorthWestern's customers will be harmed by significant and unnecessary costs if the purchase rate exceeds NorthWestern's actual avoided cost.

V. OVERVIEW OF AVOIDED ENERGY COST METHODOLOGIES

Q. Please summarize NorthWestern's avoided energy cost methodology.

A. NorthWestern utilizes a production cost modeling approach to estimate its avoided cost. Using PowerSimm software, Northwestern models its costs of its generation on an hourly basis over a twenty year period with and without Juhl's projects to determine their effect on NorthWestern's supply portfolio. The avoided cost is evaluated for the three following dispatch conditions:[6]

1. When the portfolio is short energy (i.e. generation is less than load) and is purchasing from the market, the avoided energy cost is the market purchase price of electricity that NorthWestern would otherwise have purchased;
2. When the portfolio is long energy (i.e. generation is greater than load) and the market price is higher than the variable cost of the highest economically dispatchable resource used to serve load, the avoided energy cost is the variable cost of the highest dispatchable resource serving load; and
3. When the portfolio is long energy and the market price is lower than the variable cost of any dispatchable resource, the avoided energy cost is zero because NorthWestern does not need to purchase from the market and it cannot back down its must-run generation units.

I will refer to dispatch condition 3 above as the minimum generation dispatch condition. Please see the direct testimony of Commission Staff witness Kavita Maini for more details regarding NorthWestern's avoided energy cost methodology.

Q. Please summarize Juhl's avoided cost methodology.

A. Juhl developed a differential revenue requirement analysis to estimate NorthWestern's avoided cost. Juhl used the PROMOD simulation model and Ventyx Advisors data set to forecast NorthWestern's system dispatch including and excluding Juhl's projects. Market purchase and sales were included as dispatch options in the analysis. According to Juhl witness Roger Schiffman, during hours when NorthWestern's system requires additional energy, the simulation assigns incremental costs for the energy based on forecasted Southwest Power Pool ("SPP") market prices. During hours when

NorthWestern's system is long on energy, the simulation allows the excess to be sold into the SPP market based again on forecast hourly SPP market prices.[7] Please see the direct testimony of Commission Staff witness Kavita Maini for more details regarding Juhl's avoided energy cost methodology.

Q. What avoided energy cost methodology did the Commission approve in Docket EL11-006?

A. In Docket EL11-006, the Commission approved the hybrid method recommended by NorthWestern rather than a market price method recommended by Oak Tree Energy, LLC ("Oak Tree").

The hybrid method was described as a combination of the Component/Peak method and the Market Estimates method. This method estimated avoided energy costs for various levels of purchases based on multi-year average historical trends of hourly proportional contributions of baseload generation and wholesale market purchases. The average proportional contribution factors were combined with forecasted incremental baseload production costs and forecasted wholesale market prices to develop the estimated avoided energy costs. As a result, the hybrid method accounted for NorthWestern's actual generation portfolio and reflected both generation costs and market purchase costs in the calculation of avoided energy costs.

Oak Tree's avoided cost estimate used a long-term market price forecast from Black & Veatch and applied this forecast to the expected hourly output of its project. The market approach did not consider when NorthWestern's internal generation was sufficient to cover its system needs, and assigned market prices to all energy produced by Oak Tree regardless of whether NorthWestern was long or short energy.

Q. Which of the Parties' method is more similar to the hybrid method?

A. NorthWestern's production cost modeling approach is more similar to the hybrid method approved by the Commission in Docket EL11-006. NorthWestern has since refined its method to more precisely analyze hourly dispatch conditions through the use of PowerSimm, but continues to estimate its avoided energy cost using a combination of

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[6] See the direct testimony of NorthWestern witness Luke Hansen, Pages LPH-10 through LPH-11.
[7] See the direct testimony of Juhl witness Roger Schiffman, Page 36.

market purchases and the variable cost of internal generation, depending on its dispatch position.

Q. Do you agree with how NorthWestern is addressing the minimum generation dispatch condition?

A. Yes, I agree that there should be no avoided energy cost payment assigned to the minimum generation dispatch condition. NorthWestern's avoided cost methodology associated with the minimum generation dispatch condition is consistent with the FERC's purchase obligation implementation in Order 69. Since utilities cannot curtail purchases of QF energy for general economic reasons, the FERC has indicated that parties may negotiate avoided costs with light loading periods in mind, and these conditions often are incorporated into PPAs.[8]

Q. Please provide your analysis of FERC Order 69 as it relates to the minimum generation dispatch condition.

A. See below for FERC's purchase obligation implementation from Order 69, followed by my analysis:

> *"A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load."*
>
> During light loading periods, Juhl is seeking to have NorthWestern purchase more energy than it needs to meet its total system load. Through the use of the minimum generation dispatch condition, NorthWestern's avoided cost methodology limits payment to only the energy that is used to meet its total system load. Without that condition, NorthWestern's avoided cost methodology would not include any protections from a QF that seeks to have NorthWestern purchase more energy than it requires for its total system load.
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> *"In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include*

[8] See *Idaho Wind Partners 1, LLC,* 143 FERC ¶ 61,248 (2013); *Idaho Wind Partners 1, LLC,* 140 FERC ¶ 61,219 (2012); *Entergy Services, Inc.*, 137 FERC ¶ 61,199 (2011).

payment for energy or capacity which the utility can use to meet its total system load."

As Commission Staff witness Kavita Maini also discusses, NorthWestern is a relatively small utility with adequate energy resources to serve its total system load. Specifically, NorthWestern has approximately 125 MWs of nameplate wind generation resources and approximately 224 MWs of nameplate coal generation resources through ownership and PPAs. The baseload coal generation resources have must run provisions that total 81 MWs. NorthWestern's total system peak is approximately 305 MWs, average load is approximately 185 MWs, and minimum load is approximately 107 MWs. With Juhl's projects, NorthWestern's wind generation resources would increase to approximately 185 MWs of nameplate capacity, which would be approximately equal to NorthWestern's average system load during hours when the wind resources are generating near maximum capacity.

As more wind generation resources are put on NorthWestern's system, minimum generation dispatch conditions will occur more frequently when the wind blows during low load, low market price hours. During these hours, NorthWestern is not able to use any of Juhl's energy to meet its total system load, and the energy has no value to NorthWestern's system.

"These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale."

NorthWestern is not required to sell Juhl's unusable energy during the minimum generation dispatch condition to the market. Juhl modeled its energy output during the minimum generation dispatch condition as a sale into the SPP market, and I believe that is not consistent with FERC's purchase obligation requirements. In addition, it is not in the public interest to promote policies that encourage utility's to obtain energy resources in excess of its system load. NorthWestern's customers would ultimately pay this unnecessary, unjustified cost.

Q. What concerns do you have about Juhl's avoided energy cost methodology?

A. Juhl's differential revenue requirement method assigns market prices to all energy produced by Juhl regardless of whether NorthWestern was long or short energy. As previously stated, the FERC definition of avoided cost is the incremental costs of electric energy, capacity, or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source. Juhl's method did not reflect NorthWestern's cost to generate energy in the hours it is not required to purchase from another source. By using market price in the hours where NorthWestern's owned generation has a lower variable cost, Juhl's estimation of avoided energy cost is overstated.

As a vertically integrated utility company, NorthWestern does not rely on the market for all of its purchases. NorthWestern's customers are currently paying retail rates that recover significant generation resource investments. These investments in generation limit NorthWestern's customers' exposure to market price risk by capping the cost of energy at the variable cost of NorthWestern's owned generation facilities. While Juhl's avoided cost methodology may be appropriate for a utility in a deregulated electricity market, it does not properly reflect the avoided energy cost of a vertically integrated electric utility.

In addition, Juhl's avoided energy cost methodology does not limit payment to the energy that NorthWestern can use to meet its total system load. By including sales as a dispatch option in Juhl's differential revenue requirement analysis, NorthWestern is effectively serving as a market broker for Juhl, and NorthWestern's customers are taking on the market price risk for energy that provides no service value. Under Juhl's proposed avoided cost methodology, in theory, there could be an unlimited number of QF developers that could obligate NorthWestern to purchase unlimited amounts of energy at forecasted SPP market prices that would not be needed to meet NorthWestern's load. Failing to limit payment to only energy that is used to meet NorthWestern's total system load is inconsistent with FERC's interpretation of the PURPA purchase obligation, and would not be just and reasonable to NorthWestern's customers.

Q. Which of the Parties' avoided energy cost methodology is consistent with FERC and Commission policy?

A. NorthWestern's production cost methodology is consistent with FERC and Commission policy, and Commission Staff recommends NorthWestern's method for calculating the avoided energy cost.

VI. LEO ESTABLISHMENT

Q. Please define LEO.

A. Under 18 CFR 292.304(d), FERC regulations allow each QF to have the option to either:

(1) provide energy as the QF 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) provide energy or capacity pursuant to a LEO for the delivery of energy or capacity over a specific term, in which case the rates for such purchases shall, at the option of the QF 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 is incurred.

According to FERC Order 69, FERC used the term LEO to prevent a utility from circumventing the requirement that provides capacity credit for an eligible QF merely by refusing to enter into a contract with the qualifying facility. FERC has not defined what constitutes a LEO. Instead, FERC has provided state regulatory commissions the flexibility to define the requirements of a LEO consistent with PURPA and FERC regulations. The Commission has not defined what constitutes a LEO, but currently has a rulemaking pending regarding the requirements for establishing a LEO in Docket RM13-002.

Q. Why is a LEO significant?

A. If a QF elects to sell its power pursuant to a LEO, PURPA requires that rates paid to the QF be set at the utility's avoided costs at the time the LEO is established. The underlying assumptions and forecasts to calculate the utility's avoided costs are based on the date the LEO is established.

Q. What positions have the Parties taken regarding a LEO?

A. Juhl believes the LEO should run from the date negotiations ended, which is April 4, 2016.[9] NorthWestern does not believe a LEO has been created at all.[10]

Q. Has Commission Staff previously taken a position on the requirements for establishing a LEO?

A. Yes. In Docket RM13-002, Commission Staff submitted draft rules[11] for consideration by interested parties and the Commission. The draft rules were developed by Commission Staff based on initial comments in the rulemaking, and interested parties were allowed two rounds of comments on Commission Staff's proposed rules. While parties requested clarifications and language modifications to the rules, none of the comments received on the draft rules requested that any of the five requirements proposed be eliminated.

Q. Did Juhl and NorthWestern submit comments in Docket RM13-002?

A. Yes. Juhl submitted reply comments on March 2, 2016.[12] In the conclusion on Page 12 of Juhl's reply comments, Juhl requested that the Commission allow the rules to stand as drafted by Commission Staff. NorthWestern submitted comments in the rulemaking as well, and NorthWestern's position on the requirements of establishing a LEO has not changed from the rulemaking.

Q. Is Juhl's position on the requirements for establishing a LEO in this docket consistent with its position in Docket RM13-002?

A. No, it is not. The rules that Juhl supported in Docket RM13-002 had five requirements to meet in order to establish a LEO. Based on responses to discovery in this complaint, Juhl has asserted that the LEO was established on the date negotiations ended. It is unclear if Juhl believes there are other requirements a QF would need to meet to establish a LEO.

[9] See Exhibit_JPT-4 for Juhl's response to Commission Staff Data Request 1-9.
[10] See the direct testimony of NorthWestern witness Bleau LaFave, Pg. 9, line 7, through Pg. 10, line 11.
[11] See Exhibit_JPT-5 for the draft rules recommended by Commission Staff.
[12] See Exhibit_JPT-6 for Juhl's reply comments in Docket RM13-002.

Q. Did Commission Staff try to understand why Juhl modified its position on the requirements for establishing a LEO from Docket RM13-002?

A. In Data Request 3-1,[13] Commission Staff asked Juhl to explain whether it continues to support the LEO rules as drafted in Docket RM13-002. Juhl's witness Corey Juhl responded that "given the Commission has yet to adopt the proposed rules, it is unclear why Juhl's support of the proposed rules, or lack thereof, has any bearing on this proceeding or the Juhl projects at issue in this proceeding."

The requirements to establish a LEO is an issue in this proceeding as NorthWestern disputes Juhl's assertion that it established a LEO on April 4, 2016. Through this complaint, it appears that Juhl is considering electing to sell its power through a LEO. The establishment of a LEO has "bearing on this proceeding." Unfortunately, Mr. Juhl's answer to Commission Staff Data Request 3-1(b), and Juhl's testimony, did not clearly define its position on what constitutes a LEO.

Q. Are the draft rules proposed by Commission Staff reasonable requirements for establishing a LEO?

A. Yes. When discussing factors affecting rates for purchases in Order 69, the FERC stated that:

> "if a qualifying facility offers energy of sufficient reliability and with sufficient <u>legally enforceable guarantees of deliverability</u> to permit the purchasing electric utility to avoid the need to construct a generating plant, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility than it otherwise would have purchased, then the rates for purchases from the qualifying facility must include the avoided capacity and energy costs."[14] <u>(emphasis added)</u>

The requirements provided in the draft rules are necessary for a QF to guarantee delivery, and provide sufficient commitments from a QF to obligate itself to sell electricity to the utility. Since no party in Docket RM13-002 contested any of the five requirements, Commission Staff believes the draft rules provide reasonable requirements for establishing a LEO.

[13] See Exhibit_JPT-7 for Juhl's response Commission Staff Data Request 3-1.

Q. Did Juhl meet all five requirements in the draft rules by April 4, 2016, to establish a LEO as recommended by Commission Staff in Docket RM13-002?

A. No. I will provide Commission Staff's interpretation of whether Juhl met each of the five requirements below:

(1) The qualifying facility, if it has a net power production capacity of 500 kW or more, has notified the public utility of its status as a qualifying facility at least 90 days prior, pursuant to 18 C.F.R 292.207(c)(2);

On Page 3 of Juhl's complaint, Juhl asserts that it provided copies of the FERC Form 556 for each of the three wind projects to the Commission and NorthWestern. NorthWestern admitted that Juhl previously provided these forms in its response to Juhl's complaint. The Commission received a copy of this certification on October 13, 2015. Commission Staff will submit discovery regarding the specific day Juhl provided this form to NorthWestern, but it appears Juhl met this requirement in October 2015.

(2) The qualifying facility has entered into an interconnection agreement or the interconnection process is delayed as a result of a dispute that has been filed with the proper jurisdiction;

According to Juhl's response to Commission Staff Data Request 3-1(a), Juhl had not entered into an interconnection agreement as of November 15, 2016, and Juhl did not anticipate completing the interconnection process until January 31, 2017. In addition, Juhl did not indicate any issues with the interconnection process in the dispute filed on June 23, 2016. Juhl did state on November 15, 2016, in response to Commission Staff Data Request 3-1(a), that NorthWestern has been considering Juhl's interconnection request for 416 days as of the date of that response. In response to Commission Staff Data Request 3-2(a)[15], Juhl noted that "SPP has received all of the required information and data related to the Affected System Study Agreement and Juhl expects to receive results by or before 1/31/2017." With the information provided by the Parties, it is difficult to tell if the delay is attributable

[14] Federal Register Vol. 45 No. 38, page 12226.
[15] See Exhibit_JPT-8 for Juhl's response to Commission Staff Data Request 3-2.

to NorthWestern's interconnection process or the SPP's interconnection process. Juhl does not have an interconnection agreement, and Juhl has not filed a dispute with the Commission regarding the interconnection process. Therefore, Juhl has not met this requirement.

(3) The public utility has failed to provide the avoided cost information required by 18 C.F.R. 292.302 or the qualifying facility has filed a dispute of the public utility's avoided cost information with the Commission;

Juhl met this requirement on June 23, 2016, when it filed this complaint against NorthWestern with respect to establishing a proper avoided cost for three purchase power agreements.

(4) The qualifying facility has offered a signed power purchase agreement to the public utility that includes the following:

a. A purchase price based on the qualifying facility's estimate of the public utility's avoided cost;
b. A reasonable date or range of dates for commencement of delivery of the energy or capacity, or both;
c. The length of the contract; and
d. Other terms and conditions that would be reasonable in the industry;

While Commission Staff does not have documentation that Juhl specifically offered a signed purchase agreement, there is agreement by the Parties that Juhl offered a purchase price based on Juhl's estimate of NorthWestern's avoided cost, provided a range for the commencement of delivery of power from December 2017 to December 2018, and offered a 20 year contract. The Parties also noted that they did not anticipate that the non-rate terms and conditions of the contract will prevent an agreement. Juhl appears to have met the intent of this requirement no later than April 4, 2016.

(5) The qualifying facility has shown that it has made significant progress toward bringing the qualifying facility into existence by providing:

a. A list of any permits that are needed for the facility to be operational and documentation that it has completed or started the process to obtain the permits;

b. A description of the site of the project and documentation that it has acquired or is in the process of acquiring the land or any necessary easements or options;

c. The amount of financing that is needed and documentation that it has acquired financing or its plan for acquiring financing; and

d. A description of any owners, employees, or consultants' qualifications to construct and operate the qualifying facility.

Commission Staff's primary concern with Juhl's ability to bring all three of its QFs into existence is the fact that Juhl was denied a conditional use permit by the Davison County Commission for the Davison project. In response to Commission Staff Data Request 2-2,[16] Juhl stated the Davison County Wind Project is still in the process of completing various development milestones. Juhl also indicated that it would be resubmitting a permit application after the County has adopted their new "Wind Energy Ordinance," which is expected to be in place by January 15, 2017. There have been instances of local opposition to siting wind facilities in South Dakota that have caused delays in construction. I do not believe it is appropriate to assume approval of a project without the proper permits from the appropriate local governments.

In Juhl's response to Commission Staff Data Request 2-5,[17] Juhl provided the current status of each permit needed for the QFs to become operational. Some progress has been made towards bringing the projects into existence, but it is questionable whether Juhl could obligate itself to deliver energy and capacity on April 4, 2016, from the Davison and Aurora project when Juhl had been denied a County conditional use permit for the Davison project, and it had not obtained any of the necessary permits for the Aurora project.

[16] See Exhibit_JPT-9 for Juhl's response to Commission Staff Data Request 2-2.
[17] See Exhibit_JPT-10 for Juhl's response to Commission Staff Data Request 2-5.

Q. Please summarize Commission Staff's position on whether Juhl established a LEO on April 4, 2016?

A. Based on the five requirements for establishing a LEO as set forth in the draft rules recommended by Commission Staff and supported by Juhl in Docket RM13-002, Juhl did not establish a LEO on April 4, 2016. First of all, Juhl did not file a dispute regarding the avoided cost with the Commission until June 23, 2016. Second, Juhl has not entered into a transmission interconnection agreement or filed a dispute with the Commission regarding the interconnection process. Third, while progress has been made in obtaining some of the permits necessary for the QFs to become operational, Commission Staff questions whether Juhl could obligate itself to deliver energy and capacity on April 4, 2016, from the Davison and Aurora project when it had been denied a County conditional use permit for the Davison project, and it had not obtained any of the necessary permits for the Aurora project. Commission Staff does not believe a LEO has been established.

VII. CARBON COMPLIANCE COSTS

Q. What are carbon costs?

A. Carbon costs are the estimated future costs associated with the regulation of CO_2 emissions from electric generation facilities.

Q. What are the Parties positions on including carbon costs in the avoided cost estimate?

A. NorthWestern believes it would not be appropriate to arbitrarily include an unknown carbon cost that NorthWestern customers may or may not avoid in the future.[18]
In the direct testimony of Juhl's witness Roger Schiffman, he stated, "Given the Clean Power Plan ("CPP") rules developed by the EPA, and given NorthWestern's approach taken in power supply and resource planning analyses, it is appropriate to reflect a carbon cost component in the avoided cost."[19] Juhl's wind projects produce carbon-free energy, and Juhl believes the projects will help NorthWestern in its CPP compliance activities.

[18] See the direct testimony of NorthWestern witness Bleau LaFave, Pg. BJL-21, line 17, through BJL-22, line 9.

Juhl recommends increasing the levelized avoided cost by $11.63 per MWh to reflect the inclusion of CO_2 compliance costs. Juhl asserted that it used the CO_2 price forecast recently developed by NorthWestern in its Montana Power Supply study, and assumed that fifty percent of the carbon cost, expressed on a $/MWh basis, would flow through to energy prices. Mr. Schiffman stated that fifty percent of the carbon cost "is a very conservative assumption, as it effectively assumes that efficient natural gas-fueled resources always set marginal energy prices in SPP, so the carbon pricing component would be reflective of CO2 compliance costs for a natural gas-fueled combined-cycle resource."

Q. Has the Commission previously ruled on including carbon compliance costs in a utility's avoided cost?

A. Yes. As previously stated, in Docket EL11-006, the Commission decided that carbon compliance costs were too speculative to warrant inclusion in the avoided cost.

Q. What is the current status of the CPP?

A. On February 9, 2016, the U.S. Supreme Court stayed implementation of the CPP pending judicial review. On September 27, 2016, oral arguments were heard on the CPP before the U.S. Court of Appeal for the District of Columbia Circuit. The loser is likely to appeal the decision to the U.S. Supreme Court. With the current political climate, it is unlikely the Supreme Court will uphold the CPP in its entirety. Commission Staff believes the future of the CPP is uncertain and may never be enforced.

Q. How were carbon costs modeled in NorthWestern's 2014 Integrated Resource Plan?

A. In response to Commission Staff Data Request 3-1, NorthWestern responded that it reflected the CPP as a sensitivity analysis in its 2014 Integrated Resource Plan. NorthWestern stated that "the impact of EPA's proposed 111(d) CO2 reductions is still largely unknown… Because this now relevant uncertainty poses risk to NorthWestern's resource fleet, Ascend included CO_2 risk in its analysis."

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[19] See direct testimony of Juhl witness Roger Schiffman, page 38.

Electric utilities have been modeling CO_2 risk as a sensitivity in resource planning for many decades without an actual carbon cost ever imposed. Unlike risk analysis, PURPA requires that the avoided costs be calculated based on costs actually avoided.

Q. Should the Commission include carbon costs in the avoided cost?

A. No, carbon costs are still too speculative to include in the avoided cost. In the absence of known laws or enforceable regulations that impose a cost for carbon, it is difficult to predict the actual impact carbon costs would have on NorthWestern's avoided costs. There has not been a change in facts and circumstances from Docket EL11-006 that would justify a different decision than the Commission previously rendered.

Q. Does Juhl's QFs produce any other environmental attributes?

A. Yes, Juhl's wind QFs will generate Renewable Energy Credits ("REC"). RECs represent the environmental attributes of power produced from renewable energy facilities and are sold separate from commodity electricity. A megawatt-hour of renewable electricity generated and delivered is equal to one REC.

Q. What are the Parties positions on including RECs in the avoided cost calculation?

A. To the best of my knowledge, Juhl has not stated its position on including RECs in the avoided cost. NorthWestern included RECs in the avoided cost calculation using the current price for Green-e National Wind, and escalated the REC price over the contract period using the same escalation rate as reflected in the natural gas and electric commodity price forecast.[20]

Q. Did the Commission include RECs in the avoided cost established in Docket EL11-006?

A. No, the Commission did not include RECs in the avoided cost calculation. The Commission decided that the RECs associated with the QF should remain with the developer, and the developer can market its RECs as it deems in its best interests.

Q. Do you recommend including RECs in the avoided cost calculation?

A. No, I do not recommend including RECs in the avoided cost calculation. There are no laws or regulations that require NorthWestern to obtain RECs in South Dakota. With no current requirements, NorthWestern does not actually avoid costs by obtaining RECs. In addition, NorthWestern had the ability to meet and exceed South Dakota's Renewable, Recycled, and Conserved Energy Objective[21] in 2015 with the RECs provided through purchase power agreements and ownership of the Beethoven wind facility.

Q. Does this conclude your testimony?

A. Yes.

[20] See Exhibit_JPT-11 for NorthWestern's response to Commission Staff Data Request 2-1.
[21] See SDCL 49-34A-101

12214 Federal Register / Vol. 45, No. 38

Monday, February 25, 1980

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79-55, Order No. 69]

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities, and provide for the exemption of qualifying facilities from certain federal and State regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

EFFECTIVE DATE: March 20, 1980.

FOR FURTHER INFORMATION CONTACT:
Ross Ain, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8446.
John O'Sullivan, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8477.
Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8033.

Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-376-9264.

SUPPLEMENTARY INFORMATION:
Issued February 19, 1980.

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires the Federal Energy Regulatory Commission (Commission) to prescribe rules as the Commission determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities. Additionally, section 210 of PURPA authorizes the Commission to exempt qualifying facilities from certain Federal and State law and regulation.

Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities, and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Thus, by using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities use biomass, waste, or renewable resources, including wind, solar amd water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally required to purchase the electric output, at an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulation as an electric utility.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act.

I. Procedural History

On June 26, 1979, in Docket No. RM79-54,[1] the Commission issued proposed rules to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 PURPA. Such qualifying facilities are entitled to avail themselves of the rate and exemption provisions under section 210 of PURPA; and qualifying cogeneration facilities are eligible for exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978.[2] The Commission will soon issue a final rule in Docket No. RM79-54.

As part of the rulemaking process in this docket, the Commission issued a Staff Discussion Paper[3] on June 27, 1979, addressing issues arising under section 210 of PURPA.

Public hearings on RM79-54 and the Staff Discussion Paper (RM79-55) were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking under Section 210 of PURPA in Docket No. RM79-55.[4] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79-54 and RM79-55. In a Request for Further Comments,[5] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested parties, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment.

After consideration of the comments, the Commission Staff made available a final draft rule on January 29, 1980. State public utility commissioners were invited to comment on the draft at a public meeting held on February 5, 1980. Representatives of electric utilities were invited to comment at a public meeting held on February 8, 1980. The Commission Staff also made itself available to any other interested parties who wished to comment. All of the comments were considered in the formulation of this final rule.

In the Staff Discussion Paper and the Request for Further Comments, it was stated that any environmental effects attributable to this program would result from the combined effect of these two rulemaking proceedings. As noted previously, the Commission intends to issue final rules in Docket No. RM79-54 in the near future. At that time, the Commission will also make available its final Environmental Assessment.

II. Summary

These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a nondiscriminatory basis, and at a rate that is just and reasonable and in the public interest; and that they must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilities' own generation.

[1] 44 FR 38873, July 3, 1979.
[2] 44 FR 65744, November 15, 1979.
[3] 44 FR 38863, July 3, 1979.
[4] 44 FR 61190, October 24, 1979.
[5] 44 FR 61977, October 29, 1979.

The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

III. Section-by-Section Analysis

Subpart A—General Provisions

§ 292.101 Definitions.

This section contains definitions applicable to this part of the Commission's rules. Paragraph (a) provides that terms defined in PURPA have the same meaning as they have in PURPA, unless further defined in this part of the Commission's regulations. The definitions in PURPA are found in section 3 of that Act.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Commission's regulations. Those regulations implement section 201 of PURPA, and are the subject of Docket No. RM79-54.

Subparagraph (2) defines "purchase" as the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

Subparagraph (3) defines "sale" as the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

In the proposed rule, subparagraph (4) defined "system emergency" as a condition on a utility's system "which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property." In response to comments noting the difficulty in determining what constitutes a "significant number" of customers, the Commission has amended the definition to "a condition on an electric utility's system which is likely to result in imminent significant disruption of service to customers, or is imminently likely to endanger life or property." The emphasis is placed on the significance of the disruption of service, rather than on the number of customers affected.

Subparagraph (5) defines "rate" as any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

In the proposed rule, subparagraph (6) defined "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.

The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

Many comments noted that the definition of "avoided cost" in the proposed rule failed to link the capacity costs which a utility might avoid as a result of purchasing electric energy or capacity or both from a qualifying facility with the energy costs associated with the new capacity. If the Commission required electric utilities to base their rates for purchases from a qualifying facility on the high capital or capacity cost of a base load unit and, in addition, provided that the rate for the avoided energy should be based on the high energy cost associated with a peaking unit, the electric utilities' purchased power expenses would exceed the incremental cost of alternative electric energy, contrary to the limitation set forth in the last sentence of section 210(b).

One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan,[6] *excluding* the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan *including* the qualifying facility.[7]

Subparagraph (7) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and

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[6] An optimal capacity expansion plan is the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost.

[7] Throughout the rule and preamble, the phrase "energy or capacity" is used. This phrase is intended to include the capacity and energy costs associated with the capacity, if the purchase involves both energy or capacity.

administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

The Commission has clarified this definition to include distribution and administrative costs associated with the interconnected operation, in response to comments indicating that the proposed rule was vague in these respects. This definition is designed to provide the State regulatory authorities and nonregulated electric utilities with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility under § 292.306. These costs may include, but are not limited to, operating and maintenance expenses, the costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection, and reasonable insurance expenses. However, the Commission does not expect that litigation expenses incurred by the utility involving this section will be considered a legitimate interconnection cost to be borne by the qualifying facility.

Certain interconnection costs may be incurred as a result of sales from a utility to a qualifying facility. The Commission notes that the Joint Explanatory Statement of the Committee of Conference (Conference Report) prohibits the use of "unreasonable rate structure impediments, such as unreasonable hook up charges or other discriminatory practices . . ." [8] This prohibition is reflected in § 292.306(a) of these rules, which provides that interconnection costs must be assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics.

A qualifying facility which is already interconnected with an electric utility for purposes of sales may seek to establish interconnection for the purpose of utility purchases from the qualifying facility. In this case, the qualifying facility may have compensated the utility for its interconnection costs with respect to sales to the qualifying facility, either as part of the utility's demand or energy charges, or through a separate customer charge. If this is the case, the interconnection costs associated with the purchase include only those additional interconnection expenses incurred by the electric utility as a result of the purchase, and do not include any portion of the interconnection costs for which the qualifying facility has already paid through its retail rates.

One comment recommended that the definition be revised to cover "all identifiable costs, including but not limited to, the costs of interconnection . . . resulting from interconnected operation". The Commission rejects this suggestion in order to maintain consistency with its initial determination to separate the utility's avoided costs with regard to purchases from qualifying facilities, from the costs incurred as a result of interconnection with a qualifying facility. Accordingly, legitimate costs not recovered pursuant to this section can be netted out in the calculation of avoided costs.

This definition also incorporates the concept from the proposed rule, as clarified in an erratum notice,[9] that these costs are limited to the net increased interconnection costs imposed on an electric utility compared to those interconnection costs it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

This section of the rule contains definitions of "supplementary power", "back-up power", "interruptible power", and "maintenance power" which did not appear in the proposed rule.

Subparagraph (8) defines "supplementary power" as electric energy or capacity, supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

Subparagraph (9) defines "back-up power" as electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

Subparagraph (10) defines "interruptible power" as electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

Subparagraph (11) defines "maintenance power" as electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ 292.301 Scope.

Section 292.301(a) describes the scope of Subpart C of Part 292 of the Commission's rules. Subpart C applies to sales and purchases of electric energy or capacity between qualifying cogeneration or small power production facilities and electric utilities, and actions related to such sales and purchases. Section 292.301(b)(1) provides that this subpart does not preclude negotiated agreements between qualifying cogenerators or small power producers and electric utilities which differ from rates, or terms or conditions which would otherwise be required under the subpart. Paragraph (b)(2) states that this subpart does not affect the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.[10]

Paragraph (b)(1) reflects the Commission's view that the rate provisions of section 210 of PURPA apply only if a qualifying cogenerator or small power production facility chooses to avail itself of that section. Agreements between an electric utility and a qualifying cogenerator or small power producer for purchases at rates different than rates required by these rules, or under terms or conditions different from those set forth in these rules, do not violate the Commission's rules under section 210 of PURPA. The Commission recognizes that the ability of a qualifying cogenerator or small power producer to negotiate with an electric utility is buttressed by the existence of the rights and protections of these rules.

Some comments stated that paragraph (b)(2) would unfairly penalize cogenerators and small power producers who, prior to the promulgation of these regulations, entered into binding contracts with electric utilities under less favorable terms than might be obtainable under these rules. The Commission interprets its mandate under section 210(a) to prescribe "such rules as it determines necessary to encourage cogeneration and small

[8] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[9] 44 FR 63114, November 2, 1979.

[10] The term "purchase" is defined in § 292.101(b).

power production * * *" to mean that the total costs to the utility and the rates to its other customers should not be greater than they would have been had the utility not made the purchase from the qualifying facility or qualifying facilities. That a cogeneration or small power production facility entered into a binding contractual arrangement with an electric utility indicates that it is likely that sufficient incentive existed, and that the further encouragement provided by these rules was not necessary. As a result, the Commission has not revised this provision.

§ 292.302 Availability of electric utility system cost data.

As the Commission observed in the Notice of Proposed Rulemaking, in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.304 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs, taking into account the factors set forth in paragraph (e) of that section. Section 292.302 of these rules is intended by the Commission to assist those needing data from which avoided costs can be derived. It requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system.

In the preamble to the proposed rule, the Commission stated that most electric utilities will have prepared data containing some of this information in compliance with the Commission's rules implementing section 133 of PURPA. Several commenters observed that the marginal cost data required to be provided pursuant to section 133 cannot be directly translated into a rate for purchases. The Commission has clarified paragraph (b) to emphasize that these data are not intended to represent a rate for purchases from qualifying facilities. Rather, these data are to be considered the first step in the determination of such a rate.

The Commission has also revised this section so that the rates for purchases can be more readily calculated from the data produced. The Commission has changed paragraph (b)(3) to provide that a utility shall submit the associated energy cost of each planned unit expressed in kilowatt-hours (kWh) along with the estimated capacity cost of planned capacity additions. This change is intended to ensure that the calculation of avoided costs includes the lower energy costs that might be associated with the new capacity. The Commission points out that the determination of a rate for purchases from a qualifying facility which enables a utility to defer or avoid the addition of a new unit must also reflect the hours of expected use of the deferred or avoided capacity addition.

The coverage under paragraph (a) of this section is the same as that provided pursuant to section 133 of PURPA and the Commission's rules implementing that section.[11] As noted in the Notice of Proposed Rulemaking, section 133 of PURPA applies to each electric utility whose total sales of electric energy for purposes other than resale exceeded 500 million kWh during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

Paragraph (b) provides that each regulated electric utility meeting the requirements of paragraph (a) must furnish to its State regulatory authority, and maintain for public inspection, data related to the costs of energy and capacity on the electric utility's system. Each nonregulated electric utility also must maintain such data for public inspection.

In response to comments received, the Commission has extended the date by which these data must be first provided to November 1, 1980, and changed the second date to May 31, 1982, to conform to the dates required by the Commission's regulations implementing section 133 of PURPA. The Commission has added paragraph (d) to allow a State regulatory authority or nonregulated utility to use a different approach than that provided in paragraph (b). As part of that substitute program, a State regulatory authority or nonregulated electric utility could provide that cost data be updated more frequently than every two years.

Subparagraph (1) of paragraph (b) requires each electric utility to provide the estimated avoided cost of energy on its system for various levels of purchases from qualifying facilities. The levels of purchases are to be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten percent of system peak demand for systems less than 1000 megawatts. This information is to be stated on a cents per kilowatt-hour basis, for daily and seasonal peak and off-peak periods, for the current calendar year and for each of the next five years.

Subparagraph (2) of paragraph (b) requires each electric utility to provide its schedule for the addition of capacity, planned purchases of firm energy and capacity, and planned capacity retirements for each of the next ten years.

Subparagraph (3) of paragraph (b) has been revised, as discussed previously, so that the costs of planned capacity additions include the associated energy costs.

The Commission received comment noting that some States have implemented or are planning to implement alternative methods by which electric utilities' system cost data would be made available. In order to prevent the preparation of duplicative data where the alternative method substantially deviates from the Commission approach, the Commission has added paragraph (d). This paragraph provides that any State regulatory authority or nonregulated electric utility may, after providing public notice in the area served by the utility and after opportunity for public comment, require data different than that which are otherwise required by this section if it determines that avoided costs can be derived from such data. Any State regulatory authority or nonregulated utility shall notify the Commission within 30 days of any determination to sustitute data requirements.

If a qualifying facility finds that the alternative requirements do not provide sufficient data from which avoided costs may be derived, the qualifying facility may seek court review of the matter as it can with regard to any other aspect of the State's implementation of this program.

A qualifying facility may wish to sell energy or capacity to an electric utility which is not subject to the reporting requirements of paragraph (b). In that event, paragraph (c) provides that, upon request of a qualifying facility, an electric utility not otherwise covered by paragraph (b) must provide data sufficient to enable the cogenerator or small power producer to estimate the utility's avoided costs. If such utility does not supply the requested data, the qualifying facility may apply to the State regulatory authority which has ratemaking authority over the utility or to this Commission for an order requiring that the information be supplied. The consideration of such applications should take into account the burden imposed on the small utilities.

[11] 44 FR 58687, October 11, 1979.

An electric utility which is legally obligated to obtain all of its requirements for electric energy and capacity from another utility may provide the data provided by its supplying utility and the rates at which it currently purchases such energy and capacity for any period during which this obligation will continue. The wholesale rates may require adjustment in order to reflect properly the avoided costs. This is discussed later in this preamble under § 292.303. In the case of small, non-generating utilities, the requirements of this section will be considered to have been satisfied if these cost data are readily available from the supplying utility.

Numerous comments mentioned that the proposed rule did not address the issue of validation of the data to be provided pursuant to this section. As a result, the Commission has added paragraph (e) which provides that any data submitted by an electric utility under this section shall be subject to review by its State regulatory authority. Paragraph (e)(2) places the burden of providing support for the data on the utility supplying the data.

§ 292.303 Electric utility obligations under this subpart.

Section 210(a) of PURPA provides that the Commission prescribe rules requiring electric utilities to offer to purchase electric energy from qualifying facilities. The Commission interprets this provision to impose on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities with which the electric utility is directly or indirectly interconnected, except during periods described in § 292.304(f) or during system emergencies.

A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.

§ 292.303(a) Obligation to purchase from qualifying facilities.

§ 292.303(d) Transmission to other electric utilities. All-Requirement Contracts.

Several commenters noted that the obligation to purchase from qualifying facilities under this section might conflict with contractual commitments into which they had entered requiring them to purchase all of their requirements from a wholesale supplier. One commenter noted that, with regard to all-requirements rural electric cooperatives, any impairment of the obligation to obtain all of a cooperative's requirements from a generation and transmission cooperative might affect the financing ability of the generation and transmission cooperative. The Commission observes that, in general, if it permitted such contractual provisions to override the obligation to purchase from qualifying facilities, these contractual devices might be used to hinder the development of cogeneration and small power production. The Commission believes that the mandate of PURPA to encourage cogeneration and small power production requires that obligations to purchase under this provision supersede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility.

The Commission has, however, provided an alternate means by which any electric utility can meet this obligation. Under paragraph (d), if the qualifying facility consents, an all-requirements utility which would otherwise be obligated to purchase energy or capacity from the qualifying facility would be permitted to transmit the energy or capacity to its supplying utility. In most instances, this transaction would actually take the form of the displacement of energy or capacity that would have been provided under the all-requirements obligation. In this case, the supplying utility is deemed to have made the purchase and, as a result the all-requirements obligation is not affected.

In addition, if compliance with the purchase obligation would impose a special hardship on an all-requirements customer, the Commission may consider waiving such purchase obligation pursuant to the procedures set forth in § 292.403.

Transmission to Other Facilities

There are several circumstances in which a qualifying facility might desire that the electric utility with which it is interconnected not be the purchaser of the qualifying facility's energy and capacity, but would prefer instead that an electric utility with which the purchasing utility is interconnected make such a purchase. If, for example, the purchasing utility is a non-generating utility, its avoided costs will be the price of bulk purchased power ordinarily based on the average embedded cost of capacity and average energy cost on its supplying utility's system. As a result, the rate to the qualifying facility would be based on those average costs. If, however, the qualifying facility's output were purchased by the supplying utility, its output ordinarily will replace the highest cost energy on the supplying utility's system at that time, and its capacity might enable the supplying utility to avoid the addition of new capacity. Thus, the avoided costs of the supplying utility may be higher than the avoided cost of the non-generating utility.

This would not appear to be the case if the qualifying facility offers to supply capacity and energy in a situation in which the supplying utility is in an excess capacity situation. Since the supplying utility has excess capacity, its avoided costs would include only energy costs. On the other hand, if the avoided cost were based on the wholesale rate to the all-requirements utility, the avoided cost would include the demand charge included in the wholesale rate, which would usually reflect an allocation of a portion of the fixed charges associated with excess capacity.

Use of the unadjusted wholesale rate fails to take into account the effect of reduced revenue to the supplying utility, as a result of the substitute of the qualifying facility's output for energy previously supplied by the supplying utility. As the level of purchase by the all-requirements utility decreases, the supplying utility's fixed costs will have to be allocated over a smaller number of units of output. In effect, the loss in revenue to the supplying utility will cause the demand charges to the supplying utility's customers (including the all-requirements customers interconnected with the qualifying facility) to increase. Under the definition of "avoided costs" in this section, the purchasing utility must be in the same financial position it would have been had it not purchased the qualifying facility's output. As a result, rather than allocating its loss in revenue among all of its customers, in this situation the supplying utility should assign all of these losses to the all-requirements utility. That utility should, in turn, deduct these losses from its previously calculated avoided costs, and pay the qualifying facility accordingly.

Under these rules, certain small electric utilities are not required to provide system cost data, except upon request of a qualifying facility. If, with the consent of the qualifying facility, a small electric utility chooses to transmit energy from the qualifying facility to a second electric utility, the small utility

12220 Federal Register / Vol. 45, No. 38 / Monday, February 25, 1980 / Rules and Regulations

can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself. However, the ability to transmit a purchase to another utility is not limited to these smaller systems; it applies to any utility.

Accordingly, paragraph (d) provides that a utility which receives energy or capacity from a qualifying facility may, with the consent of the qualifying facility, transmit such energy to another electric utility. However, if the first facility does not agree to transmit the purchased energy or capacity, it retains the purchase obligation. In addition, if the qualifying facility does not consent to transmission to another utility, the first utility retains the purchase obligation. Any electric utility to which such energy or capacity is delivered must purchase this energy under the obligations set forth in these rules as if the purchase were made directly from the qualifying facility.

One commenter stated that this provision could result in energy being transmitted to a utility which has little or no information regarding the reliability of the qualifying facility. The Commission believes that, prior to these transactions occurring, it will be in the interest of the qualifying facility to inform any utility to which energy or capacity is delivered, of the nature of those deliveries, so that such energy or capacity can be usefully integrated into that utility's power supply.

Several other commenters believed that this provision went beyond the authority of section 210 of PURPA—namely, that the Commission cannot require the first utility to wheel the power nor the second utility to buy the power. First, the Commission notes that this transmission can only occur with the consent of the utility to which energy or capacity from the qualifying facility is made available. Thus, no utility is forced to wheel. Secondly, section 210 does not limit the obligation to purchase to any particular utility; rather, it is a generally applicable requirement.

Paragraph (d) provides that charges for transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. In the case of electric utilities not subject to the jurisdiction of this Commission, these charges should be determined under applicable State law or regulation which may permit agreement between the qualifying facility and any electric utility which transmits energy or capacity with the consent of the qualifying facility. For utilities subject to the Commission's jurisdiction under Part II of the Federal Power Act, these charges will be determined pursuant to Part II.

The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase. In cases in which electricity actually travels across the transmitting utility's system, the amount of energy delivered will be less than that transmitted, due to line losses. When this occurs, the rate for purchase can reflect these losses. In other cases, the energy supplied by the qualifying facility will displace energy that would have been supplied by the purchasing utility to the transmitting utility. In those cases, a unit of energy supplied from the qualifying facility may replace a greater amount of energy from the purchasing utility. In that case, the rate for purchase should be increased to reflect the net gain. These provisions are also set forth in paragraph (d).

§ 292.303(b) Obligation to sell to qualifying facilities.

Paragraph (b) sets forth the statutory requirement of section 210(a) of PURPA that each electric utility offer to sell electric energy to qualifying facilities. The Commission observed in the Notice of Proposed Rulemaking that State law ordinarily sets out the obligation of an electric utility to provide service to customers located within its service area. In most instances, therefore, this rule will not impose additional obligations on electric utilities.

It is possible that a qualifying facility located outside the service area of an electric utility might require back-up, maintenance, or other types of power. The Commission believes that the instructions of section 210(a) of PURPA that it issue rules "as it determines necessary to encourage cogeneration and small power production * * *" mandate that it assure that such facilities are able to fulfill their needs for service.

However, the Commission also recognizes that State and local law limits the authority of some electric utilities to construct lines outside of their service area. Accordingly, the Commission requires electric utilities to serve any qualifying facility, and, subject to the restriction contained therein, to interconnect with any such facility as required in paragraph (c). However, an electric utility is only required to construct lines or other facilities to the extent authorized or required by State or local law. As a result, a qualifying facility outside the service area of a utility may be required to build its line into the service area of the utility.

§ 292.303(c) Obligation to interconnect.

In the Notice of Proposed Rulemaking, the Commission used the interpretation set forth in the Staff Discussion Paper, that the obligation to interconnect with a qualifying facility is subsumed within the requirement of section 210(a) that electric utilities offer to sell electric energy to and purchase electric energy from qualifying facilities. The Commission observed that to hold otherwise would mean that Congress intended to require that qualifying facilities go through the complex procedures simply to gain interconnection, contrary to the mandate of section 210 of PURPA to encourage cogeneration and small power production.

During the comment period, this question was further explored, and it was suggested that the Commission has ample authority under the general mandate of section 210(a) of PURPA—namely, that it prescribe rules necessary to encourage cogeneration and small power production—to require interconnection.

While these interpretations received substantial support in the comments submitted, they were at the same time criticized on the theory that section 210(e)(3) of PURPA does not provide that a qualifying facility may be exempted from section 210 of the Federal Power Act (added by section 202 of PURPA and providing certain interconnection authority) and that this interconnection section specifically includes qualifying cogenerators and small power producers in its applicability. These commenters contended that since section 210 of the Federal Power Act deals explicitly with the subject of interconnections between qualifying facilities and electric utilities, no other section of that Act can be interpreted as also granting authority on that subject, as such an interpretation would render the express provision "surplusage".

With regard to these criticisms, the Commission observes that this argument might be tenable in the situation in which the section of the legislation which deals explicitly with the subject does not contain an express provision that it is *not* to be considered the exclusive authority on the subject. The Commission notes that section 212 of the Federal Power Act (as added by section 204 of PURPA) sets forth certain determinations that the Commission must make before it can issue an order under either section 210 or 211 of the Federal Power Act.

Section 212(e) states that no provision of section 210 of the Federal Power Act shall be treated "(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any other authority of law, or (2) as limiting, impairing, or otherwise affecting any other authority of the Commission under any other provision of law." Thus, the Federal Power Act, as amended, expressly provides that the existence of authority under section 210 of the Federal Power Act to require interconnection is not to be interpreted as excluding any other interconnection authority available under any other law. The Commission emphasizes that the limitation is not restricted to the Federal Power Act, but rather extends to include other authority of law, such as the authority contained in the Public Utility Regulatory Policies Act of 1978, of which section 210 is a part. Clearly, the existence of this provision refutes the contention that section 210 of the Federal Power Act represents the exclusive method by which interconnection can be obtained. As a result, the comment that the direction contained in section 210(e)(3) of PURPA that no qualifying facility can be exempted from section 210 or 212 of the Federal Power Act is not persuasive.

The Commission finds that to require qualifying facilities to go through the complex procedures set forth in section 210 of the Federal Power Act to gain interconnection would, in most circumstances, significantly frustrate the achievement of the benefits of this program. The Commission does not feel that the legal interpretation set forth in the Staff Discussion Paper and the Notice of Proposed Rulemaking is the exclusive theory by which it may require interconnections under this program without resort to sections 210 and 212 of the Federal Power Act. The interpretation brought out during the comment period—that section 210(a) of PURPA provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small power production—provides, in the Commission's view, sufficient authority to require interconnection. The Commission believes that a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators. The Commission believes that accomplishment of this purpose would be greatly hindered if it were to require qualifying facilities to utilize section 210 of the Federal Power Act as the exclusive means of obtaining interconnection. It therefore concludes that such a restrictive interpretation of the law is not supportable.

Paragraph (c)(1) thus provides that an electric utility must make any interconnections with a qualifying facility which may be necessary to permit purchases from or sales to the qualifying facility. A State regulatory authority or nonregulated electric utility must enforce this requirement as part of its implementation of the Commission's rules.

In addition, several commenters contended that, if the obligation to interconnect is required under section 210(a) PURPA, the limitation provided in section 212 of the Federal Power Act would not be available. That limitation provides that an electric utility which complies with an interconnection order under section 210 of the Federal Power Act would not be subject to the jurisdiction of the Federal Energy Regulatory Commission for any purposes other than those specified in the interconnection order.

After consideration of this concern, the Commission has added paragraph (c)(2) to provide that no electric utility is required to interconnect with any qualifying facility, if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act. This exception is provided because the Commission notes that, in balance, the encouragement of cogeneration and small power production would not be furthered if, by virtue of interconnection with a qualifying facility, a previously nonjurisdictional utility were reluctantly to become subject to federal utility regulation.

§ 292.303(e) Parallel operation.

In the Notice of Proposed Rulemaking, the Commission provided that each electric utility must offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with standards established by the State regulatory authority or nonregulated electric utility with regard to the protection of system reliability pursuant to § 292.308. By operating in parallel, qualifying facilities are enabled to export automatically any electric energy which is not consumed by its own load. The comments submitted have not set forth any convincing reasons for changing the proposed rule. Paragraph (e) thus continues to require each electric utility to offer to operate in parallel with a qualifying facility.

§ 292.304 Rates for purchases.

Section 210(b) of PURPA provides that in requiring any electric utility to purchase electric energy from a qualifying facility, the Commission must ensure that the rates for the purchase be just and reasonable to the electric consumers of the purchasing utility, in the public interest, and nondiscriminatory to qualifying facilities, but that they not exceed the incremental costs of alternative electric energy (the costs of energy to the utility, which, but for the purchase, the utility would generate itself or purchase from another source).

Relation to State Programs

The Commission has become aware that several States have enacted legislation requiring electric utilities in that State to purchase the electrical output of facilities which may be qualifying facilities under the Commission's rules at rates which may differ from the rates required under the Commission's rules implementing section 210 of PURPA.

This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.

If a State program were to provide that electric utilities must purchase power from certain types of facilities, among which are included "qualifying facilities," at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on the Commission's rules.

A facility which provides energy or capacity to a utility under State authority may nevertheless seek to obtain exemption from the Federal Power Act, the Public Utility Holding Company Act, and State regulation of electric utilities as available under section 210(e) of PURPA. The Commission notes that the States lack the authority to exempt a facility from the Federal Power Act or Public Utility Holding Company Act. The Commission finds no inconsistency in a facility's taking advantage of section 210 in order to obtain one of its benefits, while relying on other authority under which to buy from or sell to a utility.

§ 292.304(a) Rates for purchases.

Paragraph (a) sets forth the statutory requirement that rates for purchases be just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying cogeneration and small power production facilities.

In the proposed rule, the Commission stated that there is a rebuttable presumption that the rate for purchases is acceptable if it reflects the avoided cost resulting from a purchase on the basis of system cost data set forth pursuant to § 292.302 (b) or (c). Many of the comments received stated that this section was ambiguous.[12] The Commission has therefore provided that the rate for purchases meets the statutory requirements if it equals avoided costs, and has eliminated the reference to the "rebuttable presumption".

Some comments recommended that, as a matter of policy, this section be revised to provide that a State regulatory authority or nonregulated utility has discretion to establish the relationship between the avoided cost and the rate for purchases. Other commenters contended that the Commission should specify that the rate for purchase must equal the avoided cost resulting from such a purchase. In addition, several suggested that the Commission adopt a "split-the-savings" approach.

It is possible that developers of technologies which may be included as qualifying facilities may produce and make available power to electric facilities even though their cost of producing this power is greater than the utility's avoided costs. In most instances, however, purchases of energy or capacity from qualifying facilities will only occur when the cost to the qualifying cogenerator or small power producer of producing the energy or capacity is lower than the utility's avoided costs. Only if this is the case will payment by the utility of its avoided costs provide economic benefit for the cogenerator or small power producer.

When one electric utility can provide energy more cheaply than could another electric utility, the two utilities will often exchange power on a "split-the-savings" basis. In that type of transaction, the two utilities split the difference between the incremental costs incurred and the incremental costs that the purchasing utility would have incurred had it generated the power itself. Several commenters argued that rates for purchases from qualifying facilities should be based upon this same general principle. The effect of such a pricing mechanism would be to transfer to the utility's ratepayers a portion of the savings represented by the cost differential between the qualifying facility and the purchasing electric utility. Several utilities contend that by so allocating these savings, the Commission would provide an incentive for the electric utility to enter into purchase transactions with qualifying cogeneration and small power production facilities.

These commenters also noted that they had previously engaged in purchases from facilities which might become qualifying facilities under the Commission's rules, and they had paid prices for these purchases based on a "split-the-savings" methodology. These commenters observed that if the Commission's rules now require the payment of full avoided cost for these types of purchases, the purchased power expenses of the electric utility would increase.

Moreover, several utilities commented that, for the forseeable future, they are inextricably tied to the use of oil to produce electricity. They contepd that unless they are permitted to purchase energy and capacity from qualifying facilities at a rate somewhere between the qualifying facilities' costs and their own costs, they and their ratepayers will be subject to the continually increasing world price of oil.

Commenters opposing this allocation of savings to parties other than the qualifying facility noted that this section of PURPA is intended to encourage the development of cogeneration and small power production. They noted that in providing for this encouragement, the Commission may not set rates for purchases at a level which exceeds the incremental cost of alternative energy. Therefore, they observed that, under the full avoided cost standard, the utilities' customers are kept whole, and pay the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility.

Although use of the full avoided cost standard will not produce any rate savings to the utility's customers, several commenters stated that these ratepayers and the nation as a whole will benefit from the decreased reliance of scarce fossil fuels, such as oil and gas, and the more efficient use of energy.

The Commission notes that, in most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual customer. On the other hand, if these savings are allocated to the relatively small class of qualifying cogenerators and small power producers, they may provide a significant incentive for a higher growth rate of these technologies.

Another concern with the use of a split-the-savings rate for purchases is that it would require a determination of the costs of production of the qualifying facility. A major portion of this legislation is intended to exempt qualifying facilities from the cost-of-service regulation by which electric utilities traditionally have been regulated. The Conference Report noted that:

> It is not the intention of the Conferees that cogenerators and small power producers become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[13]

Thus, section 210(e) of PURPA provides that the Commission shall exempt qualifying facilities from the Public Utility Holding Company Act, from the Federal Power Act and from State law and regulation respecting utility rates or financial organization, to the extent that the Commission determines that such exemption is necessary to encourage cogeneration or small power production.

Several commenters have contended that a determination of the qualifying facility's costs can be made without the detail required by cost-of-service regulation. However, the Commission believes that the basis for the determination of rates for purchases should be the utility's avoided costs and should not vary on the basis of the costs of the particular qualifying facility.

Several commenters recommended that rather than using a split-the-savings approach, the Commission should set rates for purchases at a fixed percentage of avoided costs. The Commission notes that, in most situations, a qualifying cogenerator or small power producer will only produce energy if its marginal cost of production is less than the price he receives for its output. If some fixed percentage is used, a qualifying facility

[12] The relationship between the utility system cost data and the rate for purchases is discussed under § 292.302 and § 292.304(b).

[13] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 97, 95th Cong., 2d. Sess. (1978).

may cease to produce additional units of energy when its costs exceed the price to be paid by the utility. If this occurs, the utility will be forced to operate generating units which either are less efficient than those which would have been used by the qualifying facility, or which consume fossil fuel rather than the alternative fuel which would have been consumed by the qualifying facility had the price been set at full avoided costs.

§ 292.304(b) Relationship to avoided costs.

"New Capacity"

The proposed rule differentiated between "old" and "new" production in connection with simultaneous purchases and sales. The proposed rule required an electric utility to purchase at its avoided cost the total output of a facility, construction of which was commenced after the date of issuance of these rules, even if the utility simultaneously sells energy to the facility at its retail rate. The effect of this proposed rule was to separate the production aspect of a qualifying facility from its consumption function. Under this approach, the electrical output of a facility is viewed independently of its electrical needs. Thus, if a cogeneration facility produces five megawatts, and consumes three megawatts, it is treated the same as another qualifying facility that produces five megawatts, and that is located next to a factory that uses three megawatts.

The Commission continues to believe that permitting simultaneous purchase and sale is necessary and appropriate to encourage cogeneration and small power production. The limitation contained in the proposed rule was intended to prevent a cogenerator or small power producer, which had found it economical to produce power for its own consumption prior to the issuance of these rules, from receiving the economic rent that might result from the purchase of its entire output at a utility's full avoided cost after that date without new investment on the part of the qualifying facility.

The same reasoning applies to any facility which was in existence prior to the enactment of PURPA, whether or not it seeks to purchase and sell simultaneously. That construction of the facility was commenced prior to that date may indicate that appropriate economic returns were available without the further incentives provided by section 210.

The Commission is aware that in some instances, if a previously existing qualifying facility were not permitted to receive full avoided costs for its entire output, it would no longer have sufficient incentive to continue to produce electric power. The cost of production may have risen so as to render the previous rate insufficient to cover the costs of production, or permit an appropriate return.

Thus, with regard to facilities, construction of which commenced on or after the date of enactment of PURPA (November 9, 1978), the Commission has determined it appropriate to provide that rates for purchases shall equal full avoided costs. For facilities, construction of which commenced before the enactment of PURPA, the Commission will permit the State regulatory authorities and nonregulated electric utilities to establish rates for purchases at full avoided costs, or at a lower rate, if the State regulatory authority or nonregulated electric utility determines that the lower rate will provide sufficient encouragement of cogeneration and small power production. Thus, if a previously existing facility shows that it requires rates for purchases based on full avoided costs to remain viable, or to increase its output, the State regulatory authority or nonregulated electric utility is required to establish such rates. This distinction is intended to reflect the need for further incentives and the reasonable expectations of persons investing in cogeneration or small power production facilities prior to or subsequent to the enactment of this law.

Paragraph (b)(1) defines "new capacity" as any purchase of capacity from a qualifying facility, construction of which was commenced on or after November 9, 1978. Subparagraph (2) provides that for new capacity, utilities must pay a rate which equals their avoided cost.

A utility must therefore purchase all of the output from a qualifying facility. However, as explained above, for any portion of that output which is not "new capacity," the State regulatory authority or nonregulated electric utility, as provided in paragraph (b)(3), may provide for a lower rate, if it determines that the lower rate will provide sufficient incentive for cogeneration.

Paragraph (b)(4) requires electric utilities to pay full avoided costs for purchases from new capacity made available from a qualifying facility, regardless of whether the electric utility is simultaneously making sales to the qualifying facility.

§ 292.304(c) Standard rates for purchases.

The Notice of Proposed Rulemaking required electric utilities on request of a qualifying facility to establish a tariff or other method for establishing rates for purchase from qualifying facilities of 10 kw or less. Upon consideration of the comments received, the Commission has determined that the concept of requiring a standard rate for purchases should be retained. Several comments stated that this requirement could similarly be applied to facilities of up to 100 kw or less.

The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standardized tariffs be implemented for facilities of 100 kw or less.

In addition, some commenters pointed out that standard tariffs can be used on a technology specific basis, to reflect the supply characteristics of the particular technology. Some commenters also observed that the proposed rule did not require that standard rates for purchases from these small facilities be based on the purchasing utility's avoided cost. This omission might have permitted a utility to pay less than that rate for purchases.

The Commission has accordingly revised paragraph (c) to require each State regulatory authority or nonregulated electric utility to cause to be put into effect standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The revised rule requires that standard rates for purchases equal the purchasing utility's avoided cost pursuant to paragraphs (a), (b), and (e).

Several commenters noted that standard rates for purchases can also be usefully applied to larger facilities. The Commission believes that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases. Accordingly, the Commission has added subparagraph (2) which permits, but does not require, State regulatory authorities and nonregulated electric utilities to put into effect a standard rate for purchases from qualifying facilities with a design capacity greater than 100 kilowatts. These rates must equal avoided cost pursuant to paragraphs (a), (b), and (e).

Many commenters at the Commission's public hearings and in written comments recommended that the Commission should require the establishment of "net energy billing" for small qualifying facilities. Under this billing method, the output from a qualifying facility reverses the electric meter used to measure sales from the electric utility to the qualifying facility. The Commission believes that this billing method may be an appropriate way of approximating avoided cost in some circumstances, but does not believe that this is the only practical or appropriate method to establish rates for small qualifying facilities. The Commission observes that net energy billing is likely to be appropriate when the retail rates are marginal cost-based, time-of-day rates. Accordingly, the Commission will leave to the State regulatory authorities and the nonregulated electric utilities the determination as to whether to institute net energy billing.

Paragraph (c)(3)(i) provides that standard rates for purchase should take into account the factors set forth in paragraph (e). These factors relate to the quality of power from the qualifying facility, and its ability to fit into the purchasing utility's generating mix.

Paragraph (e)(vi) is of particular significance for facilities of 100 kW or less. This paragraph provides that rates for purchase shall take into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system . . .". Several commenters presented persuasive evidence showing that an effective amount of capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is stochastic. Similarly, qualifying facilities may be able to enter into operating agreements with each other by which they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service. To the extent that this aggregate capacity value can be reasonably estimated, it must be reflected in standard rates for purchases.

Several commenters observed that the patterns of availability of particular energy sources can and should be reflected in standard rates. An example of this phenomenon is the availability of wind and photovoltaic energy on a summer peaking system. If it can be shown that system peak occurs when there is bright sun and no wind, rates for purchase could provide a higher capacity payment for photovoltaic cells than for wind energy conversion systems. For systems peaking on dark windy days, the reverse might be true. Subparagraph (3)(ii) thus provides that standard rates for purchases may differentiate among qualifying facilities on the basis of the supply characteristics of the particular technology.

§§ 292.304 (b)(5) and (d) Legally enforceable obligations.

Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.

Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.

Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also work to preserve the bargain entered into by the electric utility; should the actual avoided cost be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.

Paragraph (d)(1) provides that a qualifying facility may provide energy or capacity on an "as available" basis, i.e., without legal obligation. The proposed rule provided that rates for such purchases should be based on "actual" avoided costs. Many comments noted that basing rates for purchases in such cases on the utility's "actual avoided costs" is misleading and could require retroactive ratemaking. In light of these comments, the Commission has revised the rule to provide that the rates for purchases are to be based on the purchasing utility's avoided costs estimated at the time of delivery.[14]

Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.

Many commenters noted the same problems for establishing rates for purchases under subparagraph (2) as in subparagraph (1). The Commission intends that rates for purchases be based, at the option of the qualifying facility, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. This change enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.

A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.

[14] In addition to the avoided costs of energy, these costs must include the prorated share of the aggregate capacity value of such facilities.

§ 292.304(c) Factors affecting rates for purchases.

Capacity Value

An issue basic to this paragraph is the question of recognition of the capacity value of qualifying facilities.

In the proposed rule, the Commission adopted the argument set forth in the Staff Discussion Paper that the proper interpretation of section 210(b) of PURPA requires that the rates for purchases include recognition of the capacity value provided by qualifying cogeneration and small power production facilities. The Commission noted that language used in section 210 of PURPA and the Conference Report as well as in the Federal Power Act supports this proposition.

In the proposed rule, the Commission cited the final paragraph of the Conference Report with regard to section 210 of PURPA:

> The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforceable obligation of such cogenerator or small power producer to supply firm power to the utility.[15]

In addition to that citation, the Commission notes that the Conference Report states that:

> In interpreting the term "incremental costs of alternative energy", the conferees expect that the Commission and the States may look beyond the costs of alternative sources which are instantaneously available to the utility.[16]

Several commenters contended that since section 210(a)(2) of PURPA provides that electric utilities must "purchase electric energy" from qualifying facilities, the rate for such purchases should not include payments for capacity. The Commission observes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales for resale in interstate commerce. Demand or capacity payments are a traditional part of such rates. The term "electric energy" is used throughout the Act to refer both to electric energy and capacity. The Commission does not find any evidence that the term "electric energy" in section 210 of PURPA was intended to refer only to fuel and operating and maintenance expenses, instead of all of the costs associated with the provision of electric service.

In addition, the Commission notes that to interpret this phrase to include only energy would lead to the conclusion that the rates for sales *to* qualifying facilities could only include the energy component of the rate since section 210 also refers to "electric energy" with regard to such sales. It is the Commission's belief that this was not the intended result. This provides an additional reason to interpret the phrase "electric energy" to include both energy and capacity.

In implementing this statutory standard, it is helpful to review industry practice respecting sales between utilities. Sales of electric power are ordinarily classified as either firm sales, where the seller provides power at the customer's request, or non-firm power sales, where the seller and not the buyer makes the decision whether or not power is to be available. Rates for firm power purchases include payments for the cost of fuel and operating expenses, and also for the fixed costs associated with the construction of generating units needed to provide power at the purchaser's discretion. The degree of certainty of deliverability required to constitute "firm power" can ordinarily be obtained only if a utility has several generating units and adequate reserve capacity. The capacity payment, or demand charge, will reflect the cost of the utility's generating units.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement that the seller construct or reserve capacity. In order to provide power to customers at the seller's discretion, the selling utility need only charge for the cost of operating its generating units and administration. These costs, called "energy" costs, ordinarily are the ones associated with non-firm sales of power.

Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service. Thus, for example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output that they would only permit a utility to avoid generating an equivalent amount of energy. In that situation, the utility must continue to provide capacity that is available to meet the needs of its customers. Since there are no avoided capacity costs, rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy. On the other hand, testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity.

Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.

A facility burning municipal waste or biomass may be able to operate more predictably and reliably than solar or wind systems. It can schedule its outages during times when demand on the utility's system is low. If such a unit demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.

In order to defer or cancel the construction of new generating units, a utility must obtain a commitment from a qualifying facility that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available sufficiently ahead of the date on which the utility would otherwise have to commit itself to the construction or purchase of new capacity. If a qualifying facility provides such assurances, it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility.

Other comments with regard to the requirement to include capacity payments in avoided costs generally track those set forth in the Staff Discussion Paper and the proposed rule. The thrust of these comments is that, in order to receive credit for capacity and to comply with the requirement that rates for purchases not exceed the incremental cost of alternative energy, capacity payments can only be required when the availability of capacity from a qualifying facility or facilities actually permits the purchasing utility to reduce

[15] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 98, 95th Cong., 2d. Sess. (1978).

[16] *Id.*, pp. 98–9.

its need to provide capacity by deferring the construction of new plant or commitments to firm power purchase contracts. In the proposed rule, the Commission stated that if a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating plant, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility than it would otherwise have purchased, then the rates for purchases from the qualifying facility must include the avoided capacity and energy costs. As indicated by the preceding discussion, the Commission continues to believe that these principles are valid and appropriate, and that they properly fulfill the mandate of the statute.

The Commission also continues to believe, as stated in the proposed rule, that this rulemaking represents an effort to evolve concepts in a newly developing area within certain statutory constraints. The Commission recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences. Accordingly, the Commission supports the recommendation made in the Staff Discussion Paper that it should leave to the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

§ 292.304(e) Factors affecting rates for purchases.

As noted previously, several commenters observed that the utility system cost data required under § 292.302 cannot be directly applied to rates for purchase. The Commission acknowledges this point and, as discussed previously, has provided that these data are to be used as a starting point for the calculation of an appropriate rate for purchases equal to the utility's avoided cost. Accordingly, the Commission has removed the reference to the utility system cost data from the definition of rates for purchases, and has inserted the reference to these data in paragraph (e), as one factor to be considered in calculating rates for purchases. Subparagraph (1) states that these data shall, to the extent practicable, be taken into account in the calculation of a rate for purchases.

Subparagraph (2) deals with the availability of capacity from a qualifying facility during system daily and seasonal peak periods. If a qualifying facility can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units, this energy has a higher value to the utility than energy supplied during off-peak periods, during which only units with lower running costs are operating.

The preamble to the proposed rule provided that, to the extent that metering equipment is available, the State regulatory authority or nonregulated electric utility should take into account the time or season in which the purchase from the qualifying facility occurs. Several commenters interpreted this statement as implying that, by refusing to install metering equipment, an electric utility could avoid the obligation to consider the time at which purchases occur. This is not the intent of this provision. Clearly, the more precisely the time of purchase is recorded the more exact the calculation of the avoided costs, and thus the rate for purchases, can be. Rather than specifying that exact time-of-day or seasonal rates for purchases are required, however, the Commission believes that the selection of a methodology is best left to the State regulatory authorities and nonregulated electric utilities charged with the implementation of these provisions.

Clauses (i) through (v) concern various aspects of the reliability of a qualifying facility. When an electric utility provides power from its own generating units or from those of another electric utility, it normally controls the production of such power from a central location. The ability to so control power production enhances a utility's ability to respond to changes in demand, and thereby enhances the value of that power to the utility. A qualifying facility may be able to enter into an arrangement with the utility which gives the utility the advantage of dispatching the facility. By so doing, it increases its value to the utility. Conversely, if a utility cannot dispatch a qualifying facility, that facility may be of less value to the utility.

Clause (ii) refers to the expected or demonstrated reliability of a qualifying facility. A utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would claim to replace such capacity may go out of service during the period when the utility needs its power to meet system demand. Based on the estimated or demonstrated reliability of a qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its value to the utility.

Clause (iii) refers to the length of time during which the qualifying facility has contractually or otherwise guaranteed that it will supply energy or capacity to the electric utility. A utility-owned generating unit normally will supply power for the life of the plant, or until it is replaced by more efficient capacity. In contrast, a cogeneration or small power production unit might cease to produce power as a result of changes in the industry or in the industrial processes utilized. Accordingly, the value of the service from the qualifying facility to the electric utility may be affected by the degree to which the qualifying facility ensures by contract or other legally enforceable obligation that it will continue to provide power. Included in this determination, among other factors, are the term of the commitment, the requirement for notice prior to termination of the commitment, and any penalty provisions for breach of the obligation.

In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility's generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Clause (iv) addresses periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units during periods when demand is low. If a qualifying facility can similarly schedule its maintenance outages during periods of low demand, or during periods in which a utility's own capacity will be adequate to handle existing demand, it will enable the utility to avoid the expenses associated with providing an equivalent amount of capacity. These savings should be reflected in the rate for purchases

Clause (v) refers to a qualifying facility's ability and willingness to provide capacity and energy during system emergencies. Section 292.307 of these regulations concerns the provision of electric service during system emergencies. It provides that, to the extent that a qualifying facility is willing to forego its own use of energy during system emergencies and provide power to a utility's system, the rate for purchases from the qualifying facility should reflect the value of that service. Small power production and cogeneration facilities could provide significant back-up capability to electric systems during emergencies. One benefit of the encouragement of interconnected cogeneration and small power production may be to increase overall system reliability during such emergency conditions. Any such benefit should be reflected in the rate for purchases from such qualifying facilities.

Another related factor which affects the capacity value of a qualifying facility is its ability to separate its load from its generation during system emergencies. During such emergencies an electric utility may institute load shedding procedures which may, among other things, require that industrial customers or other large loads stop receiving power. As a result, to provide optimal benefit to a utility in an emergency situation, a qualifying facility might be required to continue operation as a generating plant, while simultaneously ceasing operation as a load on the utility's system. To the extent that a facility is unable to separate its load from its generation, its value to the purchasing utility decreases during system emergencies. To reflect such a possibility, clause (v) provides that the purchasing utility may consider the qualifying facility's ability to separate its load from its generation during system emergencies in determining the value of the qualifying facility to the electric utility.

Clause (vi) refers to the aggregate capability of capacity from qualifying facilities to displace planned utility capacity. In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.

Clause (vii) refers to the fact that the lead time associated with the addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed its own generating unit. Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring on line large generating units. In addition, reduced lead time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.

Subparagraph (3) concerns the relationship of energy or capacity from a qualifying facility to the purchasing electric utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demand, and is not planning to add any new capacity to its system, then the availability of capacity from qualifying facilities will not immediately enable the utility to avoid any capacity costs. However, an electric utility system with excess capacity may nevertheless plan to add new, more efficient capacity to its system. If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions, the rate for such purchases should reflect the avoided costs of these additions. However, as noted by several commenters, the deferral or avoidance of such a unit will also prevent the substitution of the lower energy costs that would have accompanied the new capacity. As a result, the price for the purchase of energy and capacity should reflect these lower avoided energy costs that the utility would have incurred had the new capacity been added.

This is not to say that electric utilities which have excess capacity need not make purchases from qualifying facilities; qualifying facilities may obtain payment based on the avoided energy costs on a purchasing utility's system. Many utility systems with excess capacity have intermediate or peaking units which use high-cost fossil fuel. As a result, during peak hours, the energy costs on the systems are high, and thus the rate to a qualifying utility from which the electric utility purchases energy should similarly be high.

Subparagraph (4) addresses the costs or savings resulting from line losses. An appropriate rate for purchases from a qualifying facility should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the power that would have been delivered from the source of power it replaces, then the qualifying facility should not be reimbursed for the difference in losses. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

§ 292.303(f) Periods during which purchase are not required.

The proposed rule provided that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases will result in net increased operating costs to the electric utility. This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.

The result of such a transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the purchasing electric utility would incur greater costs than it would have had it not purchased energy or capacity from the qualifying facility. A strict application of the avoided cost principle set forth in this section would assess these additional costs as negative avoided costs which must be reimbursed by the qualifying facility. In order to avoid the anomalous result of forcing a qualifying utility to pay an electric utility for purchasing its output, the Commission proposed that an electric utility be required to identify periods during which this situation would occur, so that the qualifying facility could cease delivery of electricity during those periods.

Many of the comments received reflected a suspicion that electric utilities would abuse this paragraph to circumvent their obligation to purchase from qualifying facilities. In order to minimize that possibility, the Commission has revised this paragraph to provide that any electric utility which seeks to cease purchasing from qualifying facilities must notify each affected qualifying facility prior to the occurrence of such a period, in time for the qualifying facility to cease delivery of energy or capacity to the electric utility. This notification can be accomplished in any reasonable manner determined by the State regulatory authority. Any claim by an electric utility that such a light loading period will occur or has occurred is subject to such verification by its State regulatory authority as the State authority determines necessary or appropriate either before or after its occurrence. Moreover, any electric utility which fails to provide adequate notice or which incorrectly identifies such a period will be required to reimburse the qualifying facility for energy or capacity supplied as if such a light loading period had not occurred.

The section has also been modified to clarify that such periods must be due to operational circumstances.

The Commission does not intend that this paragraph override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility. In such arrangements, the established rate is based on the recognition that the value of the purchase will vary with the changes in the utility's operating costs. These variations ordinarily are taken into account, and the resulting rate represents the average value of the purchase over the duration of the obligation. The occurrence of such periods may similarly be taken into account in determining rates for purchases.

Tax Issues

The Conference Report states that:

> * * * the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or the small power producer's power should not be burdened by the same examination as are utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[17]

The Commission notes that section 301(b)(2) of the Energy Tax Act of 1978 [18] makes certain energy property eligible for increased business investment tax credit. Some of this property is commonly used in cogeneration and small power production. However, section 301(b)(2)(B) excludes from such eligibility property "which is public utility property (within the meaning of section 46(f)(5) of the Internal Revenue Code of 1954)." [19] As a result, if the property of a qualifying facility which was otherwise eligible for the credit were to be classified as public utility property under section 46(f)(5) of the Internal Revenue Code, it would not be eligible for the increased investment tax credit.

The Commission notes that the Treasury Department's regulations provide that the definition of "public utility property" does not include property used in the business of the furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment.[20] On this basis, the Commission believes that property of a qualifying facility that would otherwise be eligible for the energy tax credit would not be excluded from that eligibility under the public utility property exclusion.

First, this Commission is exempting property of qualifying facilities from regulation under Part II of the Federal Power Act, and from similar State and local laws and regulatory programs. Secondly, the Commission observes that the rates a qualifying facility will receive for sales of power to utilities are *not* based on a regulatory scheme which fixes a rate of return on investment of the qualifying facility.

As a result, the Commission believes that energy property of qualifying facilities should not be barred from eligibility for the tax credit by reason of the public utility property exclusion. The Commission wishes to express its opinion on this matter in an effort to further encourage cogeneration and small power production by means of this rulemaking process.

§ 292.305 Rates for sales.

Section 210(c) of PURPA provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory with respect to qualifying cogenerators or small power producers. This section contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts.

Paragraph (a) expresses the statutory requirement that such rates be just and reasonable and in the public interest. Paragraph (a) also provides that rates for sales from electric utilities to qualifying facilities not be discriminatory against such facilities in comparison to rates to other customers served by the electric utility.

A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers.

In the proposed rule, paragraph (b) required electric utilities to provide energy and capacity and other services to any qualifying facility at a rate at least as favorable as would be provided to a customer who does not have his own generation. The comments received concerning this paragraph noted that this provision might be interpreted as requiring an electric utility to provide service to a qualifying facility at its most favorable rate, even if the qualifying facility would not be eligible for such a rate if it did not have its own generation. It is not the Commission's intention that, for example, an industrial cogenerator receive service at a rate applicable to residential customers; rather, such a customer should be charged at a rate applicable to a non-generating industrial customer unless the electric utility shows that a different rate is justified on the basis of sufficient load or other cost-related data. Accordingly, this section now provides that for qualifying facilities which do not simultaneously sell and purchase from the electric utility, the rate for sales shall be the rate that would be charged to the class to which the qualifying facility would be assigned if it did not have its own generation.

Subparagraph (2) provides that if, on the basis of accurate data and consistent system-wide costing principles, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, the utility may base its rates for sales upon those data and principles. The utility may only charge such rates on a nondiscriminatory basis, however, so that a cogenerator will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself.

In situations where a qualifying facility simultaneously sells its output to an electric utility and purchases its requirements from that electric utility, as a bookkeeping matter, the facility's

[17] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 98, 95th Cong., 2d Sess. (1978).

[18] Pub. L. No. 95-618, 26 U.S.C. §§ 46, 48, November 9, 1978.

[19] 26 U.S.C. § 48(e)(3)(b).

[20] Treasury Reg. § 146-3(g)(2), T.D. 7602 (March 23, 1979).

electrical output will not serve its own load, but rather will be supplied to the grid. As a result, the facility's electric load is likely to have the same characteristics as the load of other non-generating customers of the utility. If the utility does not provide data showing otherwise, the appropriate rate for sales to such a facility is the rate that would be charged to a comparable customer without its own generation.

Paragraph (b)(2) of the rule sets forth certain types of service which electric utilities are required to provide qualifying facilities upon request of the facility. These types of service are supplementary power, back-up power, interruptible power and maintenance power. In response to comments, these terms are defined in the text of the rules, as well as in this preamble.

Back-up or maintenance service provided by an electric utility replaces energy or capacity which a qualifying facility ordinarily supplies to itself. These rules authorize certain facilities to purchase and sell simultaneously. The amount of energy or capacity provided by an electric utility to meet the load of a facility which simultaneously purchases and sells will vary only in accordance with changes in the facility's load; interruptions in the facility's generation will be manifested as variations in purchases from the facility. In such a case, sales to the qualifying facility will not be back-up or maintenance service, but will be similar to the full-requirements service that would be provided if the facility were a non-generating customer.

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. Thus, a cogeneration facility with a capacity of ten megawatts might require five more megawatts from a utility on a continuing basis to meet its electric load of fifteen megawatts. The five megawatts supplied by the electric utility would normally be provided as supplementary power.

Back-up power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. In the example provided above, a cogeneration facility might contract with an electric utility for the utility to have available ten megawatts, should the cogenerator's units experience an outage.

Maintenance power is electric energy or capacity supplied during scheduled outages of the qualifying facility. By pre-arrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during peak periods.

Interruptible power is electric energy or capacity supplied to a qualifying facility subject to interruption by the electric utility under specified conditions. Many utilities have utilized interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than non-interruptible service.

During the Commission's public hearings on this rulemaking, one commenter stated that utilities which have excess capacity do not save any costs by providing interruptible service. The commenter contended that the Commission should not require a utility with excess capacity to offer interruptible service. If a utility is not adding capacity (whether by construction or purchase) to meet anticipated increases in peak demand, the rates charged for interruptible service might appropriately be the same as for non-interruptible services.

The Commission believes that these matters involving the provision of interruptible rates are best handled through the pricing mechanism. However, if as discussed above, interruptible customers provide no savings to the electric utility, the rate for interruptible service need not be lower than the rate for firm service. In such a case, the Commission would consider granting a waiver from this paragraph, under the provisions of § 292.403.

Some comments noted that certain electric utilities do not have any generating capacity, and to require the services listed in subparagraph (1) might place an undue burden on the electric utility. In light of these comments, the State regulatory authorities or the Commission, as the case may be, will allow a waiver of these requirements upon a finding after a showing by the utility to the State regulatory authority or Commission, as the case may be, that provision of these services will impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility. Notice must be given in the area served by the electric utility, opportunity for public comment must be provided, and an application must be submitted to the State regulatory authority with respect to any electric utility over which it has ratemaking authority or the Commission with respect to any nonregulated electric utility.

Paragraph (c)(1) provides that rates for sales of back-up or maintenance power shall not be based, without factual data, on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur either simultaneously or during the system peak. Like other customers, qualifying facilities may well have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities may well have interclass diversity.

The effect of such diversity is that an electric utility supplying back-up or maintenance power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. The Commission believes that probabilistic analyses of the demand of qualifying facilities will show that a utility will probably not need to reserve capacity on a one-to-one basis to meet back-up requirements. Paragraph (c)(1) prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at system peak unless supported by factual data.

The rule provides that utilities may refute these assumptions on the basis of factual data. These data need not be in the form of empirical load data. It might be the case that within certain geographic areas, weather data and performance data would constitute a sufficient basis to refute the assumption relating to the coincidence of the demands imposed, for example, by windmills or photovoltaics, with respect to their need for back-up power.

Paragraph (c)(2) provides that rates for sales shall take into account the extent to which a qualifying facility can usefully coordinate periods of scheduled maintenance with an electric utility. If a qualifying facility stays on line when the utility will need its capacity, and schedules maintenance when the utility's other units are operative, the qualifying facility is more valuable to the utility, as it can reduce its capacity requirements.

§ 292.306 *Interconnection costs.*

Paragraph (a) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs, on a nondiscriminatory basis with respect to other customers with similar load characteristics. The Commission finds merit in those comments which suggested that the basis of comparison for nondiscriminatory practices in the proposed rule to "any other customer" was too broad, and that the correct reference for nondiscrimination is the practice of the utility in relation to customers in the same class who do not generate electricity. As noted previously, the interconnection costs of a facility which is already interconnected with the utility for purposes of sales are limited to any additional expenses incurred by the utility to permit purchases.

Several commenters expressed their concern that some protection should be provided to qualifying facilities from potential harassment by utilities in the form of requiring unnecessary safety equipment. As discussed above, the State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) and nonregulated electric utilities have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.

For qualifying facilities with a design capacity of 100 kW or less, the Commission noted that interconnection costs could be assessed on a class basis, and the standard rates for purchases established for classes of facilities of this size pursuant to § 292.304(c)(1) might incorporate these costs. State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) or nonregulated electric utilities may also determine interconnection costs for qualifying facilities with a design capacity of more than 100 kW on either a class average or individual basis.

Numerous comments raised the point that the proposed rule did not address the manner in which electric utilities would be reimbursed. Potential owners and developers of qualifying facilities recommended that the costs be amortized on a reasonable basis, because paying a large lump sum payment would be a considerable obstacle to the program. Electric utilities generally preferred payment up front, although several commenters indicated that amortization might be acceptable for credit-worthy facilities. The Commission believes that the manner of reimbursements (which may include amortization over a reasonable period of time) is best left to the State regulatory authorities and nonregulated utilities. In the determination of any standard rates for purchases established pursuant to § 292.304(c)(l), if the State approves some manner of amortization, it might consider assignment of uncollected interconnection costs to the class for which the rate is established.

§ 292.307 System emergencies.

Paragraph (a) provides that, except as provided under section 202(c) of the Federal Power Act, no qualifying facility shall be compelled to provide energy or capacity to the electric utility during an emergency beyond the extent provided by agreement between the qualifying facility and the utility.

The Commission finds that a qualifying facility should not be required to make available all of its generation to the utility during a system emergency. Such a requirement might interrupt industrial processes with resulting damage to equipment and manufactured goods. Many industries install their own generating equipment in order to ensure that even during a system emergency, their supply of power is not interrupted. To put in jeopardy the availability of power to a qualifying facility during a system emergency because of the facility's ability to provide power to the system during non-emergency periods would result in the discouragement of interconnected operation and a resultant discouragement of cogeneration and small power production. The Commission therefore provides that the qualifying facility's obligation to provide energy and capacity in emergencies be established through contract.

In order to receive full credit for capacity, a qualifying facility must offer energy and capacity during system emergencies to the same extent that it has agreed to provide energy and capacity during non-emergency situations. For example, a 30 megawatt cogenerator may require 20 megawatts for its own industrial purposes, and thus may contract to provide 10 megawatts of capacity to the purchasing utility. During an emergency, the cogenerator must provide the 10 megawatts contracted for to the utility; it need not disrupt its industrial processes by supplying its full capability of 30 megawatts. Of course, if it should so desire, a cogenerator could contractually agree to supply the full 30 megawatts during system emergencies. The availability of such additional backup capacity should increase utility system reliability, and should be accounted for in the utility's rates for purchases from the cogenerator.

Paragraph (b) provides that an electric utility may discontinue purchases from a qualifying facility during a system emergency if such purchases would contribute to the emergency. In addition, during system emergencies, a qualifying facility must be treated on a nondiscriminatory basis in any load shedding program—*i.e.*, on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption of service.

Credit for capacity (as noted in § 292.304(e)(2)(v)) will also take into account the ability of the qualifying facility to separate its load and generation during system emergencies. However, the qualifying facility may well be eligible for some capacity credit even if it cannot separate its load and generation.

§ 292.308 Standards for operating reliability.

Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric utilities during emergencies. The Commission believes that the reliability of qualifying facilities can be accounted for through price; namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.

As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity.

The Commission has determined that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that each State regulatory authority or nonregulated electric utility may establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by any utility, any qualifying facility, or any other person. These standards must be accompanied by a statement showing the need for the standard on the basis of system safety and operating requirements.

Subpart D—Implementation

Summary of this Subpart

Rules in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying the nature of the obligation to implement the Commission's rules under section 210.

These rules afford the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the

Commission's rules, provided that the manner chosen is reasonably designed to implement the requirements of Subpart C. The Commission recognizes that many States and individual nonregulated electric utilities have ongoing programs to encourage small power production and cogeneration. The Commission also recognizes that economic and regulatory circumstances vary from State to State and utility to utility. It is within this context—in recognition of the work already begun and of the variety of local conditions—that the Commission promulgates its regulations requiring implementation of rules issued under section 210.

Because of the Commission's desire not to create unnecessary burdens at the State level, these rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply to the Commission for a waiver if it can demonstrate that compliance with certain requirements of Subpart C is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210.

Several commenters expressed their concern that State regulatory authorities would not be able adequately to implement the Commission's rules, and therefore, recommended that the Commission issue specific rules which the State regulatory authorities would adopt without change. The Commission does not find this proposal to be appropriate at this time, and believes that providing an opportunity for experimentation by the States is more conducive to development of these difficult rate principles.

Implementation

Section 210(f) of PURPA requires that within one year after the date that this Commission prescribes its rules under subsection (a), and within one year of the date any of these rules is revised, each State regulatory authority and each nonregulated electric utility, after notice and opportunity for hearing, must implement the rules or revisions thereof, as the case may be.

The obligation to implement section 210 rules is a continuing obligation which begins within one year after promulgation of such rules. The requirement to implement may be fulfilled either (1) through the enactment of laws or regulations at the State level, (2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission, or (3) by any other action reasonably designed to implement the Commission's rules.

Review and Enforcement

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a State regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210. Under subsection (g), review may be obtained pursuant to procedures set forth in section 123 of PURPA. Section 123(c)(1) contains provisions concerning judicial review and enforcement of determinations made by State regulatory authorities and nonregulated utilities under Subtitle A, B, or C of Title I in the appropriate State court. These provisions also apply to review of any action taken to implement the rules under section 210. This means that persons can bring an action in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations.

Section 123(c)(2) of PURPA provides that persons seeking review of any determination made by a Federal agency may bring an action in the appropriate Federal court. This distinction between Federal agencies and non-Federal agencies also applies to review of enforcement of the implementation of the rules under section 210.

Finally, the Commission believes that review and enforcement of implementation under section 210 of PURPA can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly—namely, put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement of the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or of any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce the implementation of regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but also provided that the Commission may serve as a forum for review and enforcement of the implementation of this program.

§ 292.401 Implementation by state regulatory authorities and nonregulated electric utilities

Paragraph (a) of § 292.401 sets forth the obligation of each State regulatory authority to commence implementation of Subpart C within one year of the date these rules take effect. In complying with this paragraph the State regulatory authorities are required to provide for notice of and opportunity for public hearing. As described in the summary of this subpart, such implementation may consist of the adoption of the Commission's rules, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement Subpart C.

This section does not cover one provision of Subpart C which is not required to be implemented by the State regulatory authority or nonregulated electric utility. This provision is § 292.302 (Availability of electric utility system cost data), the implementation of which is subject to § 292.402, discussed below.

Subsection (b) sets forth the obligaton of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart C. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart C through issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement that subpart.

Paragraph (c) sets forth a reporting requirement under which each State regulatory authority and nonregulated electric utility is to file with the Commission, not later than one year after these rules take effect, a report describing the manner in which it is proceeding to implement Subpart C.

Comments received regarding this section indicated a concern that the obligation of a State regulatory authority or nonregulated utility "to commence implementation * * * within one year * * *" did not provide any guidance as to when the process must be completed. The Commission notes that the intention of this section is that the State regulatory authorities and nonregulated utilities have one year in which to establish procedures and that at the end of that year each State must be prepared to entertain applications. The phrase "commence implementation" is intended by the Commission to connote that implementation of these rules is a continuing process and that oversight will be ongoing.

§ 292.402 Implementation of reporting objectives.

The obligation to comply with § 292.302 is imposed directly on electric utilities. This is different from the rest of Subpart C where the obligation to act is imposed on the State regulatory authority or the nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA and other laws within the Commission's authority to require this reporting.

Any electric utility which fails to comply with the requirements of § 292.302(b) is subject to the same penalties as it might receive as a result of a failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA. As stated earlier in this preamble, the data required by § 292.302 will form the basis from which the rates for purchases will be derived; § 292.302 is thus a critical element in this program. The Commission believes that, with regard to utilities subject to section 133 of PURPA, the Commission may exercise its authority under section 133 to require the data required by § 292.302(b) on the basis that the Commission finds such information necessary to allow determination of the costs associated with providing electric services. With regard to utilities not subject to section 133, if they fail to provide the data called for in § 292.302(c), the Commission may compel its production under the Federal Power Act and other statutes which provide the Commission with authority to require reporting of such data.

§ 292.403 Waivers.

Paragraph (a) provides for a procedure by which any State regulatory authority or nonregulated electric utility may apply for a waiver from the application of any of the requirements of Subpart C other than § 292.302. (Section 292.302(d) has been revised to permit a State regulatory authority or nonregulated utility to adopt a substitute method for the provision of system cost data without prior Commission approval.)

Paragraph (b) provides that the Commission will grant such a waiver only if the applicant can show that compliance with any of the requirements is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210 of PURPA.

This section is included in recognition of the need for the Commission to afford flexibility to the States and nonregulated utilities to implement the Commission's rules under section 210.

Several comments suggested that the Commission set forth procedures for considering applications for waivers which would allow formal participation by qualifying facilities in a public hearing. The Commission notes that interested parties would be given an opportunity to be heard in any proceeding it conducts to determine whether or not a waiver should be granted.

Subpart F—Exemption of Qualifying Small Power Production and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§ 292.601 Exemption of qualifying facilities from the Federal Power Act.

Section 210(e) of PURPA states that the Commission shall prescribe rules under which qualifying facilities are exempt, in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, from the State laws and regulations respecting the rates, or respecting the financial or organization regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. As noted in the Staff Discussion Paper, the Congress intended the Commission to make liberal use of its exemption authority in order to remove the disincentive of utility-type regulation. The Commission believes that broad exemption is appropriate.

Section 210(e)(2) of PURPA provides that the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from these laws. An exception is made for small power production facilities using biomass as a primary energy source. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State laws and regulations but may not be exempted from the Federal Power Act. The Commission will establish procedures for the determination of rates for these facilities in a separate proceeding.

Paragraph (a) sets forth those facilities which are eligible for exemption. Paragraph (b) provides that facilities described in paragraph (a) shall be exempted from all but certain specified sections of the Federal Power Act.

Section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from any license or permit requirement under Part I of the Federal Power Act. Accordingly, no qualifying facilities will be exempt from Part I of the Federal Power Act. The Commission recently issued simplified procedures for obtaining water power licenses for hydroelectric projects of 1.5 megawatts or less, and has issued proposed regulations to expedite licensing of existing facilities.[21]

The Commission believes cogeneration and small power production facilities could be the subject of an order under section 202(c) of the Federal Power Act requiring them to provide energy if the Economic Regulatory Administration determines that an emergency situation exists. Because application of this section is limited to emergency situations and is not affected by the fact that a facility attains qualifying status or engages in interchanges with an electric utility, the Commission notes that qualifying facilities will not be exempted from section 202(c) of the Act.

Furthermore, in response to comment, the Commission has revised this paragraph to provide that qualifying facilities are not exempt from sections 210, 211, and 212 of the Federal Power Act, as required by section 210(e)(3)(B) of PURPA.

Sections 203, 204, 205, 206, 208, 301, 302, and 304 of the Federal Power Act reflect traditional rate regulation or regulation of securities of public utilities. The Commission has determined that qualifying facilities shall be exempted from these sections of the Federal Power Act.

Section 305(c) of the Act imposes certain reporting requirements on interlocking directorates. The Commission believes that any person who otherwise is required to file a report regarding interlocking positions should not be exempted from such requirement because he or she is also a director or officer of a qualifying facility.

Finally, the enforcement provisions of Part III of the Federal Power Act will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§ 292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the

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[21] *See* Order No. 11, Simplified Procedures for Certain Water Power Licenses, Docket No. RM79-9, issued September 5, 1978, and Application for License for Major Projects—Existing Dam, Docket No. RM79-36, 44 FR 24095 (April 21, 1979).

Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organization. Only cogeneration facilities and small power production facilities of 30 megawatts or less may be exempted from both of these laws, with the exception that any qualifying small power production facility (*i.e.*, up to 80 megawatts) using biomass as a primary energy source can be exempted from these laws.

The Commission has determined that where a qualifying facility is subjected to more stringent regulation than other companies solely by reason of the fact that it is engaged in the production of electric energy, these more stringent requirements should be eased through exemption of qualifying facilities. By excluding any qualifying facility from the definition of an "electric utility company" under section 2(a)(3) of the Public Utility Holding Company Act of 1935, such facilities would be removed from Public Utility Holding Company Act regulation which is applied exclusively to electric utility companies. Moreover, by excluding qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric production by their subsidiaries. The Commission therefore believes that in order to encourage cogeneration and small power production it is necessary to exempt cogenerators and small power producers from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities.

Accordingly, paragraph (b) states that no qualifying facility shall be considered to be an "electric utility company", as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79b(a)(3).

Section 210(e) of PURPA states that qualifying facilities which may be exempted from the Public Utility Holding Company Act may also be exempted from State laws and regulations respecting the rates or financial organization of electric utilities.

The Commission has decided to provide a broad exemption from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

The Commission believes that such broad exemption is necessary to encourage cogeneration or small power production. Accordingly, subparagraph (c)(1) provides that any qualifying facility shall be exempt from State laws and regulations respecting rates of electric utilities, and from financial and organizational regulation of electric utilities. Several commenters noted that this section might be interpreted as exempting qualifying facilities from state laws or regulations implementing the Commission's rules, under section 210(f) of PURPA. In order to clarify that qualifying facilities are not to be exempt from these rules, the Commission has added subparagraph (c)(2) prohibiting any exemptions from State laws and regulations promulgated pursuant to Subpart C of these rules.

Some commenters indicated that § 292.301(b)(1) might be interpreted as prohibiting a State from reviewing contracts for purchases. These commenters stated that, as a part of a State's regulation of electric utilities, a State regulatory authority needs to be able to review contracts entered into by electric utilities it regulates.

These rules, and the exemptions being provided by these rules, are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities. Such authority may continue to be exercised if consistent with the terms, policies and practices under sections 210 and 201 of PURPA and this Commission's implementing regulations. If the authority or its exercise is in conflict with these sections of PURPA or the Commission's regulations thereunder, the State must yield to the Federal requirements. The Commission does not believe it possible or advisable to attempt to establish more precise guidelines than these. Accordingly, States which have questions in this regard should seek an interpretive ruling from the Commission's General Counsel.

Subparagraph (c)(3) provides that, upon request of a State regulatory authority or nonregulated electric utility, the Commission may limit the applicability of the broad exemption from the State laws. This provision is intended to add flexibility to the exemption.

The Commission perceives that there may be instances in which a qualifying facility would wish to have an interpretation of whether or not it is subject to a particular State law in order to remove any uncertainty. Under subparagraph (c)(4), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 Fed. Reg. 46267)

IV. Effective Date

The regulations promulgated in this order are effective March 20, 1980.

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective March 20, 1980. By the Commission.

Kenneth F. Plumb,
Secretary.

(1) Subchapter K is amended in the table of contents and in the text of the regulation by deleting the title for Part 292 and substituting the following in lieu thereof:

Part 292—Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 With Regard to Small Power Production and Cogeneration.

(2) Subchapter K is further amended in the table of contents to Part 292 and in the text of the regulations by reserving Subpart B and by adding new Subparts A, C, D, and F to read as follows:

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION.

Subpart A—General Provisions

Sec.
292.101 Definitions.

Subpart B—[Reserved]

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

292.301 Scope.
292.302 Availability of Electric Utility System Cost Data.
292.303 Electric Utility Obligations Under This Subpart.
292.304 Rates for Purchases.
292.305 Rates for Sales.
292.306 Interconnection Costs.
292.307 System Emergencies.
292.308 Standards for Operating Reliability.

Subpart D—Implementation

292.401 Implementation by State Regulatory Authorities and Nonregulated Utilities.
292.402 Implementation of Certain Reporting Requirements.
292.403 Waivers.

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Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities From Certain Federal and State Laws and Regulations

292.601 Exemption of Qualifying Facilities from the Federal Power Act.
292.602 Exemption of Qualifying Facilities From the Public Utility Holding Company

Act and Certain State Law and Regulation.

Authority: This part issued under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 FR 46267.

Subpart A—General Provisions

§ 292.101 Definitions.

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "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 would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart B—[Reserved]

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ 292.301 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§ 292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until May 31, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, May 31, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(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 1000 megawatts or more, and 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;

(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; and

(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.

(c) *Special rule for small electric utilities.*

(1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

(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 costs for purchases.

(b) *Relationship to avoided costs.* (1) For 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 cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated 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 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 effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) 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 is incurred.

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

(f) *Periods during which purchases not required.*

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional Services to be Provided to Qualifying Facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

Subpart D—Implementation

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence

Federal Register / Vol. 45, No. 38 / Monday, February 25, 1980 / Rules and Regulations 12237

implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonreguated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart C (other than § 292.302 thereof).

§ 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The Commission will grant such a wavier only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to:

(1) qualifying cogeneration facilities; and

(2) qualifying small power production facilities which have a power production capacity which does not exceed 30 megawatts.

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1–30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (b) (1), (2) and (3) of this section.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.*

(1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in subparagraph (1).

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(FR Doc. 80-5720 Filed 2-22-80; 8:45 am)

BILLING CODE 6450-85-M

24126 Wednesday, April 9, 1980

18 CFR Part 292

[Docket No. RM79-55]

Rates and Exemptions for Qualifying Small Power Production and Cogeneration Facilities; Correction

April 3, 1980.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Erratum notice.

SUMMARY: This notice contains a correction of § 292.302 (a) and (b) of the Federal Energy Regulatory Commission's final regulations.

FOR FURTHER INFORMATION CONTACT: Deborah Gottheil, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426 (202) 357-8000.

SUPPLEMENTARY INFORMATION: In the Federal Energy Regulatory Commission's Final Regulations, issued February 19, 1980, entitled Regulations Under Section 210 of the Public Utility Regulatory Policies Act of 1978 (45 FR 12214, February 25, 1980), at 45 FR 12234, in § 292.302 (a) and (b), the reference to May 31, 1982 should be changed to June 30, 1982. This revision will accurately carry out the Commission's intent, as stated in the preamble to the rule, to "conform to the dates required by the Commission's regulations implementing section 133 of PURPA."

Kenneth F. Plumb,

Secretary.

(FR Doc. 80-10788 Filed 4-8-80; 8:45 am)

BILLING CODE 6450-35-M

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE INVESTIGATION) OF THE IMPLEMENTATION OF CERTAIN) REQUIREMENTS OF TITLE II OF THE) PUBLIC UTILITIES REGULATORY POLICY) ACT OF 1978, REGARDING COGENERATION) AND SMALL POWER PRODUCTION.)	DECISION AND ORDER (F-3365)

Section 210 of the Public Utilities Regulatory Policy Act of 1978 (PURPA) establishes certain standards for the encouragement of cogeneration and small power production. Section 210(a) requires the Federal Energy Regulatory Commission (FERC) to prescribe rules requiring electric utilities to offer to sell electric energy to qualifying cogeneration and small power production facilities and to offer to purchase electric energy from such facilities. The FERC is also required to promulgate rules establishing a minimum reliability requirement for qualifying facilities and for emergency electrical service to those facilities. Section 210(a) prohibits the FERC from authorizing a qualifying facility to make any sale for purposes other than resale.

Section 210(b) provides general standards for establishing rates for purchases of electrical energy by a utility from a qualifying facility. Such rates are required to be just and reasonable to the electric utility electric consumers, in the public interest, and non-discriminatory as between qualifying facilities. That section also sets a ceiling for rates for purchases at the incremental cost to the electric utility of alternative electric energy. Similarly, Section 210(c) sets general standards for establishing rates for sales of electric energy by utilities to qualifying facilities. Such rates must be just and reasonable, in the public interest, and non-discriminatory.

Rules promulgated by the FERC implementing Section 210 of PURPA are found at 18 C.F.R. Section 292. Subpart A establishes General Provisions for implementing the statute. Subpart B establishes criteria for determining the qualification of small power producing facilities and cogeneration facilities. Subpart C establishes rules for arrangements between electric utilities and qualifying facilities. Subpart D provides for the implementation of the FERC's rules by state regulatory authorities. Subparts E and F establish rules for the exemption of certain qualifying facilities from other federal laws.

This docket was commenced pursuant to 18 C.F.R. Section 292.401, which requires state regulatory authorities to implement the provisions of Sections 292.303-308. Pursuant to that requirement, the Commission entered its Order for Investigation in this docket on October 31, 1980. Under the terms of that Order, Commission Staff was authorized and directed to investigate how the FERC's rules on cogeneration and small power production should be implemented. On November 24, 1981, the Commission entered its Order for and Notice of Procedural Schedule herein establishing a time for intervention, and setting a schedule for the filing of testimony and exhibits by all parties and a time and place for hearing. An Order granting the petition to intervene of the Little River Lumber Company was entered by the Commission on December 8, 1981. Public hearings were commenced in Pierre on January 6, 1982. Testimony and exhibits were presented by Commission Staff, Black Hills Power and Light Company (BHP&L), Northwestern Public Service Company (NWPS), Northern States Power Company (NSP), Montana-Dakota Utilities Company (MDU) and Otter Tail Power Company (OTP). Following the hearing, briefs or position statements were filed by Staff, Montana-Dakota Utilities Company, Northwestern Public Service Company and Northern States Power Company. Based on the testimony and evidence presented at hearing, the briefs and position statements filed by the parties, and arguments of counsel, the Commission makes the following:

FINDINGS OF FACT

I.

STAFF POSITION

Staff's position was presented through the testimony and exhibits of Luis C. Bernal of Whitfield A. Russell and Associates. Mr. Bernal testified that cost-effective cogeneration and small power production can reduce the nation's dependence on foreign oil and its use of non-renewable domestic fuel. He further testified that in his opinion, the FERC's regulations are intended to stimulate an increase in the number of cogeneration and small power production facilities for the purpose of lessening dependence on oil and reducing the cost of electricity. Mr. Bernal testified that cost-effective generation and small power production can also reduce the need for electric utilities to raise capital to finance new generation and transmission facilities, and can reduce the environmental impact of fossil fuel burning.

A. Contractual Rates for Purchases

In his recommendations for the design of rates for purchases from qualifying facilities (QF), Mr. Bernal proposed that the electric utilities and qualifying facilities should be encouraged to agree on contractual rates with minimum Commission intervention. Such an approach, he testified, will reduce the regulatory burden on the QF, the utility, and the Commission. He recommended that the contracts contain a provision making the Commission the final arbiter as to any disagreements about the reasonableness of rates, terms or conditions set by the contract. He recommended that complaint proceedings before the Commission be established as the best vehicle for resolving any contractual disputes between utilities and QF's.

Mr. Bernal's recommendations differentiate between two types of contracts for purchases by electric utilities, long-term contracts and short-term contracts. These two types of contracts are based on different considerations. Mr. Bernal testified that short-term contracts should reflect cost savings realized by the utilities' avoided higher cost of fuel mix peaking generation. As he pointed out, in the short-term, the generation provided by a QF "increases the probability" that the utility can meet its daily load with less expensive fuel cost generation and especially during the on-peak hours. He further noted that such generation also increases the utility's reliability in the short-term by providing increased overall system capacity. He recommended, therefore, that short-term contracts include capacity credits based upon the cost of the utility's installed turbine peaking generation, unless the utility can show there are no avoided capacity costs.

Mr. Bernal proposed that long-term contracts, i.e., contracts of 10 years' duration or longer, should include capacity credits based upon the avoided cost of base load generation. He recommended against adjustments to the capacity credit over the life of the contract. Mr. Bernal testified that the generation that a QF provides can change the long-run future load which must be met by the utilities' generating system. Thus, the added capacity provided by the QF increases the probability that the electric utility can alter its construction schedule so as to cancel or defer planned generating additions, scale down the size of future plant additions, or reduce its firm purchase commitments. Witness Bernal further testified that the capacity credit included in the long-term contracts should be applied to the average KW provided by the QF during the on-peak hours of each month.

Mr. Bernal testified that the energy credit included in long-term and short-term contracts should be based on the average of the expected hourly incremental avoided costs calculated over the hours in the appropriate peak and off-peak hours as defined by the utility. He recommended that the QF be paid according to its contribution of kilowatt hours during each of the periods. Witness Bernal recommended that the off-peak and on-peak periods reflected in the energy credit be consistent with the periods reported in the utility's filing with the FERC under PURPA Section 133.

B. Standard Rates

Witness Bernal recommended, as required by PURPA, that standard rates be developed for purchases from QF's with a design capacity of 100 KW or less.

C. Interconnection Costs

Witness Bernal testified that interconnection facility costs should be borne by the QF on a levelized basis over the life of the interconnection facility. He further testified that appropriate safety and/or disconnecting equipment should also be installed and controlled by the utility and paid for by the QF. He testified such equipment is necessary to prevent backfeeding on the system during maintenance or repair work on the utility's system.

D. Emergency, Backup and Supplementary Power

Witness Bernal testified that rates charged by the utility to QF's for emergency, backup or supplementary power should not exceed the capacity or energy credits collected for each period.

II.

NORTHERN STATES POWER COMPANY POSITION

A. Contractual Rates for Purchases

Northern States Power Company (NSP) presented testimony through Witness Dennis L. Platteter. Mr. Platteter agreed with Staff Witness Bernal's recommendation that the Commission maintain a role of minimum intervention in negotiated agreements between QF's and utilities on purchase rates, limited to a role of settling contractual disputes between utilities and QF's.

Although Mr. Platteter agreed with Staff Witness Bernal's recommendation that both long-term and short-term contracts should be made available to QF's, he testified against Mr. Bernal's recommendation that short-term contracts should contain capacity payments based on a combustion turbine peaking unit cost. Mr. Platteter testified that they may not be the avoided capacity costs for the particular qualifying facility. Mr. Platteter testified that each utility should be given the opportunity to determine its own avoided capacity costs depending on its own unique generation mix.

Company Witness Platteter also disagreed with Mr. Bernal's testimony that PURPA Section 133 information should be the sole basis of information for determining capacity credits. He pointed out that with the likelihood of the Department of Energy being dismantled, such information may not be available. He also disagreed with Mr. Bernal's recommendation that average monthly KW be used as the basis for capacity credits. Witness Platteter recommended that such credits be based upon actual capacity displaced.

Mr. Platteter further found fault with Staff Witness Bernal's recommended basis for determining energy credits. Although Mr. Platteter agreed generally that avoided energy payments might be based on system incremental energy costs, he suggested that the appropriate energy cost may be different depending on whether or not any associated capacity credit is given to the qualifying facility and also the basis of the avoided cost determination. He recommended that the Commission not set any general requirements for the proper basis for avoided energy payments.

Mr. Platteter expressed one final point of disagreement with Staff over the linking of sales rates with purchase rates. Mr. Platteter testified that the cost of emergency, backup and supplementary power are a part of the utility's retail tariff structure and are not, therefore, necessarily related in any way to avoided costs. Instead, he testified that the appropriate retail rate for emergency, backup and supplementary power be applied to qualifying facilities.

B. Standard Rates

Mr. Platteter also generally supported Witness Bernal's recommendation that standard rates be established for QF's of 100 KW or less. He testified that for such small QF;s, the output may not be sufficient to justify the expense of a negotiated rate. Again, Mr. Platteter urged the Commission to take a minimal role in setting standard rates for small QF's and favored placing on the utility the burden to develop rates appropriate to its system. He noted that any such rates would have to be submitted to the Commission for its final approval.

III.

NORTHWESTERN PUBLIC SERVICE COMPANY POSITION

Northwestern Public Service Company (NWPS) presented testimony through Witness Dale E. Jepsen. Mr. Jepsen testified that because of the Company's adequate capacity position, both short-term and long-term, NWPS will not likely be in a position to buy energy or capacity from a QF. He testified that the Company's generation and transmission system are "essentially complete" through the early 1990's, and that the availability of capacity from QF's would not reduce NWPS' need to raise capital to finance future generation plant and transmission line additions. He concluded, therefore, that QF's cannot reduce the Company's capital needs until such sources effectively replace part or all of a major transmission or generation project.

IV.

MONTANA-DAKOTA UTILITIES COMPANY

Montana-Dakota Utilities Company (MDU) presented testimony through Witness Gary L. Paulsen. Mr. Paulsen testified that for purposes of determining rates for purchases of QF's, he considered "avoided costs" to mean "the incremental costs to MDU of electric energy or capacity, or both which, but for the purchase from the qualifying facility ... MDU would generate itself or purchase from the Midwestern Area Power Pool ...". Mr. Paulsen differentiated between these avoided costs which MDU proposes to recognize for small QF's and those the Company proposes to recognize to large QF's. Small QF's are those with an output of less than 100 KW; large QF's are those with any greater capacity.

A. Contractual Rates for Purchases

Mr. Paulsen took issue with a number of Staff Witness Bernal's recommendations. Mr. Paulsen disagreed with Mr. Bernal's recommendation that capacity payments should be included in short-term contracts. Mr. Paulsen testified that the short-term avoided costs described by Mr. Bernal relate to energy, not capacity, and that, therefore, avoided capacity costs are not applicable to short-term contracts. In support of that position, he quoted certain sections from the FERC's Order No. 69 in Docket RM79-55 which established the final rules for cogeneration and small power production. Mr. Paulsen read the FERC's Order to allow avoided capacity costs to be included in contracts only if capacity can be avoided. Mr. Paulsen stated MDU's position to be that avoided energy costs should be provided to those QF's that provide energy only, and that capacity payments would be paid to those QF's, regardless of size, who meet the Company's reliability requirements.

Mr. Paulsen also disagreed with Mr. Bernal's recommendation that PURPA Section 133 data be used to calculate avoided capacity costs. He pointed out that the purpose for which Section 133 data is being provided is not necessarily the same as required to calculate Section 210 avoided costs. Mr. Paulsen also disagreed with Mr. Bernal's recommendation that capacity costs be paid on an average KW basis. He pointed out that MDU is proposing to pay avoided capacity costs based on a maximum demonstrated capacity, provided the 65% capacity factor requirement (discussed in Section B, infra) is met. He testified that if capacity costs are paid only on an average KW, the QF would not receive payment for all capacity actually avoided.

Mr. Paulsen disputed Mr. Bernal's testimony that all avoided energy costs be based on system incremental costs. To do so, he testified, would in some cases overstate avoided costs, contrary to FERC rules limiting rates for purchases to a utility's avoided costs. He testified that a QF which supplies energy only and does not defer capacity should receive purchase rates based on system incremental costs as those costs are actually avoided. However, where a QF also qualifies for avoided capacity payments, Mr. Paulsen testified, the avoided energy costs should be based on the cost of the energy which would have been produced by the same deferred capacity. Otherwise, avoided capacity costs would be paid on a base load unit while avoided energy costs (if based on system incremental costs) would include fuel costs for intermediate and peaking generation. Mr. Paulsen again referred to FERC Order No. 69 which he claimed prohibited Mr. Bernal's proposed system incremental cost recommendation.

B. Standard Rates

Mr. Paulsen testified that MDU proposes to offer to small QF's three purchase rate options: Non-firm energy purchases, non-time differentiated; non-firm energy purchases, time differentiated; and firm energy purchases. Time-differentiated rates would reflect on and off-peak hours. Non-time differentiated rates would not reflect the time of purchase as between on and off-peak hours. Only those small QF's which meet specified dependability qualifications would be eligible to receive firm purchase rates, which include avoided capacity cost payments. Mr. Paulsen testified that his analysis determined that purchases from small QF's would not result in any avoided distribution or transmission costs to the MDU system. He concluded, therefore, that the only factors includable in avoided energy costs to small QF's are avoided fuel costs and avoided variable operation and maintenance expenses associated with the avoided fuel costs.

Witness Paulsen determined avoided energy costs for non-firm purchases by examining MDU's non-firm sales, non-firm purchases and MDU's own generation, which are the sources of energy which would be displaced by purchases from small QF's. He testified that intermediate and peaking units would be the most common source of displaced energy, except that during off-peak hours, base load units would also become the source of displaced energy. Mr. Paulsen further testified that MDU had developed its incremental energy costs by developing a system dispatch for the year 1982 which was based on MDU's internal generation and its probable MAPP purchases. He noted that MAPP purchases generally displace peaking generation and not intermediate or base load generation.

Mr. Paulsen testified that MDU's estimated average energy costs for firm purchases were based on the Antelope Valley Station No. 2 unit. The rate for firm purchases from a small QF are calculated on the avoided capacity costs of a base load unit and the avoided energy costs of the same unit. Mr. Paulsen also testified that in order for a small QF to qualify as a firm supplier, it should deliver energy at a 65% capacity factor on-peak and supply energy during the Company's seasonal peak. The 65% figure was based on the minimum capacity factor of 65% of most base load generating units.

Mr. Paulsen testified that capacity costs should be paid to firm suppliers because firm suppliers will enable the Company to avoid some future capacity. Although MDU does not anticipate any capacity deficiencies until 1983 and does not plan adding additional capacity until 1985, Mr. Paulsen testified that the Company was willing to include capacity credits in firm purchase rates immediately in order to encourage small power production and cogeneration.

Mr. Paulsen testified that he calculated MDU's avoided capacity costs based on the cost of the Antelope Valley Station No. 2, the next major generating unit addition to MDU's system. The avoided costs reflect avoided capital costs, avoided fixed operation and maintenance expenses, and avoided fuel inventory, where applicable. The actual avoided capacity costs paid to a QF will be calculated by applying an appropriate discount factor to ensure that the purchase rate reflects only MDU's actual avoided costs.

C. Interconnection Costs

Mr. Paulsen testified that, in accordance with the FERC rules, small QF's should bear the full cost of providing a safe and reliable interconnection with the company. He testified that the utility and its ratepayers should not have to bear the burden of financing interconnection costs. Mr. Paulsen disagreed, however, with Mr. Bernal's testimony that the cost of interconnection facilities should be levelized over the life of the facility. He pointed out that in a case where MDU has to finance the interconnection costs and the QF defaults, the unpaid portion of the interconnection facility would then have to be absorbed by MDU's ratepayers.

V.

BLACK HILLS POWER AND LIGHT COMPANY'S POSITION

Black Hills Power and Light Company presented testimony through Witnesses W. R. Chaney and Dan Landguth.

Witness Landguth presented the results of a survey of BHP&L's industrial customers conducted to ascertain their interest in cogeneration. Of those customers, only 2 sawmill customers indicated interest in using their waste products for possible cogeneration. Mr. Landguth testified that BHP&L considers cogeneration to be "very limited" in the Company's service territory at this time.

Witness Chaney disagreed with Staff Witness Bernal's recommendations (1) that capacity credits be included in both short-term and long-term contracts, (2) that capacity credits for long-term contracts be based on the avoided costs of base load generation, and (3) that rates for sales for backup, emergency, and supplementary power should not exceed capacity and energy credits included in rates for purchases.

A. Contractual Rates for Purchases

Mr. Chaney first argued that Mr. Bernal's testimony on these three points was contrary to FERC rules found at 18 C.F.R. Section 292.304 regarding rates for purchase and at Section 292.305 regarding rates for sales. Mr. Chaney testified that Mr. Bernal's recommendations violate the standards of these sections that rates for purchases and sales be non-discriminatory, and that rates for purchases not exceed the utility's avoided costs.

Mr. Chaney further testified that Mr. Bernal's inclusion of capacity credits in short-term contracts would require a utility to pay for deferred capacity when no capacity costs had been avoided. He testified that the installed cost associated with peaking generation is fixed and will not be avoided as a result of purchasing power and energy from a QF on a short-term basis.

Mr. Chaney criticized Mr. Bernal's recommendation that long-term capacity credits be based on the avoided costs of base load generation, and that the capacity credits be undisturbed over the life of the contract. Mr. Chaney testified that under Mr. Bernal's proposal utilities would be required to pay an energy credit based on the avoided costs of energy both on-peak and off-peak, while at the same time it would be required to pay a capacity credit based on the avoided cost of base load capacity. He testified that the basis of the capacity credit (i.e., base load) must be the same as the basis of the energy credit. Mr. Chaney also testified that capacity credits should only be given at such time as costs have actually been avoided. Otherwise, the utility's existing customers would be required to pay for cogenerated power in advance of the time avoided costs are actually realized by the company.

B. Emergency, Backup and Supplementary Power

Finally, Mr. Chaney disagreed with Witness Bernal's recommendation that rates for sales of emergency, backup and supplementary power to QF's not exceed the energy or capacity credits collected for each period. Mr. Chaney testified that such rate treatment would be discriminatory as it is contrary to the basis upon which other rates of the utility are designed. Instead, he testified that such rates should be based on the considerations of cost used in developing the utility's basic rate structure.

VI.

COMMISSION FINDINGS

A. Contractual Rates for Purchases

18 C.F.R. Section 292(c)(1) requires state regulatory authorities to implement standard rates for purchases from QF's with a design capacity of 100 KW or less. That section leaves to the discretion of each state regulatory authority whether or not to implement standard rates for purchases from QF's with a design capacity of more than 100 KW. The Commission's findings as to standard rates for purchases from QF's with a design capacity of 100 KW or less are discussed in Subsection B, below. The Commission finds that in light of the recommendations of all parties to this proceeding, it will not implement standard rates for purchases from QF's with a design capacity of greater than 100 KW.

The Commission finds that rates for purchases from QF's with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility. The Commission agrees with the recommendations of all parties that the Commission should play a minimal role in the negotiation of such contracts, a role limited to resolving any contract disputes which arise between the parties. The Commission finds such a limited role to be consistent with the provisions of 18 C.F.R. Section 292.403(a) that an acceptable method of implementation of the FERC's rules by a state regulatory authority is "an undertaking to resolve disputes between qualifying facilities and electric utilities ...".

The Commission finds, nevertheless, that in accordance with Staff's recommendation, it should set certain parameters for the negotiation of such contracts. The Commission finds that Staff's recommendations on contractual purchase rates are reasonable and should be adopted as minimum requirements for purchase rate contracts.

The Commission finds that it is reasonable to distinguish between short-term and long-term contract purchase rates as recommended by Staff Witness Bernal. The Commission finds that Mr. Bernal's testimony offers a rational basis for distinguishing between rates for purchases fixed by contract with a duration of less than 10 years ("short-term contract") and rates for purchases set by contract with a duration of 10 years or more ("long-term contract"). As Mr. Bernal testified, 10 years is the normal planning horizon for utilities under the Commission's jurisdiction. 1/ A utility's construction plans will generally be formulated and known in advance for this 10 year period. It is not likely, therefore, that the potential capacity contribution of a QF will affect a utility's construction plans over the 10 years following the time the contract purchase rate is agreed to. A purchase rate contract for more than 10 years, however, has greater potential for altering the utility's long-range construction planning. Ten years is thus a logical demarcation point for determining long-run versus short-run avoided capacity costs.

The Commission finds that Staff Witness Bernal correctly identified the basis for long-run versus short-run avoided capacity costs. The Commission finds that long-term contracts

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1/ SDCL 49-41B-3 reflects this 10 year planning horizon by requiring electric utilities to file 10 year construction plans with the Commission and to update those plans every 2 years.

and short-term contracts should reflect such avoided capacity costs through capacity credits. The Commission finds that capacity credits included in short-term contracts should be based on the cost of installed turbine peaking generation, as short-term contracts will primarily tend to reduce the use of peaking generation and thus reduce the utility's use of more expensive and non-renewable fuels such as oil and gas. 2/ The Commission finds that capacity credits included in long-term contracts should be based on the avoided cost of base load generation. The Commission finds that it is the addition of base load capacity which will most likely be affected by the capacity contribution of the QF under the long-term contract. The Commission further finds that capacity credits included in long-term contracts should reflect the average KW supplied by the QF for each month during the utility's on-peak period.

The Commission also finds that the capacity credits included in long-term contracts should be made constant over the duration of the contract. The Commission finds this position to be consistent with the concerns expressed in the comments accompanying the FERC's rules. 45 Federal Register, 12214, 12216-12233 (1980). Those comments reflect a concern that contractual rates for purchases establish a fixed rate to which a QF can look in planning its investments. 45 Federal Register at 12224. The assurance of a constant capacity credit over the duration of the contract term provides this measure of dependability.

The Commission finds that both short-term and long-term contracts should include an 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 finds, as Mr. Bernal testified, that such a basis of calculation 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. The Commission finds that Staff's recommendation will accurately track the actual avoided energy cost to the utility.

The Commission finds that the hourly energy cost data required to be filed under Section 133 of PURPA is an appropriate data source for determining avoided energy costs. NSP's objection to the use of such data on the basis that DOE may soon be dismantled is highly speculative. Although MDU argues

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2/ Short-term capacity costs are recognized in MAPP Service Schedule H. The Commission agrees with Staff's argument that inasmuch as utilities pay for short-term capacity for purchases under MAPP Schedule H, it is not improper to reflect such short-term capacity costs in purchase rates from QF's.

that Section 133 data is not designed to satisfy Section 210 requirements, it has failed to show with any specificity how or why such data would be inappropriate for determining avoided energy costs. Staff's recommendation on this point, therefore, will be adopted. In line with this holding, the Commission finds that each utility's on-peak and off-peak periods for purposes of calculating hourly avoided incremental energy costs should be consistent with its on-peak and off-peak periods as reflected in its Section 133 filings. This requirement will assure consistency in the calculation of avoided energy costs.

B. Standard Rates

The Commission finds that 18 C.F.R. Section 292.304(c) requires electric utilities to develop standard rates for purchases from QF's with a design capacity of 100 KW or less. No party to this proceeding has disputed this basic premise. The Commission agrees with the recommendations of a number of the parties that the Commission should play a minimal role in each company's calculation of such standard rates. The Commission finds, therefore, that each company should be allowed the opportunity to develop and submit prepared rates for purchases from such small QF's. Such standard rates should include both capacity and energy credits, as applicable. The Commission finds that the capacity credits included within standard rates should be applied to the average KW provided by the QF during the utility's on-peak hours for each month, as recommended by Staff. The Commission finds that the avoided energy costs included in standard purchase rates should be calculated at the average of the expected hourly incremental avoided costs over the hours in the utility's appropriate on-peak and off-peak periods. The Commission bases this finding on the same evidence cited in support of its position set forth in Section A, supra.

The Commission finds that each company should submit such proposed rates at the earliest possible date, and that at the latest, each company should submit such proposed rates as part of its next regularly filed rate increase application. The Commission finds that if any company unreasonably delays its submission of such proposed rates, the Commission may issue a further Order in this docket ordering immediate filing of such rates.

C. Interconnection Costs

The Commission finds that 18 C.F.R. Section 292.306 requires each QF to pay "any interconnection costs which the State regulatory authority ... may assess against the qualifying facility on a non-discriminatory basis with respect to other customers with similar load characteristics". The Commission finds that an assessment of interconnection costs can only be made on a case by case basis. The amount of such costs will rarely involve a standard fee but must vary according to the specific requirements of each interconnection to be made. The Commission finds that it should limit its role in the determination of interconnection charges to such time as actual disputes arise between utilities and QF's over the amount of such costs.

As to their method of recovery, however, the Commission finds that interconnection costs should be levelized over the life of the facility, as recommended by Staff Witness Bernal. To require a QF to pay the entire cost of interconnection up front might present too great a financial obstacle, and tend to discourage development of cogeneration and small power production.

D. Supplementary, Backup, Maintenance and Interruptible Power

The Commission finds that it is precluded from adopting Staff's position on rates for sales of supplementary, backup, maintenance and interruptible power. Staff Witness Bernal recommended that such rates be limited to the amount of capacity and energy credits received by a QF over the billing period. The Commission finds that the effect of such a rate would be to limit the charge which a QF would have to pay for such power in any given period to the amount of the company's total purchases of power (based on both energy and capacity credits) from the QF over the same period, regardless of the amount of supplementary, backup, maintenance or interruptible power delivered to the QF, and regardless of the cost of that power to the utility's system. The Commission finds that such a rate for sales would be clearly discriminatory, and is, therefore, prohibited under Section 210(c) of PURPA. Excerpts from the Public Utilities Regulatory Policy Act of 1978 Conference Report make clear that such discrimination is prohibited by the Act. The Report states at page 98 that:

> (T)he conferees do not intend that the cogenerator or small power producer pay any more or any less than is otherwise just and reasonable in terms of the utility receiving the reasonable rate of return for providing service to those kinds of users.

Furthermore, the Report specifically construes the phrase "not discriminate against any cogeneration or small power production" contained in Section 210(c) of the Act to prohibit discrimination against electric consumers of the utility as well:

> This phrase should not be construed to permit discrimination against the electric consumers of an electric utility in formulating rates under this provision. The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers. (Id.)

Analysis of 18 C.F.R. 292.305 and the FERC's comments relevant thereto further lead the Commission to conclude that rates for supplementary, backup, maintenance and interruptible power must be formulated on the basis of traditional cost of service ratemaking concepts.

Paragraph (a) of that section sets general requirements for rates for sales. Such rates are to be just and reasonable, in the public interest and non discriminatory "against any qualifying facility in comparison to rates for sales to other customers served by the electric utility". Subpart 2 of Paragraph (a) provides that rates of sales shall be deemed not to be discriminatory to the extent that they are also applicable to other customers of the electric utility "with similar load or other cost-related characteristics". Paragraph (b) of that section delineates certain "additional services" which electric utilities are obligated to provide to QF's. Utilities must provide, upon request, supplementary, backup or interruptible power to the QF, as those terms are defined by the rules. Paragraph (c) provides two specific guidelines to be considered in the setting of rates for backup and maintenance power. Nothing in Paragraphs (b) or (c), however, indicate that rates for supplementary, backup, maintenance or interruptible power are to be considered outside the general framework of the requirements of Paragraph (a).

The FERC's comments on Section 292.305 support this conclusion. Generally, rates for sales are to be formulated "on the basis of traditional ratemaking (i.e., cost of service) concepts" (45 Federal Register, 12228). An industrial cogenerator should receive service "at a rate applicable to a non-generating industrial customer unless the electric utility shows that a different rate is justified on the basis of load or other cost related data" (Id.).

Specifically, as to supplementary, backup, maintenance or interruptible power, the FERC's comments reveal a similar intent that rates be based on load or other cost-related data. For example, they provide that a QF is entitled to a rate for stand-by or backup power which reflects

> the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers. (Id.)

As further example, the comments indicate that rates for interruptible power "are best handled through the pricing mechanism". (45 Federal Register at 12229). The Commission concludes from these comments that rates for supplementary, backup, maintenance and interruptible power must be arrived at according to the application of normal cost of service analysis.

Staff's proposal to set limits for such rates according to the amount of both energy and capacity credits received by a QF over a billing period attempts to artifically cap those rates, and thus contradicts the requirement that they be cost-based. Mr. Bernal's supporting rationale for Staff's proposal is to provide an additional incentive for the development of cogeneration and small power production. However desirable such an added incentive might prove to be, it does not excuse compliance with the legal requirements of the Act. It must, therefore, be rejected.

The Commission finds that each utility should develop and submit for approval tariffs for sale of supplementary, backup, maintenance and interruptible power to QF's, as those terms are defined at 18 C.F.R. Section 292.101 and Sections 292.305(b) and (c). The Commission finds that such rates should be developed to reflect the cost of providing such service and should be non-discriminatory as between rates to QF's and other electric consumers. The Commission notes that to the extent existing approved tariff revisions on file with the Commission regarding stand-by, supplementary, emergency or interruptible power are adequate to provide for such sales to QF's, no further tariffs need be filed by the companies. 3/

3/ In particular, the following companies have the following tariffs on file with the Commission: Northern States Power Company, "General Rules and Regulations", Section 10 (Tariff Section No. 5, 1st Revised Sheets 8 through 8.2); Iowa Public Service Company, "Service Rules and Regulations", Paragraph 11 (Tariff Sheet No. VI, 2nd Revised Sheet No. 3); Otter Tail Power Company, "General Rules and Regulations", Paragraph 8, (Tariff Section No. 5, Vol. I, 3rd Revised Sheet No. 2); Black Hills Power and Light Company, Section 306, "Auxiliary Electric Service", (Tariff Section No. 5, 1st Revised Sheet 12).

E. Utilities' Obligations to Purchase

Section 210(a) of PURPA requires the FERC to promulgate rules requiring utilities to offer to purchase electric energy from QF's. 18 C.F.R. Section 292.303(a) reiterates this obligation to purchase "energy and capacity" which is, either directly or indirectly, made available from a QF. The FERC's comments on this section make unequivocal the obligation of each electric utility under this Commission's jurisdiction "to purchase all electric energy and capacity made available from qualifying facilities with which the electric utility is directly or indirectly interconnected", except under certain specific circumstances. 45 Federal Register at 12219. Within this framework of federal statutory and regulatory requirements, the Commission is not in a position to entertain any argument that any particular electric utility under its jurisdiction should not have to purchase energy or capacity from a QF. Such purchases have been mandated by Congress and the FERC.

The question is, given this obligation to purchase, how much should a utility have to pay for such energy and capacity, particularly those which may currently have excess capacity. The Commission sees this question underlying a number of the objections which several companies have made to Staff's recommendations in this case. NWPS took the position at hearing that it did not expect to be in a position to buy energy or capacity from a QF for some time. NWPS seems to have moderated this position somewhat in its "Statement of Position" filed after the evidentiary hearings. It now recommends that the Commission adopt rules for small power production and cogeneration but predicts that its avoided costs over the near term would be "miniscule". Witness Chaney, on behalf of BHP&L, testified that Staff's recommendation to include capacity credits in short-term contracts would require utilities "to pay a capacity credit for a qualifying facility output where no costs have been avoided". Mr. Paulsen of MDU voiced the same complaint.

The Commission reads both the FERC's rules and Mr. Bernal's testimony in such a way as to dispel these points of contention. The Commission finds that the capacity credits to be included in any purchase rates, whether contractual or otherwise, 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. Again, the FERC's comments on Section 292.303(a) provide useful insight:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. (45 Federal Register at 12219)

Those comments further suggest that a utility with excess capacity can only be required to pay avoided energy costs (Id.). The Commission does not read the FERC's rules to permit a utility to pay capacity costs where none are avoided. To do so would have the effect of requiring the utility to pay twice for the same capacity and would thus impose added and unnecessary costs on the utility's other customers, contrary to clear congressional and FERC intent.

The Commission understands Mr. Bernal's position to be in accord with this view. On cross-examination, Mr. Bernal was specifically questioned about payment of capacity credits under short-term contracts where the utility could not be sure that the capacity contribution of the QF would allow the utility to avoid any capacity costs. Mr. Bernal replied that if the utility could not "count on" capacity savings, it should not be required to pay capacity credits.

In holding that capacity credits should be included in short-term contracts, the Commission is not requiring payment of such credits where no capacity is in fact avoided in the short run. It is the Commission's holding, however, that if in the short run there are to be capacity savings, they are most likely to be in peaking generation. Accordingly, as discussed in Section A, supra, it is the Commission's finding that such credits should be based on the cost of the company's intalled turbine peaking generation, as recommended by Mr. Bernal. But such credits can only be excluded in short-term contracts where the utility has shown that no capacity costs have been avoided.

F. Applicability to Utility Subsidiaries

The Commission finds that the provisions of this Order should be made applicable to the purchase and/or sale of electrical energy by and between electric utilities and qualifying facilities which are also subsidiaries of those electric utilities. The Commission further finds that all contracts for the purchase and/or sale of electrical energy by and between electric utilities and qualifying facilities which are also subsidiaries of those electric utilities should be submitted to the Commission for review. The Commission finds this to be necessary in order to ensure that all such contracts fully comply with applicable statutory and other regulatory requirements.

Based on these Findings, the Commission concludes as a matter of law:

I.

That it has jurisdiction over the subject matter of this proceeding and the parties hereto, pursuant to SDCL Chapter 49-34A-, 16 USC 824(a) and 18 C.F.R. Section 292.401.

II.

That the rates established by this Order are just and reasonable and fully comport with all statutory and constitutional requirements.

III.

That all motions and objections not heretofore specifically ruled on should be denied. It is therefore

ORDERED, that Black Hills Power and Light Company, Iowa Public Service Company, Montana-Dakota Utilities Company, Northern States Power Company, Northwestern Public Service Company, and Otter Tail Power Company shall file with the Commission tariff sheets consistent with the terms of this Order establishing standard rates for purchases of electrical energy and capacity from qualifying facilities (as defined under 18 C.F.R. Section 292) with a design capacity of 100 KW or less; and it is

FURTHER ORDERED, that all rates for purchases of electricity by said companies from qualifying facilities, and all rates for sales of electricity from said companies to qualifying facilities shall be consistent with the terms of this Order; and it is

FURTHER ORDERED, that such companies shall, to the extent required by the terms of this Order, file with the Commission tariff sheets providing terms for the sale to qualifying facilities of supplementary, backup, maintenance and interruptible power consistent with the terms of this Order; and it is

FURTHER ORDERED, that the Commission shall retain jurisdiction over all transactions between said companies and qualifying facilities to the extent required under 18 C.F.R. Section 292.401.

Dated at Pierre, South Dakota, this 14 day of December, 1982.

BY ORDER OF THE COMMISSION:

Charlotte Fischer, Chairman

Ken Stofferahn, Commissioner

Jeff Solem, Commissioner

(OFFICIAL SEAL)

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	)))))	**AMENDED FINAL DECISION AND ORDER; NOTICE OF ENTRY** **EL11-006**

On April 28, 2011, Oak Tree Energy, LLC (Oak Tree) filed a Complaint (Complaint) with the South Dakota Public Utilities Commission (Commission) against NorthWestern Corporation d/b/a NorthWestern Energy (NWE).[1] The dispute involves a proposed wind generation project located in Clark County, South Dakota (Project). Oak Tree alleged that the Project is a Qualifying Facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA) and that NWE refuses to enter into a power purchase agreement. On May 5, 2011, the Commission electronically transmitted notice of the filing and the intervention deadline of May 20, 2011, to interested persons on the Commission's PUC Weekly Filings electronic listserv. No petitions for intervention were filed.

On May 24, 2011, NWE filed its Answer to the Complaint. On June 17, 2011, the Commission issued a Scheduling Order setting forth a schedule for discovery by the parties, including the Commission's staff (Staff), and deadlines for filing pre-filed testimony. On September 7, 2011, Oak Tree filed a Motion to Compel. On October 20, 2011, the Commission issued an Amended Scheduling Order. On November 8, 2011, the Commission heard Oak Tree's Motion to Compel, and on November 14, 2011, issued an Order Granting in Part Motion to Compel. On December 13, 2011, Oak Tree filed its written direct testimony. On January 13, 2012, NWE filed its written direct testimony. On January 27, 2012, Staff filed its written testimony. On February 7, 2012, the parties stipulated to an amended filing schedule.

On February 8, 2012, Oak Tree filed its Second Motion to Compel and on February 9, 2012, Oak Tree filed a Motion to Expedite Hearing. At its ad hoc meeting on February 13, 2012, the Commission granted Oak Tree's Motion to Expedite, setting the Motion for consideration at its regular meeting on February 14, 2012. On February 14, 2012, NWE filed NorthWestern Energy's Resistance to Oak Tree Energy, LLC's Second Motion to Compel. On February 16, 2012, the Commission issued an Order Granting Motion to Expedite, an Order Granting in Part Second Motion to Compel and Protective Order, and a Second Amended Scheduling Order. On February 24, 2012, Oak Tree filed its rebuttal testimony, and NWE filed its responsive testimony.

On February 28, 2012, the Commission issued an Order for and Notice of Hearing setting the matter for hearing on March 21-22, 2012, and Oak Tree filed a Motion to Allow Electronic Testimony. On March 2, NWE filed NorthWestern Energy's Pre-Hearing Motions and Brief in Support of NorthWestern Energy's Pre-Hearing Motions. On March 5, 2012, Oak Tree filed Oak Tree Energy, LLC's Prehearing Motions Regarding Right to Full Avoided Cost and Creation of Legally Enforceable Obligation and Oak Tree Energy, LLC's Motion to Exclude

[1] The Commission's Orders in the case and all other filings and documents in the record are available on the Commission's web page for Docket EL11-006 at: http://puc.sd.gov/Dockets/Electric/2011/el11-006.aspx

Testimony of Steven E. Lewis in Full and Bleau Lafave in Part and Brief in Support. On March 7, 2012, NWE filed NorthWestern Energy's Brief in Opposition to Oak Tree Energy, LLC's Motion to Allow Electronic Testimony, NorthWestern Energy's Response to Oak Tree Energy, LLC's Pre-Hearing Motions Regarding Right to Full Avoided Cost and Creation of Legally Enforceable Obligation, and NorthWestern Energy's Brief in Opposition to Oak Tree Energy, LLC's Motion to Exclude Testimony. On March 8, 2012, Oak Tree filed Oak Tree Energy, LLC's Response to Northwestern Energy's Prehearing Motions.

At an ad hoc meeting on March 9, 2012, the Commission heard Oak Tree's Motion to Allow Electronic Testimony and on March 14, 2012, issued its Order Denying Motion to Allow Electronic Testimony. On March 13, 2012, the Commission heard the parties pre-hearing motions and on March 15, 2012, issued its Order Denying Oak Tree's Omnibus Prehearing Motions and Granting in Part and Denying In Part Parties' Motions to Strike and Exclude.

The hearing was held as scheduled on March 21-22, 2012, at which Oak Tree, NWE, and Staff appeared and participated. At hearing, in response to a request by Chairman Nelson, NWE agreed to produce for the hearing record its agreement with Titan Wind I, and on March 21, 2012, NWE filed the Titan Wind I Project Power Purchase Agreement, which was received into evidence as Exhibit NW 9. TR1 262, 299.[2] At the conclusion of the hearing, a discussion took place regarding post-hearing schedule, and agreement was reached between the Commission and the parties on the schedule for briefing and oral argument, with the oral argument procedures and time limits to be established following discussion between Commission Counsel and the parties. On April 10, 2012, the Commission accordingly issued a Post-Hearing Procedural Order.

On April 18, 2012, NWE filed NorthWestern Energy's Post-Hearing Brief. On April 19, 2012, Oak Tree filed Oak Tree Energy, LLC's Opening Post-Hearing Brief, and Staff filed Commission Staff's Post-Hearing Brief. On April 24, 2012, NWE filed NorthWestern Energy's Post-Hearing Response Brief, and Oak Tree filed Oak Tree Energy, LLC's Reply to Northwestern Energy's Post-Hearing Brief and Oak Tree Energy, LLC's Reply to Commission Staff's Post-Hearing Brief.

On April 26, 2012, the Commission heard oral argument from the parties. Following oral argument and Commissioner questions and discussion, Chairman Nelson described for the parties and Commissioners a proposal for possible resolution of the matter at an avoided cost value of $46.47, if acceptable to the parties. Oak Tree v. NorthWestern – Nelson Proposal. The Commission instructed the parties to submit their responses on the Nelson Proposal by close of business on April 30, 2012, and scheduled a continuation of the proceeding on May 2, 2012. On April 30, 2012, Oak Tree filed Oak Tree Energy, LLC's Response to Chairman Nelson's Question, and NWE filed NorthWestern Energy's Response to Chairman Nelson's Proposal Presented at Oral Argument on April 26, 2012.

On May 2, 2012, after consideration of the parties' post-hearing briefs, oral argument, and responses to a proposal for agreed resolution of the matter by Chairman Nelson, the

[2] References to the March 21-22, 2012, and December 5-6, 2012, Hearing Transcripts are in the format "TR1" and "TR2," respectively, followed by the Hearing Transcript page number(s) referenced and references to Hearing Exhibits are in the format Ex followed by the exhibit number and, where applicable, the page number(s) referenced and, where applicable, the attachment or sub-exhibit identifier and page number(s) referenced (the exhibit number party abbreviations employed by the parties are: Oak Tree – "OT"; NorthWestern – "NW" or "NWE"; Staff – "Staff").

Commission voted unanimously to make certain intermediate rulings in the case, and on May 15, 2012, issued an Interim Order on such rulings directing the parties to file additional pre-filed testimony and rebuttal testimony in conformity with the Interim Order on or before June 6 and June 13, 2012, respectively, and setting the matter for additional hearing on June, 19, 2012. The interim rulings made by the Commission in the Interim Order were:

1. That, given NWE's status as a vertically integrated utility with predominant reliance on its own internal generation at this time, the hybrid method is the proper method to calculate avoided costs for NWE's South Dakota system.

2. That NWE did not, however, incorporate projected carbon cost inputs into its use of this method and also may have utilized unjustifiably low natural gas inputs and electric market inputs, and as a result, the Commission cannot reliably determine the proper avoided cost with the data and analyses currently in the record.

3. That the carbon emission cost values of $5/ton starting in 2015 and shifting to $10/ton starting in 2020 and rising to $15/ton in 2025 as estimated by Lands Energy are reasonable carbon emissions cost estimates in the present environment and are the appropriate carbon emissions cost values to be included in the parties' respective hybrid method analyses of avoided cost.

4. That NWE is obligated to purchase Oak Tree's output because a legally enforceable obligation was created by Oak Tree on February 25, 2011.

5. That Oak Tree is entitled to capacity credit for the facility's output commencing in 2012 with the capacity contribution to be determined and adjusted in accordance with the method NWE is using for the Titan I project, and such capacity credit shall be incorporated into the hybrid method beginning in 2012.

6. That the proper avoided cost contract term is 20 years.

In the Interim Order, the Commission then directed the parties to submit additional testimony and scheduled a second hearing to consider 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 current market conditions and projections.

3. The proper electric market rates that the parties may deem warranted to reflect current market conditions and projections, taking into consideration the carbon emission costs previously approved and any adjustments to gas prices.

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's avoided cost levelized over a 20 year period.

On May 29, 2012, Oak Tree filed Oak Tree Energy, LLC's Motion for Partial Reconsideration of Interim Order. On May 31, 2012, the Commission issued an Order Cancelling Procedural Schedule and Hearing. On June 14, 2012, NWE filed NorthWestern

Energy's Application for Reconsideration of Findings and Conclusions in Interim Order Issued on May 15, 2012. On June 18, 2012, NWE filed NorthWestern Energy's Answer in Opposition to Oak Tree Energy, LLC's Motion for Partial Reconsideration of Interim Order, and Staff filed Commission Staff's Answer to Oak Tree's Motion for Partial Reconsideration of Interim Order. On July 5, 2012, Oak Tree filed Oak Tree Energy, LLC's Answer to Northwestern Energy's Application for Reconsideration of Findings and Conclusions in Interim Order Issued on May 15, 2012. On July 10, 2012, Oak Tree filed Oak Tree Energy, LLC's Combined Reply in Support of Its Motion for Partial Reconsideration of Interim Order.

At an ad hoc meeting on October 2, 2012, the Commission heard oral argument from all parties on Oak Tree's and NWE's respective requests for reconsideration of the Commission's Interim Order. The Commission deferred action until its regular meeting on October 9, 2012, at which the Commission again considered this matter. On October 11, 2012, the Commission issued an Order Granting in Part and Denying in Part Motion for Partial Reconsideration and Application for Reconsideration (Reconsideration Order) (i) denying Oak Tree's Motion for Partial Reconsideration with respect to the use of the hybrid method to determine avoided cost, (ii) granting Oak Tree's Motion for Partial Reconsideration with respect to the use of current market conditions and projections in determining proper natural gas inputs and proper electric market rates, (iii) denying NWE's Application for Reconsideration with respect to interim Finding and Conclusion 4 regarding Oak Tree's creation of a legally enforceable obligation (LEO) as of February 25, 2011, (iv) granting NWE's Application for Reconsideration with respect to interim Findings and Conclusions 2 and 3 on the grounds that carbon cost forecasts were too speculative as of the LEO date and remain so at this time to justify their inclusion as inputs into the avoided cost determination and that carbon costs should therefore have a value of zero, and (v) denying Oak Tree's Motion for Partial Reconsideration with respect to the use of the Land's Energy carbon emissions costs on the grounds that the issue had become moot as result of the granting of NWE's request to disallow the inclusion of carbon costs. Commissioner Fiegen dissented as to the issue of carbon cost inclusion.

On October 15, 2012, the Commission issued a Procedural Order; Order for and Notice of Hearing setting the matter for hearing on December 5-6, 2012, to address the issues as set forth in the Interim Order as modified by the Reconsideration Order:

1. The proper application of the hybrid method with no inclusion of carbon costs.
2. The proper natural gas input(s) to use in the hybrid method based on market conditions and projections as of February 25, 2011, the date on which a legally enforceable obligation was created.
3. The proper electric market rates that the parties may deem warranted reflecting market conditions and projections as of February 25, 2011.
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. NWE's avoided cost levelized over a 20 year period.

The hearing was held as scheduled. The Commission deferred taking action. The parties agreed to a procedural schedule for the filing of post-hearing briefs and consideration by the Commission, and on December 26, 2012, the Commission issued a Procedural Order setting forth the post-hearing briefing schedule and setting the matter for oral argument and decision on January 22, 2013.

On January 3, 2013, Oak Tree filed Oak Tree Energy LLC's Post Second Hearing Opening Brief. On January 16, 2013, NWE filed NorthWestern Energy's Post-Hearing Response

Brief for Supplemental Hearing. On January 18, 2013, Staff filed Staff's Post Second Hearing Brief. On January 22, 2013, Oak Tree filed Oak Tree Energy LLC's Post Second Hearing Reply Brief.

On January 22, 2013, the Commission heard brief oral arguments from the parties and then took the matter up for decision. Commission Nelson moved to adopt the avoided cost rates set forth in the columns entitled "Rounded Actual" for either "Beginning in 2013" or "Beginning in 2014" as the case may be contained in a spreadsheet handout entitled "Nelson Avoided Cost Summary Proposal January 22, 2013" (attached as Exhibit A hereto) that Commissioner Nelson provided to all persons present in person and via email attachment to those participating telephonically. The spreadsheet was based on the model developed by Staff witness Brian Rounds but with input values modified to reflect the input values that Commissioner Nelson believed were supported by the preponderance of the evidence and reflected a reasonable balance of the diversity of assumptions and inputs contained within the expert opinion evidence at hearing. After a detailed discussion among the Commissioners, primarily concerning the proper capacity cost value and energy load shape inputs and whether the avoided cost value should be the actual annual calculated value or the levelized value over the 20-year power purchase obligation contract term, Commissioner Nelson amended his motion to utilize the levelized avoided cost values as set forth on Exhibit A of $53.31/MWh if operation begins in 2013 and $55.34/MWh if operation begins in 2014. A majority of the Commission voted in favor of the motion, with Commissioner Fiegen dissenting.

On March 21, 2013, NWE filed NorthWestern Energy's Application for Reconsideration of Findings and Conclusions in Final Order Issued on February 21, 2013 (Application for Reconsideration). On April 15, 2013, Oak Tree filed Oak Tree Energy, LLC's Answer to NWE's Application for Reconsideration. The Application for Reconsideration requested reconsideration of the Decision's Findings of Fact 23, 30, and 31 and Conclusions of Law 7 and 8. On April 11, 2013, the Commission's Staff (Staff) filed Staff's Response to Northwestern Energy's Application for Reconsideration of Findings and Conclusions in Final Order issued on February 21, 2013.

At its regular meeting on April 23, 2013, the Commission considered the Application for Reconsideration. Commissioner Nelson submitted to the Commission, and provided to all persons present in person and via email attachment to those participating telephonically, an untitled spreadsheet handout depicting his load shape calculations. Following questions and discussion, the Commission voted unanimously to reconsider the Decision regarding use of levelized avoided cost without inclusion of a discount factor, but to defer final action on the appropriate resolution of the issue until the next meeting. The Commission voted unanimously to deny reconsideration of its Decision with respect to use of a 20% capacity factor in calculating avoided cost. A majority of the Commission, with Commissioner Hanson dissenting, voted to reconsider the Decision with respect to whether escalation of avoided capacity costs should commence prior to 2015, but took no substantive action on the proper capacity escalation commencement date. The Commission voted unanimously to reconsider the Decision's use of a 2.25% load growth factor in the avoided cost calculation model, but to defer decision on the issue until its next meeting. On April 29, 2013, Staff filed a letter and exhibits regarding model inputs and load shape adjustment (Staff Model). On May 6, 2013, Oak Tree filed Oak Tree Energy, LLC's Request for Levelized Rate Option.

On May 7, 2013, the Commission considered the issues remaining following the actions taken at its April 23, 2013, meeting. Commissioner Nelson submitted to the Commission, and provided copies to all persons present and via email attachment to those participating telephonically, spreadsheet and graph handouts entitled "Nelson Avoided Cost Summary on Reconsideration May 7, 2013 - Peak and Load Growth" (Nelson Proposal). The first issue for decision was the appropriate date for commencement of escalation of avoided capacity cost. Commissioner Nelson moved that avoided capacity costs remain at $36/kW-yr for 2013 and 2014 and then begin escalating at 5.84% per year. The Commission voted unanimously in favor of the motion.

The Commission then considered the issue of whether the 2.25% per annum load growth factor employed in the manner utilized to calculate the avoided energy costs over time approved in the Decision is the appropriate load growth factor and methodology for use in calculating avoided energy cost, and if not, what the appropriate load growth factor and calculation methodology should be. After an explanation of the model methodology he employed and the reasons underlying it, Commissioner Nelson moved that the methodology utilized to calculate load growth in the calculation of avoided energy costs approved by the Commission in the Decision be changed to the methodology for calculating energy and peak growth utilizing a load growth of 2.25%/yr and a peak growth of 1%/yr in the manner employed in the Nelson Proposal to calculate avoided energy costs over the 20-year contract period. After discussion, Commissioner Fiegen made a substitute motion to approve the Staff Model and its methodology for computing a 1% peak and 2.25% energy growth load shape as depicted on the lower spreadsheet on Exhibit A to the Staff Model. After discussion, a majority of the Commission voted in favor of the substitute motion, with Commissioner Nelson dissenting.

The Commission next considered the issue of whether the Commission should approve the use of non-levelized, annual avoided cost values instead of levelized avoided cost values, approve the inclusion of a discount factor in its levelized avoided cost calculation, or approve the non-discounted levelized approach as employed in the model used to calculate the levelized avoided costs approved in the Decision. Commissioner Fiegen moved to approve levelized avoided costs calculated as approved in the previous motion with the application of a 7.86% discount factor as set forth on the lower spreadsheet set forth on Exhibit B to the Staff Model. After discussion, a majority of the Commission voted in favor of the motion, with Commissioner Nelson dissenting.

In response to a question from Commission Counsel regarding a potential ambiguity with respect to the Commission's action on the appropriate date for commencement of escalation of avoided capacity costs as year 2015, Commissioner Fiegen moved to reconsider the action taken and further moved as a substitute motion that the $36/kW-yr avoided capacity cost be maintained through the end of 2015, with the commencement of escalation for avoided capacity cost to begin after 2015 by applying the escalation factor of 5.84%/yr to the 2015 value, with the escalated avoided capacity cost to take effect on January 1, 2016, and with annual escalation to continue thereafter for the remainder of the 20-year contract term as set forth in the Staff Model. The Commission voted unanimously in favor of the motion.

On May 17, 2013, the Commission issued an Order Granting in Part and Denying in Part Application for Reconsideration reflecting the actions taken as described above, setting forth the amended findings of fact and conclusions of law to be incorporated in this Amended Final Decision and Order; Notice of Entry, and directing the issuance of this Amended Final Decision and Order; Notice of Entry.

Having considered the evidence of record, applicable law, and the briefs and arguments of the parties, the Commission makes the following amended Findings of Fact, Conclusions of Law, and Decision:

FINDINGS OF FACT

Parties

1. Complainant, Oak Tree Energy, LLC, is a limited liability company registered to do business in the state of South Dakota. TR1 144. Oak Tree is an independent wind power developer active in Clark County, South Dakota. Oak Tree's proposed project is located in Clark County, South Dakota. This project is known as the Oak Tree Project. The Project will have an initial installed nameplate capacity of 19.5 megawatts. TR1 137-139; Complaint p. 2; Ex OT 3, p1.

2. Respondent, NorthWestern Corporation d/b/a NorthWestern Energy, a Delaware corporation, is a public utility as defined in SDCL 49-34A-1(12) subject to regulation by the Commission.

3. Staff participated fully as a party in this matter.

Procedural Findings

4. The Procedural History set forth above is hereby incorporated by reference in its entirety in these Procedural Findings. The procedural findings set forth in the Procedural History are a substantially complete and accurate description of the material documents filed in this docket and the proceedings conducted and decisions rendered by the Commission in this matter.

Qualifying Facility

5. In its Complaint, Oak Tree alleged that it was a qualifying small power production facility (QF) under PURPA and attached its FERC Form 556 Certification in support. Complaint ¶ 7, p. 2 and Complaint Exhibit 1. In its Answer, NWE admitted that Oak Tree is a QF. Answer ¶ 7, p. 2. The Commission finds that Oak Tree is a QF.

Negotiations and Creation of a Legally Enforceable Obligation

6. PURPA rule 18 C.F.R. § 292.304(d)(2) provides:

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 is incurred.

7. Oak Tree engaged in discussions and correspondence over a considerable period of time in an attempt to negotiate a power purchase agreement with NWE on a voluntary basis. This process had begun no later than May 10, 2010, as evidenced by correspondence concerning the interconnection and avoided cost process and referencing inquiries that had predated such date. Ex OT 3, Exhibit 1. Prior to initiating its offer to NWE and attempting to engage NWE in negotiations, Oak Tree conducted an evaluation of numerous other potential power purchases and interconnection partners and concluded that NWE was the only viable interconnection partner and purchaser given the proximity of the Project to an interconnection point with NWE's facilities and other factors. TR1 151-152, 171-172; Ex 3, p. 8. An exchange of correspondence concerning Oak Tree's offer to sell power to NWE and negotiate the terms of a power purchase agreement proceeded until at least late July, 2010, and then resumed with Oak Tree's letter to NWE sent on January 25, 2011 (incorrectly dated January 25, 2010, TR1 180). Ex OT 3, Exhibits 2-8. The hiatus in correspondence reflected in these exhibits occurred because Oak Tree felt that NWE was not willing to engage in meaningful negotiations toward a viable power purchase agreement, and Oak Tree accordingly both resumed its evaluation of and contacts with other potential purchasers and marketing arrangements and had its consultants begin the process of developing the foundation for Oak Tree to make an offer that would constitute a legally binding obligation. TR1 178-179.

8. After reinitiating its correspondence with NWE on January 25, 2011, on February 25, 2011, Oak Tree made what it termed a "notice to NWE of the establishment of a legally enforceable obligation (the "LEO") for the delivery of energy and capacity by Oak Tree to NWE." This offer committed to make delivery of energy and capacity to NWE and included an executed power purchase agreement with a price for energy, including the Project's capacity contribution, of $54.40/MWh with an annual escalator of 2.5 percent, which is equivalent to a 20-year levelized cost of approximately $65.12/MWh. TR1 3; Ex 3, Exhibit 10 (see also Exhibit 10 to the Complaint). The Commission finds that this action by Oak Tree, coupled with its unsuccessful efforts to engage NWE in meaningful negotiations, created a legally enforceable obligation under 18 C.F.R. §292.304(d).

Avoided Cost

9. Following its receipt of NWE's response to its offer of an LEO, Oak Tree concluded that negotiations that could result in a viable power purchase agreement with NWE were not going to occur and decided that bringing the matter before the Commission for determination of the avoided cost rate was the only course of action available to it. TR1 178-187; Ex 3, Exhibits 11-13.

10. One of the primary issues contested at the first hearing on avoided cost was the issue of the proper methodology to employ in analyzing and modeling avoided cost over a 20 year term, the term that Oak Tree stated in its LEO offer to NWE. 18 C.F.R. § 292.101(6) defines "avoided cost" as follows:

> 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.

11. Oak Tree's witness Lauckhart employed what he characterized as a spot market based market approach to project NWE's avoided costs over a twenty year period with the value of avoided energy costs coming directly from the Black & Veatch Fall 2010 Energy Market Forecast for the Midwest United States and applied to each hour of the twenty year QF contract term and the value of capacity coming from the Black & Veatch forecast of the value of capacity in the South Dakota area and applied to the twenty percent of the 19.5 MW nameplate capacity of the Project that the Midwest Reliability Organization applies to wind energy facilities for capacity accreditation beginning in the year 2013 when NWE indicated it would become capacity deficient in its then current biennial 10-year plan on file with the Commission pursuant to SDCL 49-41B-3. Ex OT 1, pp. 4-7. Mr. Lauckhart calculated both a "brown value" avoided cost of $78.92/MWh, which assumes the avoided costs are not from a renewable resource and a "green value" avoided cost of $70.81, which assumes the source is a renewable source.

12. NWE's witnesses LaFave, Green, and Lewis employed a combination of incremental baseload avoidable costs and spot market prices in what Mr. LaFave characterized as a mixture of the Component/Peaker method and the Market Estimates method to reflect the actual costs that NWE could avoid by offsetting market purchases and backing down the most expensive baseload unit, depending on load. The general method employed by NWE has been referred to in this proceeding as the "hybrid method." Ex Staff 1, p. 9. NWE included a capacity contribution in its calculations of avoided cost for the first hearing with such contribution to begin in 2016. Ex NW 1, p. 10. NWE calculated its avoided cost at $35.85 levelized over a 20-year term. Ex NW 1, p. 18.

13. Staff witness Rounds asserted that NWE's method seems to most accurately reflect NWE's actual avoided incremental costs. However, Mr. Rounds believed NWE's gas and electric price forecasts to be unreliable. Ex Staff 1, p. 10.

14. As the Commission ruled in its Interim Order and again in denying Oak Tree's motion for reconsideration in its Order Granting in Part and Denying in Part Motion for Partial Reconsideration and Application for Reconsideration, the Commission finds that the "hybrid method" or combination method employed by NWE of using forecasted avoided incremental baseload costs for energy supplied to NWE from such resources and projected market prices for energy supplied to NWE from such resources most closely matches NWE's actual avoided costs. NWE is a vertically integrated utility that generates most of its energy at this time from its own baseload generation resources. To the extent that NWE is supplying all energy in an hour from its own baseload generation, the only costs NWE can avoid in that hour are the variable baseload generating costs that will be avoided by backing down its costliest baseload generator.

15. In its Interim Order, the Commission found, however, that NWE may have utilized unjustifiably low natural gas inputs and electric market inputs in calculating its avoided costs, and as a result, the Commission could not reliably determine the proper avoided cost with the data and analyses in the record from the first hearing. The Commission did not overturn this finding on reconsideration. In the second hearing, the parties presented additional and revised evidence in conformity with the Commission's Interim Order.

16. In the Interim Order, the Commission found that NWE's model inputs into the hybrid method were deficient in that they did not include projected carbon costs. The Commission also found that the carbon emission cost values of $5/ton starting in 2015 and shifting to $10/ton starting in 2020 and rising to $15/ton in 2025 as estimated by Lands Energy were reasonable carbon emissions cost estimates in the present environment and were the appropriate carbon emissions cost values to be included in the parties' respective hybrid

method analyses of avoided cost. On reconsideration, the Commission reversed its findings regarding the propriety of including carbon costs in the avoided cost calculations as unjustifiably speculative at this time.

17. In the Interim Order, the Commission found that the appropriate contract term for the Project was 20 years to enable the Project to obtain financing in accordance with the objectives of PURPA. This finding was not challenged in the parties' motions to reconsider and the Commission so finds.

18. In the Interim Order, the Commission directed the parties to utilize current market conditions and projections in determining proper natural gas inputs and proper electric market rates. On reconsideration, the Commission determined that this use of current inputs violates the PURPA requirement that the avoided cost must be determined as of the LEO date of February 25, 2011, and the Commission accordingly found that cost inputs and projections should be as of such date.

19. In testimony filed for the second hearing following the Interim Order and Reconsideration Order, Oak Tree witness Lauckhart employed natural gas price forecast data from five of the forecast scenarios in the U.S. Energy Information Administration's Annual Energy Outlook, 2010, and other comparative scenarios to arrive at a range of projected avoided cost values. Mr. Lauckhart asserted that the appropriate resource upon which to base the avoided capacity component of avoided cost is NWE's Aberdeen peaking plant currently under construction and in NWE's ten year plan as of the LEO date of February 25, 2011. Mr. Lauckhart stated that the cost of the Aberdeen gas turbine is approximately $141/kw-yr. and that this is an appropriate input value for NWE's avoided capacity cost. Ex OT 10, pp. 3-4. Mr. Lauckhart asserted that based on this range of forecasted natural gas prices and other inputs, including capacity, avoided costs lie in the range between $56/MWh to $89/MWh. Mr. Lauckhart recommended the use of the average of these scenarios to factor in all of the forecast probabilities. He stated that the average of these calculated avoided values is $69.3/MWh. Ex OT 9, pp. 11-16. Mr. Lauckhart also stated that he preferred the model employed by Staff over the model employed by NWE. Ex OT 10, p. 7.

20. Using 2012 as year one of the power purchase contract, NWE's witness LaFave's analysis of avoided cost for energy resulted in a 20-year levelized avoided energy cost of $37.99. Mr. LaFave's calculation of avoided capacity cost resulted in an avoided capacity cost of $36 per kilowatt year, increasing at a rate of 5.84% for the remaining years. This results in a 20-year levelized avoided capacity cost of $56.56 per kilowatt year. Ex NW 15, pp. 7-8.

21. Staff witness Rounds asserted that the proper application of the hybrid method would be to evaluate each hour of the year and compare NWE's load, NWE's base load generation, and the QF's output. Mr. Rounds proposed method sets the avoided cost: (i) for hours in which NWE's baseload generation exceeds its load, at the cost of NWE's most expensive baseload generator: (ii) for hours in which NWE's load exceeds its baseload generation by at least the QF's output, at the market price; and (iii) and for hours in which NWE's load exceeds its baseload, but not by as much as the QF's output level, at market price for the difference between NWE's load and its base load generation capacity and at the cost of its most expensive base load generator for the remaining QF output. Ex Staff 2, p. 1. Mr. Rounds also asserted that 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, and utilized by the Eastern Interconnection Planning Collaborative (EIPC) for its analysis in the Eastern Interconnection Business As Usual future

analysis. Ex Staff 2, p. 2-5. Mr. Rounds utilized a "load block" analysis utilized by EIPC and the EIPC load growth projections, load shapes for this region, and a pricing method consisting of EIPC price projections adjusted by AEO data to scale the data to this region. Ex Staff 2, p. 5-7. Mr. Rounds computed NWE's levelized avoided cost over a 20 year period at $54.32/MWh beginning in 2013 and $55.78/MWh beginning in 2014. Ex Staff 2, p. 3. For the capacity component, Mr. Rounds used a rated capacity value of 19.5 MW, a capacity cost value of $20 per kilowatt year, and a capacity credit of 12.9 percent across the entire 20 years which yielded an avoided capacity cost of $0.66/kWh. TR2 250-251; Ex Staff 2, p. 6.

22. At hearing, Mr. Rounds testified that he felt adjustments needed to be made to certain inputs to his avoided cost calculations. This included adding an inflation adjustment to capacity cost of 2.5% per year and adjusting the capacity contribution value to 18.915 MW to reflect the net-of-losses value stated in Oak Tree's FERC Form 556 QF certification filed with the Complaint as Exhibit 1 thereto. TR2 253. Mr. Rounds also testified that the MAPP_US load shape that he had used in his modeling did not seem to accurately reflect NWE's load shape, and he therefore substituted the MISO West load shape which better matches NWE's actual energy demand. TR2 254-255; Ex Staff 5. Based on these changes, Mr. Round's revised calculations produced an avoided cost of $46.23/MWh beginning in 2013 and $47.55/MWh beginning in 2014.TR2 257; Ex Staff 6.

23. The Commission finds that Oak Tree is entitled to capacity credit for the facility's output commencing with the Project's coming online with the capacity value equal to 20% of the Project's net-of-losses capacity of 18.915 MW. The 20% value is the appropriate percentage since NWE is a member of the Midwest Reliability Organization (MRO), and as of the LEO date of February 25, 2011, the MRO accredited wind energy facilities at 20% of their rated capacity.

24. The Commission finds that the appropriate model for determining avoided costs is the model developed by Staff witness Rounds. Ex Staff 2.

25. The Commission finds that the appropriate inputs into the model to fairly reflect NWE's avoided energy costs are to utilize NWE's actual hourly load shape and apply it to the hourly forecast blocks developed by the EIPC as used by Staff witness Rounds. The EIPC projections were developed by an industry wide collaborative of professionals in the field and represent a disinterested set of projections that is generally accepted by the industry.

26. The Commission finds that the appropriate peak growth rate and energy load growth rate forecasts for the next 20 years are the 1 percent per year peak and 2.25 percent per year energy growth rates offered by NWE. Ex NWE 10, p. 2. The Commission further finds that the appropriate method for distributing the annual energy growth across NWE's load shape as it changes in response to the greater growth rate in energy than peak is to spread the energy growth across the forecast blocks as a function of each block's growth room to the total growth room of all blocks.

27. The Commission finds that the proper avoided capacity costs are the $36 per kilowatt year avoided capacity cost value presented by NWE through the end-of-year 2015 termination date of NWE's capacity contract upon which this capacity value is based, and then escalating by 5.84 percent on January 1, 2016, and at the beginning of each year thereafter for the remainder of the 20-year QF contract term. TR2 211; Ex NWE 14.

28. The Commission finds that renewable energy credits (REC) associated with the Project should remain with Oak Tree. Oak Tree will have access to the REC market, and Oak Tree can market its RECs as it deems in its best interest.

29. The Commission finds that the appropriate model input for NWE's base generation is 191 megawatts. TR2 272.

30. The Commission finds that the introduction of these inputs into the model developed by Mr. Rounds yields the resulting levelized and non-levelized avoided cost values set forth on the spreadsheet attached hereto as Exhibit A and incorporated herein by reference.

31. The Commission finds that levelized avoided cost values, discounted by a 7.86% present-value discount factor, are the appropriate values to use because they will produce a stable price that will better enable Oak Tree to finance the Project. The Commission accordingly finds that NWE's avoided cost for the Oak Tree Project is $49.24/MWh if production begins in 2013 and $51.23/MWh if production begins in 2014 as set forth on the "Levelized" columns of Amended Exhibit A.

General

32. To the extent that any Conclusion of Law set forth below is more appropriately a Finding of Fact, that Conclusion of Law is incorporated by reference as a Finding of Fact.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over this matter pursuant to 16 U.S.C. Chapter 12, § 824a-3, 18 C.F.R. Part 292, and SDCL Chapters 1-26 and 49-34A, including 49-34A-93.

2. 16 U.S.C. § 824a-3(a) required the Federal Energy Regulatory Commission to promulgate rules "to encourage cogeneration and small power production . . . , which rules require electric utilities to offer to. . . (2) purchase electric energy from such facilities." Under 16 U.S.C. § 824a-3(f), following FERC's promulgation of such rules, "each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority." Pursuant to 16 U.S.C. § 824a-3(b), "rates for such purchase—

> (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."

16 U.S.C § 824a–3 defines "incremental cost to the electric utility of alternative electric energy" as follows:

> "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such

cogenerator or small power producer, such utility would generate or purchase from another source.

The FERC rules set forth in 18 C.F.R. Part 292 set forth the standards for the Commission's determination of avoided cost.

3. A legally enforceable obligation need not have a contract executed by the utility to exist. If it did, utilities could negate the operation of PURPA by simply refusing to sign.

4. The Commission concludes that a legally enforceable obligation was created on February 25, 2011, under 18 C.F.R. § 292.304(d).

5. The appropriate contract term for the Project is 20 years to enable the Project to obtain financing in accordance with the objectives of PURPA.

6. The inclusion of carbon costs in the avoided cost calculations is not justified at this time due to the absence of any legislation that seems likely to pass that would establish such costs and is therefore too speculative to warrant inclusion in the avoided cost.

7. Oak Tree is entitled to capacity credit for the facility's output commencing with the Project's coming online with the capacity value equal to 20% of the Project's after-losses capacity of 18.915 MW. The 20% value is the appropriate percentage since NWE is a member of the Midwest Reliability Organization (MRO), and as of the LEO date of February 25, 2011, the MRO accredited wind energy facilities at 20% of their rated capacity.

8. Levelized avoided cost values, discounted by a 7.86% present-value discount factor, are the appropriate values to use because they will produce a stable price that will better enable Oak Tree to finance the Project. NWE's avoided cost for the Oak Tree Project is $49.24/MWh if production begins in 2013 and $51.23/MWh if production begins in 2014 as set forth on the "Levelized" columns of Amended Exhibit A.

9. To the extent that any of the Findings of Fact in this decision are determined to be conclusions of law or mixed findings of fact and conclusions of law, the same are incorporated herein by this reference as a Conclusion of Law as if set forth in full herein.

It is therefore

ORDERED, that the avoided cost determinations of the Commission as set forth in the Findings of Fact and Conclusions of Law shall govern the pricing and payment for the delivery of energy and capacity by Oak Tree to NWE. It is further

ORDERED, that NWE and Oak Tree shall enter into negotiations in good faith to consummate a power purchase agreement consistent with the avoided cost determinations and other Findings of Fact and Conclusions of Law of this Order and with current normative terms of such contracts. The parties shall conclude such negotiations and reach an agreement on a power purchase agreement no later than thirty (30) days following the date of issuance of this Order and file such agreement with the Commission.

NOTICE OF ENTRY AND OF RIGHT TO APPEAL

PLEASE TAKE NOTICE that this Amended Final Decision and Order; Notice of Entry was duly issued and entered on the 17th day of May, 2013. Pursuant to SDCL 1-26-32, this Amended Final Decision and Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties. Pursuant to SDCL 1-26-31, the parties have the right to appeal this Final Decision and Order to the appropriate Circuit Court by serving notice of appeal of this decision to the circuit court within thirty (30) days after the date of service of this Notice of Entry and Right to Appeal.

Dated at Pierre, South Dakota, this 17th day of May, 2013.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: [signature]

Date: 05.17.13

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

[signature]

GARY HANSON, Chairman, dissenting in part

[signature]

CHRIS NELSON, Commissioner, dissenting in part

[signature]

KRISTIE FIEGEN, Commissioner, dissenting

Amended Exhibit A

Staff's 1% Peak and 2.25% Energy Growth								
					Beginning in 2013		Beginning in 2014	
Year	Oak Tree Output (MWh)	Oak Tree Capacity Value ($)	Oak Tree Energy Value ($)	Avoided Cost ($/MWH)	Rounded Actual ($/MWh)	Levelized ($/MWh)	Rounded Actual ($/MWh)	Levelized ($/MWh)
2013	76527.3688	$136,188.00	$2,556,867.56	35.19075074	35.19	49.24		
2014	76527.3688	$136,188.00	$2,688,995.60	36.91729692	36.92	49.24	36.92	51.23
2015	76527.3688	$136,188.00	$2,827,810.08	38.73121636	38.73	49.24	38.73	51.23
2016	76527.3688	$144,141.38	$3,030,092.44	41.47841316	41.48	49.24	41.48	51.23
2017	76527.3688	$152,559.24	$3,200,408.01	43.81396221	43.81	49.24	43.81	51.23
2018	76527.3688	$161,468.70	$3,293,155.71	45.14233870	45.14	49.24	45.14	51.23
2019	76527.3688	$170,898.47	$3,341,755.54	45.90062434	45.90	49.24	45.90	51.23
2020	76527.3688	$180,878.94	$3,430,472.43	47.19032454	47.19	49.24	47.19	51.23
2021	76527.3688	$191,442.27	$3,535,886.83	48.70583105	48.71	49.24	48.71	51.23
2022	76527.3688	$202,622.50	$3,820,812.31	52.57510971	52.58	49.24	52.58	51.23
2023	76527.3688	$214,455.65	$4,160,336.83	57.16637782	57.17	49.24	57.17	51.23
2024	76527.3688	$226,979.86	$4,271,017.20	58.77631921	58.78	49.24	58.78	51.23
2025	76527.3688	$240,235.48	$4,364,360.80	60.16927477	60.17	49.24	60.17	51.23
2026	76527.3688	$254,265.24	$4,488,800.38	61.97868404	61.98	49.24	61.98	51.23
2027	76527.3688	$269,114.33	$4,595,850.57	63.57156883	63.57	49.24	63.57	51.23
2028	76527.3688	$284,830.60	$4,720,069.44	65.40013221	65.40	49.24	65.40	51.23
2029	76527.3688	$301,464.71	$4,852,732.64	67.35103316	67.35	49.24	67.35	51.23
2030	76527.3688	$319,070.25	$4,978,792.42	69.22833956	69.23	49.24	69.23	51.23
2031	76527.3688	$337,703.95	$5,092,729.42	70.96067007	70.96	49.24	70.96	51.23
2032	76527.3688	$357,425.86	$5,257,895.22	73.37663863	73.38	49.24	73.38	51.23
2033	76527.3688	$378,299.53	$5,375,926.44	75.19173939			75.19	51.23

Discount Factor 7.86%

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE COMPLAINT BY JUHL ENERGY, INC. AGAINST NORTHWESTERN CORPORATION DBA NORTHWESTERN ENERGY FOR ESTABLISHING A PURCHASE POWER AGREEMENT	**STAFF'S FIRST SET OF DATA REQUESTS TO JUHL ENERGY** **EL16-021**

1-9) On page 12 of Roger Schiffman's direct testimony, he states that Juhl believes an LEO has been established. Provide support for that statement. Upon which date does Juhl contend the LEO was established?

ANSWER: With respect to the first question, Mr. Schiffman is not a lawyer and believes the question of LEO formation is a matter of law better addressed in legal arguments between the party, assuming there is disagreement. With respect to the second part of the question, Juhl believes the LEO should run from the date negotiations ended, which would be April 4, 2016.

ARTICLE 20:10

PUBLIC UTILITIES COMMISSION

Chapter

20:10:01 General rules of practice.

20:10:02 General motor carrier rules, Repealed.

20:10:03 Regulated motor carriers, Repealed.

20:10:04 Exempt motor carriers, Repealed.

20:10:05 General telecommunications company rules.

20:10:06 Telecommunications records.

20:10:07 Telecommunications subscriber billing rules.

20:10:08 Telecommunications credit.

20:10:09 Refusal of telecommunications service.

20:10:10 Disconnection of telecommunications service.

20:10:11 Public grain warehouses.

20:10:12 Grain buyers.

20:10:13 Public utilities rate filing rules.

20:10:14 Procedure rules for public utilities, Repealed or transferred.

20:10:15 General gas and electric rules.

20:10:16 Gas and electric utility records and public information rules.

20:10:17 Gas and electric customer billing rules.

20:10:18 Gas and electric service rules.

20:10:19 Establishment of gas and electric credit.

20:10:20 Refusal and disconnection of gas and electric service.

20:10:21 Energy facility plans.

20:10:22 Energy facility siting rules.

20:10:23 Gas and electric advertising rules.

20:10:24 Interexchange carrier and classification rules.

20:10:25 Telecommunications facility construction notice rules, Repealed.

20:10:26 Master metering variance rules.

20:10:27 Telecommunications switched access filing rules.

20:10:28 Telecommunications separations procedures.

20:10:29 Telecommunications switched access charges.

20:10:30 Assignment of N11 dialing codes.

20:10:31 Assessment of fees for intrastate gas pipeline operators.

20:10:32 Local exchange service competition.

20:10:33 Service standards for telecommunications companies.

20:10:34 Prohibition against unauthorized changing of telecommunications company and charging for unauthorized services.

20:10:35 Telecommunications services.

20:10:36 Small generator facility interconnection.

20:10:37 Pipeline safety rules.

20:10:38 Renewable, recycled, and conserved energy rules.

20:10:39 Stray electrical current and voltage remediation.

20:10:40 Requirements for establishing a legally enforceable obligation.

20:10:40

REQUIREMENTS FOR ESTABLISHING A LEGALLY ENFORCEABLE OBLIGATION

Section

20:10:40:01. Definitions.

20:10:40:02. Applicability of rules.

20:10:40:03. Establishment of a legally enforceable obligation.

20:10:40:01. Definitions. Terms defined in SDCL 49-34A-1 have the same meaning when used in this chapter. In addition, terms used in this chapter mean:

(1) "Avoided cost," the incremental costs to a public utility of electric energy or capacity or both which, but for the purchase from the qualifying facility, the public utility would generate itself or purchase from another source;

(2) "Legally enforceable obligation," an obligation that the qualifying facility will sell and the affected public utility will purchase energy or capacity or both for a specified term in which the rates for purchase shall, at the option of the qualifying facility, be based on either the avoided costs calculated at the time of delivery or the avoided costs calculated at the time the obligation is incurred;

(3) "Qualifying facility," a facility that meets the definition of a qualifying facility under 18 C.F.R. § 292.101(b)(1) (July 1, 2014).

Source:

General Authority: SDCL 49-34A-93.

Law Implemented: SDCL 49-34A-93.

20:10:40:02. Applicability of rules. The provisions of § 20:10:40:03 apply only to the establishment of a legally enforceable obligation between a qualifying facility with a design capacity of more than 100 kilowatts and a public utility.

Source:

General Authority: SDCL 49-34A-93.

Law Implemented: SDCL 49-34A-93.

20:10:40:03. Establishment of a legally enforceable obligation. A legally enforceable obligation is established when a qualifying facility notifies the public utility of the qualifying facility's intent to establish a legally enforceable obligation and the following requirements have been met:

(1) The qualifying facility, if it has a net power production capacity of 500 kW or more, has notified the public utility of its status as a qualifying facility at least 90 days prior, pursuant to 18 C.F.R. § 292.207(c)(2);

(2) The qualifying facility has entered into an interconnection agreement or the interconnection process is delayed as a result of a dispute that has been filed with the proper jurisdiction;

(3) The public utility has failed to provide the avoided cost information required by 18 C.F.R. § 292.302 (July 1, 2014) or the qualifying facility has filed a dispute of the public utility's avoided cost information with the Commission;

(4) The qualifying facility has offered a signed power purchase agreement to the public utility that includes the following:

(a) A purchase price based on the qualifying facility's estimate of the public utility's avoided cost;

(b) A reasonable date or range of dates for commencement of delivery of the energy or capacity, or both;

(c) The length of the contract; and

(d) Other terms and conditions that would be reasonable in the industry; and

(5) The qualifying facility has shown that it has made significant progress toward bringing the qualifying facility into existence by providing:

(a) A list of any permits that are needed for the facility to be operational and documentation that it has completed or started the process to obtain the permits;

(b) A description of the site of the project and documentation that it has acquired or is in the process of acquiring the land or any necessary easements or options;

(c) The amount of financing that is needed and documentation that it has acquired financing or its plan for acquiring financing; and

(d) A description of any owners, employees, or consultants' qualifications to construct and operate the qualifying facility.

The notification of the qualifying facility's intent to establish a legally enforceable obligation shall be sent via certified mail to the public utility and shall include any necessary documentation demonstrating that the above requirements have been met. A copy of the notification and the attached documentation shall be sent to the commission.

Source:

General Authority: SDCL 49-34A-93.

Law Implemented: SDCL 49-34A-93.

Michael J. Uda
Uda Law Firm, P.C.
7 West 6th Avenue
Power Block West, Suite 4H
Helena, MT 59601
(406) 457-5311
michaeluda@udalaw.com

Attorney for Juhl Energy, LLC

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF The Consideration of Standards to Govern Avoided Cost Determinations	DOCKET NO. RM13-02

COMMENTS OF JUHL ENERGY, INC.

I. INTRODUCTION

At the outset, Commenter Juhl Energy, Inc., ("Juhl) wishes to express its appreciation to the South Dakota Public Utilities Commission ("Commission") for this opportunity to comment on the above-captioned rule making. As an initial observation, the only comments received on the proposed rule thus far are from utilities, utilities which as a category, have been traditionally hostile to purchasing power from qualifying facilities. Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities." *FERC v. Mississippi*, 456 U.S. 742, 750 (1982) (footnote omitted). This "reluctance" has continued to this day, as utilities continue to place impediments in the way of qualifying facilities or "QFs." Some of the utility commenters even request that the Commission adopt rules that are inconsistent with the plain language of the Federal Energy Regulatory Commission's ("FERC") rules implementing the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 824-a3, *et seq* ("PURPA").

II. REPLY COMMENTS ON PROPOSED RULE 20:10:40:03. ESTABLISHMENT OF A LEGALLY ENFORCEABLE OBLIGATION.

A. BACKGROUND

PURPA directs the states to implement PURPA consistently with the regulations adopted by the Federal Energy Regulatory Commission ("FERC"). PURPA § 210(H)(2)(a), 16 U.S.C. 824a-3(h)(2)(B). *See also Exelon Wind 1, LLC*, 140 FERC ¶ 61,152, at P 44 (2012), *rev'd on other grounds*, *Exelon Wind 1, L.L.C. v. Nelson*, 766 F.3d 380, 2014 U.S. App. LEXIS 17354, 44 ELR 20202 (5th Cir. Tex. 2014) ("As a result, a state may take action under PURPA only to the extent that that action is in accordance with the Commission's regulations.")

Under 18 C.F.R. 292.304(d), PURPA allows a QF the option as to how it will sell its generation to a utility. As FERC stated in *Hydrodynamics, et al.*, 146 FERC ¶ 61,193, P. 31 "Under section 292.304(d) of the Commission's regulations, a QF also has the unconditional right to choose whether to sell its power "as available" or at a forecasted avoided cost rate pursuant to a legally enforceable obligation."

QFs often must obtain financing to construct, operate, and build a project, thus FERC adopted regulations specifying that the choice of how a utility will offer to sell its generation to a utility was best left to the QF: "Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter argumenta, and believes that. in the long run, "overestimations" and "underestimations" of avoided costs will balance out." 45 Fed. Reg., 12,214, 12,224 (1980) (hereinafter "FERC Order

69"). Consequently, it is up to the QF under PURPA to choose how to make its commitment to sell power to utilities, not up to the Commission and not up to the utilities.

Finally, the Commission will recall that its obligation is to "encourage" QF generation.

> The Montana Rule creates, as well, a practical disincentive to amicable contract formation because a utility may refuse to negotiate with a QF at all, and yet the Montana Rule precludes any eventual contract formation where no competitive solicitation is held. Such obstacles to the formation of a legally enforceable obligation were found unreasonable by the Commission in Grouse Creek, and are equally unreasonable here and contrary to the express goal of PURPA to "encourage" QF development.

Hydrodynamics, ¶ 33.

Thus, the Commission must not only "encourage" QF generation, but FERC also has clearly stated that "amicable barriers to contract formation" are not consistent with FERC's regulations implementing PURPA. For the Commission to implement many of the suggestions offered by the utilities in their comments on the Commission's proposed rule would not accomplish that goal, but would rather discourage QF generation in South Dakota and create practical disincentives to amicable contract formation.

B. OTTER TAIL POWER'S COMMENTS

Otter Tail Power ("Otter Tail") generally supports the draft rulemaking, but suggests the following sentences be added to the definition of "Avoided costs" in Section 20:10:40:01:

> The purchasing utility may recover from the qualifying facility any costs incurred by the purchasing utility that result from the addition of the qualifying facility to the system. Such increased costs may include, but are not limited to, increased costs for congestion management, transmission service expenses, ancillary services expenses and similar items.

Otter Tail's suggestion is contrary to the definition of "avoided costs" set forth in FERC's regulations and is an invitation to error on the part of the Commission. FERC's existing rule implementing PURPA provides that "avoided cost" means "[T]he 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 would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). With respect to interconnection and transmission related costs, FERC has adopted regulations which address those issues as well:

> QFs have the right to purchase supplementary power, back-up power, maintenance power, and interruptible power at rates which are just and reasonable, based on accurate data and consistent system-wide costing principles, and that apply to the utility's other customers with similar load or cost-related characteristics (*see* 18 C.F.R. § 292.305), provided the selling utility has not been relieved from its QF sales obligation (*see* 18 C.F.R. § 312 - 313). QFs also have the right to interconnect with a utility by paying a nondiscriminatory interconnection fee approved by the State regulatory authority or a nonregulated electric utility (*see* 18 C.F.R. § 292.306).

http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp

In addition, if the proposal is to treat the interconnection costs and transmission costs associated with QFs differently than non-QF facilities, such discrimination is prohibited under FERC's implementing regulations. *See* 18 C.F.R. § 292.304(a)(1)(ii). Otter Tail's intentions in this regard are unclear, but it appears to be arguing that avoided costs should necessarily include the costs of interconnection, transmission and ancillary related costs. Presumably, these costs should already be part of the avoided cost calculation adopted by the Commission either in standard rates or for rates negotiated between QFs and utilities. Thus, not only is Otter Tail's proposal unnecessary, but it also raises the specter of FERC-prohibited discrimination against QFs and may create a formidable barrier to amicable contract formation.

C. XCEL ENERGY COMMENTS

Xcel Energy's comments are definitely an invitation to error by the Commission. First, Xcel doubts the need for a purchase obligation, given the industry changes that have taken place since the enactment of PURPA. FERC's implementing regulations already provide a process by which a utility can be relieved of its mandatory purchase obligation pursuant to 18 C.F.R. §§

292.312 and 313). However, it is incumbent on a utility, and Xcel has, to be relieved of its mandatory purchase obligation. However, for projects which are larger than 20 megawatts ("MW") or more, the purchase obligation remains unless the utility can make a demonstration that it should be relieved of its mandatory purchase obligation under PURPA. *See Northern States Power Company*, 151 FERC ¶ 61,110, P. 31(finding that Northern States Power Company had not met the burden of showing it should be relieved of its purchase obligations for QFs with a capacity of 20 MW). Although Xcel expresses doubt regarding the continuing obligation of South Dakota utilities under PURPA, those doubts are better addressed at FERC rather than before this Commission. Adopting rules which interfere with QFs rights under PURPA to sell their energy and capacity to South Dakota utilities creates as specter of being preempted by federal law.

Second, Xcel states that it supports limiting the time-frame of an LEO to a minimum of 5 years and a maximum of 20, reasoning that such a time-frame reflects an effective resource planning horizon for the purchasing utility. Limiting contract length is nowhere supported by FERC's regulations implementing PURPA nor by PURPA itself. Limiting contract length also raises the issue of whether Xcel's proposal, if adopted by the Commission would result in discrimination against QFs in violation of PURPA.

Third, Xcel also makes suggestions to amend the language of the definition in Section 20:10:40:01 to add the following language "The purchasing utility may recover from the qualifying facility any costs incurred by the purchasing utility that result from the addition of the qualifying facility to the system." Adoption of this vague language is an invitation to disputes between QFs and utilities in contract negotiations, as well as being unnecessary because presumably these issues are already addressed by FERC regulations and are already the subject matter of a proper calculation of avoided costs. Juhl has already commented on this sort of change to the definition with respect to Otter Tail's comments.

Fourth, Xcel, like Otter Tail, suggests additional language that makes clear that certain QFs have access to wholesale markets and may therefore be ineligible for LEOs under PURPA. As noted in response to Otter Tail's comments, this language is not only unnecessary but also raises the specter of preemption by PURPA.

D. MIDAMERICAN COMMENTS

MidAmerican, as well as Otter Tail and Xcel, also suggest clarification the purchasing utility will be entitled to recover the costs incurred as a result of the addition of the QF to the grid. As noted above, this is unnecessary and potentially discriminating, depending on implementation. The proper calculation of avoided costs, the "but for" test, will result in a discussion of whether it is or is not appropriate for a utility to deduct these costs from avoided costs. As noted previously in response to Otter Tail and Xcel, utilities may not discriminate against QFs. See 18 C.F.R. § 292.101(a)(1)(ii). If MidAmerican and other utilities are not following the FERC rules for interconnection and related system upgrade costs, this is nothing more than discrimination and these costs should not be included. If the Commission were to adopt such a rule, it would raise the specter of preemption by PURPA.

E. NORTHWESTERN COMMENTS

NorthWestern believes the definitions in the proposed draft rule are unclear, and therefore suggests the following amendments to 20:10:40:01 Definitions:

1. "Avoided cost," the incremental costs to a public utility of electric energy or capacity or both which, but for the purchase from the qualifying facility, the public utility would generate itself or purchase from another source <u>less any other costs that the public utility</u>

incurs which, but for the purchase from the qualifying facility, the public utility would not incur.

Again, as noted previously multiple times, it is not appropriate to change the definition of avoided cost. The definition of avoided cost is set forth already in FERC's regulations, and the Commission is obligated to implement and enforce that definition. This is merely another way of attempting to recover costs that are not properly part of the avoided cost calculation -- in other words an inappropriate deduction from the calculation of avoided costs and would, if adopted by the Commission, be preempted by PURPA. Moreover, as noted previously, the proper calculation of avoided costs, and what deductions should be included, is already a subject for discussion in negotiated QF agreements.

2. "Legally enforceable obligation," an unconditional obligation incurred by ~~that~~ the qualifying facility to ~~will~~ sell and deliver, which binds the affected public utility to purchase and accept, ~~the affected public utility will purchase~~ energy or capacity or both for a specified term in which the rates for purchase shall, at the option of the qualifying facility, be based on either the avoided costs calculated at the time of delivery or the avoided costs calculated at the time the obligation is incurred;

This definition appears nowhere in any FERC decision, FERC's regulations, in PURPA itself, or in any reported court decision interpreting PURPA. Furthermore, it makes no sense. A party cannot make an unconditional obligation to sell until it knows the price it will receive from the utility. No prudent business would enter into such an arrangement. This definition is simply another invitation to error as it is inconsistent with the plain language of FERC's definition under 18 C.F.R. 292.304(d), which the Commission is obliged to implement.

NorthWestern also suggests a series of edits to section 20:10:40:03 Establishment of a legally enforceable obligation, replicated below:

1. (2) The qualifying facility has, for interconnection purposes, been studied as a network resource and entered into an interconnection agreement or the interconnection process is delayed as a result of a dispute that has been filed with the proper jurisdiction;

This is an unreasonable barrier to amicable contract formation. Imposing significant costs on a QF prior to incurring a legally obligation is inconsistent with prior FERC decisions such as *Hydrodynamics* and *Grouse Creek Wind Park*, 142 FERC ¶ 61,187, at P 40 (2013). In *Hydrodynamics*, FERC stated:

> In *Grouse Creek*, the Commission found that the Idaho Commission's requirement that a QF file a meritorious complaint to the Idaho Commission before obtaining a legally enforceable obligation "would both unreasonably interfere with a QF's right to a legally enforceable obligation and also create practical disincentives to amicable contract formation." Similarly, we find that requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation particularly where, as here, such competitive solicitations are not regularly held.

Requiring a QF to spend potentially a very significant amount of money (depending on the size of the facility) would chill QF development and be contrary to the Commission's responsibility to encourage QF development in South Dakota. It imposes an unreasonable barrier to amicable contract formation because it requires the expenditure of substantial amounts of money on interconnection studies and network upgrade regardless of whether the utility is willing to negotiate, whether substantial negotiations have taken place, or whether the QF has committed to sell its output to the utility. Such a result would be contrary to multiple FERC decisions interpreting its own PURPA regulations. This is yet another invitation to error by NorthWestern, one which the Commission should resist.

2. (3) More than the greater of 90 days since the qualifying facility requested or 30 days since the QF provided all information needed by the utility for determination of the public utility's avoided cost have elapsed and the public utility has failed to provide either the avoided cost information required by 18 C.F.R. § 292.302 (July 1, 2014) or the public utility's estimate of its avoided cost for the specific qualifying facility, or the qualifying facility has filed a dispute of the public utility's avoided cost information with the Commission;

Again, this amendment to the definition is not only inconsistent with FERC's regulations implementing PURPA by placing obligations on QFs that they do not presently have, it provides the utility with yet another reason not to cooperate with negotiations or to make unwarranted claims of failing to negotiate. Surely, if a QF is this lax in its negotiations with a utility and yet proceeds to file a complaint with the Commission, the Commission already will attempt to determine whether the QF fulfilled its obligation to negotiate. This is yet another pretense by which utilities can impede and interfere with contract negotiations, and by this mischief, demonstrate their traditional "reluctance" to deal with QFs, as noted by the United States Supreme Court in *FERC v. Mississippi*.

3. (4) The qualifying facility has offered a signed power purchase agreement to the public utility that includes the following: (a) A purchase price based on the qualifying facility's estimate of the public utility's avoided cost; (b) A reasonable date or range of dates for commencement of delivery of the energy or capacity, or both; (c) The length of the

contract, not to exceed 10 years from the commencement of delivery of the energy or capacity, or both;

As noted previously, attempting to limit a QF contract length in this fashion is contrary to FERC's implementing regulations, as set forth in FERC Order 69. It is also discriminatory in that utilities do not limit their own commitments to 10 years when they plan to build a resource for which they must obtain financing commitments and must take advantage of favorable tax incentives such as the production tax credit or the investment tax credit. It is also an unreasonable barrier to contract formation, as QFs cannot typically obtain debt or equity financing for only a ten-year term. In the case of tax incentives, typically project finance will dictate that most of the revenue will go to the tax equity investors for the first 10 years of the project, with the project's equity owners being paid thereafter. If there is no incentive for a QF's equity owners to be paid, this will actively discourage QF generation in South Dakota.

4. (5) [. . .] (e) Security acceptable to the affected public utility to guarantee the qualifying facility's performance of the obligations incurred by creating a legally enforceable obligation.

This is yet another example of an unreasonable barrier to contract formation, and an attempt to discourage QF generation in South Dakota. Not only does it violate the letter of PURPA, but it is unnecessary. If the proposed avoided cost rates are, as NorthWestern has stated in the past, lower than market for the first years of a power purchase agreement, there is no harm to NorthWestern or its ratepayers from replacing the QF's output. In other words, the utility's ratepayers would benefit from delayed QF production, even according to NorthWestern. Traditionally, NorthWestern has used such clauses as penalties instead of as proper liquidated damages clauses in the event of non-performance/ Legal and enforceable liquidated damages clauses are typically used where damages are uncertain and cannot reasonably be calculated. Penalty clauses are unlawful because there is no need to punish a party for non-performance if damages can be easily calculated. Here, NorthWestern's request for security to secure performance is plainly a penalty clause. NorthWestern can easily determine the amount of damages, if any, in the event of nonperformance, by simply measuring the cost of the power it purchased and comparing it to the price paid to the QF. There is simply no reason for contract security. The effect and apparent intent of this provision, however, is to require QFs to come up with large amounts of security before incurring a legally enforceable obligation, and this sort of impediment to amicable contract formation is not only inconsistent with FERC's regulations and its decisions interpreting those regulations, it would actively discourage the development of QF generation in South Dakota by interfering with a QF's ability to create a legally enforceable obligation under PURPA.

III. CONCLUSION

With respect to the comments by the utilities submitted to the Commission and commented upon herein, none of the provisions suggested by the utilities are consistent with PURPA, FERC's regulations implementing PURPA, and FERC precedent on these issues. They are little more than the creation of barriers to "amicable contract formation" in South Dakota, a breeding ground for litigation, and an attempt to discourage QF generation in South Dakota.

For these reasons, Juhl Energy respectfully requests that the Commission reject these comments and allow the rules to stand as drafted.

RESPECTFULLY SUBMITTED THIS 1ST DAY OF MARCH, 2016

UDA LAW FIRM, P.C.

By: ______________________

Michael J. Uda
Of Attorneys for Juhl Energy, LLC

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

IN THE MATTER OF THE COMPLAINT BY JUHL ENERGY, INC. AGAINST NORTHWESTERN CORPORATION DBA NORTHWESTERN ENERGY FOR ESTABLISHING A PURCHASE POWER AGREEMENT	**JUHL ENERGY'S RESPONSES TO STAFF'S THIRD SET OF DATA REQUESTS TO JUHL ENERGY** **EL16-021**

Below, please find Juhl Energy's Responses to the South Dakota Public Utilities Commission Staff's Third Set of Data Requests to Juhl Energy.

<u>Third Data Request</u>

3-1) Please refer to Attachments 3-1a and 3-1b to Data Request 3-1. Attachment 3-1a is Juhl Energy's Reply Comments in Docket RM13-002, In the Matter of the Consideration of Stands to Govern Avoided Cost Determinations. Attachment 3-1b is South Dakota commission staff's draft rules submitted in Docket RM13-002. On Attachment 3-1a, page 11, section III, Juhl Energy requested that the Commission allow the rules to stand as drafted. Proposed Rule 20:10:40:03 (2), requires the following requirement be met to establish a legally enforceable obligation:

> *The qualifying facility has entered into an interconnection agreement or the interconnection process is delayed as a result of a dispute that has been filed with the proper jurisdiction.*

a) Please explain how Juhl Energy has met the requirements of a legally enforceable obligation when the qualifying facilities have not entered into interconnection agreements.
Response:(Corey Juhl)

Since the Commission has yet to adopt the proposed rules, it is unclear why the proposed rules have any bearing upon this proceeding or the Juhl projects. Having said that, the Juhl interconnection process has been delayed through no fault of the Juhl projects. NorthWestern has been considering Juhl's interconnection request for 416 days as of this response, and has advised it will now be January 31, 2017 before the interconnection process is completed.

b) Does Juhl Energy continue to support the rules as drafted in Docket RM13-002? Please explain.

Response: (Corey Juhl)

Given the Commission has yet to adopt the proposed rules, it is unclear why Juhl's support of the proposed rules, or lack thereof, has any bearing on this proceeding or the Juhl projects at issue in this proceeding.

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

IN THE MATTER OF THE COMPLAINT BY JUHL ENERGY, INC. AGAINST NORTHWESTERN CORPORATION DBA NORTHWESTERN ENERGY FOR ESTABLISHING A PURCHASE POWER AGREEMENT	* * * * * * * * *	**JUHL ENERGY'S RESPONSES TO STAFF'S THIRD SET OF DATA REQUESTS TO JUHL ENERGY** **EL16-021**

3-2) Please refer to Page AMM-4, lines 6-15 of the direct testimony of Ms. Mueller.

a) Does Juhl Energy agree with Ms. Mueller's description of the current status of the Brule County Wind interconnection request? Please explain.
Response: (Corey Juhl)
No. Juhl Energy does not agree that the Brule County Wind Project is "on hold." SPP has received all of the required information and data related to the Affected System Study Agreement and Juhl expects to receive results by or before 1/31/2017. Furthermore, Juhl does not understand how any Interconnection related items are relevant to our Complaint, especially since 18 C.F.R. §358.2 appears to prohibit NorthWestern's transmission department from attempting to disadvantage or prejudice Juhl in this proceeding. In addition, it also appears that NorthWestern's transmission department is not "functioning independently" of its non-transmission business, which is again apparently prohibited by 18 C.F.R. § 358.2. Finally, NorthWestern appears to have violated 17 C.F.R. § 358.2 by disclosing or attempting to disclose, non-public information about the Juhl projects directly or through a conduit. NorthWestern's transmission department's attempt to influence the outcome of this case against the supply side of NorthWestern's business is of great concern to Juhl, and should be to the Commission. As noted above in response to request 3-1) a), as of this writing it has been 416 days since Juhl attempted to interconnect with NorthWestern's system, leading Juhl to believe there has been inappropriate coordination between NorthWestern's transmission department and its non-transmission functions.

b) Please provide an update on the status of Affected System Study Agreement.
Response: (Corey Juhl).

Brule County Wind has signed and completed the requirements of the Affected System Study Agreement with SPP. The final results of the Affected System Study are expected on or before 1/31/2017.

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

IN THE MATTER OF THE COMPLAINT BY JUHL ENERGY, INC. AGAINST NORTHWESTERN CORPORATION DBA NORTHWESTERN ENERGY FOR ESTABLISHING A PURCHASE POWER AGREEMENT	**STAFF'S SECOND SET OF DATA REQUESTS TO JUHL ENERGY** **EL16-021**

2-2) On February 9, 2016, the Davison County Commission denied a conditional use permit for the Davison project.

a) Given the Davison County Commission's decision, what is the current status of the Davison project?
The Davison County Wind Project is still in the process of completing various development milestones including collecting wind speed data from our onsite meteorological tower, and communicating with our local land owner partners. The Project will be resubmitting a permit application after the County has adopted their new "Wind Energy Ordinance" which is expected to be in place by 01/15/17.

b) Please explain why the Davison project was included in the complaint submitted on June 23, 2016, when Davison County denied the project on February 9, 2016.
The Davison project was included in the complaint because it is part of the avoided cost rate discussion with Northwestern Energy as a Qualified Facility. Additionally, the project plans to re-submit an application with Davison County after they adopt their "Wind Energy Ordinance".

c) Does Juhl Energy intend to amend the complaint and eliminate the Davison project, effectively reducing the avoided cost calculation to reflect approximately 40 MW of nameplate wind generation instead of approximately 60 MW of nameplate wind generation? Please explain.

No. We plan to design the Davison County Wind Project in accordance with Davison County's new ordinance and continue with the development of the project.

d) Please provide justification for including Juhl's Davison county project in Mr. Schiffman's QF IN/OUT model.

As Juhl plans to continue to develop the Davison County Wind Project, and to comply with Davison County's new ordinance, when finalized, it was included in the QF IN/OUT model because it will be a qualifying facility and eligible to receive avoided cost.

e) If each Juhl project was modeled independently from one another, would that change the avoided cost amount attributable to the projects? Please explain.

The three Juhl projects were modeled as independent projects, but with all three projects included in the NorthWestern portfolio. If each were modeled separately, meaning in sequence, one at a time, avoided cost for the first two would be moderately higher than the current estimates. By modeling all three as included in the NorthWestern portfolio together, the largest possible impact on NorthWestern's system production cost is reflected in the analysis.

f) Referring to Juhl Energy's response to Staff data request 1-9 that a legally enforceable obligation was established on April 4, 2016, please explain how an obligation to sell power from the Davison Project existed when Juhl Energy was denied a permit necessary to construct and operate the proposed facility.

The existence of an LEO is important to establishing the date from which the obligation is incurred according to 18 C.F.R. 292.304(d)(2). The April 4, 2016 date was the date that negotiations concluded regarding avoided cost and the unresolved PPA terms, which are how RECS and Capacity Payments will be listed in the Exhibits, and the language around of the Right of First Offer.

The permits for the Davison project will be obtained prior to final Commission order in this proceeding. The project will be ready to proceed towards completion by that time. The permitting process does not affect the date of the LEO was incurred, which has to do with Juhl's commitment to sell which created a reciprocal obligation in NorthWestern to purchase energy and capacity from Juhl's Davison project. This occurred on April 4, 2016, when it became evident that further negotiations would prove unfruitful.

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

IN THE MATTER OF THE COMPLAINT BY JUHL ENERGY, INC. AGAINST NORTHWESTERN CORPORATION DBA NORTHWESTERN ENERGY FOR ESTABLISHING A PURCHASE POWER AGREEMENT	**STAFF'S SECOND SET OF DATA REQUESTS TO JUHL ENERGY** **EL16-021**

2-5) For each qualifying facility, specifically the Brule, Aurora, and Davison projects, please provide a list of any permits that are needed for the facility to be operational and indicate the current status of each permit. For the permits that have not been completed, please provide a detailed description of the status and the estimated completion date. For the permits that have been completed, please indicate the completion date.

	County Conditional Use Permit	**County Building Permit**	**Federal Aviation Administration**	**SD-DENR Stormwater Permit**	**SD-DOT Driveway Access Permit**
Brule	Completed – 12/17/15	Completed – 12/17/15	In Process – Expected by 1/15/17	Required prior to the start of construction	Required prior to the start of construction
Aurora	In Process – Expected by 12/15/16	Required prior to the start of construction	In Process – Expected by 1/15/17	Required prior to the start of construction	Required prior to the start of construction
Davison	Awaiting County Ordinance to be adopted – Expected by 4/15/17	Required prior to the start of construction	In Process – Expected by 1/15/17	Required prior to the start of construction	Required prior to the start of construction

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

IN THE MATTER OF THE COMPLAINT BY JUHL ENERGY, INC. AGAINST NORTHWESTERN CORPORATION DBA NORTHWESTERN ENERGY FOR ESTABLISHING A PURCHASE POWER AGREEMENT	**NORTHWESTERN'S RESPONSE TO COMMISSION STAFF'S SECOND SET OF DATA REQUESTS** **EL16-021**

Comes now, NorthWestern Corporation d/b/a NorthWestern Energy (*"NorthWestern"*) and for its responses to Commission Staff's Second Set of Data Requests, submits as follows:

NORTHWESTERN'S RESPONSE

2-1) Please refer to Page BJL-10, lines 29 through 30 of the direct testimony of Mr. LaFave. Please explain the forecasting method used to determine the value of Renewable Energy Credits reflected on Exhibits BJL-1 and BJL-2.

Response 2-1) NorthWestern used the Renewable Energy Credit price for Green-e National Wind and escalated it at the same escalation rate that it used for the natural gas and electric forecasts.