CABLE HUSTON
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP ▪ ATTORNEYS

RICHARD LORENZ

rlorenz@cablehuston.com
www.cablehuston.com

April 29, 2013

VIA ELECTRONIC FILING & US MAIL

Oregon Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
PO Box 2148
Salem, OR 97308-2148

Re: In the Matter of Oregon Public Utility Commission of Oregon, Investigation into Qualifying Facility Contracting and Pricing.
Docket No. UM-1610

Dear Filing Center:

Enclosed for filing in the above-referenced proceeding are an original and five copies of the Reply Testimony of John A. Harvey and Exhibits 201, 202 and 203 on behalf of Threemile Canyon Wind I, LLC.

Thank you for your assistance with this matter. Should you have any questions, please call.

Very truly yours,

/s/ Richard Lorenz

Richard Lorenz

RGL:tjb
Enclosures
cc: UM-1610 Service List (via electronic delivery)

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

REPLY TESTIMONY OF JOHN A. HARVEY
ON BEHALF OF
THREEMILE CANYON WIND I, LLC

APRIL 29, 2013

TABLE OF CONTENTS

INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is John A. Harvey.

Q. ARE YOU THE SAME JOHN HARVEY WHO EARLIER PROVIDED DIRECT TESTIMONY AND ACCOMPANYING EXHIBITS IN THIS CASE?

A. Yes.

Q. IS YOUR REPLY TESTIMONY BASED ON YOUR PERSONAL KNOWLEDGE AND EXPERIENCE AND DID YOU RELY ON SOURCES OF INFORMATION THAT YOU REGARD AS RELIABLE AND ARE ORDINARILY AND CUSTOMARILY USED AND RELIED ON BY THOSE INVOLVED IN THE ELECTRIC INDUSTRY?

A. Yes, as I have already explained in the introductory section of my direct testimony previously filed in Docket No. UM 1610.

Q. WHAT IS THE PURPOSE OF YOUR REPLY TESTIMONY?

A. The purpose of this testimony is to reply to certain portions of the Commission Staff testimony provided by Senior Utility Analyst Adam Bless that was filed on March 18, 2013 in Docket No. UM 1610. My reply testimony is organized by the three issues that I will address. First, I will discuss issue 4B and explain why the Commission must reject the suggestion to allocate certain third-party transmission costs to qualifying facilities ("QF"). Second, I will discuss issue 6B and explain why the creation of a Legally Enforceable Obligation must not be left to the unfettered discretion of the purchasing utility. Finally, I will discuss issue 6E and explain why Mr. Bless' recommendation that the Commission impose monetary penalties based on the cost of replacement power, though better than allowing termination of the QF's power purchase agreement ("PPA"), still goes too far in the event the QF can demonstrate it has maintained its commitment to the utility.

I. <u>Issue 4.B: Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?</u>

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY CONCERNING THIRD-PARTY TRANSMISSION COSTS.

A. In my direct testimony in this proceeding, I explained how FERC's regulations implementing PURPA do not permit a host utility to assess transmission charges to a QF that is directly selling its output to the host utility. Under FERC's PURPA regulations, as well as its decisions construing those regulations, the QF's responsibility ends with delivering its power output to the host utility. Once the QF delivers its output to the host utility, it is the host utility's sole responsibility to transmit and deliver the QF's output to the host utility's retail load.

Q. HAVE YOU REVIEWED MR. BLESS' TESTIMONY RELATED TO ISSUE 4.B? IF SO, DOES IT PROVIDE ADVICE THE COMMISSION CAN RELY UPON IN ITS DETERMINATION OF ISSUE 4.B.?

A. I have reviewed Mr. Bless' testimony related to issue 4B and, with the sole exception of his recommendations regarding third-party transmission cost responsibility for QFs located <u>off-system</u>, Mr. Bless' testimony does not provide advice the Commission can rely upon if it wishes to meet its legal obligation to adequately implement PURPA .

/ / /

Q. Why not?

A. Mr. Bless' testimony on Issue 4.B contains three critical mistakes, as described below:

- Mistake One. Mr. Bless suggests the possibility that "the third party transmission costs to move QF generation out of a load pocket may fall within the FERC's definition of 'interconnection costs' in the rules implementing PURPA." Bless Testimony, p. 31.

  I spent six years as the senior advisor (Manager of its Energy Section) to the members of the Iowa Utilities Board on electric and natural gas energy issues. A utility commission's Staff has a special relationship with its Commissioners and that special relationship is built on trust. In this instance, Mr. Bless' testimony is founded on blind speculation rather that well-reasoned conclusions with respect to Issue 4.B. As a trusted technical advisor to the Commission, I believe that it is inappropriate for Mr. Bless to be grasping at straws on issues requiring specific technical expertise. Even with his "Ordinarily yes" disclaimer, Mr. Bless should not have opened the door to the Commission making an error in implementing PURPA by suggesting there is any possibility that the Commission could reasonably conclude that **delivery-related** transmission costs are part of interconnection costs when the sale from QF to host utility is a direct sale.

  Mr. Bless has presented FERC's definition of "interconnection costs." Words in FERC regulations have meanings specific to the business FERC regulates. For example, note the presence of the words "interconnected operations" in the definition. Interconnected operations, when a QF is selling directly to its host utility, means solely the operations of facilities related to an interconnection by a generator to an electric energy delivery system. QFs, like other types of interconnection customers, have contractual responsibilities to pay reasonable interconnected operations costs—delivery provider interconnection facilities (including connecting cables and buswork, capacitor banks, switches, circuit breakers, meters, and/or substation transformers), network upgrades, communications upgrades. Those interconnection customer cost responsibilities (initial investment costs, as well as ongoing operation and maintenance costs of energy delivery owner interconnection facilities) reside in the interconnection agreement, not in a PPA. In total, Exelon's wind subsidiary QFs throughout the United States, including Threemile Canyon, have dozens of Interconnection Agreements (i.e., contracts), each of which makes the respective QF signator an interconnection customer of a delivery (transmission or distribution) provider. An interconnection customer that does not uphold its contractual responsibilities (cost and otherwise) is subject to termination of its interconnection agreement. Threemile Canyon has paid all the interconnection customer cost responsibilities stated in its interconnection agreement with PacifiCorp.

- Mistake Two. Mr. Bless' second mistake is in his statement that "[t]here is some support in FERC orders that FERC intended its definition of interconnection costs to be interpreted broadly." Bless Testimony, p.32. In my view, Mr. Bless does not fully understand the combination of the FERC Notice of Proposed Rulemaking ("NOPR") in Docket No. RM79-55, FERC Order No. 69 (the concluding order to Docket No. RM79-55), and FERC's existing PURPA regulations. This statement also indicates that he does not understand the relevant section of Order no. 888-B. To be clear, there is not a scintilla of evidence in any of the applicable FERC orders—the NOPR, Order No. 69, and Order No. 888-B--that FERC intended its definition of "interconnection costs" to be interpreted broadly.

I also take issue with Mr. Bless' following recitation of the FERC NOPR in his direct testimony:

> "In its Notice of Proposed Rulemaking, Small Power Production and Cogeneration-Rates and Exemptions, [the NOPR for the 198 rules implementing PURPA], the Commission explained:
>
>> The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility under § 292.108 of these rules. However, pursuant to agreement between the qualifying facility and any electric utility which transmits electric energy on behalf of the qualifying facility, the transmitting utility may share the costs of transmission, The electric utility to which the electric energy is committed 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."

Bless Testimony, p. 32.

I have included in a footnote below a more extensive excerpt[1] from the RM79-55 NOPR. The more extensive excerpt makes it abundantly clear the costs of transmission being discussed are those related to indirect sales, not direct sales. A sale to a host utility (including when the sale is made in a portion of a utility's service territory where transmission delivery service is provided by a third party) is a direct sale, not an indirect sale. I have included complete copies of the FERC NOPR, Order No. 69, and Order No. 888-B as exhibits to my reply testimony for ease of

[1] Section 210(a) of PURPA provides that the Commission [FERC] shall prescribe rules requiring electric utilities to offer to purchase electric energy from qualifying facilities. The Commission [FERC] interprets this provision to impose on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities, except during periods prescribed in § 292,105(e) and during system emergencies.

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 an average figure representing the average cost of energy and capacity on the 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 could replace energy supplied by specific peaking units, and its capacity might enable the supplying utility to avoid the addition of new capacity. The costs, and thus the avoided costs, of peaking energy and new capacity are generally greater than system average figures.

Under these proposed 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 can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself.

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 utility does not transmit the purchased energy or capacity. it 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.

The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility under § 292.108 of these rules. However, pursuant to agreement between the qualifying facility and any electric utility which transmits electric energy on behalf of the qualifying facility, the transmitting utility may share the costs of transmission, The electric utility to which the electric energy is committed 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. Source: Federal Register / Vol. 44, No. 207 / Wednesday, October 24, 1979 / Proposed Rules, pages 61193-4.

reference. The Order No. 69 discussion of the pertinent subject commences at the bottom of column one of page 12219 and continues over onto page 12220. Even a casual examination of that portion of Order No. 69 and the FERC NOPR demonstrates both are discussing transmission service related to indirect sales. Further, an examination of the portion of Order No. 888-B Mr. Bless has quoted shows its purpose to be a discussion of whether QFs are required to pay for Real Power Loss Service and Ancillary Services. In the context of that discussion, FERC merely recapped its earlier discussions in the NOPR and Order No. 69 without changing its conclusions regarding FERC regulation 292.303(d) that pertains only to indirect sales.

The Commission must therefore reject all of what Mr. Bless has said about third party transmission service possibly being a cost of interconnection where a direct sale will take place.

- Mistake Three. In Table 2—Costs to Be Paid by the QF, Mr. Bless assigns "Third Party Transmission (QF in Load Pocket)" cost responsibility to the QF.[2] Bless Testimony, p. 29-30. Yet, he provides no cogent record evidence this Commission can rely upon to accept his recommendation. He spent several pages dealing with the alleged possibility such costs are

[2] If the costs to transmit the QF's energy out of a load pocket are not interconnection costs under 18 C.F.R. 292.101(7), they are properly treated as any other actual cost exceeds the utility's avoided costs the incremental costs are borne by the QF. This is because the utility's liability for costs is capped at the utility's avoided costs. Bless Testimony, p31, lines 5-10.

costs of interconnection. In my discussion of mistakes one and two above, I have already noted why such costs cannot be interconnection costs where the sale is a direct sale. With respect to exceeding avoided costs, Mr. Bless merely states, "to the extent the actual cost exceeds the utility's avoided costs the incremental costs are borne by the QF." Bless Testimony, p. 31.

In my direct testimony, I (1) provided evidence that PacifiCorp bills it retail customers for the costs of third-party transmission provided to PacifiCorp-owned wind generation, (2) noted the massive amount of third-party transmission PacifiCorp uses in the ordinary course of its retail distribution business, and (3) explained that PacifiCorp considers all of its service territory to be composed of a series of load pockets. This means PacifiCorp uses third-party transmission to deliver output of other generating technology types. With that evidence as a backdrop, Mr. Bless' testimony provides no evidence for the Commission to conclude that such costs would cause actual costs to exceed PacifiCorp's avoided costs whether: (a) as determined on an individual basis for QFs not eligible for Standard Rates for Purchases, or (b) for the entire class of all QFs eligible for Standard Rates for Purchases.

/ / /

/ / /

Q. IN THEIR RESPECTIVE TESTIMONY, DOES EITHER PACIFICORP OR STAFF ATTEMPT TO RECONCILE THEIR PROPOSALS WITH FERC'S REGULATIONS CONCERNING THE ALLOCATION OF TRANSMISSION COSTS TO QFS?

A. No. Neither Mr. Bless, nor Mr. Griswold's direct testimony for PacifiCorp, addresses the very narrow circumstances under FERC's PURPA regulations in which a host utility may charge a QF for third-party transmission costs. Neither Mr. Bless nor Mr. Griswold even acknowledges the distinction made under federal law between indirect sales and direct sales to a host utility. This oversight is fatal to their respective recommendations concerning the allocation of third-party transmission costs.

Both Mr. Bless and Mr. Griswold advocate that the Commission adopt a contract term that is contrary to FERC's regulations, and therefore, the federal law giving FERC the responsibility to issue implementing regulations and requiring states to implement those regulations. As I explained in detail in my direct testimony, under FERC's PURPA regulations, a QF may be assessed delivery-related transmission charges only in one very limited circumstance. Section 292.303(d) provides that the host utility to which the QF is interconnection (Electric Utility A) may charge the QF for transmitting its output to another utility's system (Electric Utility B) *only* when both the QF and Electric Utility A agree that Electric Utility A will transmit the QF's output for purchase by Electric Utility B. In other words, only when the QF is agreeing to do an indirect sale to a second utility. FERC's regulations do not allow the host utility to charge the QF for transmission charges in any other circumstances. Specifically, there is *nothing* in FERC's regulations, as far as I am aware, that would allow the host utility to charge the QF for transmission charges incurred to move the QF output from one part of host utility's distribution system to another.

Q. DO THE FERC REGULATIONS REGARDING THE ALLOCATION OF TRANSMISSION COSTS TO QF PROJECTS RECOGNIZE ANY EXCEPTION FOR "LOAD POCKETS."

A. No, clearly they do not. Staff and PacifiCorp are trying to read into FERC's PURPA regulations a special exception for "load pockets" that simply does not exist. In fact, FERC understands the term "load pocket" to mean something quite different from how PacifiCorp uses it in its testimony. FERC defines the term "load pocket" as "an area that is separated electrically from the rest of the grid by one or more transmission constraints that limit the amount of energy that can be imported into the area."[3] PacifiCorp, on the other hand, uses the term "load pocket" to mean a portion of its distribution system that is not physically connected by PacifiCorp's facilities to other portions of PacifiCorp's distribution system. FERC does not even recognize PacifiCorp's use of the term "load pocket" in this context – let alone make an exception for it in its PURPA rules.

Q. IN PACIFICORP'S SERVICE TERRITORY, ARE "LOAD POCKETS" THE EXCEPTION OR THE RULE?

A. I believe that Mr. Griswold implies, and Mr. Bless presumes, that the existence of QF facilities in a "load pocket" is a rare exception. Threemile Canyon has learned through discovery from PacifiCorp in this proceeding, however, that *all* of

[3] See "Order On Rehearing, Clarification, And Compliance Filings, Establishing Further Hearing Procedures, And Consolidating Proceedings," (Issued July 5, 2005) 112 FERC ¶ 61,031, p. 2.

the QFs in PacifiCorp's service territory in Oregon are in what it considers to be a "Load Pocket."[4] This fact, although certainly significant, is conveniently omitted from Mr. Griswold's discussion of load pockets. This means that the ostensibly narrow exception that PacifiCorp wishes to read into FERC's PURPA regulation for load pockets would actually apply to each and every QF project in PacifiCorp's Oregon service territory.

Q. PUTTING ASIDE THE ISSUE OF "LOAD POCKETS," ARE YOU AWARE OF *ANY* FERC REGULATION OR PRECEDENT THAT WOULD SUPPORT THE PROPOSITION THAT A PURCHASING UTILITY MAY RECOVER THIRD-PARTY TRANSMISSION CHARGES FROM A QF?

A. No. I am aware of no precedent, either in FERC's decisions or its regulations, that supports the proposition that a host utility may charge third-party transmission charges to a QF other than what is expressly permitted by Section 292.303(d). In my review of their respective direct testimony, I note that neither Mr. Bless nor Mr. Griswold mentions even one FERC decision or regulation in support of the proposition that a host utility may recover third-party transmission costs from a QF making a direct sale.

Q. ARE YOU AWARE OF ANY OTHER STATE UTILITY COMMISSION THAT ALLOWS PURCHASING UTILITIES TO RECOVER THIRD-PARTY TRANSMISSION COSTS FROM QFS?

A. No. Although I have experience working on QF projects in many different states across the country, I am not aware of any other state utility commission in the

[4] In its Data Request 1.6, Threemile Canyon asked PacifiCorp to identified all existing QF projects in what PacifiCorp considered to be a load pocket. PacifiCorp responded that "[a]ll qualified facilities (QFs) are located in load pockets within PacifiCorp's service territory."

entire country that allows host utilities to impose third-party transmission charges on QFs. It is important for the Commission to recognize that neither Mr. Bless nor Mr. Griswold cites to any precedent that would show that such charges have ever been allowed by any state utility commission. In other words, both Staff and PacifiCorp would have this Commission adopt a policy that is, as far as I am aware, literally unprecedented.

Q. IF THE PURCHASING UTILITY CANNOT RECOVER THIRD-PARTY TRANSMISSION CHARGES FROM THE QF, DOES THAT MEAN THAT THE QF IS PAYING MORE THAN ITS AVOIDED COST FOR SUCH POWER?

A. No. I understand and agree with the general proposition that a purchasing utility is prohibited by PURPA from paying a QF a rate that is greater than the purchasing utility's avoided costs for power. It simply does not follow from this general proposition, however, that the QF must therefore indemnify the purchasing utility for all of the costs that the purchasing utility incurs to deliver QF power to its retail rate payers. For example, the QF clearly has no responsibility to reimburse the purchasing utility for costs incurred to maintain the poles, wires and other facilities used to distribute QF power to retail rate payers. Likewise, it is clear that the QF does not have to reimburse the purchasing utility for the cost or value of transmitting QF power across the purchasing utility's own high-voltage transmission facilities. It is no different, therefore, when the purchasing utility has chosen to rely on the high-voltage transmission facilities of third-parties to operate its retail distribution system.

Furthermore, the amount of compensation paid to the QF does not change when purchasing utility incurs distribution or even delivery-related transmission charges associated with its retail power service. Regardless of the retail distribution costs incurred by the utility, the compensation paid to the QF is capped at the utility's avoided cost. Thus, under no circumstances is the utility paying the QF more than its avoided costs for power.

Q. UNDER FERC'S DECISIONS, WHAT RESPONSIBILITY DOES THE QF HAVE WITH RESPECT TO THE PURCHASING UTILITY'S COSTS AFTER THE QF HAS DELIVERED POWER TO THE PURCHASING UTILITY?

A. None. The QF's responsibilities under PURPA are clear. It is the QF's responsibility to deliver its output to the purchasing utility. Thus, the QF must pay all costs associated with delivering the output of the generating facility to the purchasing utility. This includes, for example, transmission costs to get the power to the purchasing utility's system and interconnection costs to interconnect with the purchasing utility. Once the QF has delivered the output to the purchasing utility, however, the QF has no further cost responsibility. The FERC decisions on this point that I have seen are clear and unambiguous. *Entergy Servs., Inc.*, 137 FERC ¶ 61,199 at P 52 (2011). Neither Mr. Bless nor Mr. Griswold have identified any FERC decision that suggests otherwise.

Q. WHAT IS THE DIFFERENCE BETWEEN THIRD-PARTY TRANSMISSION COSTS AND INTERCONNECTION COSTS?

A. As discussed above, Mr. Bless incorrectly speculates that third-party transmission charges may or may not be considered "interconnection charges."

Bless Testimony, p. 31. In fact, transmission charges are categorically distinct from interconnection charges when the QF is making a direct sale.

Although 18 CFR 292.101(7) does use the term "transmission," as Mr. Bless points out, it is thereafter qualified by the phrase "directly related to the installation and maintenance of the physical facilities necessary to permit interconnect operations with a qualifying facility." In other words, 18 CFR 292.101(7) simply clarifies that the host utility is not liable for any interconnection facility costs—however characterized. This does not mean, and has never been interpreted to mean, that the host utility may charge the QF for transmission charges incurred to deliver the power to load after the point of interconnection. To illustrate the point, 18 CFR 292.101(7) also mentions "distribution" costs—but no party is even suggesting that the host utility is entitled to recover down-stream distribution costs from the QF. Make no mistake, third-party transmission charges to move QF output from one part of purchasing utility's service territory to another are not "interconnection costs."

Q. IS IT INEQUITABLE TO REQUIRE PACIFICORP'S RATEPAYERS TO PAY THIRD-PARTY TRANSMISSION CHARGES FOR QF POWER?

A. No. Mr. Bless' recommendation effectively adopts PacifiCorp's position and suggests there must be something unjust and unreasonable about Threemile Canyon's position. In fact, PacifiCorp's retail rate payers already pay third-party transmission charges all the time. Mr. Bless' recommendation, if adopted, would place this Commission in the position of siding with PacifiCorp's attempt to discriminate against QFs. As I stated in my initial testimony, Mr. Griswold paints an incomplete picture of PacifiCorp's load pockets and how PacifiCorp serves its retail ratepayers. Threemile Canyon has learned through discovery from PacifiCorp that PacifiCorp has at least two of its own wind generating projects located off PacifiCorp's system. These are the Leaning Juniper and Goodnoe Hills projects. Based on the information that I have from PacifiCorp's FERC accounting records, it is my understanding and belief that PacifiCorp uses third-party transmission service to move the output of these projects to its retail consumers and that the cost of this service is included in PacifiCorp's retail rates. To the extent that PacifiCorp's retail ratepayers already pay for third-party transmission to move PacifiCorp's own wind power, it is discriminatory—and not inequitable or unreasonable--for PacifiCorp to fail to offer similar terms with respect to QF power.

Q. DOES MR. BLESS OR MR. GRISWOLD DISCUSS THE CURRENT COMMISSION RULES CONCERNING THIRD-PARTY TRANSMISSION?

A. No. Both Mr. Bless and Mr. Griswold ignore the Commission's current rules concerning third-party transmission. They both assume that the question is simply blank slate to be decided by the Commission as a matter of first impression.

Q. UNDER THE COMMISSION'S CURRENT RULES AND POLICES, ARE UTILITIES CURRENTLY ALLOWED TO CHARGE SMALL QFS FOR THIRD PARTY TRANSMISSION CHARGES?

A. No. Under the Commission's current rules and policies regarding purchases from QFs, purchasing utilities are clearly prohibited from allocating any additional costs to small QFs that are eligible for the standard contract rates and terms.

This was settled by the Commission in its Order No. 05-584 in UM 1129. Among the issues addressed by the Commission in its Order No. 05-584 was the question of pricing adjustments for standard contracts, which had been raised by PacifiCorp and PGE. The Commission expressly rejected PacifiCorp's filing, stating: "We believe further flexibility in negotiating the terms of a standard contract would fundamentally undermine the purposes and advantages of standard contracts." Thus, the state of law for every eligible small QF from the date of Order No. 05-584 through today is that purchasing utilities may not add third-party transmission charges to the standard contract terms.

Q. DOES THE CURRENT STANDARD CONTRACT VIOLATE PURPA IN THAT REGARD?

A. No, clearly it does not. The Commission got it exactly right in its Order No. 05-584 in UM 1129. With respect to third-party transmission costs in particular, as explained above, federal law does not allow (much less require) purchasing utilities to recover third-party transmission costs from QFs other than in the case of indirect sales.

Furthermore, FERC was well aware that Standard Rates for Purchases from QFs may reflect different costs or different value to the purchasing utility—and this cost variation does not violate PURPA. In seeking to recover third-party transmission charges, PacifiCorp is essentially asking the Commission (and Mr. Bless appears to be agreeing) to require individualized rates for all QFs in PacifiCorp's Oregon service territory, regardless of size (because all QFs are in load pockets). PacifiCorp is asserting the failure to individualize the rates overcompensates the QF in violation of PURPA.

In its Order No. 69 FERC expressly rejected this very argument. "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, [FERC] will require that standardized tariffs be implemented for facilities of 100 kW or less."[5] Further, FERC provided an option to have standard rates for purchases for larger facilities:

> 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 the result of such purchases. Accordingly, the Commission has added subparagraph (2) which permits, but does not require, State regulatory authorities and non-regulated 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).[6]

There is clearly nothing unlawful about the Commission's current policy of not allowing utilities to add third-party transmission costs to the standard contract rates and terms.

[5] Order No. 69 as published in Federal Register, Vol. 45, No. 38, February 25, 1980, p. 12223.
[6] *Id.*

Q. EVEN IF FEDERAL LAW WERE TO ALLOW PURCHASING UTILITIES TO CHARGE QFS FOR THIRD-PARTY TRANSMISSION COSTS, SHOULD THE COMMISSION ADOPT A RETROACTIVE CHANGE IN POLICY?

A. While Mr. Bless remains agnostic on this point, Mr. Griswold clearly contemplates a retroactive change in state law that would allow PacifiCorp to recover third-party transmission costs from Threemile Canyon. Again, Mr. Griswold does not tell the whole story. Specifically, Threemile Canyon applied for a standard contract from PacifiCorp nearly four years ago. Threemile Canyon met all of PacifiCorp's criteria to be eligible for a standard contract, and had in fact reached commercial operations, as of September of 2009. Threemile Canyon was and is entitled by state and federal law to a long-term power purchase agreement under the standard contract terms and conditions adopted by the Commission in UM 1129. This specifically includes a standard contract with no adjustment for third-party transmission costs in compliance with this Commission's Order No. 05-584. Rather than comply with its legal obligations, PacifiCorp has for four years simply refused to tender a long-term standard contract to Threemile Canyon. Whatever decisions the Commission may reach in this proceeding, the Commission should clearly articulate that changes in policy are prospective only and that this proceeding is not intended to alter or ameliorate the legal obligations that PacifiCorp had to Threemile Canyon (or any other person) back in 2009.

/ / /

/ / /

II. Issue 6.B: When is there a Legally Enforceable Obligation?

Q. HAVE YOU PREVIOUSLY ADDRESSED IN TESTIMONY ISSUE 6.B?

A. Yes. In my direct testimony, I explained that a Legally Enforceable Obligation ("LEO") is created when a QF commits to making a PURPA sale to a purchasing utility. I went on to explain why PacifiCorp's proposal does not work. Mr. Griswold describes a contracting process that culminates with the utility offering, and the QF accepting, the final contract terms. Griswold Testimony, p. 4, 30. According to Mr. Griswold, the LEO can be established if and only if the utility tenders the final contract for approval by the QF. Under PacifiCorp's proposal, therefore, the purchasing utility retains virtually unfettered discretion and control over the creation of the LEO.

Q. DO ANY OTHER PARTIES ENDORSE PACIFICORP'S PROPOSAL CONCERNING THE CREATION OF A LEO?

A. Yes. The Mr. Bless concurs with PacifiCorp's proposal. Bless Testimony, p. 40.

Q. DOES MR BLESS' CONCURRENCE IN ANY WAY MAKE THE PACIFICORP PROPOSAL ACCEPTABLE OR MORE WORKABLE?

A. No. This Commission has an obligation to implement FERC's regulations. § 292.304(d)(2) provides QFs the option "[t]o provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term … ." (emphasis added). A state commission and a purchasing utility cannot escape an acceptable implementation of PURPA—the requirement to leave the formation of a LEO in the hands of the QF through the QF's commitment to the utility—by adopting a process that does not leave the formation in the QF's hands.

PacifiCorp's proposal, and Mr. Bless' concurrence, to have a LEO commence only at the time a QF executes an acceptable final draft PPA presented to it by an electric utility does not work because it puts control of the commitment process entirely in the electric utility's hands. This allows the utility to delay or even to stifle the creation of a LEO simply by withholding the final contract.

Q. ARE YOU AWARE OF PACIFICORP OR ANY OTHER UTILITY ACTUALLY REFUSING TO ISSUE A FINAL CONTRACT FOR EXECUTION BY QF?

A. Yes. As I already mentioned in my initial testimony, that is precisely why Threemile Canyon was forced to participate in this proceeding. Almost four years ago now, in 2009, Threemile Canyon asked PacifiCorp to execute the long-term, standard contract. PacifiCorp has steadfastly refused to tender the long-tem, standard contract for execution by Threemile Canyon unless and until Threemile Canyon agrees (contrary to Order No. 05-584) to modify the standard contract and pay for third party transmission. Under FERC's decisions on the subject, a legally enforceable obligation between Threemile Canyon and PacifiCorp was created (at the latest) in September of 2009 when Threemile Canyon achieved commercial operation and satisfied every one of the eligibility criteria for a long-term standard contract. If Threemile Canyon had to wait for PacifiCorp to present it with an acceptable final draft of the long-term standard contract in order to create a LEO, Threemile Canyon would still be waiting four years later.

III. Issue 6.E: How should contracts address mechanical availability?

Q. PLEASE SUMMARIZE YOUR INITIAL TESTIMONY CONCERNING THE MECHANICAL AVAILABILITY GUARANTEE ("MAG").

A. In my opening testimony I explained that standard contracts actually do not need to include a MAG provision at all. It is an out-of-date concept, given the change in compensation schemes over time. All pricing under PacifiCorp's Schedule 37, for example, is now paid based on actually energy production and not capacity. Thus, the QF already has the direct economic incentive to maximize the mechanical availability of the facility, and no additional penalties are likely to increase availability or otherwise change QF behavior.

Q. HAVE YOU REVIEWED MR. BLESS' TESTIMONY REGARDING MECHANICAL AVAILABILITY GUARANTEES? IF SO, ARE THERE ANY PARTS OF IT THAT PARTICULARLY STAND OUT?

A. Yes, I have reviewed Mr. Bless' testimony regarding MAG and there are several things that stand out to me. First, he discussed the history of MAGs and their purpose. Second, he recommends the Commission "place parameters on the terms of the MAG and on the penalties for failure to comply." Bless Testimony, p. 44. I will discuss these issues in turn.

<u>History of MAGs and Their Purpose</u>

Mr. Bless states, "Power purchase agreements (PPAs) have traditionally included an output delivery guarantee." Bless Testimony, p. 41. I would state things a little differently. As FERC discussed in its Order No. 69,[7] PPAs providing firm power have placed the discretion for whether a sale will be made in the hands of the customer. Enforcement of this discretion might be in the form of a penalty from the seller to buyer in the event of non-performance. On the other hand, in the case of non-firm sales, the discretion remains in the hands of the seller and there would be no penalties. FERC stated, "Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service." This discussion takes place during FERC's determination of whether a QF ought to be compensated for any value of capacity it provides (including as part of dispersed systems where the payment for value provided is to be distributed to the class providing the capacity) to a utility.

<u>Recommendation to Place Parameters on the Terms of the MAG/Penalties for Failure to Comply</u>

Later in his testimony, Mr. Bless makes the following two statements:

[7] 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. See Federal Register / Vol. 45, No. 38 / Monday, February 25. 1980 / Rules and Regulation, p. 12225.

> Staff recommends a monetary penalty based on the cost of replacement power, rather than termination. (p. 45)
> Staff recommends that the Commission order that any penalty must be based on the failure to meet the annual limit on scheduled maintenance and be based on actual net replacement power costs for the incremental unavailable hours that exceed the aggregate annual mechanical unavailability limit for all turbines. (pp. 45-46)

Although Mr. Bless' recommendation is less draconian than contract termination, in my view his recommendation still goes too far—in the event the QF has maintained its commitment to the utility. In my initial testimony, I stated the following:

> The need for mechanical availability provisions in QF contracts is out-of-date and contracts should not address mechanical availability.
>
> Mechanical availability in QF contracts commonly is designed to extract financial penalties in the event such availability falls below benchmark levels. Standard QF contracts must be in compliance with the requirement that QFs be compensated at the particular electric utility's avoided cost level and having a contract address mechanical availability is not a way a utility is allowed to get around the avoided cost requirement. So, in the event the Commission wishes to continue to address mechanical availability in QF contracts, the total financial impact of the standard contract, including mechanical availability, must not stray from the avoided cost requirement.

Assume a QF, which elected to be paid based on forecast avoided cost based pricing, that can document meeting all manufacturer-recommended maintenance of facilities. Also assume such QF suffers a full or partial forced outage, and promptly (a) informs the purchasing utility of the forced outage and (b) submits to the purchasing utility its plan for restoring the QF's ability to generate electricity to the full expected capabilities of the wind-turbine generators installed at the facility. Given those assumptions, it is reasonable to conclude the forced outage was beyond the QF's reasonable control and that such QF is maintaining its commitment to the purchasing utility. Such QF, which is being compensated purely on a cents per kilowatt-hour basis, does not get paid during the forced outage and the revenue it is not receiving is based on the forecasted avoided cost prices for energy and capacity. By definition then, the QF is already being penalized in an amount equal to the value of the purchasing utility's full avoided cost. Any penalty that exceeds the value of the purchasing utility's full avoided cost would violate the QF's statutory/regulatory right to be compensated at the utility's full avoided cost.

Q. DOES THIS CONCLUDE YOUR REPLY TESTIMONY?

A. Yes.

4817-3448-2707, v. 1

CERTIFICATE OF SERVICE

I hereby certify that I caused to be served the foregoing **REPLY TESTIMONY AND EXHIBITS OF JOHN A. HARVEY ON BEHALF OF THREEMILE CANYON WIND I, LLC** via electronic mail and, where paper service is not waived, via postage-paid first class mail upon the following parties of record:

PACIFIC POWER
Mary Wiencke
R. Bryce Dalley
825 NE Multnomah St., Ste 1800
Portland, OR 97232-2149
Mary.wiencke@pacificorp.com
Bryce.dalley@pacificorp.com

PUBLIC UTILITY COMMISSION OF OREGON
Brittany Andrus
Adam Bless
P.O. Box 2148
Salem, OR 97308-2148
Brittany.andrus@state.or.us
Adam.bless@state.or.us

PORTLAND GENERAL ELECTRIC
J. Richard George (C)
121 SW Salmon ST - 1WTC1301
Portland OR 97204
richard.george@pgn.com

PACIFICORP, DBA PACIFIC POWER
Oregon Dockets
825 NE Multnomah St., Ste 2000
Portland, OR 97232
oregondockets@pacificorp.com

LOYD FERY
11022 Rainwater Lane SE
Aumsville OR 97325
dlchain@wvi.com

THOMAS H. NELSON
PO Box 1211
Welches OR 97067-1211
nelson@thnelson.com

OREGON DEPARTMENT OF ENERGY
Matt Krumenauer
Kacia Brockman
625 Marion ST NE
Salem OR 97301
matt.krumenauer@state.or.us
Kacia.brockman@state.or.us

ANNALA, CAREY, BAKER, PC
Will K. Carey
PO Box 325
Hood River OR 97031
wcarey@hoodriverattorneys.com

ASSOCIATION OF OREGON COUNTIES
Mike McArthur
PO BOX 12729
Salem OR 97309
mmcarthur@aocweb.org

CITIZENS UTILITY BOARD OF OREGON
OPUC Dockets
Robert Jenks
G. Catriona McCracken
610 SW Broadway, STE 400
Portland OR 97205

dockets@oregoncub.org; bob@oregoncub.org
catriona@oregoncub.org

CITY OF PORTLAND-
PLANNING AND SUSTAINABILITY
David Tooze
1900 SW 4TH STE 7100
Portland OR 97201
david.tooze@portlandoregon.gov

CLEANTECH LAW PARTNERS , PC
Diane Henkels
6228 SW Hood
Portland OR 97239
dhenkels@cleantechlawpartners.com

OBSIDIAN RENEWABLES, LLC
David Brown
Todd Gregory
5 Centerpointe Drive, Suite 590
Lake Oswego, Oregon 97035
dbrown@obsidianfinance.com
tgregory@obsidianrenewables.com

DAVISON VAN CLEVE
Irion A Sanger
Melinda Davison
S. Bradley VanCleve
333 SW Taylor - Ste 400
Portland OR 97204
ias@dvclaw.com; mjd@dvclaw.com
bvc@dvclaw.com

ENERGY TRUST OF OREGON
Elaine Prause
John Volkman
421 SW Oak ST #300
Portland OR 97204-1817
elaine.prause@energytrust.org
john.volkman@energytrust.org

ESLER STEPHENS & BUCKLEY
John W Stephens
888 SW Fifth AVE Ste 700
Portland OR 97204-2021
stephens@eslerstephens.com;
mec@eslerstephens.com

IDAHO POWER COMPANY
Donovan E Walker
Regulatory Dockets
PO Box 70
Boise, ID 83707-0070
dockets@idahopower.com
dwalker@idahopower.com

SMALL BUSINESS UTILITY
ASSOCIATES
James Birkelund
548 Market ST Ste 11200
San Francisco CA 94104
james@utilityadvocates.org

LOVINGER KAUFMANN LLP
Kenneth Hoffman
Jeffrey S. Lovinger
825 NE Multnomah Ste 925
Portland OR 97232-2150
kaufmann@lklaw.com
lovinger@lklaw.com

MCDOWELL RACKNER & GIBSON PC
Adam Lowney
Lisa F. Rackner
419 SW 11TH AVE, Ste 400
Portland OR 97205
adam@mcd-law.com
dockets@mcd-law.com

NORTHWEST ENERGY SYSTEMS COMPANY LLC
Daren Anderson
1800 NE 8TH ST., Ste 320
Bellevue WA 98004-1600
da@thenescogroup.com

ONE ENERGY RENEWABLES
Bill Eddie
206 NE 28TH AVE
Portland OR 97232
bill@oneenergyrenewables.com

OREGON DEPARTMENT OF JUSTICE
Renee M. France
Natural Resources Section
1162 Court ST NE
Salem OR 97301-4096
renee.m.france@doj.state.or.us

OREGON SOLAR ENERGY INDUSTRIES ASSOCIATION
Glenn Montgomery
PO BOX 14927
Portland OR 97293
glenn@oseia.org

OREGONIANS FOR RENEWABLE ENERGY POLICY
Kathleen Newman
1553 NE Greensword DR
Hillsboro OR 97214
k.a.newman@frontier.com
kathleenhoipl@frontier.com

OREGONIANS FOR RENEWABLE ENERGY POLICY
Mark Pete Pengilly
PO BOX 10221
Portland OR 97296
mpengilly@gmail.com

REGULATORY & COGENERATION SERVICES, INC
Donald W. Schoenbeck
900 Washington ST Ste 780
Vancouver WA 98660-3455
dws@r-c-s-inc.com

STOLL BERNE
David A Lokting
209 SW Oak Street, Suite 500
Portland OR 97204
dlokting@stollberne.com

PUBLIC UTILITY COMMISSION STAFF--DEPT OF JUSTICE
Stephanie S. Andrus
Business Activities Section
1162 Court ST NE
Salem OR 97301-4096
stephanie.andrus@state.or.us

RENEWABLE ENERGY COALITION
John Lowe
12050 SW Tremont ST
Portland OR 97225-5430
jravenesanmarcos@yahoo.com

RENEWABLE NORTHWEST PROJECT
RNP Dockets
Megan Walseth Decker
421 SW 6TH AVE., Ste. 1125
Portland OR 97204
dockets@rnp.org
megan@rnp.org

RICHARDSON AND O'LEARY
Gregory M. Adams
Peter J. Richardson
PO BOX 7218
Boise ID 83702
greg@richardsonandoleary.com
peter@richardsonandoleary.com

ROUSH HYDRO INC
Toni Roush
366 E Water
Stayton OR 97383
tmroush@wvi.com

Dated in Portland, Oregon, this 29th day of April, 2013.

/s/ Richard Lorenz
Richard Lorenz, OSB No. 003086
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Avenue, Suite 2000
Portland, OR 97204-1136
(503) 224-3092 (Telephone)
(503) 224-3176 (Fax)
rlorenz@cablehuston.com

Of Attorneys for
Threemile Canyon Wind I, LLC

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Charles B. Curtis, Chairman; Georgiana Sheldon, Matthew Holden, Jr., and George R. Hall.

Small Power Production and Cogeneration Facilities - Rates and Exemptions) Docket No. RM79-55

ORDER NO. 69

FINAL RULE REGARDING THE IMPLEMENTATION OF SECTION 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

(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 and 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 facilties 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

---

1/ 44 F.R. 38873, July 3, 1979.

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)

2/ 44 F.R. 65744, November 15, 1979.

3/ 44 F.R. 38863, July 3, 1979.

4/ 44 F.R. 61190, October 24, 1979.

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 pre-

---

5/ 44 F.R. 61977, October 29, 1979.

viously, 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.

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/, <u>excluding</u> 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 <u>including</u> the qualifying facility. 7/

6/ An optimal capacity expansion plan is the schedule for the addition of new generating and transmisison 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.

Subparagraph (7) defines "interconnection costs" as 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 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.

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

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.

9/ 44 F.R. 63114, November 2, 1979.

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/

10/ The term "purchase" is defined in section 292.101(b).

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 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 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 substitute 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.

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 facilites, 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 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

---

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

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 foreseeable future, they are inextricably tied to the use of oil to produce electricity. They contend 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 on 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/

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

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 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 Comission 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 a 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 rate-making. 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

---

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

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.

§ 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

---

15/ Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 99, 95th Cong., 2d. Sess. (1978).

16/ Id., pp. 98-9.

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 <u>to</u> 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 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 similarily 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 occurence 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

---

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).

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.

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

§ 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 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 faciliuty 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)(i), 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 back-up 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 obligation 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 facilitites 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 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

---

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 F.R. 24095 (April 21, 1979).

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.

Futhermore, 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 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.

(S E A L)

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

Sec.
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.

SUBPART D - IMPLEMENTATION

* * * * *

SUBPART F - EXEMPTION OF QUALIFYING SMALL POWER PRODUCTION FACILITIES AND COGENERATION FACILITIES FROM CERTAIN FEDERAL AND STATE LAWS AND REGULATIONS

(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 F.R. 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 subparagraph (2), 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 in paragraph (a) shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) 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) applies) shall, upon request:

(i) provide comparable data to that required under paragraph (b) to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b); 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 rate-making 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).

(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 subparagraph (2), 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 subparagraph (3), a rate for purchases satifies the requirements of paragraph (a) if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e).

(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

which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a), and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with subparagraph (2), 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); 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 subparagraph (2), 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 subparagraph (2) 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 subparagraph (1) 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 subparagraph (2) will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in subparagraph (1) 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 subparagraph (1) 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 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 nonregulated 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 waiver only if an applicant under paragraph (a) 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) section 305(c); and

(4) any necessary enforcement provision of Part III with regard to the sections listed in subparagraphs (1), (2) and (3).

§ 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 subparagraph (2)) 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.

☆ U.S. GOVERNMENT PRINTING OFFICE: 1980 O— 314-331/6019

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426
EQUAL OPPORTUNITY EMPLOYER

POSTAGE AND FEES PAID
FEDERAL ENERGY REGULATORY COMMISSION
FERC-351
FIRST CLASS MAIL

Document Content(s)

81 FERC ¶ 61,248

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

[Docket Nos. RM95-8-003 and RM94-7-004; Order No. 888-B]

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

(Issued November 25, 1997)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Order No. 888-B (Order on Rehearing).

SUMMARY: The Federal Energy Regulatory Commission (Commission) affirms, with certain clarifications, the fundamental calls made in Order No. 888-A.

EFFECTIVE DATE: The tariff change ordered in the order on rehearing (see footnote 1) will become effective on [insert date 60 days after date of publication in the Federal Register]. The current requirements of Order Nos. 888 and 888-A will remain in effect until this order becomes effective.

FOR FURTHER INFORMATION CONTACT:

David D. Withnell (Legal Information -- Docket No. RM95-8-003)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 208-2063

Deborah B. Leahy (Legal Information -- Docket No. RM94-7-004)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 208-2039

Daniel T. Hedberg (Technical Information -- Docket No. RM95-8-003)
Office of Electric Power Regulation
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 208-0243

Joseph M. Power (Technical Information -- Docket No. RM94-7-004)
Office of Electric Power Regulation
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426
(202) 208-0243

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the Federal Register, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 2A, 888 First Street, N.E., Washington, D.C. 20426. The complete text on diskette in WordPerfect format may be purchased from the Commission's copy contractor, La Dorn Systems Corporation. La Dorn Systems Corporation is located in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, also provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user. CIPS can be accessed over the Internet by pointing your browser to the URL address: http://www.ferc.fed.us. Select the link to CIPS. The full text of this document can be viewed, and saved, in ASCII format and an entire day's documents can be downloaded in WordPerfect 6.1 format by searching the miscellaneous file for the last seven days. CIPS also may be accessed using a personal computer with a modem by dialing 202-208-1397, if dialing locally, or 1-800-856-3920, if dialing long distance. To access CIPS, set your communications software to 19200, 14400, 12000, 9600, 7200, 4800, 2400, or 1200 bps, full duplex, no parity, 8 data bits and 1 stop bit. The full text of this order will be available on CIPS in ASCII and WordPerfect 6.1 format. CIPS user assistance is available at 202-208-2474.

TABLE OF CONTENTS

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, and William L. Massey.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities	)	Docket No. RM95-8-003
Recovery of Stranded Costs by Public Utilities and Transmitting Utilities	)	Docket No. RM94-7-004

ORDER NO. 888-B

(Issued November 25, 1997)

I. INTRODUCTION

In this order, the Commission affirms, with certain clarifications, the fundamental calls made in Order No. 888-A. 1/

II. PUBLIC REPORTING BURDEN

This order on rehearing issues a minor revision to Order Nos. 888 and 888-A. 2/ We find, after reviewing this revision,

---

1/ As described further below, the Commission is making one revision to the pro forma open access transmission tariff. See infra Section IV.A.10.f and Appendix B. Because of this single revision and its minor nature, the Commission concludes that it would be administratively burdensome to require all public utilities with pro forma open access transmission tariffs on file with the Commission to submit compliance tariffs to reflect the revision. Accordingly, the Commission will amend all pro forma open access transmission tariffs currently on file with the Commission to incorporate the tariff revision and no tariff compliance filings will be necessary.

2/ Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12,274 (March 14, 1997), FERC Stats.
(continued...)

that it does not increase or decrease the public reporting burden.

Order No. 888 contained an estimated annual public reporting burden based on the requirements of the Open Access Final Rule and the Stranded Cost Final Rule. 3/ Using the burden estimate contained in Order No. 888 as a starting point, we evaluated the public burden estimate in light of the revision contained in this order and assessed whether the estimate needed revision. We have concluded, given the minor nature of the revision, that our estimate of the public reporting burden of this order on rehearing remains unchanged from our estimate of the public reporting burden contained in Order Nos. 888 and 888-A. The Commission has conducted an internal review of this conclusion and has assured itself that there is specific, objective support for this information burden estimate. Moreover, the Commission has reviewed the collection of information required by Order Nos. 888 and 888-A, as revised and clarified by this order on rehearing, and has determined that the collection of information is necessary and conforms to the Commission's plan, as described

2/ (...continued)
& Regs. ¶ 31,048 (1997).

3/ 61 FR 21,540, 21,543; FERC Stats. & Regs. ¶ 31,036 at 31,638 (1996). In Order No. 888-A, the Commission concluded that its estimate of the public reporting burden in that order on rehearing remained unchanged from its estimate in Order No. 888. 62 FR 12,274, 12,280; FERC Stats. & Regs. ¶ 31,048 at 30,183 (1997).

in Order Nos. 888 and 888-A, for the collection, efficient management, and use of the required information.

Persons wishing to comment on the collections of information required by Order Nos. 888 and 888-A, as modified by this order on rehearing, should direct their comments to the Desk Officer for FERC, Office of Management and Budget, Room 3019 NEOB, Washington, D.C. 20503, phone 202-395-3087, facsimile: 202-395-7285. Comments must be filed with the Office of Management and Budget within 30 days of publication of this document in the Federal Register. Three copies of any comments filed with the Office of Management and Budget also should be sent to the following address: Ms. Lois Cashell, Secretary, Federal Energy Regulatory Commission, Room 1A, 888 First Street, N.E., Washington, D.C. 20426. For further information, contact Michael Miller, 202-208-1415.

III. BACKGROUND

In Order No. 888, the Commission required all public utilities that own, operate or control interstate transmission facilities to offer network and point-to-point transmission services (and ancillary services) to all eligible buyers and sellers in wholesale bulk power markets, and to take transmission service for their own uses under the same rates, terms and conditions offered to others. Order No. 888 required functional separation of the utilities' transmission and power marketing functions (also referred to as functional unbundling) and the adoption of an electric transmission system information network.

To implement the requirements of comparable open access transmission, the Commission required all public utilities that own, operate or control interstate transmission facilities to file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory transmission service. In Order No. 888, the Commission established rules for discounting practices, provisions governing priority of service and curtailment, and a right of first refusal for all firm transmission customers. In addition, Order No. 888 conditioned the use of a public utility's open access service on the agreement that, in return, it is offered reciprocal service by non-public utilities that own or control transmission facilities.

With regard to stranded costs, Order No. 888 gives utilities the opportunity to seek to recover legitimate, prudent, and verifiable wholesale stranded costs associated with serving customers under wholesale requirements contracts executed on or before July 11, 1994 that do not contain explicit stranded cost provisions, and costs associated with serving retail-turned-wholesale customers. The opportunity to seek stranded costs is limited to situations in which there is a direct nexus between the availability and use of a Commission-required transmission tariff and the stranding of the costs. The Commission adopted a revenues lost approach for calculating a utility's stranded costs, and determined that stranded costs should be recovered from the customer that caused the costs to be incurred. The

Commission decided in Order No. 888 to be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers, but not to be the primary forum in cases involving existing municipal utilities that annex retail customer service territories. Order No. 888 also clarified whether and when the Commission may address stranded costs caused by retail wheeling and the extent of the Commission's jurisdiction over unbundled retail transmission. The Commission determined that the only circumstance in which it will entertain requests for the recovery of stranded costs caused by unbundled retail wheeling is when the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required.

Order No. 888 further addressed the circumstances under which utilities and their wholesale customers may seek to modify contracts made under the old regulatory regime, taking into account the goals of reasonably accelerating customers' ability to benefit from competitively priced power and at the same time ensuring the financial stability of electric utilities during the transition to competition. The Commission determined that pre-existing contracts would continue to be honored until such time as they were revised or terminated. The Commission also found that those who were operating under pre-existing requirements contracts containing Mobile-Sierra clauses would nonetheless be allowed to seek reform of the contracts on a case-by-case basis, and that public utilities would be allowed to file to amend their

Mobile-Sierra contracts for the limited purpose of providing an opportunity to seek recovery of stranded costs, without having to make a public interest showing that such cost recovery should be permitted.

In Order No. 888-A, the Commission reaffirmed its basic determinations in Order No. 888, with certain clarifications. For example, it revised the discounting requirements to better permit the ready identification of discriminatory discounting practices while also providing greater discount flexibility, and it clarified several aspects of the reciprocity condition. It also clarified that if utilities under Mobile-Sierra contracts seek to modify provisions that do not relate to stranded costs, they will have the burden of showing that the provisions are contrary to the public interest. In addition, the Commission reconsidered its decision in Order No. 888 not to be the primary forum for determining stranded cost recovery in cases involving municipal annexation and concluded that such cases should fall within the Commission's province.

In this order, the Commission affirms, with certain clarifications, the fundamental calls made in Order No. 888-A.

IV. DISCUSSION

A. Open Access Issues

1. Discounting

A number of entities seek rehearing and/or clarification of the Commission's modified discounting policy that requires transmission providers to offer the same discount over all unconstrained paths to the same point of delivery. 4/ Several of these entities assert that the Commission's modified policy encourages discriminatory behavior. 5/ NRECA and TDU Systems argue that the Commission's policy opens the door to customer-by-customer discrimination (including discrimination by the transmission provider in favor of its native load customers) because it is likely that only one or a few customers would want transmission service to a particular delivery point. They also assert that the transmission provider unreasonably could discount service on a path where it has load, but decline discounts to another delivery point halfway along the same path. 6/ They further contend that the Commission's new policy "swings the pendulum too far in the direction of allowing price discrimination" by the transmission monopolist. According to TDU Systems, the Commission's policy "does not confine the transmission provider's incentive to give discounts for its own transmission uses to those instances, and only those instances, in which such discounts are economically justified." TDU Systems adds that "the OASIS reporting will be inadequate to remedy

---

4/ Arizona, NRECA, TAPS, and TDU Systems. APPA also raises this issue, but APPA filed its request for rehearing out-of-time on April 4, 1997. APPA failed to file its rehearing request within the 30 day period required by the Federal Power Act. See 16 U.S.C. § 825l(a). Accordingly, we will not accept the rehearing request for filing, but will accept the pleading as a motion for reconsideration.

5/ NRECA, TDU Systems, TAPS and APPA.

6/ See also TAPS.

discrimination in discounting short-term non-firm transmission, since the transactions will be over before complaints can even be filed." 7/

TAPS likewise asserts that "[b]y allowing transmission providers to select the delivery points meriting a discount, the Commission is encouraging discriminatory behavior that it will be unable to remedy" through an after-the-fact complaint proceeding. 8/ It maintains that the Commission's approach "makes it less likely that transmission providers will provide competitors non-firm transmission service at rates reflecting the lower quality of the service (if the Commission permits non-firm transmission rates to be capped at the firm rate)." 9/ It notes that TAPS members

> have experienced withdrawal of discounts they have enjoyed under the Order No. 888 discounting policy and have seen evidence that the revised policy will be applied by transmission providers to offer discounts to each other, in the hope, expectation, or tacit agreement that they will be offered reciprocal discounts on the other transmission provider's system when requested, while a transmission dependent utility must always pay full freight. [10/]

APPA asserts that the Commission properly required all discount negotiations to occur on the OASIS, but erroneously

---

7/ TDU Systems at 8-10.

8/ TAPS at 17.

9/ *Id.* at 18 (footnote omitted).

10/ *Id.*

removed the requirement that affiliate discounts be offered for all service on unconstrained paths. It argues that the Commission "has failed to balance its policy of ending discrimination in wholesale transmission services with the objective to send proper price signals to transmission providers and customers." 11/ Under the Commission's modified approach, APPA believes that transmission providers can offer discounts on a very selective basis -- "public utility transmission providers will have the ability to provide discounts to affiliates in ways that exclude smaller utilities, including municipal utilities, from receiving those same discounts." 12/

These entities propose several approaches to resolve the competitive problems they believe are associated with the Commission's modified approach to discounting. NRECA states that the Commission should revert to its Order No. 888 policy or require that discounts be offered on all unconstrained paths serving all similarly situated customers. NRECA and TDU Systems (which supports the second alternative) state that the alternative approach could be accomplished by requiring discounts on all unconstrained "posted paths," or, if a discount is provided within a particular unconstrained area, the transmission provider should be required to offer the same discount on all unconstrained paths within the same area. Similarly, TAPS states

---

11/ APPA at 17.

12/ Id. at 19.

that the Commission should revert to its Order No. 888 policy or, at a minimum, "the discounts should be extended to all delivery points in the same unconstrained portion of the transmission provider's transmission system plus other similarly situated customers (from an operational/cost, rather than competitive, viewpoint)." 13/ Moreover, APPA states that the Commission should revert to Order No. 888 or, in the alternative, "should require uniform discounts across interfaces and within control areas, or, at a minimum, within unconstrained zones." 14/

TAPS adds that the best way to promote efficient transmission usage and competitive bulk power markets is "to set non-firm rates at the lowest reasonable rate, in accordance with the Commission's statutory mandate. . . . It is unreasonable to rely on discounting, especially delivery point-specific discounts, to ensure that customers are not charged firm rates for interruptible, low priority, non-firm service." 15/ It requests that the Commission clarify that it will actively exercise its responsibility to ensure that customers are not overcharged for non-firm service.

Arizona, on the other hand, seeks to narrow the Commission's revised discounting policy. It requests that the Commission

---

13/ TAPS at 19.

14/ APPA at 20.

15/ TAPS at 20.

allow a transmission provider to offer varying degrees of discount depending upon whether

> (1) transactions over a particular path alleviate constraints on another transmission path, (2) certain transmission paths are loaded to a different degree than other paths, and (3) initial discounts encourage a sufficient number of transactions. [16/]

For example, it asserts that "there could be multiple paths to the same delivery point, with each path potentially warranting different discounting treatment. A steep discount may be appropriate on one unutilized transmission path to encourage counter-wheeling transactions that will alleviate constraints on another path into the delivery point, whereas a smaller discount (or no discount at all) may be appropriate on another unconstrained, but highly valued, path into the delivery point." 17/

With respect to its second point, Arizona asserts that a transmission path with relatively little available transmission capability (ATC) deserves a lower discount than a transmission path with relatively high ATC. It urges the Commission to clarify "whether a transmission path that has an ATC equal to 80% of [total transmission capability (TTC)] should be discounted to the same degree as a transmission path that has an ATC equal to

---

16/ Arizona at 4.

17/ Id. at 5 (footnote omitted).

only 30% of TTC." 18/ As to its third point, it seeks clarification that it "may initially offer a steep discount on a transmission path into a particular delivery point to encourage transactions, but reduce the discount as more and more transactions take place over that path." 19/

American Electric Power System (AEP) responds to TAPS' assertion that transmission providers will only offer discounts to each other as evidenced by a printout from AEP's OASIS under which TAPS contends "discounts are now available only to delivery points of other transmission providers, not those of TDUs." 20/ AEP indicates that, contrary to TAPS' assertion, it offers discounts to any transmission customer that has alternatives to using AEP's transmission system. It notes that this is consistent with the Order No. 888-A statement that a transmission provider should discount only if necessary to increase throughput on its system. It also adds that no customer is being charged rates that exceed a just and reasonable, cost-based rate. According to AEP, "[t]o charge customers without alternatives less than the cost-based rate would be unduly discriminatory to AEP's native load customers who would otherwise have to make up

---

18/ Id. at 6 n.12.

19/ Id. at 6 (footnote omitted).

20/ AEP at 3. On April 17, 1997, AEP filed an answer to the request for clarification and rehearing of TAPS. In the circumstances presented, we will accept the answer notwithstanding our general prohibition on allowing answers to rehearing requests. See 18 CFR 385.713(d).

the revenues not recovered from such customers." 21/ Moreover, because discounting must be conducted through the OASIS, AEP declares that there is no chance that a transmission provider will use discounting for any purpose other than to increase throughput. AEP also opposes TAPS' request to establish a price cap for non-firm service below that for firm service. It claims that such a change would allow customers on largely unconstrained transmission systems such as AEP's to game the system by requesting non-firm service priced at a low level with the knowledge that the service is essentially the equivalent of firm service.

Commission Conclusion

We deny the requests for rehearing of our discounting policy. In Order No. 888-A, we addressed certain concerns raised by various parties on rehearing regarding our prior discounting policy and adopted a more balanced approach that would provide incentives to transmission providers to operate the transmission grid efficiently while ensuring that they do so in a not unduly discriminatory manner. 22/ Our balanced approach requires that (1) a transmission provider should discount only if necessary to increase throughput on its system, (2) any offer of a discount and the details of any agreed upon discount transaction must be posted on the OASIS (including any negotiation, i.e., any offers

---

21/ Id. at 4 (emphasis in original).

22/ FERC Stats. & Regs. ¶ 31,048 at 30,274-76.

and counteroffers, of the discount), and (3) a transmission provider must offer the same discount for the same time period on all unconstrained paths that go to the same point(s) of delivery.

We believe that this approach is a reasonable and workable means to permit transmission providers to provide discounts in a not unduly discriminatory manner. Transmission providers will not have unnecessary restrictions on their ability to increase throughput on their transmission systems, which accrues to the benefit of all of their firm customers, while OASIS will allow the Commission and other users of the system to monitor for instances of unduly discriminatory behavior by such transmission providers. 23/

In this regard, we also disagree that posting of discounts on OASIS is inadequate for short-term discounts because the transactions will be over before a complaint could be filed. All complaint proceedings occur after the fact, but we believe that such proceedings nevertheless act as a deterrent to improper behavior. The Commission will not be reluctant to impose

23/ With respect to Arizona's request that a transmission provider be allowed to offer varying degrees of discount depending on the circumstances, we note that this Rule does not reach that level of specificity. A transmission provider is free to implement any discounting proposal which it believes can increase throughput without doing so in an unduly discriminatory manner, provided that the proposal offers the same discount for the same period to all eligible customers on all unconstrained paths that go to the same point(s) of delivery. However, if challenged on complaint, it should be prepared to defend its method. The only alternative is to require no discounting, an approach we reject as contrary to firm customers' interests and efficient grid use.

appropriate sanctions in instances where transmission providers engage in unduly discriminatory discounting practices. Moreover, any alternative would likely require a preapproval process that could, as parties to this proceeding have argued, shut down a substantial portion of the hourly transactions in short-term markets that depend upon discounted transmission to go forward.

We see no need at this time to adopt a more restrictive discounting policy that could hinder a transmission provider's ability to increase throughput on its system based solely on allegations that the transmission provider may act in an unduly discriminatory manner. The opportunity to monitor the discounting behavior of transmission providers through OASIS will provide data that will allow the Commission to evaluate the adequacy and effectiveness of its discounting policy. 24/ Until we see evidence that our discounting policy will not work or see patterns of unduly discriminatory discounting practices, we will continue the Order No. 888-A discounting policy, with the OASIS safeguards in place.

2. Reciprocity

Several entities raise a variety of issues with respect to the Commission's reciprocity condition. NRECA and TDU Systems request clarification that the amendment to section 6 of the pro

24/ As the market evolves, the Commission may need to take up a broad array of transmission pricing issues. It may well develop that a long-term solution to any problems raised by discounting requires fundamental changes to the transmission pricing methods currently in place in the electric industry.

forma tariff that deleted the words "in interstate commerce" was intended to affect only the reciprocity obligation of foreign transmission customers and not the reciprocity obligation of transmission customers located in the United States. 25/ They seek clarification that transmission customers within the United States need provide reciprocal service only on facilities used for the transmission of electric energy in interstate commerce and not over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce.

Also with respect to section 6 of the pro forma tariff, NEPOOL takes issue with the additional language that provides that reciprocity applies to "all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer." 26/ It asserts that the breadth of this language could cause New Brunswick Power Corporation (New Brunswick), a Canadian utility that has engaged in economy and emergency transactions with NEPOOL and made unit sales to New England buyers, to cease or reduce sales in New England. According to NEPOOL, New Brunswick has indicated a concern that it does not have the legal authority to implement a generic open access tariff in New Brunswick. Thus, NEPOOL requests that the Commission provide that where a seller is simply continuing to

---

25/ NRECA at 13-14; TDU Systems at 13-14.

26/ NEPOOL at 7.

make sales in the same manner as it did before Order Nos. 888 and 888-A, and is legally unable to provide reciprocity, the reciprocity requirement will not be applicable to it. 27/

TAPS takes issue with the Commission's modified "safe harbor" procedure set forth in Order No. 888-A that permits a non-public utility to provide reciprocal service only to the transmission provider from whom it receives open access transmission service. TAPS believes that the Commission's modification is "an unnecessary step backwards from its expressed aim of remedying past undue discrimination and providing non-discriminatory open access." 28/ It believes that the transmission provider's access to third party systems will be superior to that of its customers that support the transmission grid. According to TAPS, a customer would be at a disadvantage because it would be forced to resort to a filing under section 211. Thus, it asserts that the safe harbor should be available only to those that offer open access to all eligible wholesale transmission customers. "At the very least, [it argues,] the special protections offered by the safe harbor should be available only if the non-jurisdictional utility makes its tariff available to the long term customers of the transmission provider." 29/

27/ Id. at 7-8.

28/ TAPS at 22.

29/ Id. at 23 (footnote omitted).

RUS seeks rehearing and/or clarification with respect to a number of reciprocity related issues. RUS first complains that there is confusion regarding the alternatives available to non-public utilities. It asserts that in certain places in Order No. 888-A the Commission indicates that it will no longer allow bilateral agreements (e.g., "Alternatively, bilateral agreements for transmission service provided by a public utility will not be permitted."), but that in other places the Commission encourages the use of bilateral agreements (e.g., "A non-public utility may also satisfy reciprocity through bilateral agreements with a public utility."). It also notes that Order No. 888-A appears to substitute public utility waivers for the alternative of bilateral agreements. In any event, however, it argues that

> [p]ublic utilities have no incentive to enter into bilateral agreements or to waive the reciprocity requirement for a non-public utility that owns transmission. Indeed, these so-called options effectively invite public utilities to deny access to non-public utilities that have not filed open access tariffs. If a non-public utility cannot qualify for a waiver from the Commission, the public utility can, by denying a waiver or refusing to enter into a bilateral agreement, force the non-public utility to file a reciprocal tariff with the Commission. Moreover, requiring a non-public utility to seek a waiver -- whether from the public utility or the Commission -- is inconsistent with the Commission's assertions that the provision of open access by non-public utilities is not required, but merely voluntary. [30/]

30/ RUS at 10-11.

RUS takes issue with the following statement in Order No. 888-A, claiming that it mischaracterizes the RUS program and RUS as anti-competitive:

> With respect to TDU System's assertion that reciprocal service should not have to be rendered if it would interfere with RUS loan financing, we note that we have already indicated that reciprocal service need not be provided if tax-exempt status would be jeopardized. If TDU Systems is arguing that we should not require reciprocal service if RUS attaches such a condition in its regulation of RUS-financed cooperatives, we reject such argument. Such cooperatives have the option to seek bilateral service agreements. [Order No. 888-A, mimeo at 318].

RUS maintains that it does not place any prohibitions, restrictions, or conditions on financing to electric systems based on rendering reciprocal service. It states that while the Rural Electrification Act places restrictions on RUS financing, it does not prohibit cooperatives from obtaining financing for facilities through non-RUS sources.

RUS seeks clarification that the statement in Order No. 888-A that "the seller as well as the buyer in the chain of a transaction involving a non-public utility will have to comply with the reciprocity condition" does not mean that if a G&T uses an open access tariff, both the G&T and its distribution system are subject to the reciprocity provision.

RUS also states that although the Commission acknowledges that it lacks jurisdiction to enforce rates charged by non-public utilities in reciprocal open access tariffs and to adjudicate stranded cost claims of non-public utilities, the Commission has indicated that if a non-public utility includes a stranded cost component in a reciprocity tariff, "the Commission will review that stranded cost provision if a public utility claims that the stranded cost component, as applied, violates the principle of comparability." 31/ According to RUS, "any comparability determination with respect to stranded cost or other provisions contained in a non-public utility's open access tariff will involve the exercise of Commission jurisdiction over a non-public utility's open access transmission tariff as well as a determination of the legitimacy of the non-public utility's stranded cost claims." 32/ RUS says that the Commission has not indicated that it will apply the comparability standard to the transmission rates that rural cooperatives charge members and non-members in a manner that will take into account the unique characteristics of a cooperative system, the inherent differences between members and non-members, and the intended beneficiaries of the RE Act.

Commission Conclusion

With respect to NRECA and TDU Systems' requested clarification of the deleted words "in interstate commerce" from section 6 of the pro forma tariff, we reiterate that transmission customers in the United States must provide reciprocal transmission service "over facilities used for the transmission

---

31/ Id. at 12.

32/ Id.

of electric energy owned, controlled or operated by the Transmission Customer." 33/ Thus, a transmission customer must provide transmission service over all transmission facilities that it owns, controls or operates. This includes transmission facilities in both interstate and intrastate commerce. Such a customer, however, need not provide reciprocal service over facilities used solely in local distribution.

We recently addressed concerns similar to those raised by NEPOOL as to the applicability of the reciprocity condition to a Canadian utility selling power to a U.S. utility. In an order addressing Ontario Hydro's motion for a stay of the reciprocity provision of Order Nos. 888 and 888-A as those orders apply to transmission-owning foreign entities, we explained that the reciprocity condition does not apply

> in circumstances where a Canadian utility sells power to a U.S. utility located at the United States/Canada border, title to the electric power transfers to the U.S. border utility, and the power is then resold by the U.S. border utility to a U.S. customer that has no affiliation with, and no contractual or other tie to, the Canadian utility. The reciprocity provision thus does not in any way affect historical Canadian-United States buy-sell arrangements, i.e., those involving sales to U.S. border utilities who then resell power to purchasers that have no contractual or other transactional link to the Canadian seller. For these types of historical sales, a Canadian seller is no worse off under Order Nos. 888 and 888-A than it was prior to the orders' issuance. Additionally, Order Nos. 888 and 888-A do not disrupt any pre-Order No. 888 power sales

---

33/ See FERC Stats. & Regs. at 30,513.

> contracts under which Ontario Hydro sells to U.S. utilities, or any pre-Order No. 888 transmission contracts under which it purchases transmission from U.S. utilities. [34/]

Thus, Order Nos. 888 and 888-A do not disrupt any existing agreements, as defined in those orders, between New Brunswick and any of its U.S. customers. Moreover, to the extent any of New Brunswick's transactions are buy-sell arrangements of the type described above, such transactions also are not affected by Order Nos. 888 and 888-A. However, if New Brunswick seeks to sell power under new agreements or through new coordination transactions, such transactions are subject to Order Nos. 888 and 888-A and New Brunswick would have to agree to provide reciprocal open access transmission, unless waived by the U.S. public utility or this Commission.

TAPS' rehearing request with respect to the safe harbor procedure was not timely filed. In Order No. 888, the Commission explicitly stated that "we intend that reciprocal service be limited to the transmission provider." 35/ The Commission also stated, in establishing the safe harbor procedure, that "[w]e are aware that many non-public utilities are very willing to offer reciprocal access, and that some are willing to provide access to

---

34/ Order Clarifying Order No. 888 Reciprocity Condition and Requesting Additional Information, 79 FERC ¶ 61,182 at (1997) (footnotes omitted); see also Order Denying Motion for Stay, 79 FERC ¶ 61,367 (1997).

35/ FERC Stats. & Regs. at 31,760.

all eligible customers through an open access tariff." 36/ Thus, it was clear that a non-public utility could meet reciprocity under the safe harbor procedure by agreeing to provide service only to the transmission provider or to any eligible customer. Nothing in Order No. 888-A changed this approach. The Commission's discussion of the safe harbor procedure in Order No. 888-A was limited to Santee Cooper 37/ -- a company-specific case decided subsequent to Order No. 888. The Commission noted that while the company in that case chose to offer an open access tariff to all eligible customers, "Order No. 888 provides, as a condition of service, that reciprocal access be offered to only those transmission providers from whom the non-public utility obtains open-access service." 38/

We also disagree with TAPS' assertion that the Commission has taken "an unnecessary step backwards from its expressed aim of remedying past undue discrimination and providing non-discriminatory open access." We explicitly stated in Order No. 888 our rationale for requiring that reciprocal access be offered only to the transmission provider from whom the non-public utility obtains open access service:

> We believe the reciprocity requirement strikes an appropriate balance by limiting its application to circumstances in which the

---

36/ Id. at 31,761.

37/ South Carolina Public Service Authority, 75 FERC ¶ 61,209 at 61,701 (1996).

38/ FERC Stats. & Regs. ¶ 31,048 at 30,289.

> non-public utility seeks to take advantage of open access on a public utility's system. [39/]

With respect to RUS' concerns regarding the availability of bilateral agreements, we clarify the distinction between the two different circumstances: (1) that of a non-public utility seeking transmission service from a public utility, and the requirement imposed on the public utility in providing the service; and (2) that of a public utility seeking transmission from a non-public utility, and what is sufficient for the non-public utility to provide reciprocal transmission service. As we stated in Order No. 888-A, if a non-public utility seeks service from a public utility, that public utility should, except in unusual circumstances, provide the service "pursuant to the open access tariff and not pursuant to separate bilateral agreements." 40/ On the other hand, if a public utility seeks service from a non-public utility through the reciprocity condition, Order No. 888-A provides that the non-public utility may provide that service pursuant to a bilateral agreement to satisfy its reciprocity obligation. 41/

We do not agree with RUS that public utilities will have no incentive to take service under bilateral agreements or to waive the reciprocity condition for non-public utilities. If a public

39/ FERC Stats. & Regs. ¶ 31,036 at 31,762.

40/ FERC Stats. & Regs. ¶ 31,048 at 30,285.

41/ Id. at 30,289.

utility needs transmission service from a non-public utility to maximize its profits or to make sales or purchases on behalf of its native load, then it should not care whether it takes service from the non-public utility under a bilateral agreement or an open access tariff. However, we recognize that even if the public utility does not need transmission service from a non-public utility, it may use the reciprocity condition as a reason to deny transmission service. But this is no different from the situation non-public utilities were in prior to the issuance of Order No. 888 when utilities could outright deny any transmission service. In that situation, the only recourse for the non-public utility was to file a request for service under section 211. The same is true post-Order No. 888. 42/

In any event, should a public utility refuse to provide transmission service based on a claim that the non-public utility requesting transmission service is not willing to provide reciprocal service, the non-public utility may always file a transmission tariff under the safe harbor procedure. We do not see this as any burden as the Commission has made available for interested entities a complete open access tariff that would require little modification to file. 43/ Moreover, as we have

42/ Of course, the flip side is equally true. If a public utility seeks service from a non-public utility, the only way it may be able to seek such service is by filing a section 211 application.

43/ We note that since issuance of Order No. 888, ten non-public utilities have filed reciprocity tariffs, including (continued...)

explained, this reciprocal tariff, filed under the safe harbor procedure, need only be made available to the public utility (or utilities) from whom the non-public utility obtains open access transmission service. Further, if, as RUS seems to imply, the cooperatives do not want to provide any service, that is fundamentally at odds with the basic reciprocity provision and the fairness/competition concepts that underlie it.

We also reject RUS' argument that requiring a non-public utility to seek a waiver is inconsistent with the Commission's assertion that the reciprocity condition is voluntary. First, we did not require that non-public utilities seek a waiver, but merely provided a waiver as an option for them to pursue. Moreover, the waiver option (from the public utility or the Commission) is available only if a non-public utility voluntarily chooses to request open access transmission service from a public utility. As we explained in Order No. 888-A:

> we are not requiring non-public utilities to provide transmission access. Instead, we are conditioning the use of public utility open access tariffs, by all customers including non-public utilities, on an agreement to offer comparable (not unduly discriminatory) services in return. [44/]

We will clarify for RUS that the Commission's statement that "the seller as well as the buyer in the chain of a transaction

43/ (...continued) cooperatives.

44/ FERC Stats. & Regs. ¶ 31,048 at 30,285 (emphasis in original).

involving a non-public utility will have to comply with the reciprocity condition" does not apply to member distribution cooperatives when their G&T cooperative obtains open access transmission service. We did not intend this statement to change our position with respect to cooperatives and reaffirm our prior pronouncement that

> if a G&T cooperative seeks open access transmission service from the transmission provider, then only the G&T cooperative, and not its member distribution cooperatives, should be required to offer transmission service. [45/]

Finally, we disagree with RUS' claim that "any comparability determination with respect to stranded cost or other provisions contained in a non-public utility's open access tariff will involve the exercise of Commission jurisdiction over a non-public utility's open access transmission tariff as well as a determination of the legitimacy of the non-public utility's stranded cost claims." 46/ In Order No. 888-A, the Commission explained that a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity condition can include a stranded cost provision in its tariff, but adjudication of any stranded cost claims under that tariff would not be subject to our

---

45/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,286. We note that this does not prevent an eligible entity from filing a section 211 request with a "distribution" cooperative.

46/ RUS at 12.

jurisdiction. We said that although we would not determine the rate of a non-public utility (including the stranded cost component of the rate), "we would review a public utility's claim that it is entitled to deny service to a non-public utility because the stranded cost component of the non-public utility's transmission rate is being applied in a way that violates the principle of comparability." 47/ In reviewing a public utility's claims that a non-public utility is applying its stranded cost provision in a non-comparable (or discriminatory) manner, we would not be exercising jurisdiction over the non-public utility or its rates. We simply would be enforcing the reciprocity condition. As we said in Order No. 888-A, "[i]t would not be in the public interest to allow a non-public utility to take non-discriminatory transmission service from a public utility at the same time it refuses to provide comparable service to the public utility." 48/

3. Indemnification/Liability

Several petitioners argue that the Commission erroneously established a new standard of liability for transmission providers -- simple negligence -- that is contrary to the weight of authority in states across the country. 49/ They claim that

---

47/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,364 n.527.

48/ Id. at 30,285.

49/ See KCPL and Coalition for Economic Competition. EEI also raises this issue, but EEI filed its request for rehearing (continued...)

the Commission's standard would expose transmission providers and their native load customers to potentially enormous liability, including large consequential damage awards. 50/ EEI also argues that the Commission has made no finding that a change in the standard is needed to remedy alleged undue discrimination nor, it argues, has the Commission demonstrated any reason to change the liability standard. According to EEI, the proper standard is "gross negligence."

Similarly, Puget argues that the Commission erroneously refuses to allow the express exclusion of consequential and indirect damages. It argues that the exception language in section 10.2 of the pro forma tariff ("except in cases of negligence or intentional wrongdoing by the Transmission Provider") should be changed to "except in cases of and to the extent of comparative or contributory negligence or intentional wrongdoing by the Transmission Provider." It further argues that Order No. 888 should be revised to exclude liability for special, incidental, consequential or indirect damages.

49/ (...continued)
out-of-time on April 4, 1997 with a request that the Commission accept the rehearing request because it has occurred at the very start of the proceeding, no response is required by any other party and there will be no prejudice to any other party. EEI failed to file its rehearing request within the 30 day period required by the Federal Power Act. See 16 U.S.C. § 825l(a). Accordingly, we will not accept the rehearing request for filing, but will accept the pleading as a motion for reconsideration.

50/ See Coalition for Economic Competition, EEI.

Coalition for Economic Competition states that the Commission erroneously relied upon a gas decision as a basis for adopting an ordinary negligence standard. It asserts that the characteristics of gas and electric service and the risks associated with each are very different: (1) the wires for electric transmission are located above ground and more susceptible to outages than buried pipelines and (2) the electric grid is more complex, with the potential for a single problem to affect a significant number of customers over a large geographic area. Thus, it argues, electric transmission providers face a much greater exposure to liability than gas transporters.

EEI and KCPL request that the Commission clarify whether states have authority to establish the scope of a utility's liability in providing federally mandated transmission service, as provided for in Order No. 888-A. Because of some uncertainty on this issue and the fact that 25 states do not have reported decisions on the issue, EEI indicates that there is likely to be significant litigation, which may lead to uncertainty between the parties to the interstate service transaction. If the Commission determines that states do not have authority, EEI and KCPL assert that the Commission should establish a rule of liability based on a standard of gross negligence. If the Commission determines that states do have the authority to establish the scope of a transmission provider's liability, EEI, as well as KCPL, assert that the Commission "should clarify that states are preempted from attaching liability to actions taken by a transmission provider in compliance with the provisions of its filed pro forma tariff" and "should make an affirmative statement that it is expressing no opinion on whether a transmission provider should be liable, for public policy reasons, for acts of ordinary negligence." 51/

Coalition for Economic Competition further maintains that

> while the Commission directs transmission providers to rely on state law for protection against liability, it ignores the policies established at the state level which already address the issue. As a result, FERC is reallocating the risks associated with the transmission of electricity. To the extent that reallocation forces utilities to experience an additional financial burden, captive customers will be forced to pay more -- more than the parties agreed would be their fair share. [52/]

Furthermore, Coalition for Economic Competition states that case law may not protect the utility and its captive customers from the costs associated with the reallocation of risk:

> Frequently, the outcome of a case is closely related to any applicable tariff language that embodies that state's public policy as set by its regulatory commission. If the pro forma liability provision differs from the standards used in a particular state, the applicability and usefulness of that state's prior court decisions is unclear. [53/]

Coalition for Economic Competition also asserts that the Commission appears to be sending contradictory signals, citing a

---

51/ EEI at 7; KCPL at 7-8.

52/ Coalition for Economic Competition at 7.

53/ Id. at 8.

recent decision (New York State Electric & Gas Corporation, 78 FERC ¶ 61,114 (1997)) in which the Commission rejected a provision in an open access tariff that acted as a choice of law provision. It argues that issues involving which jurisdiction provides the most appropriate forum, and which law should apply, are likely to be contested issues. In sum, Coalition for Economic Competition states that "the Commission's reliance on state law leaves a wide open gap in which the outcome of potential claims is completely unknown, and the risk to which transmission providers are exposed is increased even more." 54/

Commission Conclusion

The tariff provisions on Force Majeure and Indemnification, as clarified in Order No. 888-A, provide certain limited protections to the transmission provider as well as its customers, when they faithfully attempt to carry out their duties under the tariff. The petitioners want the Commission to extend these limited protections to other situations or otherwise set forth definitive rules on liability in various situations that might arise under the tariff. We believe that the tariff provisions strike the right balance, and we will not here attempt to define the consequences of every conceivable breach that might occur under the tariff. Nor will we use the tariff, as some appear to want us to do, as an instrument for defining exclusive

54/ Id. at 9.

and preemptive federal laws for liability for all damages that might arise from the operation of the transmission system.

The Force Majeure provision of the tariff, in its essence, provides that neither the transmission provider nor the customer will be liable to the other when they behave in all respects properly, but unpredictable and uncontrollable force majeure events prevent compliance with the tariff. The Indemnification provision of the tariff, in its essence, provides that when the transmission provider behaves in all respects properly, the customer will indemnify the transmission provider from claims of damage to third parties arising from the service provided under the tariff. Under the terms of the tariff, the transmission provider may not rely on the protections provided by the Force Majeure clause or the Indemnification Clause for acts or omissions that are the product of negligence or intentional wrongdoing. Likewise, the customer may not rely on the protections provided by the Force Majeure clause for acts or omissions that are the product of negligence or intentional wrongdoing.

Contrary to the contention of EEI, the Force Majeure and Indemnification provisions do not establish a new simple negligence standard of liability for transmission providers. As we explained in Order No. 888-A, the issue of whether liability will attach to certain acts or omissions by a transmission provider is a different question from whether a customer should be obligated to indemnify the transmission provider in such circumstances. 55/ In Order Nos. 888 and 888-A, the Commission has made no finding and expressed no opinion concerning whether a transmission provider should be held liable for damages to third parties arising from the transmission provider's acts or omissions of simple negligence, and the tariff language should not be construed as preempting the appropriate tribunal's consideration of whether liability should attach for acts or omissions of the transmission provider that injure third parties.

While the Commission has not established an exclusive and preemptive liability standard for electric utilities, EEI and the Coalition for Economic Competition would have us do so. They seek exculpatory language in the tariff that would protect the transmission provider from liability in all cases, except where gross negligence has been shown. Both acknowledge in their rehearing requests that such an exculpatory standard would in some regions alter the current liability standards, citing a study which concludes that 25 states have addressed the issue, with 21 of the 25 finding a gross negligence standard appropriate. Both argue that the Commission could eliminate potential uncertainties and conflicts among tribunals by determining a comprehensive and exclusive federal standard that accords with the determinations of the majority of states that have addressed this issue. EEI and KCP&L also question whether reference to state law is appropriate at all, suggesting that the

55/ FERC Stats. & Regs. ¶ 31,048 at 30,301.

Commission must develop a comprehensive federal standard of liability for service under the tariffs. We do not believe that such a determination is necessary or appropriate at this time.

First, we note that there is no question that the Commission has exclusive jurisdiction to determine the reasonableness of rates, terms, and conditions for the transmission of electric energy in interstate commerce. 56/ Moreover, it is clear that state tribunals may not second-guess or collaterally attack Commission determinations of the reasonableness of filed rates, terms, and conditions. 57/ On the other hand, it is likewise clear that the Commission's jurisdiction to consider disputes arising under jurisdictional tariffs does not as a matter of law preclude state courts from also entertaining such disputes in the appropriate circumstances. 58/ In determining whether the Commission will exercise jurisdiction in such cases, the Commission is guided by the principles set forth in Arkansas

---

56/ 16 U.S.C. § 824b; see, e.g., Nantahala Power & Light Company v. Thornburg, 476 U.S. 953, 963-66 (1986); FPC v. Southern California Edison Company, 376 U.S. 205 (1964); Public Utilities Commission v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927).

57/ See, e.g., Mississippi Power & Light Company v. Mississippi ex rel Moore, 487 U.S. 354, 374-75 (1988); Gulf States Utilities Company v. Alabama Power Company, 824 F.2d 1465, 1471-72, amended, 831 F.2d 557 (5th Cir. 1987).

58/ See, e.g., Pan American Petroleum Corporation v. Superior Court of Delaware, 366 U.S. 656, 662, 666 (1961).

Louisiana Gas Company v. Hall. 59/ Application of these principles suggests the possibility that tribunals other than the Commission may be called upon to adjudicate disputes arising from service under the tariff.

With that background, the concerns expressed by EEI and KCP&L concerning the need for a uniform federal liability standard closely resemble the concerns addressed by the court in United Gas Pipe Line Company v. FERC. 60/ In that case, the Commission had approved a tariff that limited a pipeline's liability to claims of "negligence, bad faith, fault or wilful misconduct" and the pipeline appealed, arguing that a uniform standard of liability should be established that was more protective of the pipeline. The court rejected the claim that there was a need for a uniform federal standard more favorable to the pipeline. As the court explained, "uniformity of result is needed only to protect the federal interest, that is, only to exculpate [the pipeline] from contract liability in all cases not based on [the pipeline's] fault. Uniformity of exculpation beyond those cases is not a matter of federal concern" because in such instances "liability flows only from [the pipeline's] mismanagement." 61/ This same reasoning applies here. It is appropriate for the Commission to protect the transmission

59/ 7 FERC ¶ 61,175, reh'g denied, 8 FERC ¶ 61,031 (1979).

60/ 824 F.2d 417 (5th Cir. 1987).

61/ 824 F.2d at 427.

provider through the tariff provisions on Force Majeure and Indemnification from damages or liability that may occur when the transmission provider provides service without negligence, but to leave the determination of liability in other instances to other proceedings. 62/

4. Qualifying Facilities (QF)/Real Power Loss Service

NIMO and EEI 63/ seek rehearing of the Commission's clarification in Order No. 888-A that a

> QF arrangement for the receipt of Real Power Loss Service or ancillary services from the transmission provider or a third party for the purpose of completing a transmission transaction is not a sale-for-resale of power by a QF transmission customer that would violate our QF rules. [64/]

NIMO argues that the Commission's clarification is inconsistent with the criteria for QF status under sections 3(17) and 3(18) of the FPA and the Commission's precedent. NIMO argues

---

62/ Some of the rehearing requests concerning indemnification/liability raise issues that previously were raised on rehearing of Order No. 888 and were addressed by the Commission in Order No. 888-A. See Coalition for Economic Competition argument that the circumstances of electric transmission require a different result than the gas pipeline cases and Puget arguments that the negligence language of the indemnification provision should be changed to reference comparative or contributory negligence and that the tariff should exclude transmission provider liability for special, incidental, consequential, or indirect damages. The Commission will not further address such issues in this proceeding.

63/ As discussed above, EEI filed its request for rehearing out-of-time. Accordingly, we are treating EEI's pleading as a motion for reconsideration.

64/ FERC Stats. & Regs. ¶ 31,048 at 30,237 (1997). See also Puget.

that the Commission has decided that a QF can only sell the net output of its facility without losing QF status. According to NIMO, allowing QFs to purchase Real Power Loss Service will result in QFs selling in excess of their net output at avoided cost. 65/

Finally, NIMO argues that if the Commission wishes to allow QFs to purchase power to compensate for line losses from third parties, and to include such power in their sales, it must do so only after a rulemaking in which it has noticed its intention to amend its QF regulations. 66/

Commission Conclusion

As a preliminary matter, we reject NIMO's argument that the Commission could only grant the clarification provided in Order No. 888-A after a rulemaking in which it noticed its intent to amend its QF regulations. All of the QF cases cited by NIMO in its rehearing request involve the Commission clarifying its rules in case-specific situations. For example, in Occidental Geothermal, Inc. (Occidental), the Commission was required to define the term "power production capacity" of a facility as that

---

65/ On April 21, 1997, Granite State Hydropower Association filed an answer to NIMO's rehearing request arguing that gross sales are permissible for QFs. In the circumstances presented, we will accept the answer notwithstanding our general prohibition on allowing answers to rehearing requests. See 18 CFR 385.713(d).

66/ EEI supports NIMO's arguments.

term was used in 18 CFR 292.204(a). 67/ The Commission did so without issuing a notice of proposed rulemaking and seeking comments.

Moreover, the issue raised by NIMO and EEI is whether the Commission's clarification would result in a facility losing QF status, as defined in sections 3(17) and 3(18) of the FPA. The Conference Report on PURPA provides:

> The new paragraphs 17(C) and 18(B) of the definitions provide that the Commission shall determine, by rule, <u>on a case-by-case basis, or otherwise</u>, that a small power production facility or a cogeneration facility is a qualifying small power production facility or cogeneration facility, as the case may be. [68/]

Accordingly, NIMO's argument that the Commission has improperly amended its PURPA regulations is wrong.

The substantive issue raised on rehearing is an issue of first impression. 69/ In Occidental, Turners Falls, as well as

---

67/ 17 FERC ¶ 61,231 (1981).

68/ H.R. Rep. No. 95-1750, Public Utility Regulatory Policies Act, 95th Cong. 2d Sess. 89 (1978) (emphasis added). See also Turners Falls Limited Partnership, 55 FERC ¶ 61,487 at 62,670 n.33 (1991) (Turners Falls).

69/ We note that other aspects of the "net/gross" issue are pending before the Commission in separate proceedings and will be addressed by the Commission in subsequent orders. See Connecticut Valley Electric Company, Inc. v. Wheelabrator Claremont Company, L.P., et al. (Docket Nos. EL94-10-000 and QF86-177-001); Carolina Power & Light Company v. Stone Container Corporation (Docket Nos. EL94-62-000 and QF85-102-005); and Niagara Mohawk Power Company v. Penntech Papers, Inc. (Docket Nos. EL96-1-000 and QF86-722-003).

in Power Developers, Inc., 70/ Malacha Power Project, Inc. (Malacha), 71/ and Pentech Papers, Inc., 72/ the Commission found that QFs were permitted to sell only the net output of their power production facilities as measured at the point of interconnection with the electric utility to which they were interconnected. The Commission did not decide the question of whether "the receipt of Real Power Loss Service or ancillary services from the transmission provider or a third party for the purpose of completing a transmission transaction" would be a sale-for-resale of power by a QF that would violate the Commission's QF rules.

At first glance, it would appear that Real Power Loss Service and ancillary services fall within the definition of "supplementary power" as defined in 18 CFR 292.101(b)(8). 73/ If this were in fact the case, the precedent cited above would be relevant because supplementary power would be subtracted from gross output to determine the net output available for sale and, pursuant to Turner Falls, any sale in excess of the net output would result in a loss of QF status. However, if Real Power Loss Service and ancillary services are part of the costs of

---

70/ 32 FERC ¶ 61,101 (1985).

71/ 41 FERC ¶ 61,350 (1987).

72/ 48 FERC ¶ 61,120 (1989).

73/ Supplementary power is defined 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."

transmission, they are not covered under the definition of "supplementary power."

As the Commission explained in its Notice of Proposed Rulemaking, Small Power Production and Cogeneration-Rates and Exemptions:

> The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility. . . . 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. [74/]

This view was adopted by the Commission in Order No. 69, Small Power Production and Cogeneration Facilities, Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978. 75/ There the Commission defined "'interconnection costs' as the reasonable costs of . . . transmission. . . ." 76/ It is also consistent with the Commission's findings in 18 CFR 292.303(d) that if a QF transmits its output to an electric utility with which it is not interconnected, the rate for the purchase of such energy "shall

---

74/ FERC Stats. & Regs., Proposed Regulations 1977-1981, ¶ 32,039 at 32,437 (1979). See also id. at 32,447 (costs of transmission constitute interconnection costs and must be borne by QF unless transmitting utility agrees to share them).

75/ FERC Stats. & Regs., Regulations Preambles 1977-1981, ¶ 30,128 (1980).

76/ Id. at 30,866. See also 18 CFR 292.101(b)(7).

not include any charges for transmission." Thus, all that remains is to determine whether Real Power Loss Service and ancillary services are part of the costs of transmission.

Ancillary services as defined in Order Nos. 888 and 888-A are part of the costs of transmission services. In Order No. 888, we defined ancillary services as those services "that must be offered with basic transmission service under an open access transmission tariff." 77/ We noted that these services are those "needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service." 78/ Thus, there is no question that ancillary services are part of the cost of transmission and therefore are included among the interconnection costs a QF is responsible for.

Real Power Loss Service is an interconnected operations service. 79/ It is thus not a service which a transmission provider is required to provide under its open access transmission tariff. Nevertheless, the Commission recognized that a transmission customer must make provisions for Real Power Loss. As the Commission noted, a customer "cannot take basic transmission service without such a provision." 80/ As a result,

---

77/ FERC Stats. & Regs. ¶ 31,036 at 31,705 (footnote omitted).

78/ Id.

79/ Id. at 31,709.

80/ Id.

we find that Real Power Loss Service is also a part of the cost of transmission and included among the interconnection costs a QF is responsible for.

Consistent with 18 CFR 292.303(d), however, a QF purchasing Real Power Loss Service shall have its purchase rate adjusted up or down consistent with 18 CFR 292.304(e)(4). 81/ In other words, while a QF can never sell more power than its net output at its point of interconnection with the grid, its location in relation to its purchaser (and thus its losses) may be relevant in the calculation of the avoided cost which it is entitled for the power it does deliver to its electric utility purchaser. However, as explained above, the receipt of Real Power Loss Service or ancillary services is not a sale-for-resale of power. Rather, they are part of the costs of transmission which the QF

81/ In Order No. 69, the Commission noted:

> 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.

Order No. 69 at 30,885-86.

must bear, in the absence of an agreement to share such costs with the transmitting utility.

5. Right Of First Refusal/Reservation Of Transmission Capacity

NRECA, TDU Systems and TAPS seek clarification that the rights of network customers to reserve capacity to serve their own retail load are comparable to a transmission provider's right to reserve transmission capacity for its retail native load. They point to language in Order No. 888-A that supports their interpretation, but note that other language concerning the Right of First Refusal (ROFR) mechanism seems to provide an advantage to transmission providers in serving their retail native load.

NRECA and TDU Systems argue that the Commission improperly allows a transmission provider to reserve capacity as needed to serve its existing native load customers, but the cooperative wholesale power or firm transmission customer has only a right of first refusal that requires it to match competing bids, which exposes it to matching an incremental rate or opportunity cost rate capped at the cost of system expansion. They assert that "[t]o the extent the transmission provider is able to continue to provide service to its retail native load at average embedded transmission costs, so too should the network customer have the right to continued service at average embedded-cost rates, rather than at incremental-cost rates or opportunity-cost rates capped only at the cost of system expansion." 82/ TDU Systems requests that the Commission clarify that

> the ROFR provisions allow an existing network customer to continue to reserve transmission capacity at rates that remain comparable to the transmission provider's service to its retail native load. [83/]

Similarly, NRECA requests the Commission to clarify that

> firm transmission customers for which the transmission provider has a planning requirement are on an equal footing with the transmission provider's retail load in reserving transmission capacity. The Commission accordingly should clarify that the ROFR provisions allow existing firm transmission customers for which the transmission provider has a planning requirement to continue to reserve their existing transmission capacity at rates that remain comparable to the transmission provider's existing service to its retail native load. [84/]

TAPS asks the Commission to clarify that

> its discussion of the rights of a transmission provider to reserve and reclaim capacity needed for native load growth apply with equal force to capacity needed for network customers for which the transmission provider is equally responsible for planning its system. The Commission should also clarify that the transmission provider's reclamation/reservation right cannot be used to withdraw capacity currently or reasonably forecasted to be used by a network customer. [85/]

82/ TDU Systems at 6; NRECA at 5.

83/ TDU Systems at 7.

84/ NRECA at 7.

85/ TAPS at 33.

TDU Systems further requests that the Commission clarify the rate an existing transmission customer would have to match to retain its reservation priority. It requests that the Commission clarify that the customer need match only the undiscounted tariff rate of general applicability and not the highest rate the transmission provider is then collecting from any customer, i.e., an incremental rate based on an upgrade for a particular customer.

Commission Conclusion

In Order No. 888-A, we addressed concerns raised by transmission providers that the right of first refusal may prohibit them from recalling capacity needed for native load growth, by clarifying that the transmission provider may reserve existing capacity for retail native load growth. While the Commission's conclusion in Order No. 888-A, in the context of the treatment of retail native load, is correct, a transmission provider may also reserve existing capacity for both its own wholesale native load growth and network customers' load growth. As the Commission originally explained in Order No. 888:

> public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utility's current planning horizon. [86/]

Accordingly, in order to allay the concerns of NRECA, TDU Systems and TAPS, we clarify that network transmission customers are

86/ FERC Stats. & Regs. ¶ 31,036 at 31,694 (emphasis added).

afforded the same treatment as the transmission provider on behalf of native load (retail and wholesale requirements customers) in terms of the reservation of existing transmission capacity by the transmission provider.

Regarding NRECA's and TDU Systems' allegation that a transmission provider's right to reserve existing transmission capacity for its retail native load is superior to a firm transmission customer's right of first refusal, we note that it is not clear if NRECA and TDU Systems' argument pertains to network transmission customers or to point-to-point transmission customers. The right of a transmission provider to reserve existing transmission capacity on behalf of network transmission customers is discussed above. The reservation priority of transmission capacity for point-to-point transmission customers is different because point-to-point transmission customers do not undertake the same payment obligation as either network transmission customers or the transmission provider on behalf of native load customers. As the Commission explained in Order No. 888-A in the context of reservation of existing capacity:

> We note that network service is founded on the notion that the transmission provider has a duty to plan and construct the transmission system to meet the present and future needs of its native load and, by comparability, its third-party network customers. In return, the native load and third-party network customers must pay all of the system's fixed costs that are not covered by the proceeds of point-to-point service. This means that native load and third-party network customers bear ultimate responsibility for the costs of both the capacity that they use and any

> capacity that is not reserved by point-to-point customers. In this regard, native load and third-party network customers face a payment risk that point-to-point customers generally do not face. [87/]

Additionally, we note that a firm transmission customer may always elect to take network transmission service in lieu of point-to-point transmission service, thereby obtaining rights to reserve existing transmission capacity that are comparable to the rights of other network customers and the transmission provider on behalf of native load.

Furthermore, unless prohibited by the terms of the existing transmission customer's contract, there is nothing to prevent an existing point-to-point transmission customer from seeking to extend the term of its contract. An existing transmission customer may also enter into an additional agreement for point-to-point transmission service and reassign such capacity until needed or choose a service commencement date concurrent with the termination of its existing contract.

TDU Systems asserts that Order No. 888-A "leaves unresolved whether the customer must pay the undiscounted rate of general applicability for tariff service at the time of conversion or the highest rate the transmission provider is then collecting from any customer," such as an incremental cost-based rate. 88/ We clarify that the right of first refusal does not require an

---

87/ FERC Stats. & Regs. ¶ 31,048 at 30,220.

88/ TDU Systems at 8.

existing transmission customer to match the highest rate the transmission provider is then collecting from any customer. The highest rate collected from any customer may involve a different service than that service received by the existing customer, which may result in an inappropriate comparison. In this regard, the Commission stated in Order No. 888-A that the purpose of the right of first refusal is to be a tie-breaker and, therefore, the competing requests should be substantially the same in all respects. 89/ Accordingly, we clarify that the existing transmission customer exercising its right of first refusal will be required to match the term of service requested by another potential customer and may be required to pay the transmission provider's maximum filed transmission rate. However, the rate must be for substantially similar service of equal or greater duration.

TDU Systems also asks whether the maximum rate that a customer must match in exercising its right of first refusal would include an incremental cost-based rate for an upgrade to a competing customer or if the customer is required to match only the undiscounted tariff rate of general applicability. The right of first refusal is predicated on an existing customer continuing to use its transmission rights in the existing transmission system. The right of first refusal acts as a tiebreaker to determine whether the competing eligible customer or the existing

---

89/ FERC Stats. & Regs. ¶ 31,048 at 30,197.

transmission customer gets the existing transmission capacity. Accordingly, the maximum rate for such existing transmission capacity would be the just and reasonable transmission rate on file at the time the customer exercises its right of first refusal. 90/

In conclusion, we believe that we have struck an appropriate balance between our goals of: (1) protecting the rights of retail and wholesale native loads and network customers by allowing the transmission provider to reserve existing transmission capacity for their projected load growth and (2) providing existing firm transmission customers with a priority over new requests for firm transmission service to continue receiving transmission service from existing transmission capacity when there is insufficient existing capacity available to accommodate all requests for transmission service.

6. Energy Imbalance Service

a. Appropriate bandwidth for small utilities

APPA argues that the Commission's revision in Order No. 888-A to the deviation bandwidth did not go far enough and does not address the requirements of all small utilities, i.e., utilities

---

90/ Depending on the rate design on file for the existing capacity, a customer exercising its right of first refusal could face an average embedded cost-based rate, an incremental cost-based rate, a flow-based rate, a zonal rate, or any other rate design that the Commission may have approved under section 205 of the FPA.

that sell no more than 4 million MWh annually. 91/ It asserts that the Commission has adequately remedied the problem for those small utilities serving load with a peak demand of less than 20 MW, but not for those utilities serving loads with greater peak demands.

To remedy the problem, APPA asks the Commission to revise the minimum bandwidth to provide a minimum deviation bandwidth of 2 MW for utilities serving load with a peak demand of less than 20 MW, 5 MW for utilities serving load less than 100 MW, and 7.5 MW for all other small utilities.

Commission Conclusion

We deny APPA's motion for reconsideration. 92/ As the Commission explained in Order No. 888-A, the deviation bandwidth was developed "to promote good scheduling practices by transmission customers. It is important that the implementation of each scheduled transaction not overly burden others." 93/ The Commission reaffirmed its use of the 1.5 percent energy imbalance bandwidth as "consistent with what the industry has been using as a standard and is as close to an industry standard as anyone can

---

91/ APPA at 21-23 (citing Blue Creek Hydro, Inc., 77 FERC ¶ 61,232 at 61,941 (1996), in which the Commission used the 4 million Mwh level for determining small utilities eligible for waiver of the requirements of Order No. 889).

92/ As discussed above, APPA filed its request for rehearing out-of-time. Accordingly, we are treating APPA's pleading as a motion for reconsideration.

93/ FERC Stats. & Regs. ¶ 31,048 at 30,232.

set at this time." 94/ However, the Commission recognized the needs of small customers and raised the minimum energy imbalance from one megawatthour per hour to two megawatthours per hour. In doing so, the Commission sought to balance its primary goal of promoting good scheduling practices with its commitment to provide as much relief as possible to small customers. Larger minimum deviation bandwidths, as proposed by APPA, could only unnecessarily jeopardize this balance at the expense of good scheduling practices.

Moreover, in Order No. 888-A, the Commission provided all customers, including small customers, further options to deal with any difficulties that may be experienced as the result of the minimum deviation bandwidth set forth in Order No. 888-A:

> To help customers with the difficulty of forecasting loads far in advance of the hour, the Final Rule pro forma tariff permits schedule changes up to twenty minutes before the hour at no charge. By updating its schedule before the hour begins, a transmission customer should be able to reduce or avoid energy imbalance and associated charges. However, we will allow the transmitting utility and the customer to negotiate and file another bandwidth more flexible to the customer, subject to a requirement that the same bandwidth be made available on a not unduly discriminatory basis. [95/]

APPA has simply not shown that the minimum deviation or the procedures to reduce or avoid energy imbalance charges or to

94/ Id. at 30,232.

95/ Id.

negotiate another bandwidth do not provide adequate relief for small customers. Nor has APPA shown that larger bandwidths could be implemented without unduly undermining good scheduling practices.

b. Settlements establishing a deviation bandwidth or minimum imbalance

TDU Systems states that Order No. 888-A allows a transmission provider and a customer to negotiate and file another bandwidth more flexible to the customer on a not unduly discriminatory basis, but if a settlement was approved subject to the outcome of Order No. 888, it must be revised in the subsequent compliance filing to reflect the language in the pro forma tariff. Accordingly, TDU Systems seeks clarification that if such a settlement contains a bandwidth above 1.5% or a minimum imbalance above 2 MW, those amounts need not be revised downward to conform to the pro forma tariff. 96/

Commission Conclusion

We will not grant the clarification sought by TDU Systems. In Order No. 888-A, we explicitly stated that

> service provided pursuant to a settlement that was expressly approved subject to the outcome of Order No. 888 on non-rate terms and conditions must be revised in the subsequent compliance filing to reflect the language contained in the pro forma tariff. [97/]

96/ TDU Systems at 12-13.

97/ FERC Stats. & Regs. ¶ 31,048 at 30,233.

This is consistent with our desire to have all public utilities at the same starting line as open access is implemented in the electric industry:

> By initially requiring a standardized tariff, we intend to foster broad access across multiple systems under standardized terms and conditions. [98/]

However, as we also recognized, "public utilities are free to file under section 205 to revise the tariffs (e.g., to reflect various settlement provisions) and customers are free to pursue changes under section 206." 99/ Thus, the settlement discussed by TDU Systems must be revised to conform to the pro forma tariff, but the public utility transmission provider to the settlement may then make another filing with the Commission to seek a change to the bandwidth contained in the pro forma tariff.

7. Transmission Provider "Taking Service" Under Its Tariff for Power Purchased on Behalf of Bundled Retail Customers

a. Jurisdiction

IL Com states that the Commission agreed with IL Com's jurisdictional arguments on rehearing of Order No. 888 and made the following appropriate clarifications in Order No. 888-A:

> In a situation in which a transmission provider purchases power on behalf of its retail native load customers, the Commission [FERC] does not have jurisdiction over the transmission of the purchased power to the bundled retail customers insofar as the

98/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,734.

99/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,234 (footnote omitted).

> transmission takes place over such transmission provider's facilities. [quoting Order No. 888-A at 117-18 (emphasis added)].
>
> * * *
>
> [The Commission] does have jurisdiction over transmission service associated with sales to any person for resale, and such transmission must be taken under the transmission provider's pro forma tariff. [quoting Order No. 888-A at 118 (emphasis added)]. [100/]

However, IL Com argues that the Commission

> nevertheless neglected to revise § 35.28(c)(2) and § 35.28(c)(2)(i) to incorporate these clarifications into the Rule. Therefore, [IL Com] reiterates its request that the words 'for sale for resale' be inserted into the Rule after the word 'purchases' in § 35.28(c)(2) and 'purchase' in § 35.28(c)(2)(i) to codify the Order 888-A clarification concerning the extent of required power purchase unbundling. [101/]

CCEM, however, argues that the Commission's disclaimer of jurisdiction over the transmission in interstate commerce of purchased power headed for retail customers is contrary to the FPA's assertion of jurisdiction over all transmission of electric energy in interstate commerce. 102/ It states that

> [t]he Commission has already embraced the proposition that it has the statutory authority and mandate to require utilities to adopt tariffs that will ensure all market participants comparable access to transmission services. It must now extend

---

100/ IL Com at 8.

101/ Id. at 8-9.

102/ CCEM at 2-6.

> that authority and mandate to apply to all transmission service. [103/]

CCEM further argues that the Commission's failure to assert jurisdiction over interstate transmission of purchased power to retail customers is contrary to precedent under the Natural Gas Act (NGA). 104/ It cites to Mississippi River Transmission Corp. v. FERC, 969 F.2d 1215 (D.C. Cir. 1992), stating that the court affirmed the Commission's interpretation of NGA section 1(b) as authorizing the Commission to regulate the price of natural gas transportation service that MRT provided in support of certain firm direct sales.

If the Commission does not grant rehearing as requested by CCEM, CCEM argues that "the Commission should nevertheless clarify that its jurisdictional disclaimer does not extend to power pool transmission services." 105/ It asserts that because pools themselves do not have native load and do not purchase power on behalf of native load, "when a public utility takes poolwide service to transmit purchased power, it should be required to take that service on an unbundled basis pursuant to the power pool's open-access tariff." 106/ In this regard, it states that it is "aware that certain public utilities claim that

---

103/ Id. at 4.

104/ Id. at 4-6 (citing Mississippi River Transmission Corp. v. FERC, 969 F.2d 1215 (D.C. Cir. 1992)).

105/ Id. at 6.

106/ Id.

the Commission's disclaimer of jurisdiction extends to their uses of poolwide transmission service to transmit purchased power to their captive, native loads." 107/

CCEM further argues that the Commission's failure to require that all transmission service be taken under an open access tariff is arbitrary and irreconcilable with the Commission's concurrent determination in connection with the rules pertaining to stranded cost recovery that it has jurisdiction over the rates, terms and conditions of unbundled interstate transmission services by public utilities to retail customers, and that it has the authority to address retail stranded costs through its jurisdiction over such services. It adds that experience from restructuring the natural gas industry (Order Nos. 436 and 636) shows the need to unbundle and separately regulate transmission provided in connection with retail service.

Commission Conclusion

CCEM's arguments with respect to the Commission's disclaimer of jurisdiction over bundled retail transmission are the same arguments it raised on rehearing of Order No. 888 (and were addressed by the Commission) 108/ or should have raised on rehearing of Order No. 888. We will not accept CCEM's invitation to further address this issue.

107/ Id.

108/ FERC Stats. & Regs. ¶ 31,048 at 30,225-26.

In response to CCEM's request for clarification regarding power pool transactions, we note that all power pool transactions must be taken under the terms of the pool-wide pro forma tariffs that were filed on compliance to Order No. 888. 109/ The appropriateness of the terms and conditions contained in those pool-wide pro forma tariffs will be addressed on a case-by-case basis when the Commission addresses the merits of the various pools' compliance filings.

Finally, we deny IL Com's request to modify sections 35.28(c)(2) and 35.28(c)(2)(i) of the Commission's regulations. The additional language proposed by IL Com simply will not work. As we describe in more detail in section 7.b below, it is not possible, as a practical matter, to divide a single power purchase made on behalf of both wholesale and retail native load such that the transmission provider takes service under the terms and conditions of the pro forma open access transmission tariff for the wholesale part of the purchase and under the terms and conditions of a different tariff for the retail part. Thus, the entire purchase transaction must be undertaken pursuant to the terms and conditions of the pro forma open access transmission tariff. The language proposed by IL Com does not recognize the

---

109/ See MidContinent Area Power Pool, et al., 78 FERC ¶ 61,203 (1997) (Order Accepting for Filing and Suspending Proposed Pool-Wide and Single-System Holding Company Open Access Transmission Tariffs and Revised Tariffs, and Deferring Further Action), reh'g pending.

indivisible nature of single power purchases made on behalf of both wholesale and retail native load.

b. Purchases for retail native load

TAPS argues that the Commission significantly contracts its functional unbundling requirement and the associated Standards of Conduct "by exempting from functional unbundling all use by a transmitting utility of its own transmission system to serve bundled retail native load." 110/ By exempting a key aspect of the transmission provider's activities in wholesale markets from the open access rules, TAPS asserts, comparability is destroyed and the market is severely distorted. It emphasizes that

> because of the interdependence, elasticity and fungibility of purchases on behalf of unbundled retail load with the transmission provider's other wholesale marketing activities, there is little, if anything, left of functional unbundling. [111/]

TAPS states that Order No. 888-A leaves unclear issues critical to comparability, "such as request procedures and priority for usage of limited interface capability applicable to the transmission provider's use of transmission for economy imports for retail bundled load." 112/ It argues that without clearly established rules that put the transmission provider in the same position as network customers, the transmission provider will have a competitive advantage.

110/ TAPS at 4 and 6-14.

111/ Id. at 5.

112/ Id. at 9.

TAPS further argues that the Commission's approach defeats the Commission's Standards of Conduct and allows transmission provider employees involved in the transmission function to "share operational and reliability information with employees engaged in making economy and other purchases for retail bundled load on a preferential basis as compared with other transmission customers or the transmission provider's 'wholesale' merchant function." 113/ Further, it asserts that the Commission's approach to functional unbundling will encourage a transmission provider to retain its preferential access to transmission service and information and discourage it from joining an ISO, under which it would lose its preferential treatment.

TAPS concludes by arguing that "[c]ontrary to the Commission's suggestion, constriction of functional unbundling is not required by limitations on the Commission's jurisdiction." 114/ It asserts that the Commission has provided no support for its position and adds that the Commission's position cannot be reconciled with its treatment of transmission agreements between jurisdictional and non-jurisdictional entities whereby the Commission stated that its authority over a jurisdictional contract involving a public utility cannot be impaired by virtue of the fact that the other party is non-jurisdictional.

113/ Id. at 10-11.

114/ Id. at 14.

Commission Conclusion

While we have reiterated our view that the Commission does not have jurisdiction over the rates, terms and conditions of bundled retail service, based on the comments received on rehearing, we believe certain clarifications need to be made. As a practical matter, we do not believe that it is possible to divide a single power purchase made on behalf of both wholesale and retail native load such that the transmission provider takes service under the open access non-rate terms and conditions for the part of the purchase that goes to wholesale native load, but takes service under different terms and conditions for the part of the purchase that goes to retail native load. Because the power purchase transaction (including the delivery across the transmission provider's system to both wholesale and retail customers) is indivisible, and because the transmission of the purchased power to the wholesale native load customer must be done pursuant to the open access tariff, this means that the entire transaction *de facto* must be pursuant to the non-rate terms and conditions of the tariff.

Concerning the Standards of Conduct requirement that public utilities separate their wholesale power marketing functions from their transmission operations, the Commission did not require separation of the retail power marketing function because the state has jurisdiction over retail power marketing and over bundled retail transmission. However, here too we believe further clarification is necessary. First, the public utility has no choice pursuant to Order Nos. 888 and 888-A but to separate its wholesale power marketing function (including power purchase transactions made by the marketing function on behalf of wholesale native load) from the transmission operations function. This means that those persons in the company that are involved in wholesale power purchases as well as wholesale sales cannot interact with the transmission personnel other than through the OASIS. Thus, to the extent they are making purchases on behalf of wholesale as well as bundled retail native load as part of a single purchase, they will have to abide by the separation of function requirement. As discussed above, such a purchase is not divisible. Additionally, it is conceivable that there could be a separate retail marketing function for native load and a separate wholesale marketing function for native load. If a challenge is made to the way a utility organizes its functions, then the utility bears the burden of demonstrating that it is maintaining a separate staff to perform retail marketing functions. Furthermore, in such cases, it would clearly be inappropriate for the retail staff to share transmission information with the wholesale marketing staff.

8. Indirect Unbundled Retail Transmission in Interstate Commerce

Referencing the Commission's conclusion that section 212(h) does not prohibit the Commission from ordering public utilities to provide indirect unbundled retail transmission in interstate commerce, BPA states that it appears that the Commission intended to clarify its jurisdiction to order retail transmission in certain limited, interstate situations -- namely, to ensure that state initiatives would not be frustrated by the failure of neighboring states to undertake similar initiatives. Where a state has not mandated retail access, but a local utility agrees to provide retail access, 115/ BPA argues that it should not be required to distribute another supplier's power to its customers.

BPA also argues that section 212(h)(2) prohibits orders requiring "indirect retail transmission." It declares that the Commission ignored section 212(h)(2), which it asserts prohibits orders requiring indirect retail transmission. BPA contends that, if it and other transmitting utilities are required to provide indirect retail transmission, BPA's ability to meet its statutory obligation to recover all of the costs of the Federal Columbia River Power System and the Commission's ability to meet its statutory obligation to ensure that BPA's rates are sufficient to assure repayment of the federal investment in the power system will be placed at risk.

Commission Conclusion

We disagree with BPA that we ignored section 212(h)(2) in concluding that we have the authority to order indirect retail transmission in interstate commerce to accommodate retail access programs ordered by a state or voluntary retail delivery by the local utility. We clarify that while section 212(h)(2) may limit

115/ See also Puget at 27.

the Commission in certain circumstances, as a general matter, we believe we can order indirect interstate transmission services necessary to accommodate direct retail access programs that are state ordered or voluntary. Clearly, whether section 212(h) would prohibit the Commission from ordering transmission in a particular circumstance would depend upon the facts presented, including who the transmission requestor is, who the seller of energy is, and who is transmitting or delivering the energy and over what facilities. If parties wish to raise section 212(h)(2) in a particular case, they may do so; however, we do not believe Congress intended section 212(h)(2) to be used as a competitive shield against state-ordered retail access programs or voluntary retail access by local utilities. 116/

9. Mobile-Sierra

Met Ed objects to what it describes as the Commission's asymmetric treatment of customers and suppliers in Order No. 888-A. First, it argues that the existence of uneven bargaining power prior to Order No. 888 (that is referred to in Order No. 888-A) does not provide a rational basis for imposing different standards for customer-initiated and supplier-initiated requests

---

116/ BPA's arguments that requiring indirect retail wheeling may put at risk its ability to meet its statutory obligation to recover all of the costs of the Federal Columbia River Power System and the Commission's ability to meet its statutory obligation to ensure that BPA's rates are sufficient to assure repayment of the federal investment in the power system are speculative and more appropriately addressed in a fact-specific proceeding if and when this possible risk may arise. Moreover, BPA may propose appropriate stranded cost provisions.

for modification of existing contracts. It says that the Commission does not identify the specific manner in which existing wholesale contracts would lose their just and reasonable character due to changes in the electric industry. "Just as competitive wholesale markets may present opportunities to buyers that are less costly than existing contracts, they may also give sellers greater opportunities to reach new buyers who would be willing to pay more than customers under existing below-cost contracts. If the Commission's initiatives to expand wholesale markets provide a rational basis for making it easier for buyers to modify existing contracts, then these initiatives equally provide a basis to ease the burden on sellers." 117/

Second, Met Ed argues that because the existence of uneven bargaining power was not universal, it cannot provide the basis for a uniform refusal to apply a just and reasonable standard in evaluating all supplier-initiated requests for modification (other than of stranded cost provisions). "The Commission cannot properly distinguish customers from suppliers based on a premise that is only true in the 'majority' of the cases, particularly when the Commission has the ability to make the appropriate determination on a case-by-case basis." 118/

Third, Met Ed says that the Commission's distinction between customers and suppliers is not rationally related to the purpose

---

117/ Met Ed at 6.

118/ *Id.* at 7.

of Order No. 888. It contends that broad competition is not furthered by a policy that would hold suppliers, but not customers, to the terms of existing unfavorable contracts. Met Ed states that ending the subsidies reflected in long-term below-cost contracts promotes the most efficient use of power supply resources. According to Met Ed, Order No. 888-A's treatment of existing contracts will exacerbate stranded costs (a utility would not be able to obtain relief from a wholesale contract that does not cover its costs, while a customer under another contract could obtain a modification or termination of the contract). "Even if the Commission persists in its conclusion that it can reasonably distinguish requests for modifications by customers from those by utilities because existing contracts reflect one sided bargaining, it should clarify that it will not make such a distinction when customers had other options at the time the contracts were executed." 119/

Commission Conclusion

Met Ed has not raised issues not previously addressed by the Commission. Concerning its argument that uneven bargaining power was not universal, Order No. 888 clearly recognized that this was the case. 120/ However, we clarify that, in determining whether to modify an existing contract, we will look at, among other things, whether a customer had other supply options available to

---

119/ Id. at 10.

120/ See, e.g., FERC Stats. & Regs. ¶ 31,048 at 30,193.

it at the time it negotiated its existing contract. We agree with Met Ed that the existence of uneven bargaining power may not have been "universal" and clarify that utilities are free to present to the Commission, on a case-by-case basis, arguments that their contracts are no longer in the public interest or just and reasonable, and therefore should be modified.

10. Tariff Issues

a. Load served "behind-the-meter"

Central Maine states that the Commission required all of a wholesale network customer's load "behind-the-meter" to be included in its load-ratio share. It asserts, however, that the Commission "failed to state whether the utility also must include all of a retail customer's load 'behind-the-meter' in computing the load-ratio share." 121/ It indicates that it is concerned that it cannot identify the "behind-the-meter" generation that its retail customers own and operate. Central Maine maintains that "[o]nly if the utility invests significant effort and incurs substantial expense to install metering technology will it have the ability to monitor its retail customers." 122/ In any event,

> Central Maine believes that the Commission did not intend to require utilities to determine their retail customers "behind-the-meter" load when calculating network customers' load-ratio shares. Moreover, the Commission cannot require a non-jurisdictional wholesale customer to determine its retail customers "behind-the-

121/ Central Maine at 2.

122/ Id. at 3.

> meter" load. Thus, if FERC required jurisdictional companies to make such a determination, the load-ratio share of network non-jurisdictional wholesale customers would always be understated. The Commission should clarify Order No. 888-A so that it is clear that utilities are not required to meter retail customer's "behind-the-meter" load. [123/]

Commission Conclusion

Central Maine's concern regarding the identification of a retail customer's "behind-the-meter" generation and load is unclear. The Commission's discussion in Order Nos. 888 and 888-A regarding the treatment of behind-the-meter generation and load specifically pertained to an individual network customer's designated network generation and load. If Central Maine's concern pertains to the calculation of a transmission provider's total network load, including the load of the transmission provider's retail native load customers, such an inquiry is beyond the scope of Order Nos. 888 and 888-A and should be addressed on a case-by-case basis.

b. Definition of "Native Load Customers"

Dairyland argues that the definition of "Native Load Customers" in section 1.19 of the pro forma tariff is limited to wholesale and retail power customers and "could be read not to encompass the native loads of parties to transmission joint use and construction agreements but who are not power customers of

---

123/ Id.

the Transmission Provider." 124/ It proposes that the following clause be added to the end of section 1.19: "including obligations arising from transmission joint use agreements in effect as of July 9, 1996." 125/ Dairyland argues that the Commission should recognize these agreements and modify the definition so that "transmission facilities constructed and operated to meet the reliable electric needs of each party's native load customers are treated comparably, without regard to whether either party is or is not a 'power' customer of the other." 126/ It further indicates that its primary concern in seeking this modification is in terms of priority under the pro forma tariff for curtailment and reservations and believes that its status and rights are unclear.

Commission Conclusion

We believe that Dairyland's argument is misplaced and deny its request for rehearing. In Allegheny Power Systems, Inc., et al., 127/ we found that Dairyland's joint use agreements "are in

124/ Dairyland at 4 (emphasis in original).

125/ Dairyland notes that it filed a supplemental rehearing request on this issue that the Commission accepted as a motion for reconsideration. It asserts that the Commission did not address its issue in Order No. 888-A, but instead described the arguments as being similar to an argument it rejected that joint planning is a sufficient criterion to be considered a "Native Load Customer" and that construction and operation by the transmission provider should not be necessary for native load status to be conferred.

126/ Id. at 6.

127/ 80 FERC ¶ 61,143 at 61,555 (1997).

the nature of bilateral transmission agreements and are not superseded or otherwise affected by Interstate Power's compliance tariff. Thus, any changes to the definition of 'native load customers' are not necessary." 128/ Accordingly, any change to the definition of native load customers contained in the pro forma tariff would have no affect on Dairyland's joint use agreements.

We also note that Dairyland has stated that under its joint use agreement "the native loads of Dairyland and the native loads of the public utility party to the agreement were to be treated comparably in terms of transmission service utilizing the transmission facilities." 129/ Thus, Dairyland already is obtaining the comparable treatment that it is apparently seeking through its proposal to change the definition of native load contained in the pro forma tariff.

c. Schedule changes

NRECA states that Order No. 888-A provided that schedule changes for firm point-to-point service were not limited up to twenty minutes before the start of each clock hour, but could be set at a reasonable time limitation that is generally accepted in

128/ We further note that Interstate Power Company did not file on December 31, 1996, as provided in Order No. 888, to modify its joint use agreements with Dairyland. See 18 CFR 35.28(c)(iii). Thus, those agreements must not prohibit transmission over the facilities to third parties and, accordingly, remain in effect as existing bilateral transmission agreements.

129/ Dairyland at 6.

the region and consistently adhered to by the transmission provider. NRECA requests rehearing to not only permit, but also to require, scheduling changes during emergency conditions. 130/ It asserts that the Commission should make this revision consistent with the language of section 30.4 of the pro forma tariff that permits network resources to be rescheduled in response to an emergency or other unforeseen condition. In any event, if "schedule changes are not permissible in such situations, at least any associated penalties, e.g., punitive charges for energy imbalances exceeding the 1.5% 'deadband,' should be waived." 131/

Commission Conclusion

We deny NRECA's rehearing request to require transmission providers to make schedule changes requested by customers during emergency conditions. It is the responsibility of transmission customers to make arrangements for emergencies, such as operating reserves for the loss of a power supplier's generation source. If an emergency arises, a transmission provider should not be required to accept a customer-requested schedule change, though we would expect the transmission provider to permit a schedule change to the extent possible. Granting NRECA's request would ignore the fact that requiring the transmission provider to

---

130/ See also TAPS at 35-36; TDU Systems at 24-25.

131/ NRECA at 16; see also TAPS at 36-37.

accept a requested scheduling change may not be consistent with maintaining system reliability.

Moreover, an emergency situation does not automatically cause a customer to use Energy Imbalance Service or to pay a penalty. For example, if a customer resource becomes unavailable due to an emergency situation, but is replaced by an equivalent amount of reserves, the customer would remain in balance if its load meets the schedule. 132/ However, if the emergency is the cause of the customer's energy imbalance, that is, the transmission provider is unable to deliver the scheduled energy, the customer should not be responsible for paying an Energy Imbalance Service penalty.

d. Restriction on making firm sales from designated network resources

NRECA argues that section 30.4 of the pro forma tariff unreasonably restricts network customers' ability to make firm sales from their generation and that similar restrictions do not apply to transmission providers' own generation resources. 133/ It asserts that this restriction on network customers "is unnecessarily limiting both the number of competitors and the array of generation products available, as well as skewing the

---

132/ See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,233 (emergency situations caused by loss or failure of facilities should be addressed in the transmission customer's service agreement (or the generation supplier's separate interconnection agreement) and not as part of Energy Imbalance Service).

133/ See also TDU Systems at 18-21.

market in favor of generation sales by incumbent public utility transmission providers." 134/ If the Commission does not change its position, NRECA states that the Commission should at least provide network customers greater flexibility in designating network resources under section 30.1 of the pro forma tariff:

> the Commission should at least grant network customers the ability to designate network resources over shorter time periods (e.g., one month) or permit the network customer to designate its network resources in a manner that varies by season or by month to track projected variations in network loads plus reserve requirements. This would provide network customers more flexibility in using their network resources to make firm off-peak sales to loads other than their network loads when it makes economic sense to do so, while still ensuring that adequate resources are committed to meet the network load and reserve requirements of the period. [135/]

TDU Systems adds that if the Commission does not change its position, "transmitting utilities should be required to designate their network resources, and those resources, too, should be restricted to serving the transmitting utilities' network loads." 136/

Commission Conclusion

We disagree with NRECA, as well as TDU Systems, that the restrictions set forth in section 30.4 of the pro forma tariff do

---

134/ NRECA at 17; see also Dairyland at 8.

135/ NRECA at 18.

136/ TDU Systems at 21.

not also apply to a transmission provider's own generation resources. In Order No. 888, we explicitly stated that

> a transmission provider taking network service to serve network load under the tariff also is required to designate its resources and is subject to the same limitations required of any other network customer. [137/]

In addition, we note that, contrary to NRECA's assertion, the pro forma tariff does not prevent network customers from designating network resources over shorter time periods or in a manner that varies by season or by month. It only prohibits network customers from making sales from designated network resources. The purpose of the prohibition is to ensure that such resources are available to meet the network customer's network load on a non-interruptible basis. Sections 30.2 and 30.3 of the pro forma tariff already provide network customers with a significant level of flexibility. Specifically, a network customer that seeks to engage in firm sales from its current designated network resources may terminate the generating resource (or a portion of it) as a network resource and request, as set forth in section 29 of the pro forma tariff, that the same generation resource be designated as a network resource effective with the end of its power sale. We note that network customers, as well as the transmission provider's merchant function, must obtain point-to-point transmission service for off-system sales.

137/ FERC Stats. & Regs. ¶ 31,036 at 31,753-54.

e. Reactive Power

NY Com states that under Order No. 888-A "a transmission customer may satisfy part of its obligation [to supply reactive power service] through self-provision or purchases from generating facilities under the control of the control area operator." 138/ It requests clarification that the phrase "under the control of the control area operator" refers only to generators with continuously operating automatic voltage control (AVC). NY Com argues that units that do not have AVC and operate "flat out" do not support reliability and increase operating difficulty and inflict higher costs because system operators need to monitor local voltage levels and anticipate changing reactive support requirements.

The Independent Power Producers of New York, Inc. (NY IPPs) responds to NY Com's request that only generators with continuously operating AVC be allowed to self supply reactive power. 139/ It asserts that "[t]here is no reason to suppose that the Commission intended that suppliers of reactive power without AVC should not receive credit for the service they render." 140/ It claims that NY Com's assertion that generators

---

138/ NY Com at 15-16.

139/ On April 11, 1997, NY IPPs filed an answer to the request for clarification of NY Com. In the circumstances presented, we will accept the answer notwithstanding our general prohibition on allowing answers to rehearing requests. See 18 CFR 385.713(d).

140/ NY IPPs at 3.

that do not have AVC and operate flat out cannot supply reactive power without inflicting higher costs on the system "shows a fundamental misunderstanding of the operations of an electric generator." 141/ It maintains that

> [t]he ability to provide reactive support at full power output without imposing higher system costs has nothing to do with whether a generator has AVC. Rather, the ability to provide reactive power support stems from the design of the generator itself, specifically the rating of the rotor and stator windings. The NYPSC's assertion that providing reactive support manually "increases operating difficulty and inflicts higher costs because system operators need to actively monitor local voltage levels, and anticipate changing local voltage levels" is both unsupported and irrelevant. [142/]

Moreover, it asserts that "[t]o the extent that generators with AVC that self provide reactive support render a more valuable service than those that self provide reactive support without AVC, they should be credited accordingly -- but that does not mean that generators without AVC should not be credited at all for self providing reactive support." 143/ In addition, NY IPPs responds to NY Com's assertion that it has discouraged the practice of manual voltage support by requiring non-utility generators to either use AVC or pay a fee based on the absorption of reactive power. It states that NY Com's requirement "that non-utility generators pay a utility when the generator absorbs

141/ Id.

142/ Id. at 3-4.

143/ Id. at 4.

reactive power at the utilities' request is currently the subject of litigation in the United States District Court for the Northern District of New York." 144/

TAPS is concerned that without specific tariff language some transmission providers will try to deny reactive power credits to transmission customers that should otherwise receive such credits. It suggests that the following language should be added to the pro forma tariff:

> The service agreement of the transmission customer that can supply at least a part of the reactive service it requires, either through self-supply or purchases from a third party, shall specify the generating sources made available by the transmission customer that provide reactive support. [145/]

TAPS also asks the Commission to clarify that the phrase "under the control of the control area operator" refers to "the reactive production or absorption capability of the generator and not necessarily to the generator's ability to produce real power." 146/ It states that

> while a generator's real power output may be on automatic generation control (AGC) and dispatched economically, its reactive power output usually is not on automatic control or dispatched on a moment-by-moment basis. Rather, the plant operator separately regulates the output of the two kinds of power. As a result, a customer can give the control area operator the ability to rely upon the customer's generation to produce or

---

144/ Id. (emphasis in original).

145/ TAPS at 28.

146/ Id. at 29.

> absorb reactive power independent of control over the unit's real power output, for example, by the customer's setting its generator's voltage regulator to respond to the needs of the control area as established by the control area operator. Thus, the Commission's statement that "a customer who controls generating units equipped with automatic voltage control equipment may be able to use those units to help control the voltage locally and reduce the reactive power requirement of the transaction," (Order No. 888-A at 150-51) should not be read to require that the entire generating unit be under the control area operator's control. [147/]

Furthermore, TAPS argues that comparable standards should be applied to customer-owned and transmission provider facilities. "The control area operator should not be permitted to refuse the offer of a customer to turn over to the control area operator the control of the reactive capabilities of the customer's generating facilities." 148/ Moreover, it asserts that "[i]f the control area operator is able to rely upon its own or its customer's facilities to produce or absorb reactive power, then rate base treatment or credits, respectively, are appropriate." 149/

Commission Conclusion

We do not agree with NY Com's assertion that the phrase "generating facilities under the control of the control area operator" refers only to generators with AVC. We clarify that what is "under the control of the control area operator" in

---

147/ Id. at 30.

148/ Id.

149/ Id.

Schedule 2 of the pro forma tariff is the reactive production and absorption capability of the generator and not the generator's ability to produce real power. With regard to the dispute between NY Com and NY IPPs concerning the appropriate reduction in charges for Reactive Supply and Voltage Controls from Generation Sources Service, we find that this dispute is fact-specific and beyond the scope of this proceeding.

There is no need to add the specific language to the pro forma tariff as requested by TAPS. As stated in Order No. 888-A, the Commission specifically requires that a transmission customer's service agreement specify all reactive supply arrangements, including the generating resources made available by the transmission customer that provide reactive support.

In response to TAPs' other concern, we note that Order No. 888 requires that a transmission customer obtain or provide ancillary services for <u>its</u> transactions. We do not intend that requirement to provide a means for a generation owner to compel a transmission provider to purchase services it may not need. As we stated in Order No. 888-A, a third party may offer ancillary services voluntarily to other customers if technology permits. However, simply supplying some duplicative ancillary services (<u>e.g.</u>, providing reactive power at low load periods or providing it at a location where it is not needed) in ways that do not reduce the ancillary services costs of the transmission provider or that are not coordinated with the control area operator does not qualify for a reduced charge.

f. Network Operating Agreements

TAPS asks that section 29.1 of the pro forma tariff be modified to permit a network customer to request that a network operating agreement be filed on an unexecuted basis, just as it may request a network service agreement to be filed on an unexecuted basis. It asserts that this would "permit service to commence, pending resolution of disputed matters, and would reduce the ability of the transmission provider to use the network operating agreement as a competitive tool." 150/

Commission Conclusion

In Order No. 888-A, in response to TAPS' argument that to avoid improper use of operating agreements by transmission providers the Commission should either permit network operating agreements to be filed in unexecuted form or include a network operating agreement as part of the pro forma tariff, we rejected mandating a particular network operating agreement but indicated that

> if a transmission provider wishes to include a generic form of network operating agreement in its pro forma tariff (to be modified as required and as mutually agreed to on a customer-specific basis), it may propose to do so in a section 205 filing or it may file an unexecuted network operating agreement in a section 205 filing.
>
> To the extent a customer believes a transmission provider is engaging in unduly discriminatory practices via the network operating agreement, the customer may file a

150/ *Id.* at 34.

> section 206 complaint with the Commission.
> [151/]

On rehearing, TAPS points out that our approach would still permit a transmission provider to delay the commencement of service. We recognize this and will permit a network customer to request that a network operating agreement be filed on an unexecuted basis, just as we have allowed a network customer to request that a network service agreement be filed on an unexecuted basis. Accordingly, we will modify section 29.1 of the pro forma tariff by adding the following language to the end of section 29.1: ", or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement." 152/

g. Network customers with loads and resources in multiple control areas

TDU Systems argues that Order No. 888-A does not respond to its "core contention that network service under the pro forma tariff does not provide them comparable service." 153/ It argues that

> [r]equiring the network customer to assign a designated network resource to a single control area, and arbitrarily limiting the ability of a network customer to schedule the output of network resources between and among control areas by limiting the output of those resources to network load in a single control area, effectively prevents the network

151/ FERC Stats. & Regs. ¶ 31,048 at 30,325.

152/ See Appendix B and note 1 supra.

153/ TDU Systems at 15.

> customer from operating an integrated system. [154/]

Thus, it requests that the Commission "rule that TDU systems with loads and resources in multiple control areas may designate as Network Resources for each control area the totality of their resources that meet the owned, purchased, or leased requirement of section 1.25 of the tariff." 155/ .

TDU Systems further asserts that a network customer can integrate loads and resources in multiple control areas only by purchasing network service in each control area and point-to-point service for transmission between the control areas. Thus, it argues,

> [a]bsent a regional network tariff, the Commission should require the provision of service to network customers with loads and resources located on multiple systems under a rate that recovers the customer's load ratio share -- but no more -- of the transmission owners' collective transmission investment in the control areas that the customer straddles. [156/]

Commission Conclusion

We disagree with TDU Systems that network service under the pro forma tariff does not provide network customers with comparable service. Significantly, a network customer with resources and loads in multiple control areas is simply not similarly situated to a transmission provider serving native load

154/ Id.

155/ Id. at 18.

156/ TAPS at 18 n.36.

located entirely within the transmission provider's single control area. Unlike a transmission provider serving load entirely within a single control area, a network customer with resources and loads in multiple control areas must not only integrate its resources and loads within the individual control areas, but must also arrange transmission services (network or point-to-point) for transactions occurring between and among the multiple control areas in which it seeks to transact business. However, we emphasize that if a transmission provider has resources and loads in multiple control areas, it must treat network customers that also have resources and loads in multiple control areas on a comparable basis.

In this regard, we also disagree with TDU Systems' assertion that we have required a network customer to assign a designated network resource to a single control area and limit the scheduling of such resources to serve load in a single control area. Tariff sections 30.6 and 31.3 allow for the designation of both network resources and network loads that are not physically interconnected with the transmission provider. Under the pro forma tariff, a network customer that seeks network service for all of its loads in multiple control areas may designate all such loads as network loads. 157/ By designating all of its loads as

157/ Alternatively, a network customer with resources and load in multiple control areas may elect to designate only such load that is located in a single control area as its designated network load and separately arrange for transmission service (e.g., point-to-point service) to serve load in adjacent (continued...)

network loads, such network customer will receive comparable service in each control area and will have the ability to schedule the output of network resources between and among control areas, just as a transmission provider or other network customer would need to do to serve load in an adjacent control area.

TDU Systems is concerned with the rates it must pay to the various control area operators to integrate its resources and loads. In rejecting TDU Systems' virtually identical argument in Order No. 888-A, we explained:

> Because the additional transmission service to non-designated network load outside of the transmission provider's control area is a service for which the transmission provider must separately plan and operate its system beyond what is required to provide service to the customer's designated network load, it is appropriate to have an additional charge associated with the additional service. [158/]

h. Network customer designation of load

TDU Systems asks the Commission to clarify that open access transmission providers must credit or eliminate double charges arising from the inability of network customers to designate less

---

157/ (...continued)
control areas from generation resources located in the control area in which it designated its network load. Here too the network customer would be receiving comparable transmission service because a transmission provider or any other network customer seeking to serve load in an adjacent control area would also have to arrange for point-to-point transmission service to make the service possible.

158/ FERC Stats. & Regs. ¶ 31,048 at 30,255.

than all of the load at a delivery point as network load. TDU Systems asks the Commission to make the following points clear:

> first, there will be no double recovery of either transmission costs or ancillary costs that are being recovered in the existing bundled generation supply agreement; second, as the Commission properly noted in requiring the unbundling of bilateral economy energy coordination transactions, the transmission provider will not be permitted to recover more under the new arrangement for those (transmission and ancillary) services than it does under the existing bundled generation supply agreement; and third, the transmission provider is required to achieve these results by using one of the alternatives stated in Order No. 888-A at the transmission customer's election or by an alternative arrangement agreed upon by the customer. [159/]

It concludes that "[i]f the Commission relegates the customer to a section 206 complaint proceeding, it has reversed the burden of proof on the transmission provider to show that its increased rate is just and reasonable."

Commission Conclusion

As noted by TDU Systems, we stated in Order No. 888-A that

> the Commission did not intend for a transmission provider to receive two payments for providing service to the same portion of a transmission customer's load. Any such double recovery is unacceptable and inconsistent with cost causation principles. [160/]

We intended this language to apply broadly and, accordingly, clarify that it applies to transmission costs and ancillary

159/ TDU Systems at 23.

160/ FERC Stats. & Regs. ¶ 31,048 at 30,261-62.

costs. Moreover, while we expect transmission providers to design rates that will avoid double recovery of such transmission costs or ancillary costs, we believe that this is a fact-specific issue that is appropriately addressed on a case-by-case basis. 161/ Finally, while we indicated in Order No. 888-A that a transmission customer may file a complaint under section 206 with the Commission to address any claims of double recovery, the transmission customer would most likely raise this issue in the section 205 proceeding in which the transmission provider files to initiate the particular service with the transmission customer. Indeed, it would be in such a section 205 proceeding in which this transitional problem would first arise and the transmission customer would first have the opportunity to challenge any possible double recovery.

11. Waivers of Order Nos. 888 and 889

NRECA states that the Commission's policy on waivers of Order Nos. 888 and 889 provides that such waivers terminate upon a request for service or a complaint. It argues that permitting the termination of a waiver upon a complaint improperly subjects the utility to baseless complaints and significantly diminishes the value of the waiver. It asserts that a waiver of Order No. 889 should terminate only upon a finding by the Commission that

---

161/ In this regard, we will not mandate that a transmission provider accept a customer-specified approach to resolving any double recovery concerns.

there is a valid basis for the complaint. 162/ Similarly, it asserts that a waiver of Order No. 888 should terminate "only upon a Commission order finding that, in light of changed circumstances or new evidence, the waiver should not be continued and the utility should be required to file the pro forma tariff." 163/

Commission Conclusion

NRECA's request for rehearing with respect to the termination of a waiver of Order No. 888 should have been raised on rehearing of Order No. 888, which first established that a waiver would be granted if, among other things, the utility "commits to file an open access tariff within 60 days of a request to use its facilities and to comply with the rule in all other ways." 164/ Nothing set forth in Order No. 888-A changed this requirement. Accordingly, NRECA's request for rehearing was not timely filed.

However, we note that the Commission, in a recent order modifying the circumstances under which a waiver of Order No. 889 165/ will be revoked, 166/ addressed this very issue:

162/ See also TDU Systems at 10-12 (raising similar arguments with respect to waivers of Order No. 889).

163/ NRECA at 12.

164/ FERC Stats. & Regs. ¶ 31,036 at 31,853.

165/ Open Access Same-Time Information System and Standards of Conduct, Final Rule, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & (continued...)

> We will not, however, alter our determination that a utility that has been granted waiver of Order No. 888 is required to file a pro forma tariff within 60 days after it receives a request for transmission service and must comply with any additional requirements that are effective on the date of the request. The filing with the Commission of a pro forma tariff places significantly less burden on a utility than does full compliance with Order No. 889, and we continue to believe that 60 days from receipt of a request for service provides sufficient time for such compliance. [167/]

12. Financial Independence of ISO Employees

NEPOOL expresses concern that the requirement in Order No. 888-A that ISO employees sever all financial ties "can be interpreted to foreclose the Commission from even considering the merits of provisions for ownership of securities by ISO employees contained in NEPOOL's ISO proposal that is now pending before the Commission in Docket Nos. OA97-237-000 and ER97-1079-000." 168/ It contends that severance of all financial ties would impose an

---

165/ (...continued) Regs. ¶ 31,049 (1997), order on reh'g, Order No. 889-B, __ Fed. Reg. ______ (1997), FERC Stats. & Regs. ¶ ______ (1997).

166/ NRECA's request with respect to the revocation of waivers of Order No. 889 is addressed in Order No. 889-B, which is being issued concurrently with this Order. In Order No. 889-B, the Commission notes that in Central Minnesota Municipal Power Agency, et al., 79 FERC ¶ 61,260 (1997) (Central Minnesota), it already has revised its approach concerning the revocation of waivers of Order No. 889 to provide that such waivers will remain effective until the Commission takes action in response to a complaint, rather than until 60 days after a complaint to the Commission.

167/ Central Minnesota, 79 FERC at 62,127 (1997).

168/ NEPOOL at 2.

economic hardship on certain NEPOOL employees in pension and stock ownership plans of market participants through the years. In particular, it notes that many of the existing NEPOOL staff have accumulated Northeast Utilities stock in their pension or other employee benefit plans, but that the market price of that stock has recently declined significantly. However, NEPOOL has required ISO employees to divest themselves of such securities in excess of $50,000 within six months of their employment by the ISO. Thus, NEPOOL requests that the Commission clarify that it could waive the requirement that ISO employees sever all financial ties with market participants in compelling circumstances or clarify the acceptable length of a transition period during which they may continue to hold such securities.

Commission Conclusion

In a recent order conditionally authorizing the establishment of an ISO by NEPOOL, the Commission specifically addressed the concerns raised here by NEPOOL. 169/ The Commission rejected NEPOOL's proposal to allow employees to possess securities of market participants as long as the value does not exceed $50,000. The Commission reaffirmed its strong commitment, set forth in Order Nos. 888 and 888-A, to ensure that an ISO is truly independent and that employees of an ISO are financially independent of market participants. However, the Commission recognized, as it had in Order No. 888-A, that there

169/ New England Power Pool, 79 FERC ¶ 61,374 (1997), reh'g pending.

may be a need for flexibility with respect to the length of a transition period and that this matter is best addressed on a case-by-case basis.

13. Distribution Charges

NY Com seeks clarification of the Commission's statement that a utility is free to include a "distribution charge" in a customer's service agreement and/or the network customer's network operating agreement. 170/ In particular, it requests that the Commission clarify that it did not intend to preempt state jurisdiction, but rather that when a term, condition or rate is required for local distribution service, the state determination will apply. It asserts that such a clarification would avoid forum shopping that would otherwise occur. In the alternative, it requests rehearing, arguing that the Federal Power Act, its legislative history and case law all dictate against Commission jurisdiction over local distribution.

Commission Conclusion

We clarify, as requested by NY Com, that when a term, condition or rate is required for local distribution service the state determination applies. We reiterate that we believe there is always a local distribution service element of a retail transaction, through which the state may impose charges on the retail customer. We also reiterate, however, that where a public utility is delivering unbundled energy to a supplier that then

170/ NY Com at 5-12.

resells the energy to an end-user, the Commission has exclusive jurisdiction over the public utility's facilities used to effect the transaction without regard to their being labeled "transmission," "distribution," or "local distribution." 171/ Moreover, where a public utility is delivering unbundled energy from a third-party supplier directly to an end user, the particular facts of the case will determine which of the facilities are FERC-jurisdictional transmission facilities and which are state-jurisdictional local distribution facilities. 172/

14. Tight Power Pools

a. Non-pancaked rates

NY Com seeks clarification of the following statement in Order No. 888-A:

> Order No. 888 does not require a non-pancaked rate structure unless a non-pancaked rate structure is available to pool members. Although the Commission has encouraged the industry to reform transmission pricing, the Commission's current policy does not mandate a specific transmission rate structure. [173/]

It argues that this statement conflicts with other statements that "require power pools to file joint pool-wide tariffs and to offer all transmission services that they are capable of

---

171/ See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,969 (Appendix G) and Allegheny Power System, Inc., et al., 80 FERC ¶ 61,143 at 61,551-52 (1997).

172/ See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,969.

173/ NY Com at 12.

providing." 174/ NY Com asks that the Commission clarify that utility members of tight power pools must provide transmission service jointly under a single tariff. It states that this is the best way to eliminate undue discrimination. It argues that tight power pools must provide, pursuant to prior Commission orders, all transmission services that they are reasonably capable of providing and must file joint tariffs to provide transmission service on a pool-wide basis.

Commission Conclusion

NY Com appears to be confusing services that a power pool is capable of providing with pricing methodologies that a power pool may elect to use. While the Commission required that by December 31, 1996 all pool transactions be taken under a joint pool-wide tariff on file with the Commission, the Commission did not mandate a specific transmission rate structure for such tariff. 175/ As we stated in Order No. 888-A, the primary goal for pooling arrangements is to ensure comparability regarding transmission services offered on a pool-wide basis. Thus,

174/ Id. at 13 (emphasis in original).

175/ However, as explained in Order No. 888-A, the Commission did require that all transmission rate proposals filed in compliance with Order Nos. 888 and 888-A be cost based and meet the standard for conforming proposals set out in the Commission's Transmission Pricing Policy Statement. See 18 CFR 2.22.

comparability is achieved if the same service is provided at the same or comparable rate to both pool and non-pool members. 176/

b. Coordination transactions

Otter Tail requests that the Commission clarify the following statement in Order No. 888-A:

> we do not find it to be unduly discriminatory to provide some pool-wide transmission services to members under a pooling agreement and to provide other transmission services to members under the individual tariff of each member, as long as members and non-members have access to the same transmission services on a comparable basis and pay the same or a comparable rate for transmission. [177/]

It asks the Commission to clarify that this statement

> is meant only to indicate that in the case of different services, one service (e.g., wholesale transactions) can be offered to all potential customers under the pool tariff, but another service (e.g., ancillary services) may not be offered to any customers under the pool tariff. Otter Tail specifically requests that the Commission clarify that where the same service is involved, pools cannot discriminate against certain transactions based solely on the transaction's duration, that is, pool-wide tariffs cannot exclude longer term transactions but include short-term transactions. [178/]

In its case, Otter Tail is concerned that MAPP limits coordination transactions under the pool to those with a duration of two years or less and thereby prevents any longer term service

176/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 31,728.

177/ Otter Tail at 3 (emphasis added by Otter Tail).

178/ Id. at 4 (emphasis in original).

from using the pool tariff. It argues that MAPP's tariff does not comply with Order No. 888 because it does not offer pool-wide service for all coordination transactions, regardless of duration. Otter Tail further argues that excluding the benefits of pool-wide service for coordination transactions based only on the length of term is contrary to, and incompatible with, Congress' and the Commission's goal to promote competition at the generation level and permits pools to exercise market power.

Commission Conclusion

We disagree with Otter Tail. As we stated in Order No. 888-A, the primary goal of Order No. 888's requirements for pooling arrangements, including "loose" pools, such as MAPP, is to ensure comparability regarding transmission services that are offered on a pool-wide basis. 179/ In the case of the MAPP agreement, pool transactions are limited to periods not to exceed two years for all members. 180/ Comparability is achieved if all parties, both pool members and non-pool members, are treated in a non-discriminatory fashion as to access to transmission services, the types of transmission services and the rates paid for such transmission services.

In addition, Order No. 888 requires loose pools to take service under a joint pool-wide tariff for all pool transactions.

179/ FERC Stats. & Regs. ¶ 31,048 at 31,241.

180/ Mid-Continent Area Power Pool Rate Schedule FERC No. 5.

181/ If transactions of more than two years in duration are not pool transactions, then transmission for those transactions need not be pursuant to the pool-wide tariff, and instead would be provided pursuant to the individual companies' pro forma tariffs. This is consistent with our finding in Order No. 888-A that we will not require pool members to offer transmission services to third parties that the pool members do not provide to themselves on a poolwide basis. 182/

15. Legal Authority

Puget states that the Commission does not have the legal authority to require public utilities to file open access tariffs and argues that Order No. 888 does not contain any specific finding that any rate, term or condition of Puget's tariff is unjust, unreasonable or unduly discriminatory or preferential.

Commission Conclusion

The Commission set forth its legal authority to require public utilities to file open access tariffs in Order No. 888. Puget's request for rehearing with respect to this issue should have been raised on rehearing of Order No. 888 and therefore was not timely filed. 183/

16. Ancillary Services

181/ FERC Stats. & Regs. ¶ 31,036 at 31,728.

182/ *See* FERC Stats. & Regs. ¶ 31,048 at 30,241.

183/ We note that Puget filed a rehearing request of Order No. 888, but did not challenge the Commission's authority to require public utilities to file open access tariffs.

Puget argues that ancillary services such as reactive power and voltage control cannot be considered merely ancillary to the provision of transmission service, but are significant generation services that should be subject to market rates. Puget asserts that "[i]t is wholly inappropriate for the Commission to provide for the sale of power as an ancillary service under the pro forma tariff; instead, utilities such as [Puget] should be compensated for the sale of such power at market based rates." 184/ It argues that the Commission "must recognize that ancillary services are generation related and should be priced at market in order to be consistent." 185/

Commission Conclusion

Puget raises issues that were previously addressed in Order No. 888. In that order the Commission determined that ancillary services are transmission related and indicated that market-based pricing for ancillary services would be addressed on a case-by-case basis. Puget's request for rehearing with respect to these issues should have been raised on rehearing of Order No. 888 and therefore was not timely filed.

17. Fair Market Value

Puget argues that Order No. 888-A improperly shuts the door on the pricing of transmission property at fair market value.

184/ Puget at 18.

185/ Id. at 19.

Citing footnote 261 of Order No. 888-A, 186/ Puget asserts that the Commission changed its policy from Order No. 888 and claims that in Order No. 888-A "the Commission ruled that each utility is now expressly limited by the transmission pricing policy to charging only embedded costs for existing transmission facilities to competitors and others even though rates for generation assets are priced at market." 187/ Puget argues that Order No. 888-A achieves "the effect of a condemnation by forcing [Puget] and other integrated electric utilities to allow competitors to use private utility property, but at less than fair market value." 188/ Puget further argues that the Constitution "does not permit the taking of private property of one citizen to benefit competitors or other private citizens." It contends that

> [t]he voluntary provision of transmission service to noncompetitors in an entirely cost-based integrated system is not the same as a forced provision of service and use of property by a competitor under a new set of regulations treating generation at market rates. [189/]

Puget goes on to argue that

> Order 888 erroneously asserts that there "simply cannot be an unconstitutional taking

---

186/ Footnote 261, which is in the section entitled Opportunity Cost Pricing, provides in relevant part that "[u]nder the Commission's transmission pricing policy, utilities are limited to charging the higher of embedded costs or opportunity/incremental costs."

187/ Puget at 21.

188/ Id. at 21-22.

189/ Id. at 26.

> of property when public utilities continue to have the right to file for and receive rates that provide them a reasonable opportunity to recover their prudently incurred costs." 62 Fed. Reg. at 12,433. For example, by illegally requiring unbundling of generation assets at market without at the same time providing for utility recovery of the fair market value of its transmission property, the Commission is attempting to deprive public utilities of fair market value compensation. [190/]

In conclusion, Puget declares that "[t]he Commission cannot create a situation in which generation is sold at a new market-based rate and transmission is limited to an old historic embedded-cost rate. Neither the Constitution nor the FPA will permit such a result." 191/

Commission Conclusion

We reject Puget's rehearing request. Puget makes a far-ranging argument that Order No. 888-A improperly shuts the door on the pricing of transmission property at fair market value. It bases its argument entirely on a single footnote in Order No. 888-A that has been taken completely out of context. The footnote in Order No. 888-A cited by Puget merely recites the Commission's longstanding policy as to opportunity cost pricing. 192/ Indeed, in the sentence to which that footnote is attached, the Commission explicitly stated that it "does not believe that

---

190/ Id.

191/ Id. at 27.

192/ See Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,739-40; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,263-66.

any changes are necessary to its policy on opportunity cost recovery." 193/ Moreover, the entire discussion to which that footnote applies is in a section entitled "Opportunity Cost Pricing." 194/

18. Pre-Existing Transmission-Only Contracts

Soyland argues that the Commission's Mobile-Sierra findings must apply not only to wholesale requirements contracts but also to unbundled transmission-only contracts. It asserts that "[t]here is no legitimate reason to deny unbundled, transmission-only customers timely and meaningful access to the open access regime and competitive markets on the same terms as requirements customers." 195/ It contends that it faced the same problem as requirements customers -- "use of transmission monopoly power to force a purchase of power as a condition to getting transmission access to deliver owned resources from off-system." 196/ Moreover, it asserts that the Commission has not explained how or why requirements contracts and transmission-only contracts should be treated differently as a result of the past and continuing changes in the industry. Soyland further states that utilities had the upper hand over "customers who executed unbundled transmission and power supply contracts simultaneously; together,

---

193/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,265.

194/ Id. at 30,263.

195/ Soyland at 8.

196/ Id.

such contracts are the functional equivalent of bundled partial requirements contracts, and should not be subject to a different standard for contract reform." 197/

Commission Conclusion

Soyland's rehearing request addresses an issue that should have been raised on rehearing of Order No. 888. In that order, the Commission explicitly indicated that customers under requirements contracts executed on or before July 11, 1994 that contained Mobile-Sierra clauses should have the opportunity to demonstrate that their contracts no longer are just and reasonable. 198/ Soyland's opportunity to request that we expand the scope of the contracts covered to include unbundled transmission-only contracts was on rehearing of Order No. 888. 199/ Accordingly, Soyland's request for rehearing with respect to this issue was not timely filed.

19. Apportionment of Transmission Revenues for Public Utility Holding Companies and Power Pools

TDU Systems asks the Commission to clarify that the "apportionment of credits for customer transmission facilities among the operating companies of a utility holding company or in power pools should be subject to Commission approval." TDU

197/ Id. at 10.

198/ FERC Stats. & Regs. ¶ 31,036 at 31,664.

199/ In this regard, we note that other entities did file rehearing requests of Order No. 888 seeking to expand the scope of the contracts covered by the Commission's Mobile-Sierra findings. See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,190-91.

Systems states that the method of crediting transmission customers for operating companies' uses of their own and each other's transmission facilities in setting transmission rates must meet the Commission's comparability standards and should not be filed on a unilateral basis. Similarly, it requests that customer credits for pool participants' use of their own and each other's transmission facilities should be subject to Commission review in approving the pool's transmission rates and tariff terms and conditions. 200/

Commission Conclusion

TDU Systems' rehearing request addresses issues that should have been raised on rehearing of Order No. 888. In Order No. 888, the Commission stated that credits for customer-owned facilities should be addressed on a case-by-case basis. 201/ Accordingly, TDU Systems' request for rehearing with respect to these issues was not timely filed.

20. Accounting for Transmission Provider's Own Use of Its System

TDU Systems argues that the Commission's requirement that a transmission provider's methodology to credit customers for the transmission provider's off-system sales be addressed in

---

200/ TDU Systems at 33-34.

201/ *See* FERC Stats. & Regs. ¶ 31,036 at 31,742.

compliance filings and will depend on the rate design is insufficient. 202/ It argues that this ignores that

> comparability has a time dimension, requiring the prompt crediting of such charges if they are not automatically accounted for in the rate design. Thus, the order fails to address whether a new kind of rate mechanism is needed if comparability is to be ensured on an ongoing basis under open-access transmission, just as the Commission years ago approved the use of fuel-adjustment clauses to deal with more volatile fuel prices. Requiring parties to resolve this issue in individual compliance filings does not address this generic problem. The Commission should provide more guidance to public utilities as to what crediting mechanisms are necessary if comparability is to be achieved. [203/]

Commission Conclusion

In Order No. 888-A, the Commission explained that an automatic pass-through mechanism for revenue credits raises a number of potential problems including: "(1) use of estimates versus actuals; (2) the appropriate time period to be utilized and (3) firm versus non-firm distinctions." 204/ The Commission further noted that the appropriate treatment of revenue credits for off-system sales is dependent on the rate design used by a transmission provider and concluded that this issue is not appropriately resolved on a generic basis. Despite these identified problems, TDU Systems continues to request that the

202/ TDU Systems at 34-35.

203/ Id. at 34-35.

204/ FERC Stats. & Regs. ¶ 31,048 at 30,310.

Commission adopt an automatic revenue credit mechanism without attempting to address such problems or proposing an appropriate mechanism to accomplish its request.

To bolster its proposal, TDU Systems claims that automatic treatment of revenue credits is comparable to the Commission treatment of fuel charges through the use of an automatic fuel adjustment charge. We disagree. An automatic fuel cost adjustment clause was determined to be appropriate because of the unpredictability of fuel prices. 205/ TDU Systems has not demonstrated that revenue credits warrant the same treatment. 206/

Moreover, TDU Systems has not demonstrated that the lack of an automatic credit mechanism is likely to result in unjust and unreasonable rates. For example, the Commission's traditional means of accounting for transmission revenues from non-firm uses of the transmission system is to reflect a representative level of revenue credits (based on historical and/or projected revenue levels) in each rate case, which has the effect of lowering the

---

205/ See Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities, FERC Stats. & Regs. ¶ 30,524 at 30,800 (1983).

206/ In Pennsylvania-New Jersey-Maryland Interconnection, et al., 81 FERC ¶ ______ (1997), issued concurrently with this order on rehearing, the Commission made an exception to its general approach to revenue credits and allowed monthly crediting of non-firm transmission revenues. However, this was done in the context of a major restructuring of a tight power pool.

transmission rate for all firm transmission users. 207/ TDU Systems has not shown why a similar rate case approach to revenue credits (as opposed to an automatic credit mechanism) is not appropriate, particularly for all transmission providers. In any event, we would anticipate little or no difference between the results of an automatic revenue credit mechanism and our traditional approach and TDU Systems has not shown otherwise.

Finally, TDU Systems' proposal is one-sided in that it would only require the automatic passthrough of revenues from the transmission provider's use of the transmission system for off-system sales. As the Commission stated in Order No. 888-A,

> revenue from the transmission component of all off-system uses of the transmission system (whether by the transmission provider or a transmission customer) must be treated on a comparable basis, whether through rate design or through revenue credits. [208/]

207/ *See*, *e.g.*, Pennsylvania Power Company, 26 FERC ¶ 61,354 at 61,781 (1984).

208/ FERC Stats. & Regs. ¶ 31,048 at 30,310 (emphasis added).

B. Stranded Cost Issues 209/

1. Municipal Annexation

In Order No. 888, the Commission decided that it would not be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory. 210/ In Order No. 888-A, the Commission reconsidered this decision and concluded that it would be the primary forum for stranded cost recovery in a discrete set of municipal annexation cases, namely, those involving existing municipal utilities that annex retail customer service territories and, through the availability of Commission-required transmission access, use the transmission

---

209/ Some of the rehearing requests raise issues that previously were raised on rehearing of Order No. 888 and were addressed by the Commission in Order No. 888-A. The Commission will not further address such issues in this proceeding. For example, Puget repeats some of the same arguments that it raised in its request for rehearing of Order No. 888 concerning the federal causes of stranded costs, the Commission's alleged abdication of its legal authority to ensure recovery of stranded costs associated with bypass and retail wheeling, the application of the reasonable expectation test to departing retail customers, and the Commission's failure to include deferred costs in the revenues lost formula. The Commission addressed these concerns in Order No. 888-A. See FERC Stats. & Regs. ¶ 31,048 at 30,358-62, 30,424, 30,426-27. TDU Systems reiterates its objection to the Commission's elimination of the section 35.15 prior notice of termination requirement for power sales contracts executed after July 9, 1996 that terminate by their own terms. The Commission addressed TDU Systems' concerns in this regard in Order No. 888-A. See FERC Stats. & Regs. ¶ 31,048 at 30,392, 30,393-94.

210/ FERC Stats. & Regs. ¶ 31,036 at 31,818.

system of the annexed customers' former supplier to access new suppliers to serve the annexed load. 211/

A number of petitioners seek rehearing or reconsideration 212/ of the Commission's decision in Order No. 888-A to be the primary forum for stranded cost recovery in the case of municipal annexations. 213/ Some oppose this decision for the same reasons that they opposed the Commission's decision to be the primary forum for stranded cost recovery in the case of new municipal utilities. For example, some entities argue that the Commission does not have any authority with respect to costs in retail rate base that may be stranded as a result of the annexation of electric service territory by a municipal utility. 214/ A number of petitioners also contend that municipal annexation occurs pursuant to state or local law, not federal law, and that every

---

211/ FERC Stats. & Regs. ¶ 31,048 at 30,408-09.

212/ As discussed above, APPA filed its request for rehearing out-of-time. Accordingly, we are treating APPA's pleading as a motion for reconsideration.

213/ See APPA, CAMU, IL Com, NARUC, TAPS. TDU Systems, on the other hand, argues that the Commission should permit non-public utilities providing reciprocal transmission service to recover stranded costs arising from municipal annexation. TDU Systems submits that allowing public utilities to seek stranded cost recovery arising from municipal annexation exacerbates the unequal and unduly discriminatory treatment accorded transmission dependent utilities and electric cooperatives.

214/ See APPA at 11-12; IL Com at 4-5; NARUC at 2-3.

facet of municipal annexation, including compensation and valuation, is governed by state or local authorities. 215/

Several submit that annexation is a form of franchise competition that predated Order No. 888, that transmission access was available (though not as readily as after Order No. 888) for many franchise competitors utilizing annexation, 216/ and that annexations have occurred and will continue to occur based upon motivations removed from the open access regime. 217/ CAMU states that

> [a]nnexations have occurred and will continue to occur in a[n] unbroken string based upon motivations entirely removed from this Commission's open access regime. There is simply no reason to assume that the open access rule will accelerate the pace of annexations. [218/]

NARUC asks the Commission to grant rehearing as a matter of policy. It argues that the Commission's assertion of authority to address stranded cost issues related to annexation will force the Commission to inject itself into state-established processes to second-guess a state commission's cost recovery

---

215/ E.g., APPA at 12-13; NARUC at 3; TAPS at 24-25. APPA objects that federal regulation of stranded costs associated with municipal annexation results in the establishment of overlapping federal/state authority that precludes the execution of state laws by state authority in a matter normally within the power of the state, in violation of the Tenth Amendment. APPA at 13

216/ APPA at 11; see also NARUC at 3.

217/ CAMU at 2.

218/ Id.

determinations. According to NARUC, this will require the Commission to resolve difficult factual issues to match specific generation and transmission facilities with specific annexed customers. 219/

CAMU similarly contends that the Commission's assertion that it is the primary forum for the resolution of annexation-related stranded cost issues will introduce needless procedural complications. CAMU submits that various state-created mechanisms exist for the identification and payment of just compensation in the case of municipal annexations. It questions how the Commission will offset against stranded cost recovery any compensation provided under state law and whether the Commission will await the completion of state proceedings before it addresses the issue. 220/ CAMU asks the Commission to defer to existing state mechanisms and to be the primary forum for the resolution of stranded cost recovery issues in annexation

---

219/ NARUC at 3-4.

220/ CAMU at 3-5. CAMU notes that some state compensation statutes require the annexing municipality to pay "expectation" damages for a defined future period based upon revenues received from the annexed area. CAMU says that this element of damage, which is applied in addition to payment for condemned facilities, is meant to liquidate claims for lost service territory, idled generation assets and other business opportunities, but the awards do not separately value each of these elements of damage. CAMU questions how the Commission is going to ascertain what element of recovery pertains specifically to stranded costs if a state has adopted this liquidated damages approach. Id. at 5.

situations only where there is no state procedure for stranded cost recovery.

IL Com argues that determining whether the availability of wholesale open access is the principal cause of the stranding of public utility costs would be administratively difficult. 221/ IL Com also submits that the Commission's expectation that parties raise retail-turned-wholesale stranded cost claims before this Commission in the first instance is internally inconsistent with, and contradictory to, its statements that it will give great weight in its proceedings to a state's view of what might be recoverable and will deduct any recovery a state has permitted from departing retail-turned-wholesale customers from the costs for which the utility will be allowed to seek recovery under the Rule. 222/

Commission Conclusion

After careful consideration of the arguments raised on rehearing, we have decided not to grant rehearing, but we do provide further clarification of our decision in Order No. 888-A to be the primary forum for stranded cost recovery in certain cases involving municipal annexation. As a policy matter, we will consider recovery of stranded costs that potentially could arise as a result of municipal annexation but only when there is a sufficient nexus in such cases to the Commission's Open Access

---

221/ IL Com at 5.

222/ Id. at 5-6.

Rule. To clarify, this determination to be the primary forum is not a blanket determination for all cases involving annexation. A determination of what circumstances make Commission review appropriate will be made on the facts pertinent to individual cases. The Commission has limited the opportunity to seek stranded cost recovery under the Rule to situations in which the availability and use of wholesale open access transmission enable a generation customer to escape a current power supplier to obtain cheaper power supplies. Annexations occur for a myriad of reasons that may have nothing to do with seeking less expensive power supplies (for example, tax or zoning considerations or consolidation of local public services). These reasons existed before adoption of Order No. 888 and, absent the nexus to the new availability of these transmission services, would not require us to consider the stranded costs from annexation in the first instance. On the other hand, an existing municipal utility that has newly-annexed territory may use an open access tariff of the annexed customers' former power supplier. Accordingly, the Commission does not believe it is necessary to reverse its previous position that annexations may raise jurisdictional stranded cost issues but instead provides this clarification.

In the course of reviewing the rehearing petitions on annexation, the Commission has also had the opportunity to reflect on the rationale for our decision to be the primary forum for addressing the recovery of stranded costs associated with retail-turned-wholesale customers (including a newly-formed municipal utility). We wish to further elaborate upon and clarify our prior discussions about recovery of costs stranded by retail-turned-wholesale customers. 223/

First, in setting forth our position on costs stranded in certain retail-turned-wholesale and municipal annexation situations, the Commission recognized that states may also have jurisdiction over retail-turned-wholesale stranded costs and that state adjudications of such costs may precede consideration of them here. 224/ Moreover, we indicated that "we are not second-guessing the states as to what a utility may recover under state law." 225/ As we stated in Order No. 888-A and reiterate here,

> our decision to be the primary forum for recovery of stranded costs from retail-turned-wholesale customers is not intended to prevent or to interfere with the authority of a state to permit any recovery from departing retail customers, such as by imposing an exit fee prior to creating the wholesale entity. [226/]

223/ In so doing, we also reiterate our concern (expressed in Order Nos. 888 and 888-A) that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission -- either this Commission or state commissions -- to address recovery of stranded costs. In Order Nos. 888 and 888-A, we reserved the right to address such situations on a case-by-case basis. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,819; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,409.

224/ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,819; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,405.

225/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,405.

226/ Id. at 30,410.

In making this statement, the Commission clearly recognized that it may indeed be the states that first address the difficult stranded cost issues associated with the formation of new municipal utilities or other wholesale entities. The Commission contemplated then, as now, that it would nevertheless adjudicate these stranded cost issues where states lack authority to do so or where, based on the record before us, they fail to provide a forum. 227/

Second, as the Commission stated in Order No. 888-A,

> if the state has permitted any recovery from departing retail-turned-wholesale customers [for example, if it imposed an exit fee prior to, or as a condition of, creating the wholesale entity], such amount will not be stranded for purposes of this Rule. We will deduct that amount from the costs for which the utility will be allowed to seek recovery under this Rule from the Commission. [228/]

Further, we will take into account state findings on cost determinations associated with retail-turned-wholesale situations and "we will give great weight in our proceedings to a state's view of what might be recoverable." 229/ We believe it is important to emphasize that in those instances where states do address stranded costs associated with retail-turned-wholesale

---

227/ See City of Las Cruces, New Mexico, 80 FERC ¶ 61,160 (1997).

228/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,405. See also Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,819.

229/ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,405.

customers and in cases of municipal annexation, we intend to give substantial deference to their determinations.

2. Pre-existing Transmission Rights

TAPS requests clarification that the required nexus between the availability and use of Commission-required transmission access and the stranding of costs would not be met "if the municipal utility, including as expanded through annexation, possessed rights to transmission prior to Order No. 888 and EPAct (for example, NRC license conditions and the like)." 230/ TAPS submits that "[t]he utility exercising these transmission rights should not be subject to stranded costs claims before the Commission simply because the municipal utility chooses to use the Commission's preferred open access tariff, instead of a bilateral or other arrangement available under pre-existing rights." 231/

Commission Conclusion

We will deny TAPS' requested clarification. The existence of rights to transmission prior to Order No. 888 would not, in and of itself, indicate that the customer should be relieved of potential stranded cost liability under Order Nos. 888 and 888-A. 232/ It may be that a customer with some right to transmission

230/ TAPS at 27.

231/ Id.

232/ As we explained in Order No. 888-A, we declined to include "exercise of pre-existing contract rights for transmission and designation of wholesale loads" as an example of a (continued...)

service prior to Order No. 888 (for example, as a consequence of NRC license conditions), was unable to reach an alternative supplier through the use of that transmission. Thus, notwithstanding the existence of pre-existing transmission rights, and depending on the facts of a particular case, it may be that the utility incurred costs based on a reasonable expectation of continuing to serve the customer.

On this basis, the Commission will not conclusively presume that a customer with a pre-existing right to transmission service could never be subject to a stranded cost obligation under Order Nos. 888 and 888-A. Similarly, the Commission will not conclusively presume that the mere existence of a pre-existing right to transmission service precludes any reasonable expectation of continued service by the utility. However, the existence of pre-existing transmission rights, and any circumstances surrounding them, may be used as evidence in the determination of whether the utility had a reasonable expectation of continuing to serve a customer. 233/

232/ (...continued)
situation for which stranded costs may not be sought because we are not prepared to make individual factual determinations in the context of the Rule. The Commission will address specific requests for stranded cost recovery on the facts presented and the merits of the particular request. FERC Stats. & Regs. ¶ 31,048 at 30,358.

233/ See Duquesne Light Company, 79 FERC ¶ 61,116 at 61,520 (1997).

3. Load Growth and Excess Capacity

Boston Edison seeks rehearing of the Commission's finding in Order No. 888-A that a "cost is not stranded if it is fully recovered in the cost-based rates paid by native load." 234/ It submits that this phrase

> suggests that the cost of capacity released by a departing wholesale customer can and should be recovered in the rates of the remaining retail and wholesale customers if the remaining customers' load or load growth will be sufficient to absorb the released capacity. . . . Such cost shifting directly contradicts the cost responsibility principles set forth in Order No. 888 [i.e., direct assignment]. [235/]

Boston Edison objects that the rationale for this policy reversal is not articulated in Order No. 888-A.

Commission Conclusion

At the outset, we reiterate that we remain committed to the cost responsibility principles established in Order No. 888 and continue to believe that a departing wholesale customer should be responsible for the costs it strands. Our statement that a "cost is not stranded if it is fully recovered in the cost-based rates paid by native load" was not meant to imply that the cost of capacity released by a departing wholesale customer should always be recovered in the rates of the remaining retail and wholesale customers through load growth. Rather, our discussion of load growth correctly recognizes that in some instances a utility can

234/ FERC Stats. & Regs. ¶ 31,048 at 30,440.

235/ Boston Edison at 3.

meet native load growth with existing capacity freed-up by the departure of wholesale load. If a utility can recover the costs of existing capacity freed up by a departing customer from another customer or group of customers, the expected revenues should be reflected in the CMVE component of the formula. 236/ Moreover, our requirement that a utility reflect in the CMVE component of the formula the revenues it expects to receive from the sale of the released capacity does not automatically result in remaining customers being forced to subsidize a departing customer's stranded cost obligation as Boston Edison posits. Rather, the rate treatment of the released capacity needed to meet the load growth of native load customers is an open issue that is properly addressed in future rate proceedings.

In short, the revenues lost approach already takes account of the marketability of the released capacity and appropriately incorporates load growth associated with remaining retail and wholesale customers and does not contradict the cost responsibility principle set forth in Order Nos. 888 and 888-A.

4. G&T and Distribution Cooperatives

RUS seeks rehearing and clarification of the Commission's determination in Order No. 888-A that, unless stranded costs arise as a result of a section 211 order to a G&T cooperative, G&T cooperatives may not seek (through the Commission) recovery of stranded costs from the customers of their distribution

236/ See City of Alma, Michigan, 80 FERC ¶ 61,265 at 61,961 (1997).

members. RUS argues that the customers of a G&T cooperative's distribution members, as well as the distribution members themselves, meet the Commission's pro forma tariff definition of "native load customer" with respect to the G&T. It says that, "as native load customers, both distribution members and their customers should be responsible to a G&T for stranded costs arising from their use of Commission-required transmission access, or from state mandated retail wheeling." 237/

RUS also questions the Commission's assertion that "'to treat a G&T cooperative and its member distribution systems as a single economic unit for stranded cost purposes would be inconsistent with the Commission's decision not to treat cooperatives as a single unit for the purposes of Order No. 888's reciprocity provision.'" 238/ RUS asserts that different treatment for different purposes is justified because the relevant issues with respect to the application of the reciprocity requirement on a system-wide basis and the ability to recover stranded costs on a system-wide basis are different. RUS submits that the Commission confuses corporate affiliation with economic integration, and that lack of corporate affiliation does not preclude economic integration. RUS says that although G&T cooperatives and their distribution members are operationally separate, G&T cooperatives and their distribution members

---

237/ RUS at 16.

238/ Id. (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,366).

function in many ways like a single economic unit. According to RUS, G&Ts undertake an obligation to construct and operate their systems to meet the reliable electric needs of their distribution members and customers of their distribution members, and G&T cooperatives and their members are bound together by long-term requirements contracts.

RUS states that, as single economic units, G&T cooperatives or distribution members both should be able to seek recovery of stranded costs from the customers of distribution members. RUS contends that "the Commission's reliance on distribution members to seek to recover stranded costs 'through contracts with [their] customers or through the appropriate regulatory authority' is misplaced" because "[d]istribution members -- many of which are not subject to state commission jurisdiction -- may have neither an appropriate regulatory forum through which to seek stranded cost recovery, nor the ability to seek to recover stranded costs incurred by their G&T cooperatives to serve native load customers." 239/

Finally, RUS argues that failing to permit G&T cooperatives to seek recovery of stranded costs arising from the loss of native load customers due to Commission-required transmission access or the lack of state commission authority to permit stranded cost recovery will result in unduly discriminatory treatment of cooperatives. Where G&T costs are stranded by the

239/ Id. at 17.

ability of customers of distribution members to switch suppliers through Commission-required transmission access, RUS submits that there is a direct nexus between Commission-required access and the stranding of costs. In the case of retail stranded costs, RUS says that many state regulatory authorities do not have the authority under state law to regulate distribution or G&T cooperatives, thereby creating a regulatory gap. RUS states that

> [f]ailure to allow a G&T the opportunity to recover stranded costs caused by [the] departure of any of its native load customers, including both distribution members and the customers of the distribution members, will drastically reduce the G&T's ability to cover its costs, including payments on RUS-financed debt, thereby endangering the existence of the G&T itself and exposing Federal taxpayers to the risk of massive loan defaults. [240/]

Commission Conclusion

We will deny RUS' rehearing request. To grant the request would require the Commission to reach beyond its regulatory authority (and allow entities not subject to our section 205-206 jurisdiction an opportunity to recover stranded costs) and would broaden the scope of the Order Nos. 888 and 888-A stranded cost recovery mechanism. 241/ Indeed, RUS' rehearing request appears

240/ Id. at 19.

241/ RUS expresses concern in its rehearing request that distribution members "may have neither an appropriate regulatory forum through which to seek stranded cost recovery, nor the ability to seek to recover stranded costs incurred by their G&T cooperatives to serve native load customers." RUS at 17. However, presumably when a retail customer of a distribution cooperative switches suppliers,
(continued...)

to be based on a misunderstanding of the limited scope of the stranded cost recovery mechanism contained in Order Nos. 888 and 888-A.

The stranded cost recovery provisions in Order Nos. 888 and 888-A apply, in the case of wholesale stranded costs, to public utilities 242/ and transmitting utilities. 243/ In the case of stranded costs associated with retail wheeling customers, the provisions of the Rule apply only to public utilities. 244/

241/ (...continued)
the retail customer would still have to use the distribution lines of the distribution cooperative to receive its power. RUS has not explained why the distribution cooperative cannot assess a charge to recover stranded costs when the retail customer uses those lines.

242/ A "public utility" is defined under section 201(e) of the FPA as "any person who owns or operates facilities subject to the jurisdiction of the Commission under this Part (other than facilities subject to such jurisdiction solely by reason of sections 210, 211, or 212)." 16 U.S.C. § 824(e).

243/ A "transmitting utility" is defined under section 3(23) of the FPA as "any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale." 16 U.S.C. § 796(23).

244/ As we explained in Order No. 888-A, our decision to entertain (in certain limited circumstances) requests to recover stranded costs associated with retail wheeling customers applies to public utilities only because it is based on our jurisdiction under sections 205 and 206 of the FPA over the rates, terms, and conditions of retail transmission in interstate commerce. FERC Stats. & Regs. ¶ 31,048 at 30,419. Since RUS-financed cooperatives are not public utilities subject to our jurisdiction under sections 205 and 206 of the FPA, we do not have authority to allow them to seek recovery under Order Nos. 888 and 888-A of stranded costs associated with retail wheeling customers.

The Commission has limited the opportunity for public utilities and transmitting utilities to seek stranded cost recovery under Order Nos. 888 and 888-A primarily to two discrete situations: (1) costs associated with customers under wholesale requirements contracts executed on or before July 11, 1994 (referred to as "existing wholesale requirements contracts") that do not contain an exit fee or other explicit stranded cost provision; and (2) costs associated with retail-turned-wholesale customers (including bundled retail customers of a utility that become bundled retail customers of a new municipal utility). 245/

As the Commission explained in Order No. 888-A, if a cooperative obtains its financing through RUS, it is not a public utility subject to our jurisdiction under sections 205 and 206 of the FPA. Although we have no objection to these G&T cooperatives being able to seek cost recovery (including recovery of costs on behalf of their distribution cooperatives) through the appropriate regulatory or contractual channels, this Commission does not have authority to allow them to seek recovery of stranded costs unless they do so in conjunction with transmission access that they are required to provide through a section 211 order. In the latter case, a G&T cooperative that is a transmitting utility could seek recovery of stranded costs if it

245/ Whether a G&T cooperative's member distribution cooperatives and the customers of the distribution cooperatives meet the definition of "native load customer" under the open access tariff (as RUS submits they do) is not relevant for purposes of the stranded cost recovery mechanism set forth in Order Nos. 888 and 888-A.

is ordered to provide transmission services that permit its distribution cooperative to reach another supplier and if it had a requirements contract with the distribution cooperative that was executed on or before July 11, 1994 that did not contain an exit fee or other explicit stranded cost provision. 246/

As we also explained in Order No. 888-A, a G&T cooperative that is a public utility (a non-RUS financed cooperative) would have to have a jurisdictional wholesale requirements contract with its distribution cooperative in order to be able to seek recovery of stranded costs under Order No. 888's stranded cost recovery provisions. We said that, in the case of a jurisdictional G&T cooperative, the request that the G&T be treated as a single economic unit with the distribution cooperative (such that departure of a distribution cooperative's retail customer would be treated as resulting in stranded costs for the G&T cooperative for which the G&T could seek recovery) is, in effect, a request for recovery of stranded costs from an indirect customer. In Order No. 888-A, we explained why the Commission does not believe it is appropriate or feasible to allow a public utility (or a transmitting utility under section 211 of the FPA) to seek recovery of stranded costs from an indirect customer (i.e., a customer of a wholesale requirements customer of the utility) under the Rule. We indicated that "[t]he reasonable expectation analysis would apply only to the

---

246/ FERC Stats. & Regs. ¶ 31,048 at 30,366.

direct wholesale customer of the utility, not to the indirect customer. It is up to the direct wholesale customer of the utility, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover such costs from its customers." 247/ We explained that commenters had provided no basis for making an exception in the case of cooperatives. Further, we said that "to treat a G&T cooperative and its member distribution cooperatives as a single economic unit for stranded cost purposes would be inconsistent with the Commission's decision not to treat cooperatives as a single unit for purposes of Order No. 888's reciprocity provision." 248/

Although RUS refers in its rehearing request to a scenario in which costs may be stranded by the ability of customers of a distribution cooperative to switch suppliers through the use of Commission-required transmission access, the scenario RUS posits is not one for which Order Nos. 888 and 888-A would permit an opportunity for recovery. Because the Commission cannot order retail wheeling, the principal way in which the retail customers of a distribution cooperative could use Commission-required transmission access (and trigger stranded costs on the part of the distribution cooperative) would appear to be through

---

247/ Id.

248/ Id. We continue to believe that it would be inconsistent to treat G&T cooperatives and their member distribution cooperatives differently for purposes of the reciprocity condition and stranded cost recovery, notwithstanding RUS' arguments to the contrary.

municipalization (*i.e.*, through the creation of a new wholesale entity to obtain power supplies on their behalf in lieu of obtaining power from the distribution cooperative). In such a scenario, however, since the distribution cooperative (if RUS-financed) would not be a Commission-jurisdictional public utility or transmitting utility, it would not be allowed to seek stranded cost recovery under Order Nos. 888 and 888-A.

5. Treatment of Contracts Extended or Renegotiated Without a Stranded Cost Provision

In Order No. 888-A, the Commission clarified that it will consider on a case-by-case basis whether to waive the provisions of 18 CFR 35.26 (which define a "new wholesale requirements contract" as "any wholesale requirements contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994" (emphasis added)) and treat a contract extended or renegotiated (without adding a stranded cost provision) to be effective after July 11, 1994, but before March 29, 1995, as an existing contract for stranded cost purposes. 249/

Port of Seattle opposes the Commission's decision in this regard. It argues that the Commission in Order No. 888-A sided with Puget on an issue that is being litigated between Port of Seattle and Puget in a separate proceeding (Docket No. ER96-714), and that the Commission improperly prejudiced Port of Seattle by not addressing the concerns expressed by Port of Seattle in the

249/ FERC Stats. & Regs. ¶ 31,048 at 30,396.

underlying case. 250/ It submits that Order No. 888-A was not the forum in which it expected the final decision in Docket No. ER96-714 to be made, and that its procedural rights have been violated. Port of Seattle asks the Commission on rehearing to withdraw any determination, reference or statement in Order No. 888-A that addresses the issues pending in Docket No. ER96-714.

Port of Seattle further argues that the Commission improperly granted Puget an exclusive waiver of (or private exception to) the Rule's definition of "new" contracts.

Commission Conclusion

We will deny Port of Seattle's request for rehearing. Port of Seattle misconstrues the scope of the Commission's decision and its effect on the pending proceeding in Docket No. ER96-714-001. The Commission's decision in Order No. 888-A to consider on a case-by-case basis whether to waive the provisions of 18 CFR 35.26 and treat a contract extended or renegotiated to be effective after July 11, 1994, but before March 29, 1995, as an existing contract for stranded cost purposes does not constitute a ruling on the merits in the pending proceeding in Docket No.

250/ Port of Seattle at 7. Port of Seattle also contends that the Commission mischaracterized Port of Seattle's position when it referred to Puget's statement that the parties were working within the context of the stranded cost NOPR, which provided that the utility had three years from the date of the publication of the final rules to negotiate or file for stranded cost recovery. Port of Seattle says its assumption and position was that Puget made the business decision not to include a stranded cost or exit fee provision in its letter agreement, thus preventing its recovery of any stranded costs. Id. at 8.

ER96-714-001. In Order No. 888-A, the Commission has gone no further than to state that the matter should be considered on a case-by-case basis, and to acknowledge that the issue, as between Puget and Port of Seattle, is pending in Docket No. ER96-714-001. 251/ Contrary to Port of Seattle's claim, Order No. 888-A does not grant Puget a waiver of the Rule's definition of "new wholesale requirements contract."

6. Customer Expectations of Continued Service at Below-Market Rates

TDU Systems seeks rehearing of the Commission's decision not to adopt a generic mechanism to allow existing requirements customers with below-market rates a means to continue to receive power beyond the contract term at the pre-existing contract rate if the customer had a reasonable expectation of continued service. TDU Systems states that the Commission's decision rests on the conclusion that, even if customers generally expected to stay on a supplier's system beyond the contract term, it is not likely that most customers could have expected to continue service at the existing rate. TDU Systems maintains that this finding rests on a false distinction between the rate the wholesale requirements customer reasonably could have expected to pay and the rate the wholesale requirements seller reasonably could have expected to collect. It says that neither stranded

---

251/ We note that a certification of an uncontested offer of settlement in that proceeding is pending before the Commission.

costs nor "stranded benefits" 252/ arise from a right to, or expectation of, a grandfathered rate. TDU Systems contends that "stranded benefits" arise because, prior to open access transmission, wholesale requirements customers had a reasonable expectation of continuing to receive wholesale service at just and reasonable cost-based rates. It argues that when open access transmission allows the supplier to charge a higher market-based rate instead, the customer's expectation of continued cost-based service is destroyed, and the customer may lose the benefits it had under the prior regulatory regime.

TDU Systems submits that while Order No. 888-A suggests that customers could not reasonably expect to continue paying their existing rate, the revenues lost approach to quantifying stranded costs assumes that sellers reasonably expected to continue collecting a cost-based rate equal to the existing rate. TDU Systems says that the Commission's best estimate of the seller's lost revenue from a wholesale requirements contract is based on the seller's existing, cost-based, just and reasonable rate -- the same existing cost-based rate that the Commission in Order No. 888-A finds the captive requirements customer had no

252/ TDU Systems uses the term "stranded benefits" to refer to the benefits to a wholesale requirements customer that may be lost if "open access transmission forces [the customer] to buy power at market-based rates" instead of at cost-based rates. TDU Systems at 25.

reasonable expectation of continuing to pay. TDU Systems says these findings directly contradict one another. 253/

TDU further challenges the Commission's statement that "it is not clear" that the customer could show it reasonably expected continued service "at the existing contract rate (which may be below the market price)" because the utility might have filed changed rates during the contract term or sought new rates at the end of the contract term. TDU Systems submits that before open access, established Commission policy would only have allowed the monopoly utility to charge its captive wholesale requirements customer a cost-based rate, whether that rate was above or below market price. 254/

TDU Systems asks the Commission to adopt a generic mechanism to allow customers to demonstrate and recover their stranded benefits, just as it has done for the recovery of utility stranded costs. If the Commission is unwilling to promulgate such a generic rule, TDU Systems asks that the Commission clarify the standard that a customer must meet in seeking relief under section 206. It says that although Order No. 888-A states that a customer may file a petition under section 206 "to show that the contract should be extended at the existing contract rate," the issue is not whether to extend a contract at the existing rate, but whether to continue requirements service at a cost-based

---

253/ Id. at 27-28.

254/ Id. at 28-29.

rate. It asks the Commission to correct its description in Order No. 888-A of the standard the customer must meet in a case-by-case proceeding and the relief the Commission would provide.

Commission Conclusion

As discussed below, we will deny TDU Systems' request for rehearing on this issue, but will grant, in part, its request for clarification.

In Order No. 888-A, the Commission rejected TDU Systems' request that the Commission provide a generic mechanism to allow existing requirements customers a means to continue to receive power beyond the contract term at the pre-existing contract rate if the customer had a reasonable expectation of continued service. The Commission noted that TDU Systems had requested that the customer be given the choice of extending its existing contract at existing rates for a period corresponding to the customer's expectation of continued service or receiving a "stranded benefits" payment from the utility consisting of the difference between what the customer must pay for new supplies and what it paid under the contract. 255/ We concluded that we did not have a sufficient basis on which to make generic findings or provide a generic formula for addressing this issue:

> Utilities' expectations may have resulted in millions of dollars of investments on behalf of certain customers and the possibility of shifting the costs of those investments to other customers that did not cause the costs to be incurred. In the case of customers'

255/ FERC Stats. & Regs. ¶ 31,048 at 30,391.

> expectations, however, even if customers generally expected to stay on a supplier's system beyond the contract term, it is not likely that most customers could have expected to continue service at the existing rate unless specified in the contract. Moreover, the consequences of customers' expectations as a general matter would not have the potential to shift significant costs to other customers. [256/]

At the same time, however, we indicated that a customer under a contract may exercise its procedural rights under section 206 of the FPA to show that the contract should be extended at the existing contract rate. We noted that the customer also may make such a showing in the context of a utility's proposed termination of a contract pursuant to the section 35.15 notice of termination (approval) requirement, which the Commission has retained for power supply contracts executed prior to July 9, 1996 (the effective date of Order No. 888).

TDU Systems has not persuaded us that our decision to address this issue on a case-by-case, not a generic, basis is in error. Notwithstanding TDU Systems' arguments, we continue to believe that the extent to which a customer could demonstrate a reasonable expectation of continued service at the existing contract rate (or at a cost-based rate, if that was the customer's expectation) is best addressed on a case-by-case basis. As we explained in Order No. 888-A, we do not intend to prejudge whether a requirements customer could ever make such a

256/ Id. at 30,393 (emphasis in original).

showing, nor do we intend to preclude a customer from attempting to make such a showing in appropriate circumstances.

In response to TDU Systems' request that the Commission clarify the standard that a requirements customer must meet in seeking relief under section 206, we clarify that a customer may exercise its procedural rights under section 206 to show either that the contract should be extended at the existing contract rate or, as TDU Systems suggests, that the contract should be extended at a cost-based rate. However, the relief that the Commission would provide in such a case is a matter that is more appropriately determined on a case-by-case basis based on the particular facts and circumstances.

7. Miscellaneous

IL Com seeks rehearing of the following sentence in Order No. 888-A: "It was not unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet their needs." 257/ IL Com objects that this sentence prejudges the reasonable expectation issue. 258/ It asks that the Commission withdraw the quoted sentence in full or, at a minimum, withdraw the reference to retail customers in the quoted sentence.

257/ *Id.* at 30,351 (emphasis added by IL Com).

258/ IL Com at 9-10.

IL Com also seeks clarification of the Commission's statement in Order No. 888-A that "[i]f a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, the utility is entitled to seek recovery of legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer." 259/ IL Com asks the Commission to withdraw the words "or a former retail customer" from this sentence and to clarify that it is not prejudging utilities' entitlement to retail stranded cost recovery and is not imposing a "legitimate, prudent and verifiable" standard for the recovery of retail stranded costs. 260/

Commission Conclusion

The Commission statements that are the subject of IL Com's request for rehearing initially appeared in Order No. 888 261/ and were repeated in Order No. 888-A's summarization of Order No. 888. IL Com's request for rehearing with respect to these statements should have been raised on rehearing of Order No. 888 and therefore was not timely filed. However, we clarify that while we will not withdraw our statements, the statements are not intended to prejudge the reasonable expectation issue as it might apply to any state proceedings on retail stranded costs.

259/ FERC Stats. & Regs. ¶ 31,048 at 30,351 (emphasis added by IL Com).

260/ IL Com at 10-11.

261/ See FERC Stats. & Regs. ¶ 31,036 at 31,789.

V. ENVIRONMENTAL STATEMENT

In Order No. 888-A, the Commission denied requests for rehearing on eight categories of issues relating to the Commission's analysis of environmental issues. No rehearing requests were filed concerning Order No. 888-A's analysis of environmental issues.

VI. REGULATORY FLEXIBILITY ACT CERTIFICATION

The Regulatory Flexibility Act 262/ requires rulemakings to either contain a description and analysis of the effect that the proposed or final rule will have on small entities or to contain a certification that the rule will not have a significant economic impact on a substantial number of small entities. In Order No. 888, the Commission certified that the Open Access and Stranded Cost Final Rules would not impose a significant economic impact on a substantial number of small entities. In Order No. 888-A, the Commission addressed requests for rehearing that questioned this certification and that the final rule would not impose a significant economic impact on a substantial number of small entities. No rehearing requests of Order No. 888-A were filed on this issue and the Commission finds no reason to alter its previous findings on this issue.

VII. INFORMATION COLLECTION STATEMENT

Order No. 888 contained an information collection statement for which the Commission obtained approval from the Office of

---

262/ 5 U.S.C. §§ 601-612.

Management and Budget (OMB). 263/ Given that this order on rehearing makes only minor revisions to Order Nos. 888 and 888-A, none of which is substantive, OMB approval for this order will not be necessary. However, the Commission will send a copy of this order to OMB, for informational purposes only.

The information reporting requirements under this order are virtually unchanged from those contained in Order Nos. 888 and 888-A. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention: Michael Miller, Information Services Division, (202) 208-1415], and the Office of Management and Budget [Attention: Desk Officer for the Federal Energy Regulatory Commission (202) 395-3087].

VIII. EFFECTIVE DATE

The tariff change to Order Nos. 888 and 888-A made in this order on rehearing (see footnote 1) will become effective on [insert date 60 days after the date of publication of this order in the Federal Register].

By the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Secretary.

263/ The OMB control number for this collection of information is 1902-0096.

APPENDIX A

ORDER NO. 888-B
LIST OF PETITIONERS

1. American Public Power Association, Colorado Association of Municipal Utilities, Municipal Electric Systems of Oklahoma, and Utah Associated Municipal Power Systems (APPA) 1/

2. Bonneville Power Administration (BPA)

3. Arizona Public Service Company (Arizona)

4. Boston Edison Company, Central Vermont Public Service Corporation, Florida Power Corporation, Montaup Electric Company, and Wisconsin Public Service Corporation (Boston Edison)

5. Coalition for a Competitive Electric Market (CCEM) 2/

6. Central Maine Power Company (Central Maine)

7. Coalition for Economic Competition (Coalition for Economic Competition) 3/

8. Colorado Association of Municipal Utilities (CAMU)

9. Dairyland Power Cooperative (Dairyland)

10. Edison Electric Institute (EEI) 4/

11. Illinois Commerce Commission (IL Com)

12. Kansas City Power & Light Company (KCPL)

13. Metropolitan Edison Company (Met Ed)

1/ APPA filed its request for rehearing out-of-time on April 4, 1997. As discussed in Order No. 888-B, the Commission is accepting this pleading as a motion for reconsideration.

2/ CNG Energy Services Corp., Coastal Electric Services Company, Destec Power Services, Inc., Enron Power Marketing, Inc., Koch Energy Trading, Inc., NorAm Energy Services, Inc., and Vitol Gas & Electric Services, Inc.

3/ General Public Utilities Corp., Illinois Power Co., Long Island Lighting Co., and New York State Electric & Gas Corp.

4/ EEI filed its request for rehearing out-of-time on April 4, 1997. As discussed in Order No. 888-B, the Commission is accepting this pleading as a motion for reconsideration.

14. National Association of Regulatory Utility Commissioners (NARUC)

15. National Rural Electric Cooperative Association (NRECA)

16. New England Power Pool Executive Committee (NEPOOL)

17. Public Service Commission of the State of New York (NY Com) 5/

18. Niagara Mohawk Power Corporation and PURPA Reform Group (NIMO) 6/

19. Otter Tail Power Company (Otter Tail)

20. Puget Sound Energy, Inc. (Puget) 7/

21. Rural Utilities Service, USDA (RUS)

22. Port of Seattle (Port of Seattle)

23. Soyland Power Cooperative, Inc. (Soyland)

24. Transmission Access Policy Study Group and certain of its Members (TAPS) 8/

5/ Independent Power Producers of New York, Inc. (NY IPPs) filed an answer on April 11, 1997.

6/ Granite State Hydropower Association filed an answer on April 21, 1997.

7/ Formerly Puget Sound Power & Light Company.

8/ American Municipal Power-Ohio, Inc., Illinois Municipal Electric Agency, Indiana Municipal Power Agency, Littleton Electric Light Department, Massachusetts Municipal Wholesale Electric Company, Michigan Public Power Agency, Municipal Energy Agency of Mississippi, Municipal Energy Agency of Nebraska, New Hampshire Electric Cooperative, Inc., Northern California Power Agency, Virginia Municipal Electric Association No. 1, on behalf of itself and its members (City of Franklin, City of Manassas, Harrisonburg Electric Commission, Town of Blackstone, Town of Culpepper, Town of Elkton, and Town of Wakefield), and Wisconsin Public Power, Inc. The operating companies of the American Electric Power System (AEP) filed an answer on April 17, 1997.

25. Transmission Dependent Utility Systems (TDU Systems) 9/

9/ Arkansas Electric Cooperative Corporation, Golden Spread Electric Cooperative, Inc., Holy Cross Electric Association, Kansas Electric Power Cooperative, Inc., Magic Valley Electric Cooperative, Inc., Mid-Tex Generation and Transmission Electric Cooperative, Inc., North Carolina Electric Membership Corporation, Oklahoma Municipal Power Authority, Old Dominion Electric Membership Corporation, and Seminole Electric Cooperative, Inc.

APPENDIX B

REVISION TO PRO FORMA OPEN ACCESS TRANSMISSION TARIFF

PURSUANT TO ORDER NO. 888-B

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

union as an alternative to undergoing a liquidation. In many instances the Administration would look favorably upon such an alternative, not only because it avoids the disruption, inconvenience, and hardship that a liquidation imposes upon the membership of a credit union, but also because it will reduce the risk of loss to the Share Insurance Fund. If a merger can be arranged that is consistent with longstanding NCUA policies regarding field of membership and common bond, the members will be benefitted by the relatively uninterrupted continuation of credit union services that results from a merger. Additionally, expenses to the Share Insurance Fund can be substantially reduced if a merger, as opposed to a liquidation can be consummated.

The Administration is also mindful of the merger alternatives used in the case of failing banks. While the ability of a bank to absorb another failing bank hinges on the financial strength of the absorbing bank, its location and the impact on competition, in the case of a credit union, it is a question of financial strength and compatibility of fields of membership. Although the authority of the Administration to prescribe rules governing mergers is somewhat broader than that provided other financial institution regulatory agencies, Congress did provide those agencies with a procedure to be used in emergency situations, i.e., in the case of a failing bank. The Administration, however, did not previously provide for a merger procedure in the case of a filing credit union. The proposed rule is designed to address this area.

Under current merger guidelines the requirement of obtaining the approval of the membership for the merger proposal may well frustrate a merger as a practical alternative to liquidation. The added costs of preparing and distributing the ballots and holding the special meeting of the members, coupled with the attendant time delays, may put the credit union into such an insolvent position that a merger cannot be completed or to the point that a merger is no longer a viable alternative. Moreover, the Administration views as academic the question of whether the members, when faced with liquidation as their alternative, would approve a merger as a viable way to continue operations. Members who are dissatisfied with the merger are free to close their accounts and thus have credit union services terminated; the same result as if the credit union were placed into liquidation. The second of the proposed rules, therefore, eliminates the requirement of membership approval for these limited classes of mergers.

In proposing these amendments, the Board relies on, in addition to section 120(a) and 205 of the Act, section 208 (12 U.S.C. 1788), which provides the Board with the authority to take certain actions in order to reduce the risk to the National Credit Union Share Insurance Fund and to facilitate a merger or consolidation of insured credit unions, and section 209 (12 U.S.C. 1789), the general relemaking authority for purposes of the provisions of Title II of the Act.

This proposed regulation provides for a 30-day comment period; comments must be received by November 26, 1979. A 60-day comment period is not provided because the proposal is not viewed as a significant change, it would relieve a previous restriction and the Administration finds it to be in the best interest of credit unions, their members and the National Credit Union Share Insurance Fund.

In addition, a regulatory analysis was not prepared for this proposed regulation because it was determined the proposal will not result in a significant impact on the national economy or cause a major increase in the costs or expenses of Federal credit unions. Also, certain other procedures provided for in NCUA's Report on Improving Government Regulations were not followed because the proposal is in response to an emergency and the process is unnecessary for the public interest. This determination was made by James J. Engel, Assistant General Counsel.

Accordingly, the National Credit Union Administration proposes to amend 12 CFR Part 708 to read as set forth below.

Rosemary Brady,
Secretary, NCUA Board.

October 18, 1979.

1. Part 708 is amended by deleting the term "Administrator" each time it appears therein and by inserting the term "Board" in lieu thereof.

§ 708.7 [Amended]

2. Paragraph (b) of 12 CFR 708.7 is amended by deleting the words "in a vote in which at least 20 per centum of the total membership of the credit union participates."

§ 708.6 [Amended]

3. Paragraph (a) of 12 CFR 708.6 is amended by deleting the period at the end of the subsection and inserting in lieu thereof the following: "; *Provided, however,* That in the event the Board determines that the merging credit union, if it is a Federal credit union, is in danger of insolvency, and that the proposed merger would reduce the risk or avoid a threatened loss to the National Credit Union Share Insurance Fund, the Board may permit the merger to become effective without an affirmative vote of the membership of the merging Federal credit union, not withstanding the provisions of § 708.7."

(Sec. 120, 73 Stat. 635 (12 U.S.C. 1766) and Sec. 209, 84 Stat. 1104 (12 U.S.C. 1789)).

[FR Doc. 79-32780 Filed 10-23-79; 8:45 am]

BILLING CODE 7535-01-M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79-55]

Small Power Production and Cogeneration—Rates and Exemptions

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The proposed rules would implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules set forth rates for the sale of electric energy between qualifying small power production and cogeneration facilities and electric utilities, and provide for the exemption of qualifying facilities from certain State and Federal regulation. The proposed rules also provide guidelines for the interconnection arrangements between qualifying facilities and electric utilities.

DATE: Written comments by December 1, 1979. Dates of the public hearings will be announced at a later time.

ADDRESS: All responses to reference Docket No. RM79-55, and to be addressed to: Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Locations of the public hearings will be announced at a later time.

FOR FURTHER INFORMATION CONTACT: Adam Wenner, Executive Assistant to the Associate General Counsel, 825 North Capitol Street, N.E., Washington, D.C. 20426 (202) 357-8171.

SUPPLEMENTARY INFORMATION:

Issued: October 10, 1979.

Section 210(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA)

DOCKET NO. UM-1610/THREEMILE/203
EXHIBIT/HARVEY-2

requires that the Commission prescribe rules as it determines necessary to encourage cogeneration and small power production, requiring electric utilities to offer to:

(1) Sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities, and

(2) Purchase electric energy from such facilities.

In addition, section 210(e) of PURPA requires the Commission to prescribe rules under which qualifying cogeneration and small power production facilities are exempted, in whole or in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, and from State laws and regulations respecting the rates or respecting the financial or organizational regulation of electric utilities, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

On June 26, 1979, in Docket No. RM79-54, the Commission issued proposed rules regarding the determination of which cogeneration and small power production facilities are qualifying cogeneration facilities or qualifying small power production facilities. Such qualifying facilities are entitled to avail themselves of exemptions set forth in section 210 of PURPA, and are eligible for exemption from the incremental pricing provisions of section 206(c) of the Natural Gas Policy Act of 1978 (Order No. 49, § 282.203(e), issued September 28, 1979, 44 FR 57726).

On June 27, 1979, in Docket No. RM79-55, the Commission issued a Staff discussion paper regarding issues arising under section 210 of PURPA.[1] The Staff discussion paper set forth many legal and policy questions arising under section 210 of PURPA. In addition to those issues, comments received in response to the Staff discussion paper and in the public hearings held in San Francisco, Chicago, and Washington, D.C. in July, 1979 on this topic raised new questions regarding the Commission's responsibility to exercise its authority under section 210. The Commission has taken into consideration these questions and comments in developing this proposed rulemaking.

[1] The Staff discussion paper in Docket No. RM79-55 concerned subjects also addressed in this proposed rulemaking. Since interested persons may submit comments in response to this rulemaking, the deadline for the filing of comments on the Staff discussion paper was not extended beyond the original deadline of August 1, 1979.

Summary

The proposed 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 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 with regard to 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 non-discriminatory basis, at a rate that is just and reasonable and in the public interest, and must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilties' own generation.

The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from rate and certain other regulations under the Federal Power Act, from 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 any other means reasonably designed to give effect to the Commission's rules.

The Commission observes that this rulemaking represents an effort to evolve concepts in a newly developing area within rigid statutory constraints. The Commission is attempting to afford broad discretion to the State regulatory authorities and nonregulated electric utilities in recognition of the variety of institutional, economic, and local circumstances which may be affected by this proposed rulemaking. In this regard, the Commission seeks the fullest range of comments on the legal authority of proposed Commission action, and on the technical and practical aspects of the proposals set forth in this rulemaking.

Section-by-Section Analysis

Subpart A—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities under Section 210 of the Public Utilities Regulatory Policies Act of 1978.

§ *292.101 Scope.*

Section 292.101(a) describes the scope of Subpart A of Part 292 of the Commission's rules. Subpart A applies to sales and purchases of electric energy and capacity between qualifying cogeneration and small power production facilities and electric utilities, and actions related to such sales and purchases. Section 292.101(b) provides that the authority of this subpart does not preclude negotiated agreements between qualifying cogenerators or small power producers and electric utilities which differ from rates or terms which would otherwise be required under this subpart. 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 producer chooses to avail itself of the rights and protections set forth in that section. An agreement between an electric utility and a qualifying cogenerator or small power producer to conduct sales or purchases at rates higher or lower, or under terms or conditions different from those set forth in these rules, does not violate the Commission's rules under section 210 of PURPA. Nor would provisions of State law or regulations which provide different incentives for small power production and cogeneration (than are provided in the Commission's rules) be preempted. 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 statutory rights and protections of these rules, and the right of State regulatory agencies and nonregulated electric utilities to provide further encouragement of these technologies.

If, prior to the existence of the rights and protections set forth in PURPA, a cogenerator or small power producer entered into a contractual agreement by which he received sufficient financial incentive to sell his electric output to a utility, the encouragement of cogeneration or small power production does not require that he be given additional incentives. Accordingly, paragraph (b)(2) provides that Subpart A will not affect the validity of any contract between a qualifying cogenerator of small power production facility and an electric utility. At the expiration of the contract, a cogenerator or small power producer will be able to avail himself of these rules.

§ *292.102 Definitions.*

This section contains definitions applicable to Subpart A.

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.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under § 292.208 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 from a qualifying facility by an electric utility.

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

Subparagraph (4) defines "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.

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.

Subparagraph (6) defines "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. 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.

Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities. 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 enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility, then the rates for such a purchase will be based on the net avoided capacity and energy costs.[2]

There is considerable language in both the statute and the Conference Report, as well as the Federal Power Act, in support of the proposition that capacity payments are not only legally permitted to be required by the Commission, but also, at least in some circumstances, mandated.

The Conference Report addresses the calculation of the alternative cost standard at some length. The final paragraph of this section of the Report is the following:

> 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.[3]

The references to "additions to capacity" and to obligations "to supply firm power" (the rates for which, in this Commission's experience, always include a capacity component) lead the Commission to the conclusion that, under Section 210, capacity payments to qualifying facilities can be required under certain circumstances; and that a utility's refusal to make payments based in part on avoided capacity payments could be discriminatory.

In addition, the Commission notes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales or resale in interstate commerce. Demand or capacity rates 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.

To interpret this phrase to include only the energy would lead to the conclusion that the rates for sales to qualifying facilities only include the energy component of the rate. It is the Commission's belief that this was not the intended result, and thus provides an additional reason to interpret the phrase electric energy to include both energy and capacity.

§ *292.103 Availability of electric utility system cost data.*

In order to be able to evaluate the financial viability of a cogeneration or small power production facility, an investor needs to be able to ascertain, before construction of a facility, the expected return on a potential investment. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.105 of these rules, the rate at which a utility must purchase

---

[2] "Net avoided costs" are the excess of the total costs of the system developed in accordance with the utility's optimum capacity expansion plan, excluding the qualifying facility, over the system's total costs (before payment to the qualifying facility) developed in accordance with the utility's optimum capacity expansion plan including the qualifying facility. This concept recognizes that the energy cost associated with a deferred or avoided unit may be different from the energy costs of the qualifying facility which permitted that deferral or avoidance. In determining an optimum capacity expansion plan, a utility must consider both capacity and energy costs in order to minimize the anticipated total system costs. In providing for payments for avoided capacity, the Commission uses the term "net avoided cost" in recognition of the fact that various types of capacity will not produce the same amount of energy, so that some change in the dispatch of generation may be necessary from the remaining plants after a planned unit is deferred and the qualifying facility's capacity is substituted along with other available capacity to produce the same amount of energy at the minimum cost. This is particularly true, for example, where the capacity factor for the qualifying facility is less than the planned capacity factor from a base load (high capacity cost—low energy cost) alternative facility which is deferred. In such a case, although adequate capacity may exist on the system due to the purchase from the qualifying facility in lieu of the deferred base load unit, additional energy costs may be incurred due to increased generation from intermediate plants to make up the difference between the planned generation from the base load plant and the lesser total energy produced by the qualifying facility. Such increased energy cost is appropriately recognized by providing for the payment to the qualifying facility of the *net* avoided costs. In this way, the ratepayers are assured of paying no more than the total costs that would have been incurred had the unit not been deferred.

[3] Conference Report on H.R. 4018, Public Utilities Regulatory Policies Act of 1978, H. Rep. No. 1750, 99, 95th Cong., 2d Sess. (1978).

that output is based on the utility's avoided costs.

In order to provide data to qualifying facilities which will assist them in determining the utility's avoided costs, § 292.103(b) of the rules 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. The data required to be provided to determine these avoided costs will have been prepared in compliance with the Commission's rules implementing section 133 of PURPA.[4] This section will thus, for the most part, require a table presenting data already developed.

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. (The phrase "before the immediately preceding calendar year" refers to the year two years prior to the current year. For example, if an electric utility exceeded the 500 million kWh limit both during 1976 and 1979, it must comply with section 133 requirements in 1981.) Section 290.102(d) of the Commission's rules implementing section 133 of PURPA granted an extension until June 30, 1982,[5] to electric utilities covered by that section having total sales of energy for purposes other than resale of less than 1 billion kWh in each of the calendar years 1976, 1977, and 1978.

The proposed coverage under paragraph (a) of these regulations is the same as that provided pursuant to section 133 of PURPA and the Commission's rules implementing that section, with an exception provided in paragraph (c) as will be discussed.

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

Subparagraph (1) 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 one hundred megawatts or less 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 immediately preceding year, and on an estimated cents per kWh basis for the current calendar year and for each of the next five years.

Subparagraph (2) 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 10 years.

Subparagraph (3) requires each electric utility to provide the estimated costs at completion, on the basis of dollars per kilowatt, of planned capacity additions, including planned firm purchases.

Qualifying facilities may wish to sell energy or capacity to electric utilities which are 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 sufficient data to enable the cogenerator or small power producer to determine the utility's avoided costs. If such utility refuses to supply the requested data, the qualifying facility may apply to this Commission for an order requiring that the information be supplied. The Commission, in considering such applications, will take into account the burden on the utility.

A non-generating electric utility which does not own or plan to acquire generating capacity may incorporate the data provided by each of its supplying utilities in its compliance with the provisions of this section.

§ 292.104 Electric utility obligations under this subpart.

Section 210(a) of PURPA provides that the Commission shall 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, except during periods prescribed in § 292.105(c) and during system emergencies.

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 an average figure representing the average cost of energy and capacity on the 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 could replace energy supplied by specific peaking units, and its capacity might enable the supplying utility to avoid the addition of new capacity. The costs, and thus the avoided costs, of peaking energy and new capacity are generally greater than system average figures.

Under these proposed 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 can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself.

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 utility does not transmit the purchased energy or capacity, it 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.[6]

The costs of transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility.

---

[4] For example, § 290.303(h) of the Commission's rules implementing section 133 of PURPA requires such electric utilities to report marginal energy costs for each month of the reporting period and for each month of the next five years. Section 290.302(g) of these rules requires electric utilities to report the estimated cost, in dollars per kilowatt of generation, of generation units likely to be installed to meet increases in peak demand. Section 290.302(f) requires the reporting of estimates, for the next ten years of information regarding total system capacity, and capacity to be supplied by other utilities.

[5] Docket No. RM79-6, issued June 6, 1979, granted an extension until May 31, 1982, to electric utilities having total sales of electric energy for purposes other than resale of less than 1 billion kilowatt-hours in each of the calendar years 1976, 1977, and 1978. The Commission recently issued revised regulations in this docket which extended this date to June 30, 1982.

[6] The Commission notes that while a purchase from a qualifying facility may have value as energy and capacity, what is actually transmitted to the second utility is properly described as electric energy. The utility to which energy is transmitted, however, must pay rates based on energy and capacity value.

These costs are part of the costs of interconnection, and are the responsibility of the qualifying facility under § 292.108 of these rules. However, pursuant to agreement between the qualifying facility and any electric utility which transmits electric energy on behalf of the qualifying facility, the transmitting utility may share the costs of transmission. 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.

Paragraph (b) sets forth the statutory requirement of section 210(a) of PURPA that electric utilities offer to sell electric energy to qualifying facilities. This section creates a Federal right for qualifying facilities to obtain electric service, in addition to any service the electric utility is obligated to provide under State laws.

The Staff discussion paper dealt with the issue of whether there is inherent in section 210 of PURPA the authority to order interconnections between electric utilities and qualifying facilities, or whether qualifying facilities must use the procedures set forth in the new sections 210 and 212 of the Federal Power Act to gain interconnection.[7] The Commission believes that the requirement to interconnect is within the legal authority of the Commission under section 210 of PURPA, particularly subsumed within the requirement to buy and sell. To hold otherwise would mean that Congress intended to have qualifying facilities go through an extended and expensive proceeding simply to gain interconnection, contrary to the entire thrust of sections 201 and 210 of PURPA.

These sections evince the clear Congressional intent to encourage development of these desirable forms of generation, and to have the commercial development of these facilities proceed expeditiously. In other words, Congress has already made the judgment that these kinds of facilities serve one of the purposes of the Act as set out in section 101, *viz*, "the optimization of the efficiency of use of facilities and resources by electric utilities", and it would be both redundant and unduly burdensome to have the sponsors of individual facilities show in an evidentiary hearing conducted under section 210 of the Federal Power Act that their project in particular would serve this end (or one of the other related goals established as criteria for an interconnection order in section 210(c)(2)). The purpose of an interconnection application, whether under section 202 or 210 of the FPA, is to secure service, whether emergency or otherwise; and section 210 of PURPA establishes the entitlement of a qualifying facility to service from the interconnected utility. In effect, the proponents of the view that a qualifying facility must apply under sections 210 and 212 of the FPA have the burden of showing that Congress intended interconnection and the entitlement to buy and sell be denied to a qualifying facility which is unable to make the showings required by those sections, especially in light of the fact that a previously interconnected customer installing qualifying facilities would not have to so apply.

This is not to say that all of the protections that Congress has given the target of an interconnection application in sections 210 and 212 of the FPA are necessarily absent from section 210 of PURPA. The Conference Report on section 210 states that customers of utilities are not to be compelled to subsidize qualifying facilities, and this principle would seem to bear on the question of who pays the costs of interconnection as well as on the per-unit price to be paid for energy. On the other hand, the Conference Report includes a proscription against "unreasonable rate structure impediments, such as unreasonable hook up charges." This provides another argument in favor of reading section 210 of PURPA as including interconnection authority, since the elaborate cost determination required under sections 210 and 212 of the FPA is redundant if the costs of interconnection are viewed simply as a feature of the rate structure with the charge therefor based on the cost of the utility. However, the Commission does view section 210 of the FPA as an alternate avenue for remedy available to any qualifying facility which wishes to apply under it.

The obligation to interconnect can be part of either an electric utility's option to purchase from or sell to a qualifying facility. With regard to the obligation to sell, State law ordinarily sets out the obligation of an electric utility to provide service to customers located within its service area. The Commission believes that State law will normally impose on an electric utility the obligation to interconnect and that the Commission's proposal will not, in most instances, impose any additional obligation on electric utilities.

As noted in the Staff discussion paper, by installing certain equipment, an electric utility can be protected from disruption of its operations caused by a qualifying facility. The Commission has not received comments which disagree with this understanding. Therefore, through the allocation of the costs associated with such equipment to the qualifying facilities, as provided in § 292.109, and through the imposition of standards for operating reliability under § 292.110, appropriate physical and financial protection for the electric utilities is provided in the Commission's proposed rules.

Several commentors urged that the Commission require electric utilities to offer to operate in parallel with a qualifying facility. By operating in parallel, a qualifying facility is enabled automatically to export any electric energy which is not consumed by its own load. Therefore, provided that the qualifying facility complies with the standards set forth in § 292.110 regarding operating reliability, the Commission proposes in paragraph (e) that electric utilities be required to offer to operate in parallel with a qualifying facility.

§ *292.105 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 insure that the rates for such purchases be just and reasonable to the electric consumers of the purchasing utility, in the public interest, nondiscriminatory to qualifying facilities, and that they not exceed the incremental costs of alternative electric energy (the costs of energy, which, but for the purchase, the utility would generate from another source).

Types of Purchases

In impelementing 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 and the

[7] Staff discussion paper, *supra*, at 10–14.

associated costs of assuring that firm power will be available on demand.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement for the construction of capacity on the seller. In order to provide power to customers at the seller's discretion, the selling utility needs only to provide for the cost of operating its generating units. 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 as only to permit a utility to avoid generating an equivalent amount of energy. The utility must continue to provide capacity that is available to meet the needs of its customers. Rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy (system lambda), and not based on avoided capacity.

On the other hand, 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 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 can 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 the capacity costs.

In order to be able to defer or cancel the construction of new generating units, a utility must obtain a commitment, sufficiently ahead of the lead time for the construction of its own new capacity, that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available. If a qualifying facility makes such a commitment, the Commission believes that, as a matter of both policy and interpretation of section 210, the qualifying facility is entitled to receive rates based on the utility's avoided costs resulting from the capacity the qualifying facility supplies. Moreover, if a cogenerator or small power producer were permitted to receive only the energy (fuel, and operating and maintenance) expenses which the purchasing utility can avoid—while the cogenerator or small power producer must himself invest in new, and oftern highly capital-intensive, machinery—these potential sources of energy may go undeveloped. In light of the Commission's statutory obligation to encourage cogeneration and small power production, the Commission believe that a proper interpretation of "the incremental costs of alternative electric energy" requires that, when purchases of energy can substitute for intermediate, or base-load, the rate to the cogenerator or small power producer include the net avoided capacity and energy costs.

If a qualifying facility opts to receive rates based on avoided energy costs, such rates should reflect the energy costs of the electric utility's units which otherwise would have been operated. The Commission believes that there are a variety of acceptable ways to carry out this policy at the State level. The general concept here is that rates for purchases from the qualifying facility would be based on the highest energy cost unit then operating. The qualifying facility would continue to be dispatched until the cost of energy from the utility's generating unit with the highest energy costs is lower than the price at which the qualifying facility wishes to sell.

The Commission neither expects nor requires that the determination of utilities' avoided costs will be so precise. By definition, these costs are based on estimates of costs which would be incurred if certain events were to take place. Electric rates are ordinarily calculated on the basis of averaging. So long as a rate for purchases reasonably accounts for the avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as implementing these rules.

Paragraph (a) therefore provides that the statutory requirements regarding rates for purchases of energy and capacity from a qualifying facility are satisfied if the rate reflects the avoided costs resulting from such a purchase as determined on the basis of the cost of energy and capacity set forth pursuant to § 292.103(b) or (c).

Method of Implementation

The Commission is required under section 210 of PURPA to prescribe rules requiring electric utilities to offer to sell electric energy to and purchase electric energy from qualifying facilities. Paragraphs (b) and (c) of section 210 set forth the standards regarding the rate at which such purchases and sales shall be made. The implementation of Commission rules promulgating these standards is reserved to the State regulatory authorities and non-regulated utilities, which are required under section 210(f) to implement the Commission's rules.

One major area of concern expressed in comments received from electric utilities, cogenerators and small power producers, and State regulatory authorities has been that the Commission's rules should state general principles sufficient to leave the states and non-regulated utilities flexibility.[6] The basis for this recommendation is the need for experimentation in a new technological area and in an area that is subject to a variety of State procedures, the diverse nature of cogeneration and small power production systems, and the differences in the costs of energy and capacity on individual electric systems. As a result, while we herein propose that, for example, capacity costs must be paid if a utility can actually avoid the construction or purchase of capacity, our rules will not dictate the method by which such a payment is to be determined. Rather the Commission proposes to leave the selection of a methodology to the States and nonregulated electric utilities, with the understanding that should a State or nonregulated utility not fulfill the intent and purposes of our rules and of section 210 of PURPA, the Commission and others have available the enforcement power set forth in section 210(h) of PURPA to assure compliance. Additionally, the Commission is authorized to revise these rules in the future to provide greater specificity to these rules if that is necessary.

Paragraph (b) requires electric utilities, on request of a qualifying facility, to promulgate a tariff or other method for establishing rates for purchases from qualifying facilities of ten kilowatts or less. In Docket No. RM79-54 the Commission proposed a minimum size limitation for qualifying facilities of ten kilowatts. However,

[6] Comments of American Electric Power, filed August 1, 1979, at 2-3; Comments of Electric Consumer Resource Council (ELCON), filed August 1, 1979, at 6; Comments of the National Association of Regulatory Utility Commissioners (NARUC), filed August 1, 1979, at 2-5.

comments received in response to that proposed rulemaking indicate that such a limitation could hamper the development of auxiliary solar and wind power units. Without finally determining that question in this rulemaking, it appears to the Commission that the burden of interconnected operation on both utilities and qualifying facilities can be minimized if standard tariffs are used.

Some utilities already have such tariffs in effect. For units of ten kilowatts or less, it is likely that few changes in the utility's distribution system would be required. For example, an electric utility might offer to permit certain customers to reverse their electric meters, thus permitting consumption by the customer. While the Commission will deal more extensively with the matter of a size limitation for qualifying facilities in its final rule in Docket No. RM79-54, the Commission solicits comment here on the merits of requiring utilities to promulgate tariffs for qualifying facilities of ten kilowatts of less.

Paragraph (c) concerns a problem arising in the implementation of the concept of avoided costs. At the time that a qualifying facility delivers electric energy to an electric utility, that utility can determine its system lambda and thus calculate the costs it can avoid by making the purchase. Subparagraph (1) therefore provides rates for purchases made on an "as available" basis may be based on the purchasing utility's avoided energy costs.

In order to establish certainity of future revenue, a qualifying facility might seek to obtain a contract from a utility providing that the utility will pay a certain price for energy from a qualifying facility, under specified terms and conditions. Indeed, a qualifying facility desiring to obtain capacity credit must provide the purchasing utility with assurance that such capacity will continue to be available.

In the case of future purchases pursuant to a legally enforceable obligation, the utility's avoided energy or capacity costs may be based on the costs of production facilities which are not built and for which the only available cost data are estimates. When the qualifying facility actually supplies electricy, the utility's avoided costs may deviate from these estimated figures. The Commission believes that these potential deviations are a normal result of risk allocation resulting from contractual commitments or other legal obligations, and believes that they must be permitted if the Commission is to fulfill its mandate to encourage cogeneration and small power production. Accordingly, subparagraph (2) provides that rates for such purchases may be based on future estimated utility costs of energy or capacity regardless of whether these estimated costs actually track the actual costs that are incurred.

Paragraph (d) sets forth factors on the basis of which the State regulatory authority or nonregulated utility should determine a utility's avoided costs. These principles relate both to the quality of power available from the qualifying facility and its ability to displace or replace energy and capacity on the utility's system.

Subparagraph (1) 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 offpeak periods during which only units with lower running costs are operating. Ideally, the rates for purchases would reflect the cost in the purchasing utility's system at the precise moment when such energy is supplied. The metering equipment that would be required to ascertain these times of delivery with the requisite specificity may be either unavailable or prohibitively expensive. To the extent that such metering equipment is available, however, the State or nonregulated utility should take into account the time at which the purchase from a qualifying facility is made.

Clauses (i), (ii), (iii), (iv), and (v) deal with 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.*

Clause (ii) refers to a qualifying facility's ability and willingness to provide power and energy during system emergencies. Section 292.109 of these proposed regulations concerns the provision of electric services 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.

Clause (iii) deals with periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units at periods during which 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 capacity will be adequate to handle existing demand, it will enable the utility to avoid the necessity to provide redundant capacity. With regard to forced or unscheduled outages, addressed in clause (iv), it is clear that a utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would replace such capacity may go out of service during the period when the utility needs its power to meet demand. Based on estimated and demonstrated reliability of the qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its forced and scheduled outage rate.

Subclause (v) refers to the lenght 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 service from the qualifying facility to the electric utility will be affected by the degree to which the qualifying facility contractually insures that it will continue to provide power. 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 normally include temporary purchases of firm power from other utilities in years preceeding the addition of a major

*See comments of Hawaiian Electric Company, filed July 27, 1979, at 2.

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 that such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Subparagraph (2) 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 demands 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.[10] This is not to say that electric utilities with systems which have excess capacity need not make purchases from qualifying facilities; qualifying facilities may obtain payment for the avoided energy costs on a purchasing utility's system. Utility systems with excess capacity normally have intermediate or peaking units which use 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. In addition, 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.

Clause (i) of subparagraph (2) refers to the aggregate capability of capacity from qualifying facilities to displace existing or 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 or purchases. 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 reflect the equivalent of firm power. The States and nonregulated utilities should attempt to devise rate mechanisms which will appropriately compensate qualifying facilities whose aggregate capacity enables the purchasing utility to defer or avoid capacity additions.

Clause (ii) 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 cost.

Subparagraph (3) addresses the cost of savings resulting from line losses. In determining an appropriate rate for purchases from a qualifying facility the rate 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 source of power it replaces, then the qualifying facility should be reimbursed only for the equivalent amount. 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.

Subparagraph (4) provides that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases might result in net increased operating costs to the electric utility. Identification of these periods will be made by the State regulatory authority which has jurisdiction over the utility or by the nonregulated electric utilities. Comments received in response to the Staff discussion paper noted that if, for example, during low load periods, a utility were operating a nuclear plant as its most expensive unit, and were forced to cut back output from such a unit in order to accommodate a purchase from a qualifying facility, the utility would experience increased costs in increasing the output from the nuclear facility when the system demand increases.[11]

Thus, because the avoided cost is zero or actually involves expense to the utility, requiring the utility to purchase energy from a qualifying facility during such a period would not be just and reasonable to the consumers of the electric utility, because it would result in increased costs to the system's rate payers. Under the proposed § 292.104(a) an electric utility would not be required to make energy purchases during such a period.

Tax Issues

The Statement of the Committee of Conference 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.

We note that section 301(b)(2) of the Energy Tax Act of 1978 [12] made eligible for increased business investment tax credit certain property that may be used by small power producers or cogenerators. 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)." [13] As a result, if a qualifying facility were to be classified as a public utility under section 46(f)(5) of the Internal Revenue Code, it would not be eligible for the increased investment tax credit otherwise available.

The Commission notes that a recent change [14] in Treasury Department regulations amended the definition of the exclusion "public utility property" for purposes of eligibility for the investment tax credit so as to exclude [from the definition] 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. Prior to the change, any rate regulation made property subject thereto (and involved in the furnishing or sale of energy) public utility property.

The Commission observes that the rates for purchases set forth in this rulemaking for purchases of energy from qualifying facilities are *not* based on a rate of return on investment. As a result, the Commission believes that property owned by qualifying facilities should not be classified as public utility property under section 46(f)(5) of the Internal Revenue Code of 1954. If such property is not classified as public utility property, the qualifying facility will be eligible to receive the additional investment tax credit set out in section 301(b) of the Energy Tax Act of 1978. 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.

---

[10] Such availability may, however, permit the utility to advance the retirement of its least effective units.

[11] Comments of Commonwealth Edison Company, filed August 1, 1979 at 4.

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

[13] 21 U.S.C. § 48(e)(3)(b).

[14] Treasury Reg. § 1.46-3(g)(2), T.D. 7602 (March 23, 1979).

§ 292.106 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 against qualifying cogenerators or small power producers. As noted in the Staff discussion paper,[15] this section contemplates rates formulated on the basis of traditional ratemaking (*i.e.*, cost of service) concepts.

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

A qualifying facility is entitled to purchase back-up or standby power at a rate which reflects the probability that the qualifying facility will or will not contribute to the need for utility capacity and the use of utility capacity.[16] Thus, when 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 assess these costs to non-generating customers.[17]

Paragraph (b) provides that electric utilities must provide to qualifying facilities any services which would be provided by the electric utility to a retail customer who does not have his own generation.

Normally the determination of an appropriate rate to a class of customers is based on an examination of load data relating to such customers. At this time, however, even those utilities which have good load data regarding existing customer classes do not have load data regarding usage by qualifying cogeneration and small power production facilities. Until such data is collected, the Commission believes that rates for sales to qualifying facilities should be at least as favorable as those available to utility customers having comparable load characteristics or falling under similar load classifications.

Paragraph (c) sets forth certain types of service which electric utilities are required to provide to qualifying facilities even if such types of service are not provided to other customers. These types of service are: supplementary power, back-up power, interruptible power, and maintenance power. The Commission believes that this requirement is necessary to encourage small power production and cogeneration.

Supplementary power is power 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 power available to replace power generated by a facility's own generation equipment. 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.

Interruptible power is power supplied by a utility on an "as available" basis. Because interruptible power normally is sold at a lower rate, a qualifying facility may wish to cease operations when utility power is interrupted rather than pay the higher rate necessary to assure firm supplementary supplies.

Maintenance power is supplied during scheduled outages. By prearrangement, a utility can agree to provide such power during periods when the utility's other loads are low, thereby avoiding the imposition of large demands on the utility during peak periods.

Paragraphs (d)(1) and (d)(2) provide that rates for sales of back-up or maintenance power shall not be based on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur simultaneously or on the assumption that they will occur during the system peak. Like other customers, qualifying facilities have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities will 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 analysis of their demand will show that a utility need not reserve capacity on a one-to-one basis to meet back-up requirements. Paragraphs (d)(1) and (d)(2) prohibit utilities from basing rates on the unsupported assumption that qualifying facilities will impose demands simultaneously and at system peak.

Paragraph (d)(3) provides that rates for sales from an electric utility to a qualifying facility shall take into account the extent to which a qualifying facility has coordinated periods of scheduled maintenance with an electric utility. If a qualifying facility coordinates periods of outage with an electric utility the demand that the qualifying facility imposes on the utility's system will not create capacity requirements to the same extent that such a demand would create if the utility were required to provide such service without prior notice.

§ 292.107 Simultaneous purchase and sale.

Section 292.107 deals with the situation referred to in the Staff discussion paper in which a cogenerator or small power producer desires to sell all of its output to a utility and purchase all of its needs from the utility simultaneously. As observed in the Staff discussion paper, and efficient use of society's resources requires that when there is a need for additional capacity, and a utility's customer can construct a new plant more cheaply than the utility can, he should be encouraged to do so.[18] A qualifying facility may have previously used a portion of its electric output to supply its own power needs. That it chose to generate its own electric power, rather than purchase such power from an electric utility, indicates that there were sufficient economic incentives to so act. To permit such a facility to sell that portion of its electric output to the utility at the utility's avoided costs and replace that electricity from the electric utility at non-incremental (and presumably lower) rates would increase the purchased power costs of the pruchasing utility and thus would increase the rates charged to the utility's other customers. The Commission believes that it is not necessary to the encouragement of cogeneration and small power production that a qualifying facility be permitted to obtain avoided cost-based rates for this portion of its electric output. Accordingly, the Commission proposes that for energy generated by a new facility or by capacity installed after the date of issuance of these rules, a qualifying facility be permitted to sell its output at rates established under the section 210(b) of PURPA pricing mechanism while simultaneously purchasing electric energy from a utility pursuant to its retail rate schedules.

[15] Staff discussion paper, *supra*, at 14–20.

[16] Comments of ELCON (Electricity Consumer Resource Council), filed August 1, 1979, at 5.

[17] Comments of Consumers Power Company, filed August 1, 1979, at 3.

[18] Staff discussion paper, *supra* at 24–25.

§ 292.108 Costs of interconnection.

Paragraph (a) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, safety provisions and other costs to an electric utility resulting from interconnected operation between an electric utility and a qualifying facility.

Paragraph (b) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs. These costs are limited to the net increased costs imposed on an electric utility compared to those it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

If, with the consent of a qualifying facility, an electric utility elects to transmit energy from the qualifying facility to another electric utility, the costs of transmission constitute interconnection costs as defined in this paragraph. Under paragraph (b), these costs must be borne by the qualifying facility unless the transmitting utility agrees to share them.

The cost responsibility of the qualifying facility was well summarized in comments by The Southern Company:

> We believe that the interconnection costs which should be addressed in the rules are those incremental costs that go beyond the cost to the system for connecting a normal (i.e., no generation) customer. These costs will include the additional relaying, switching, metering, line, and protective equipment—inclusive of equipment changeout cost—required in the general vicinity of the facility because of the customer's generation. Recognition must be given to the fact that protection goes beyond the protection of equipment and personnel of the qualifying facility and utility. The rules also must provide for the protection of other customers of the utility that may be affected by the operation of the qualifying facility.[19]

Thus, it is only the additional costs which result from interconnected operation for which the qualifying facility is responsible; if the utility would have provided retail service to the customer, those expenses may not be assessed against the qualifying facility merely because the facility is also supplying power and energy. If, however, as a result of the qualifying facility's export of power, the utility is required to install additional switching, safety or other equipment, the qualifying facility is responsible for those expenses.

Paragraph (c) provides that a qualifying facility must reimburse an electric utility which sells capacity or energy to the qualifying facility for interconnection costs resulting from such sale. Ordinarily, the service obligation of an electric utility will contain standard procedures for the allocation of interconnection costs between a retail customer and the electric utility. Paragraph (c) also provides that interconnection costs to qualifying facilities shall not be discriminatory in relation to the practices of the electric utility with regard to other retail customers.

§ 292.109 System emergencies.

Paragraph (a) provides that, except as provided under section 202(c) of the Federal Power Act or pursuant to a contract or agreement between a qualifying facility and an electric utility, 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.

Many comments from cogenerators and small power producers expressed concern that, during a system emergency, they might be required to make available all of their generation to the utility. 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 insure that even during a system emergency, their supply of power is not interrupted. To put in jeopardy the availability of power 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 proposes that the qualifying utility's obligation to provide power be established through contract.

In order to receive full credit for capacity, a qualifying facility must offer power during system emergencies to the same extent that it has agreed to provide power at the purchasing utility's discretion. 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 back-up 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 a purchase would contribute to the emergency. In addition, during system emergencies, a qualifying facility must be treated on a non-discriminatory basis—i.e., on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption in service.

§ 292.110 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 energy service to be available to such facilities from electric utilities during emergencies. Staff's analysis presented in the discussion paper regarding reliability of a particular qualifying facility concluded that every incidence of qualifying facility reliability 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 of its power by the utility. The majority of comments received regarding this issue endorsed the Staff's recommendation. Accordingly, the Commission proposes that there be no specific standard relating to the reliability in the sense of ability to provide power for qualifying facilities.

Many commentors have proposed that the Commission's rules ensure that interconnection with qualifying facilities does not disrupt system reliability. One commentor proposed that qualifying facilities must automatically disconnect from utility lines upon interruption or interference with utility service, or upon the flow of excessive current between the utility system and the non-utility generator.[20]

It is the Commission's understanding that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that any qualifying facility may be subject to reasonable standards to ensure system safety and reliability in

[19] Comments of The Southern Company, filed July 30, 1979, at 5.

[20] Comments of Illinois Power Company, filed August 14, 1979.

interconnected operations. Each State regulatory authority and nonregulated electric utility is permitted to establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by a utility or any other person. The standards must be accompanied by a statement showing the need for the standard on the basis of system safety and operating requirements.

Subpart C

Summary of This Subpart

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

In the Commission's view, section 210(f) affords the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the Commission's rules so long as the manner chosen is reasonably designed to implement the requirements of Subpart A. 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 broad latitude, and with the recognition of the work already begun and of the variety of local conditions that the Commission proposes to promulgate 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 proposed rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply for a waiver if it can demonstrate that compliance with certain requirements of Subpart A is not necessary to encourage congeneration or small power production and is not otherwise required under section 210.

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 requirements to implement may be fulfilled either through (1) 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. In the first case, implementation would consist of the issuance of rules after notice, and an opportunity for a hearing. In the second case, the State regulatory authority or nonregulated utility would be required to hold hearings regarding its proposed procedure for operating on a case-by-case basis, within the one-year statutory period.

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. This section contains provisions with regard to 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 actions in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations. Section 123(c)(2) of PURPA restates the requirements of section 123(c)(1) as they apply to Federal agencies. This distinction between Federal agencies and non-Federal agencies also applies to review and 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 with regard to the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or 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 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 has also given to the Commission that authority.

Section-by-Section Analysis

§ 292.301 Implementation by State regulatory authorities and nonregulated utilities.

Paragraph (a) of § 292.301 sets forth the obligation of each State regulatory authority to commence implementation of Subpart A 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 and opportunity for public hearing. As described in the summary of this part, 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 A, or any other action reasonably designed to implement Subpart A.

This section does not cover one provision of Subpart A which is not required to implemented by the State regulatory authority or nonregulated electric utility. This provision is § 292.103, the implementation of which is subject to § 292.302, which will be discussed below.

Subsection (b) sets forth the obligation of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart A. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart A through issuance of regulations, an undertaking to comply with Subpart A, 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 A.

§ 292.302 Implementation of reporting objectives.

The obligation to comply with § 292.103 is imposed directly on electric utilities. This is different from the rest of Subpart A where the obligation to act is imposed on the State regulatory authority or nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA to require this reporting.

Any electric utility which fails to comply with the requirements of § 292.103(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 § 292.103 will form the basis for the rates for purchases; § 292.103 is thus a critical element in the program this Commission is providing. 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 § 292.102(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 § 292.103(c), the Commission may compel its production under the Federal Power Act and other statutes which give the Commission authority to require reporting of this data.

§ 292.303 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 A other than § 292.103. This provision 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.

Paragraph (b) provides that any electric utility subject to the requirements of § 292.103(c) may apply to the Commission for a waiver from the application of such requirements. This provision is included to afford to the Commission flexibility to enforce the obligations of § 292.103(c) so that it may consider the burden which may be placed on the utility by application of this section.

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

§ 292.401 Exemptions for 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 State laws and regulations respecting the rates, or respecting the financial or organizational 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 any of these laws. An exception is made for small power production facilities using biomass. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State regulations but may not be exempted from the Federal Power Act.

Paragraph (a) sets forth those facilities 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, the Commission proposes not to exempt qualifying facilities 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]

As noted in the discussion paper, cogenerators 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 proposes that qualifying facilities not be exempted from section 202(c) of the Act.

Sections 203, 204, 205, 206, 208, 301, 302 and 304 of the Act reflect traditional rate regulation or regulation of securities of public utilities. The Commission proposes that qualifying facilities 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 proposes that any person who otherwise is requred to file a report regarding interlocking positions 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 will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§ 292.402 Exemptions for qualifying facilities from the Public Utility Holding Company Act and Certain State Laws and Regulations.

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organizations. 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 Staff discussion paper recommended 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 79 (b)(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

[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 Project—Existing Dam, Docket No. RM79-30, 44 F.R. 24095 (April 21, 1979).

qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric activities of 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 the provisions of the Public Utility Holding Company Act of 1935.

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

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 respecting the financial or organization regulation of electric utilities. The Staff discussion paper sets forth two approaches to be taken to exemption from State law. One would be to analyze the laws of each State and apply the exemptions citing specific sections of State law and regulations. The second approach discussed would be to make a broad proscription from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

All of the comments received recommended the broader approach. 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 for sales of electric energy to electric utilities, and from financial and organizational regulation of electric utilities.

Subparagraph (c)(2) provides that, upon request of a State regulatory authority a 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)(2), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

Written Comments and Public Hearings

Interested persons are invited to submit written comments on the proposed regulation to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Comments should reference Docket No. RM 79-55 on the outside of the envelope and on all documents submitted to the Commission. In order that the Commission be able to take into account as many comments as possible, the Commission requests that persons submitting comments assist in three ways. First, persons should identify specifically the section or subpart they are addressing. Second, comments should clearly state whether they involve technical, policy or legal matters. Finally, where comments urge a different approach from one presented, specific alternative language should be proposed to the extent practicable.

In addition, the preliminary Environmental Assessment prepared by Commission Staff regarding the Commission's proposed rules implementing sections 201 and 210 of PURPA is available in the Commission's Office of Public Information. As stated in the Request for Further Comment on Proposed Rulemaking Establishing Requirements and Procedures for a Determination of Qualifying Status for Small Power Production and Cogeneration issued today, the Commission is seeking comments on specific issues relating to the preliminary Environmental Assessment.

The Commission has also received many comments in response to the Staff discussion paper and the notice of proposed rulemaking in Docket No. RM79-54. All comments filed in response to those documents are being made part of the record and will be considered in the determination of the final rule in this proceeding.

Fifteen (15) copies should be submitted. All comments and related information received by the Commission by December 1, 1979, will be considered prior to the promulgation of final regulations.

In addition, the Commission will conduct public hearings in several cities at which interested persons will have the opportunity to present their views. Places, dates and times will be announced shortly.

(Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 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, Pub. L. 95-91, E.O. 12009, 42 FR 46267)

In consideration of the foregoing, it is proposed to amend Chapter I of Title 18, Code of Federal Regulations, as set forth below.

By direction of the Commission.
Kenneth F. Plumb,
Secretary.

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

PART 292—REGULATION OF SMALL POWER PRODUCTION AND COGENERATION FACILITIES UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978.

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

PART 292—REGULATION OF SMALL POWER PRODUCTION AND COGENERATION FACILITIES UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

Subpart A—Rates for Sales Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities

Sec.

* * * * *

Subpart C—Implementation

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

Authority: This part issued under the Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 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, Pub. L. 95-91, E.O. 12009, 42 FR 46267.

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

§ 292.101 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases of electric energy and capacity between qualifying cogeneration and small power production 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 purchases or sales, or terms or conditions relating to such sales, which differ from the rate or terms 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.

§ 292.102 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:* For purposes of this part:

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under § 292.208 of the Commission's regulations;

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

(3) "Sale" means the sale of electric energy or capacity 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 disruption of service to a significant number of customers or is 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 costs to the electric utility of electric energy or capacity or both which, but for the purchase from such cogenerator or small power producer, such utility would generate itself or purchase from another source.

§ 292.103 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in subparagraph (2), 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 June 30, 1982.

(b) *General Rule.* Not later than June 30, 1980, and every two years thereafter, each regulated electric utility to which this section applies shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility to which this section applies shall maintain for public inspection, the following data:

(1) The estimated avoided cost of energy on the electric utility's system for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one hundred megawatts or less for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten 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 immediately preceding year, and on an estimated cents per kilowatt-hour basis for the current calendar year and each of the next 5 years;

(2) The electric utility's plan and schedule for the addition of capacity, for purchases of firm energy and capacity, and for capacity retirements for each of the next 10 years; and

(3) The estimated costs at completion, on the basis of dollars per kilowatt, of the planned capacity additions and planned firm purchases. These costs should be expressed in terms of individual generating units and by planned firm purchases.

(c) *Special Rule.* Each electric utility (other than any electric utility to which paragraph (b) applies) shall, upon request of a qualifying facility, provide sufficient data to enable such qualifying facility to determine the electric utility's avoided costs for any period described in paragraph (b). If any such electric utility fails to provide such information or request, the qualifying facility may apply to the Commission for an order requiring that the information be provided.

§ 292.104 Electric utility obligations under this subpart.

(a) *Obligation to Purchase from Qualifying Facilities.* Except during periods identified in § 292.105(e), each electric utility shall purchase in accordance with § 292.105 any capacity or energy which is made available either directly from the qualifying facility or which is transmitted to such utility from the qualifying facility through the facilities of another electric utility.

(b) *Obligation to Sell to Qualifying Facilities.* Each electric utility shall sell to any qualifying facility energy and capacity requested by such qualifying facility in accordance with § 292.106.

(c) *Obligation to Interconnect.* Any electric utility shall make all interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligations for the cost of any such interconnection shall be determined in accordance with § 292.108.

(d) *Transmission of Purchases to Other Electric Utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase capacity or energy from such qualifying facility may transmit the energy to any other electric utility. Any electric utility to which such energy is transmitted shall purchase such energy under this subpart as if such qualifying facility were supplying energy and capacity directly to such electric utility. The cost of transmission shall be assigned to the qualifying facility pursuant to § 292.108 of these rules. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted to reflect line losses pursuant to § 292.105(d)(3).

(e) *Parallel Operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any relevant standards established pursuant to § 292.110.

§ 292.105 Rates for purchases.

(a) *Rates for Purchases.* Rates for purchases of energy and capacity from any qualifying facility:

(1) Shall be just and reasonable to the electric consumer of the electric utility and in the public interest;

(2) Shall not discriminate against qualifying cogeneration and small power production facilities; and

(3) Shall not exceed the avoided costs of such a purchase. There is a rebuttable presumption that the rate for purchases meets the requirements of this paragraph if the rate reflects the avoided costs resulting from such purchase as determined on the basis of the cost of energy and capacity set forth pursuant to § 292.103(b) or (c).

(b) *Tariffs for Purchases From Facilities of Ten Kilowatts or Less.* Each electric utility, upon request of a qualifying facility, shall establish a tariff or other method for setting forth standard rates for purchases from qualifying facilities with a design capacity of 10 kilowatts or less.

(c) *Purchases "As Available" or Pursuant to a Legally Enforceable Obligation.* A qualifying facility shall have the option either to provide energy or capacity to an electric utility—

(1) As the qualifying facility determines such energy or capacity to be available for such purchases, in which case the rates for such purchases may be based on the purchasing utility's avoided energy costs, or

(2) Pursuant to a legally enforceable obligation for the delivery of energy or capacity at a future date, in which case the rates for purchases may be based on estimates of future avoided costs of energy or capacity.

(d) *Factors Affecting Rates For Purchases.* In implementing the provisions of this subpart, a State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility shall consider with regard to rates for purchases the following factors:

(1) The availability of capacity from a qualifying facility during system daily and seasonal peak periods, including—

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

(ii) The qualifying facility's ability and willingness to provide energy or capacity during system emergencies;

(iii) The length, frequency, and scheduling flexibility of scheduled maintenance by the qualifying facility;

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

(v) The length of any contract term between the electric utility and the qualifying facility and its termination notice requirements or the length of any legally enforceable obligation to provide energy or capacity undertaken by the qualifying facility;

(2) The relationship of energy or capacity from a qualifying facility to an electric utility's capacity and energy needs as expressed in § 292.103, including:

(i) The ability of the electric utility to reduce or avoid costs, including the deferral of capacity additions, as a result of the availability individually or in the aggregate from qualifying facilities; and

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

(3) 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 or purchased an equivalent amount of electric energy.

(e) *Periods During Which Purchases Not Required.* An electric utility will not be required to purchase electric energy and capacity during any period identified by the State regulatory authority having jurisdiction over the rates of such utility, or the nonregulated electric utility, during which purchases from qualifying facilities might result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated or purchased an equivalent amount of electric energy.

§ 292.106 Rates for sales.

(a) *General Rules.* (1) Rates for sales shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for sales shall be just and reasonable and in the public interest.

(b) Each electric utility shall provide electric 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 costs of interconnection shall be assigned pursuant to § 292.108 of this part.

(c) *Additional Services to be Provided by Qualifying Facilities.* Each electric utility shall provide to any qualifying facility the following types of service, even if such types of service are not provided to other retail customers:

(1) Supplementary power;

(2) Back-up power;

(3) Interruptible power; and

(4) Maintenance power.

(d) *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;

(2) 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 will occur during the system peak; and

(3) Shall take into account the extent to which a qualifying facility has coordinated periods of scheduled maintenance with such electric utility.

§ 292.107 Simultaneous purchase and sale.

A qualifying facility shall be permitted to receive rates established pursuant to § 292.105(a) for the electric energy and capacity generated by the facility, while simultaneously buying energy and capacity from such utility for use in the facility at rates established in accordance with § 292.106(a), to the extent that such purchases are produced by capacity the construction of which was commenced after the date of issuance of this part.

§ 292.108 Costs of interconnection.

(a) *Definition.* For purposes of this subpart, "interconnection costs" means the costs of connection, switching, metering, transmission, safety provisions and other costs incurred by the utility reasonably resulting from interconnected operation between an electric utility and a qualifying facility.

(b) *Reimbursement for Interconnection Costs for Purchases.* Each qualifying facility must reimburse any electric utility which purchases capacity or energy from such qualifying facility for any interconnection costs. These costs are limited to those costs which the purchasing utility would incur if it did not make such purchases but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy from other sources.

(c) *Reimbursement for Interconnection Costs for Sales.* Each qualifying facility must reimburse any electric utility which sells capacity or energy to such qualifying facility for any interconnection costs. The apportionment of interconnection costs between such qualifying facility and electric utility under this paragraph shall not discriminate against any qualifying facility in comparison to any other customers served by the electric utility.

§ 292.109 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 provided by agreement between such qualifying facility and electric utility or to the extent 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.

§ 292.110 Standards for operating reliability.

Any qualifying facility may be subject to reasonable standards to ensure system safety and reliability in interconnected operations. Such standards may be recommended by any electric utility, or by any other person. Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or any nonregulated electric utility may establish such standards as it determines necessary to carry out the purposes of this section. Such standards must be accompanied by a statement setting forth the need for such standards on the basis of system safety and reliability requirements.

* * * * *

Subpart C—Implementation

§ 292.301 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 implementation of Subpart A (other than § 292.103 thereof). Such implementation may consist of the issuance of regulations; an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart A, or any other action reasonably designed to implement such subpart (other than § 292.103 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 A (other than § 292.103 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart A, or any other action reasonably designed to implement such subpart (other than § 292.103 thereof).

(c) *Reporting Requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonregulated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart A (other than § 292.103 thereof).

§ 292.302 Implementation of reporting objectives.

Any electric utility which fails to comply with the requirements of § 292.103(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.

§ 292.303 Waivers.

(a) *State regulatory authority and non-regulated utility waivers.* Any State regulatory authority or non-regulated electric utility may apply for a waiver from the application of any of the requirements of Subpart A (other than § 292.103 thereof).

(b) *Electric utility waiver.* Any electric utility may apply for a waiver from the application of any of the requirements of § 292.103(c).

(c) *Commission action.* The Commission will grant such a waiver only if an applicant under paragraph (a) or (b) demonstrates that compliance with the requirements of Subpart A or § 292.103, as the case may be, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

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

§ 292.401 Exemptions for 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) Section 202(c);

(3) Section 305(c); and

(4) Any necessary enforcement provisions of Part III with regard to the sections listed in (1), (2) and (3).

§ 292.402 Exemptions for qualifying facilities from the Public Utility Holding Company Act and certain State laws and regulations.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.401(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.* Any qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 79(b)(3) of the Public Utility Holding Company Act of 1935.

(c) *Exemption from Certain State Laws and Regulations.*

(1) Any qualifying facility shall be exempted from State laws and regulations respecting:

(i) The rates for sales of electric energy by qualifying cogeneration and small power production facilities to electric utilities; and

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

(2) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider any limitation of the application of subparagraph (1).

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

[FR Doc. 79–32819 Filed 10–23–79; 8:45 am]

BILLING CODE 6450-01-M

---

18 CFR Part 292

[Docket No. RM79-54]

Small Power Production and Cogeneration—Qualifying Status; Request for Further Comments on Proposed Rulemaking

October 19, 1979.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Request for Further Comments on Proposed Rulemaking.

SUMMARY: The proposed rules set forth the procedure under which small power production facilities and cogeneration facilities may be certified as qualifying facilities pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules are being renoticed so that the Commission may elicit comment on the preliminary Environmental Assessment of the combined environmental effects of these rules and its companion rulemaking,