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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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| In re: Petition of Florida Power Corporation for Determination that its plan for curtailing purchases from Qualifying Facilities in minimum load conditions is consistent with Rule 25-17.086, F.A.C. | ) ) ) ) ) ) ) | DOCKET NO. 941101-EQ<br><br>FILED: April 10, 1995 |

ORIGINAL FILE COPY

DIRECT TESTIMONY AND EXHIBITS

OF

ROY J. SHANKER, PH.D.

ON BEHALF OF

ORLANDO COGEN LIMITED, L.P.

AND

PASCO COGEN, LTD.


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**DOCKET NO. 941101-EQ**

**INTRODUCTION**

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Roy Shanker. My business address is 9113 Burning Tree Road, Bethesda, Maryland 20817.

Q. **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am self employed as a consultant in the natural resources area, with the majority of my practice being in the electric and natural gas fields, particularly in the areas of electric utility generation planning and implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), 16 U.S.C. § 824a (1985), as it applies to qualifying facilities ("QFs").

Q. **FOR WHOM DO YOU APPEAR IN THIS PROCEEDING?**

A. I am appearing in this proceeding on behalf of Orlando Cogen Limited, L.P. ("OCL") and Pasco Cogen, Ltd. ("Pasco"), each of which executed virtually identical negotiated power purchase contracts with Florida Power Corporation ("FPC"). These and six other virtually identical power purchase contracts (collectively, the "Negotiated Contracts") were entered into pursuant to a RFP process initiated by FPC in January, 1991, and approved by the Florida Public Service Commission (the "Commission") in Order No. 24734 on July 1, 1991. I will refer collectively to OCL, Pasco and the other six QFs which entered into Negotiated Contracts with FPC as the "Cogens."

Q. **PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.**

A. I have been involved in work related to natural resource issues since 1973, and specifically in work related to cogeneration facilities and their development since 1976. Since that time, I have worked for several state energy offices in developing cogeneration development plans, and have been involved in contract negotiations for numerous generation facilities. I have also worked for several state regulatory commissions. Finally, on behalf of electric utilities, industrial concerns, project financing interests and project developers, I have participated in general regulatory proceedings and related contract negotiations for over 260 engagements, in over 20 states for projects representing over 7,[illegible]00 MW of generation.

Representative clients have included: New England Electric System; Boston Edison Company; Commonwealth Electric Co.; Puerto Rico Electric Power Authority, Reedy Creek Utilities; Washington Gas Light Co.; Air Products and Chemicals, Inc.; Anheuser-Busch Companies, Inc.; The Boeing Company; International Business Machines; BASF Corporation; Stone Container Corporation; Westvaco Corporation; Chesapeake Corporation; Virginia Fibre Corp.; Merck & Co., Inc.; Cargill Inc.; Georgia-Pacific Corporation; Weyerhauser Company; International Paper Company; American Paper Institute; Finch Pryun; Hammermill Papers Business; Longview Fibre Company; Boise Cascade; Crown Zellerbach International Inc.; James River Corporation; Occidental Chemicals Corporation; the United States Army, Air Force, Navy, and Government Services Administration; Metropolitan Dade County, Florida; Broome and Duchess Counties, New York; New York City; Montgomery County, Maryland; Montgomery County, Pennsylvania; Butler County, Pennsylvania; Cogen Technologies; U.S. Generating Company; Enron Corp.; Mission Energy Company; CRSS Capital; Tenneco; Sonat Inc.; Cogentrix Inc.; LG&E Power Systems; AES; Sithe Energy; Transco Energy Ventures; Montenay; Wheelabrator; Panda Energy; Diamond Energy; Energy Investors Fund; and Westmoreland Energy.

I have also worked on a number of engagements related to electric utility system planning requirements. For example, I conducted a number of studies for the United States Department of Energy that reviewed the alternative system planning models available, and selected several for further use in planning and technology development evaluations. I have also directed a private firm in the development of a proprietary production costing model similar to PROMOD which has been used in studies for regulators, utilities and industrial customers. Lastly, I have been involved in state administrative proceedings related to QFs, production costing modeling and system expansion planning before the District of Columbia, Florida, Maryland, New Hampshire, New Jersey, New York, Oklahoma, Virginia and Vermont commissions, the Bonneville Power Administration and the Federal Energy Regulatory Commission ("FERC").

A summary of my educational background and professional experience is attached as Exhibit No. ___ (RJS-1).

Q. **PLEASE DESCRIBE YOUR EXPERIENCE WITH RESPECT TO THE TECHNICAL INTERPRETATION OF REGULATIONS IMPLEMENTING PURPA.**

A. As can be seen in Exhibit No. ___ (RJS-1), I have been involved in numerous state regulatory proceedings related to PURPA over the past 13 years, including eight QF-related proceedings before this Commission. My work in this area has included the development of draft regulations implementing PURPA for the Arkansas Public Service Commission, as well as numerous engagements related to the proper technical definition and measurement of avoided costs as defined in the FERC's regulations implementing PURPA. One such engagement involved working with a task force of the Virginia State Corporation Commission on the development of technical procedures for measuring avoided costs using both optimal expansion models and the PROMOD production costing model. I have also worked for several electric utilities to develop the correct technical and modelling procedures to implement PURPA. In addition, I have served as an arbitrator with respect to disputes over the measurement of avoided costs under PURPA. Each of these engagements has required that I be familiar with the FERC's regulations implementing PURPA and/or the modelling applications implementing various costing methodologies in accordance with PURPA.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I have been engaged to evaluate whether FPC's curtailment plan for "minimum load conditions" (the "Curtailment Plan") conforms with the Negotiated Contracts and PURPA and the regulations implemented thereunder. More specifically, I have been asked to determine whether the

Curtailment Plan and the actual curtailments announced to date comport with (i) section 292.304(f) of the FERC's regulations implementing PURPA, 18 C.F.R. § 292.304(f) (1994), and (ii) Commission rule 25-17.086, Florida Administrative Code, implementing PURPA.

**Q. WHAT IS THE SIGNIFICANCE OF SECTION 292.304(f) OF THE FERC'S REGULATIONS?**

A. Section 292.304(f) is one of only two narrow exceptions (the other being section 292.307 for "system emergencies") to the Congressionally mandated obligation of utilities to purchase QF power which the FERC recognized in its regulations implementing PURPA. Specifically, section 292.304(f)(1) provides, in relevant part:

> Any electric utility . . . 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.

18 C.F.R. § 292.304(f)(1) (1994).

**Q. HOW DOES COMMISSION RULE 25-17.086 RELATE TO SECTION**

**292.304(f) OF THE FERC'S REGULATIONS?**

A. Rule 25-17.086 was adopted to implement section 292.304(f) and, as such, must give full effect to the FERC's regulation. Therefore, in order for the Curtailment Plan to comply with rule 25-17.086, it must ultimately comply with section 292.304(f) of the FERC's regulations. FPC concedes as much by its numerous references to and discussions of section 292.304(f) in this proceeding. See, e.g., FPC's Petition, at 4-5 (Oct. 13, 1994); FPC's Generation Curtailment Plan For Minimum Load Conditions, at 17-19 (Exhibit No. __ (RDD-1)); Dolan Direct Testimony, at 12-16.

Q. **WITH RESPECT TO THE OTHER EXCEPTION THAT YOU MENTIONED EARLIER, DO YOU BELIEVE THAT FPC CAN DISCONTINUE QF PURCHASES DURING THE ALLEGED LIGHT LOADING PERIODS BY CLAIMING THE EXISTENCE OF A "SYSTEM EMERGENCY" AS MR. DOLAN SUGGESTS?**

A. No. FPC has failed to provide any evidence which would support Mr. Dolan's assertion. Indeed, the only information presented by FPC in this proceeding has dealt with the economic consequences to FPC of responding to light loading in terms of curtailing QFs or its own units. FPC has not provided any evidence to support the existence of an "operational" emergency as contemplated by section 292.307 of the FERC's regulations. Moreover, the very fact that FPC is and has been aware of its "minimum load conditions" and could, through one or more actions, effectively respond to such "minimum load conditions" demonstrates that it is not experiencing a system emergency. FPC simply does not wish to take one of several actions available to it to respond to its "minimum load conditions," because it finds such actions economically unpalatable. This is not a "system emergency."

Q. **HAVE YOU COMPLETED YOUR EVALUATION OF FPC'S CURTAILMENT PLAN?**

A. Yes.

Q. **PLEASE SUMMARIZE YOUR CONCLUSIONS.**

A. FPC's Curtailment Plan is inconsistent with PURPA and the regulations implemented thereunder, as is evident from careful consideration of the technical and operational considerations addressed in the legislative history of PURPA and the documents discussing the formulation and adoption of the FERC's regulations implementing PURPA. The clear intent of PURPA was to prefer and to promote cogeneration through the creation of a mandatory market for QF power and an obligation of utilities to purchase from QFs. Consistent with this overriding goal to promote QFs, the FERC recognized only two narrow exceptions to the utilities' mandatory purchase obligation. Section 292.304(f) of the FERC's regulations is one of these exceptions.

Section 292.304(f) excuses utilities from their obligation to purchase QF power only under extraordinary "operational circumstances" for which they cannot plan and to which they cannot otherwise respond. In order to curtail QF purchases under section 292.304(f), utilities must demonstrate (i) that they will experience "operational circumstances" (ii) which give rise to "negative avoided costs" (i.e., the utilities' costs to generate during such "operational circumstances" with QFs exceeds their costs to generate without QFs) and (iii) that they have taken available measures to mitigate the very circumstances giving rise to the need to curtail. Absent such a showing, section 292.304(f) does not, and was not intended to, excuse utilities from their Congressionally mandated purchase obligation. FPC has not satisfied these requirements and, therefore, the Curtailment Plan must fail under both section 292.304(f) of the FERC's regulations and rule 25-17.086 of the Commission's rules.

First, FPC has not demonstrated that it has or will encounter the very limited kind of "operational circumstances" that the FERC contemplated when it promulgated section 292.304(f) of its regulations.

Rather than the result of extraordinary "operational circumstances," FPC's alleged "minimum load conditions" have been the result of conscious, long term planning as well as short term purchase/sale and unit commitment decisions which are fully within its control and which can be rectified without recourse to involuntary curtailment of mandatory QF purchases. As such, they are outside the purview of section 292.304(f) and rule 25-17.086.

What FPC is attempting to do is shift the cost of excess generation during minimum load conditions -- excess generation which is the result of FPC's own deliberate decisions -- to the Cogens. Thus, the Curtailment Plan ultimately is not directed at lessening operational risks beyond FPC's control, but instead is designed to shift to the Cogens the economic risks FPC chose to accept in its contracts with them. The Commission should not permit FPC to achieve, through a distortion of its curtailment regulation, that which it otherwise did not bargain for in the contracts it negotiated with the Cogens -- the ability to control the output of firm non-dispatchable QF resources.

Second, before FPC can even begin involuntary curtailment of QF purchases, FPC must, consistent with PURPA, take available measures to mitigate the very conditions that may give rise to the need for curtailment. This FPC has not done. Thus, even if FPC could demonstrate a legitimate "operational circumstance" of the kind contemplated by section 292.304(f) of the FERC's regulations, FPC cannot justify either its Curtailment Plan or any of the curtailments announced to date, because it has not undertaken available measures to mitigate the occurrence of excess generation.

There are at least four types of mitigation efforts that are available to FPC which it has not taken, but which it must take in order to be eligible to curtail QF purchases. First, FPC has not established a policy of interrupting its purchases from the Southern Companies or other utilities prior to curtailing purchases from QFs, as it must do to comply with the requirements of PURPA. Second, FPC has failed to take available measures that would enhance its ability to reduce its own generation or to reconfigure the commitment of its own units so as to mitigate the potential for excess generation. Third, FPC has failed to aggressively pursue off-system sales of its excess generation both on the Florida Energy Broker (the "Energy Broker") and elsewhere at prices that would be favorable to buyers, but nonetheless preclude FPC from experiencing "negative avoided costs." Fourth, FPC has failed to modify its retail pricing during periods of excess generation so as to encourage large users to move more of their consumption to these periods.

Finally, even if one were to assume (for the sake of argument) that FPC had taken all available steps to avoid an imbalance between generation and load, FPC's method for determining the existence of "negative avoided costs" is flawed. First, FPC fails to base its analysis of avoided costs (i.e., the difference between the costs FPC would incur with and without the Cogen purchases) on its system as it should, consistent with PURPA, be operated rather than how it actually is operated. Second, FPC uses an inappropriate time frame for its avoided costs analysis and incorporates costs that do not belong in its calculations. In these ways, FPC skews the results and ensures that its prediction of "negative avoided costs" is self-fulfilling.

Q. **HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?**

A. The remainder of my testimony is divided into two major sections. In the first section, I discuss the legislative history of PURPA and the documents considering the formulation and adoption of the FERC's regulations implementing PURPA in light of the technical and operational considerations that PURPA and the regulations were designed to address. In particular, I focus on these documents as they relate to section

292.304(f) of the FERC's regulations. In the second section, I discuss my conclusion that the Curtailment Plan is not consistent with PURPA and the regulations implemented thereunder. Specifically, I discuss my conclusions that FPC has failed (i) to establish the type of "operational circumstances" contemplated by the FERC in section 292.304(f) of its regulations, (ii) to undertake available measures to mitigate the potential for excess generation on its system, and (iii) to correctly measure "negative avoided costs."

## SECTION I

Q. **WHY IS A REVIEW OF THE TECHNICAL AND OPERATIONAL CONSIDERATIONS ADDRESSED IN THE LEGISLATIVE HISTORY OF PURPA AND THE DOCUMENTS DISCUSSING THE FORMULATION AND ADOPTION OF THE FERC'S REGULATIONS IMPLEMENTING PURPA RELEVANT TO THESE PROCEEDINGS?**

A. This review is necessary because consideration of the legislative history of PURPA and these documents in light of the technical and operational settings to which they were being applied is essential to an understanding of the proper context in which the Commission should reach its decision in this proceeding. By way of example, the Commission should recall its recent development and consideration of the PURPA-related jurisdictional issues in Docket Nos. 940771-EQ and 940357-EG. In those dockets, the Commission's labors ultimately took it "beneath the surface" to a detailed analysis of underlying legal principles that led it to conclude that the utility was misinterpreting PURPA.

The Commission is confronted with an analogous situation here. I can appreciate that, on its face, FPC's proposition may have some initial appeal. However, as one digs deeper into the subject matter, it is apparent that the FERC's regulations upon which FPC ultimately relies for its authority to curtail have an instructive history that discloses a very limited purpose and intent -- one which FPC's Curtailment Plan does not meet.

Q. **WHAT LEGISLATIVE HISTORY ARE YOU REFERRING TO?**

A. In particular, I am referring to the House Conference Report (the "Conference Report"), H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. (1977), which discusses PURPA and the objectives which Congress intended it to achieve, a copy of which is attached as Exhibit No. __ (RJS-2). As is evident from the Conference Report, PURPA was designed to promote cogeneration. Id. at 97-99 (Exhibit No. __ (RJS-2)). To that end, PURPA was intended to remove the impediments to cogeneration, including burdensome federal and state regulation. Id. at 97-98 (Exhibit No. __ (RJS-2)). Moreover, because Congress viewed traditional utilities' reluctance to purchase power from non-traditional facilities as a powerful obstacle to the development of cogenerators, PURPA obligated utilities to purchase power from QFs. See 123 Cong. Rec. 32,403 (1977) (remarks of Sen. Durkin); id. at 32,437 (remarks of Sen. Haskell); id. at 32,419 (remarks of Sen. Hart), copies of which are attached as Exhibit No. __ (RJS-3). In addition, Congress required utilities to provide necessary services to QFs at non-discriminatory rates. Conference Report, at 98 (Exhibit No. __ (RJS-2)). All of these requirements evidence Congress' goal to promote cogeneration by removing the impediments to QF power sales.

Q. **PLEASE IDENTIFY THE DOCUMENTS WHICH DISCUSS THE FORMULATION AND ADOPTION OF THE FERC'S REGULATIONS IMPLEMENTING PURPA TO WHICH YOU EARLIER REFERRED.**

A. In order to understand the full context in which section 292.304(f) of the FERC's regulations implementing PURPA was developed, I have reviewed the technical and operational considerations addressed in (i) the notice of proposed rulemaking prescribing proposed regulations implementing PURPA (the "NOPR"), Small Power Production and Cogeneration-Rates and Exemptions, 44 Fed. Reg. 61,190 (1979), a copy of which is attached as Exhibit No. __ (RJS-4), (ii) the summary of comments put forward to the FERC regarding the proposed regulations (the "Summary of Comments"), FERC, Office of General Counsel, Summary of Comments on Cogeneration and Small Power Production in Docket No. RM 79-55 (1980), a copy of which is attached as Exhibit No. __ (RJS-5), (iii) the final rule and full preamble to the PURPA regulations (collectively, the "Preamble"), Order No. 69, Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12,214 (1980), a copy of which is attached as Exhibit No. __ (RJS-6), and (iv) all of the PURPA regulations, 18 C.F.R. §§ 292.101-.602 (1994).

**Q. PLEASE DESCRIBE HOW YOU TRACED IN THESE DOCUMENTS THE TECHNICAL AND OPERATIONAL CONCERNS THAT THE FINAL REGULATION WAS INTENDED TO ADDRESS.**

A. I began my analysis by examining the history of the FERC's regulations implementing PURPA and how that history manifests itself in the final regulations adopted by the FERC. One of the first discussions of curtailment appears in the NOPR in which the FERC prescribed proposed regulations implementing PURPA. There the FERC provided that utilities would be excused from their Congressionally mandated obligation to purchase QF power only under the extraordinary circumstances of a system emergency or a period during which QF purchases might result in net increased operating costs to the utility. NOPR, at 61,193, 61,204 (Exhibit No. __ (RJS-4)).

This last exception excused utilities from their obligation to purchase QF power during periods when "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." Id. at 61,204 (Exhibit No. __ (RJS-4)). It is clear from the NOPR's discussion of this proposed "curtailment" regulation, that the FERC was concerned only with changes in utility costs due to unexpected, short term operational impacts, and not changes in utility revenues.

In comments responding to the NOPR, the FERC noted a recurrent concern that the proposed "curtailment" regulation might be abused by or deemed an escape provision for utilities to circumvent their primary obligation to purchase power from QFs. Summary of Comments, at 89-94 (Exhibit No. __ (RJS-5)). Accordingly, these commenters urged the FERC to narrowly restrict the scope and application of the exception. Id. (Exhibit No. __ (RJS-5)). The New York Public Service Commission further suggested that the proposed "curtailment" regulation be modified to make clear that it could not be used by a utility to avoid existing contractual obligations to purchase power. Id. at 94 (Exhibit No. __ (RJS-5)). This same concern was again apparent at the public hearings which followed, as several commenters expressed their concern that the proposed regulation be clarified so as to assure that it could not be used by the utilities to escape their contractual purchase obligations. See Public Hearings on Docket Nos. RM79-54 and RM79-55, Implementing Sections 201 and 210 of PURPA, statement of Maura O'Neil, Consumer Action Now, Nov. 28, 1979, New York, New York; statement of John J. Plunkett, Staff Economist, Institute for Local Self-Reliance, Dec. 5, 1979, Washington, D.C., copies of which are attached as Exhibit No. __ (RJS-7).

**Q. DID YOUR REVIEW REVEAL WHETHER THE FINAL REGULATION WAS REVISED TO ADDRESS THE TYPE OF CONCERNS EXPRESSED BY THESE COMMENTERS?**

A. Yes. In the final regulation, the proposed "curtailment" regulation was modified to put the burden on the utility first to notify any affected QFs prior to curtailment and second to substantiate its claim for curtailment as required by its state regulatory authority. Preamble, at 12,228 (Exhibit No. _ (RJS-6)). Reflecting the FERC's concern for QFs, the final regulation further provided that, absent such prior notice and substantiation, the utility must reimburse the affected QFs for energy or capacity supplied as if such light loading period had not occurred. Id. (Exhibit No. __ (RJS-6)).

The Preamble to the final regulations states that these modifications were adopted in direct response to the concerns of the commenters discussed above:

> Many of the comments received reflected a suspicion that electric utilities would abuse this paragraph to circumvent their obligation to purchase from qualifying facilities. In order to minimize that possibility, the Commission has revised this paragraph to provide that any electric utility which seeks to cease purchasing from qualifying facilities must notify each affected qualifying facility prior to the occurrence of such a period, in time for the qualifying facility to cease delivery of energy or capacity to the electric utility.

Id. at 12,227-28 (Exhibit No. __ (RJS-6)). The FERC's overriding concern in adopting these revisions to the proposed "curtailment" regulation was to protect QFs, in general, and the primacy of the utilities' QF purchase obligation, in particular.

**Q. HOW ELSE DID THE FERC REVISE THE PROPOSED "CURTAILMENT" REGULATION IN ORDER TO AVOID ABUSE?**

A. In the final regulation, the FERC limited those circumstances under which a curtailment would be permissible. First, the FERC eliminated the cost of purchased power from the utility's calculation of "operating costs" that potentially could justify curtailment. As a result, the FERC limited the calculation to true "operating costs" only.

Second, the FERC clarified in the final regulation that increased "operating costs" alone are not sufficient to justify curtailments; they also must be "due to operational circumstances." This term was not defined in the final regulations; however, the FERC did offer a characterization of "operational circumstances" in the Preamble:

> 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.

Id. at 12,227 (Exhibit No. __ (RJS-6)).

As is evident in the description of "operational circumstances" quoted above, the final "curtailment" regulation clearly focused on preventing increases in the utility's costs caused by the inability of one of its cheap base load units to return to full service after a reduction in its output forced by a low load period. Thus, one of the factors relevant to determining the existence of "operational circumstances" must be an increase in costs due to the purchase of QF power during low load periods versus the level of costs the utility would incur in the absence of QF power purchases during such periods.

As with the proposed "curtailment" regulation, the circumstances the final regulation was intended to address were expected to be short term and unexpected in nature. In its description of "operational circumstances," it is clear that the FERC contemplated circumstances for which the utility could not plan and to which the utility could not otherwise respond. This is entirely consistent with the FERC's general view of the primacy of the QF purchase obligation and the very limited nature of the curtailment exception.

Q. **WERE THERE OTHER CLARIFICATIONS TO THE FINAL REGULATION WHICH ADDRESSED CONCERNS ABOUT UTILITY ABUSE WHICH IMPACTED YOUR DETERMINATION WITH REGARD TO THE PROPER TECHNICAL IDENTIFICATION OF OPERATIONAL CIRCUMSTANCES?**

A. Yes. The Preamble also clearly stated that the final regulation was not intended to override contractual or other obligations of the utility to purchase from a QF.

> 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.

*Id.* at 12,228 (Exhibit No. __ (RJS-6)). Thus, the FERC recognized that the relative costs of QF purchases would vary in comparison to utility costs as the utility's costs rise or fall, but that those expected variations were or could be taken into account in the overall avoided cost rate to be paid for QF power. By comparison, "operational circumstances" justifying curtailment occur during short term, unexpected periods of increased operating costs.

Q. **WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THESE DOCUMENTS REGARDING THE TECHNICAL AND OPERATIONAL CONCERNS WHICH THE FINAL REGULATION WAS DESIGNED TO ADDRESS?**

A. I believe that the FERC's regulations implementing PURPA faithfully reflect the Congressional mandate favoring cogeneration through the creation of a mandatory market for QF power and an obligation of utilities to purchase from QFs. This obligation to purchase is one of the cornerstones of PURPA and as such, is, with only two exceptions, treated as sacrosanct under the FERC's regulations. Section 292.304(f), which the Commission has implemented in its rule 25-17.086, is one of the these limited exceptions.

As is evident from the previous review, section 292.304(f) was not intended to override the contractual obligations of a utility to purchase from a QF, but instead was intended to respond to a short term, extraordinary occurrence during which a utility would, absent curtailment, have to turn off its own base load generation due to QF purchases, resulting in net increased operating costs (i.e., "negative avoided costs"). Section 292.304(f) excuses a utility from its obligation to purchase QF power only in the limited, short term context of extraordinary "operational circumstances" which give rise to "negative avoided costs." Absent such a showing, section 292.304(f) does not relieve a utility of its obligation to purchase QF power. FPC has not made such a showing and, therefore, should not be permitted to curtail its purchases of QF power pursuant to rule 25-17.086.

## SECTION II

Q. **WHAT ARE THE REQUIREMENTS OF SECTION 292.304(f) OF THE FERC'S REGULATIONS THAT THE COMMISSION MUST IMPLEMENT THROUGH RULE 25-17.086?**

A. In order to be excused under section 292.304(f) from its primary obligation to purchase QF power, a utility must demonstrate (i) that "operational circumstances" within the meaning of section 292.304(f) exist which would cause the utility to incur "negative avoided costs" if it purchased QF power, (ii) that it has exhausted available measures to mitigate the circumstances giving rise to the need to curtail QF power purchases, and (iii) that it has properly measured and established the existence of "negative avoided costs" associated with the QF purchases.

**Q. WITH RESPECT TO THE CURTAILMENT PLAN, HAS FPC SATISFIED THESE REQUIREMENTS?**

A. No. As I discuss below, FPC has failed to demonstrate any of these requirements.

**SECTION A -- THE FIRST REQUIREMENT**

**Q. HAS FPC IDENTIFIED THE KIND OF "OPERATIONAL CIRCUMSTANCES" WHICH THE FERC CONTEMPLATED IN SECTION 292.304(f) AND WHICH WOULD JUSTIFY CURTAILMENT UNDER RULE 25-17.086?**

A. No. FPC's "minimum load conditions" do not represent the kind of "operational circumstances" the FERC contemplated when it adopted section 292.304(f). As discussed above, section 292.304(f) addresses "operational circumstances" in the very limited context of short term, unexpected and extraordinary circumstances where, absent curtailment, a utility would be compelled to incur increased operating costs as a result of having to turn off its own base load generation due to purchases from QFs. Similarly, FPC has acknowledged that rule 25-17.086 of the Commission's rules has a "limited application . . . to extreme conditions only." FPC's Cogeneration Review: An Assessment of Florida Power's Qualifying Facility

"Cogeneration" Purchases, at 46 (Dec. 1993) (hereinafter "Cogeneration Review") (Exhibit No. __ (RJS-8)). FPC's alleged "minimum load conditions" are neither unexpected, extraordinary nor extreme and therefore do not justify curtailment under section 292.304(f) or rule 25-17.086. Moreover, the contractual relationship between the QFs and FPC was defined in the context of long term negotiated contracts. There was nothing short term or unexpected about FPC's purchase obligations under the Negotiated Contracts.

Of specific importance is the fact that the Negotiated Contracts establish the various Cogens as firm must run (must take) suppliers to FPC. These contracts set the compensation and operational obligations of the Cogens based on the explicit recognition that they would be supplying firm generation resources and associated benefits (e.g., the avoidance of utility construction) over terms as long as 30 years. As discussed above, section 292.304(f) was explicitly not intended to interfere with the relative quid pro quo of compensation and performance established in such contracts. To the extent that these QF purchase obligations may be at odds with FPC's "minimum load conditions", it must be recognized that this is the result of, among other things, a conscious planning decision to pursue non-dispatchable QF contracts, rather than more expensive, dispatchable contracts which would have provided FPC with control over the output of QF generation.

**Q. WHAT DO YOU MEAN WHEN YOU STATE THAT THE "MINIMUM LOAD CONDITIONS" ARE THE RESULT OF CONSCIOUS PLANNING BY FPC?**

A. I think it is very important for the Commission to recognize that FPC made a conscious choice to negotiate must run versus dispatchable contracts with the Cogens. At the time that it was developing these contractual arrangements, FPC conducted a number of analyses and debated internally whether it should include dispatch provisions in its contracts. See FPC internal correspondence attached as Exhibit No. __ (RJS-9).

At the time it made the decision not to pursue dispatchable contracts, FPC weighed whether the expected benefits from being able to dispatch a QF (e.g., control the level of generation and thereby reduce output during low load conditions) were sufficient to justify the increased payments that it would have had to make to obtain dispatchability rights in the contract. See id In exchange for dispatch rights, FPC would have had to offer compensation for the associated start-up and cycling costs for the avoided unit, as well as the increased capacity payments that would be associated with the design of a more expensive avoided unit that would be better able to vary its output in response to fluctuating loads. FPC apparently concluded that it would not need the dispatch rights from QFs and/or that it did not want to incur the costs of obtaining those rights from QFs. Having declined to obtain dispatch rights and to pay the costs associated with such rights, FPC should not now be allowed to obtain those benefits at no cost under the pretext of curtailment.

Yet, that is precisely the result FPC seeks to achieve in this proceeding. FPC's motivations are clearly revealed in its own Cogeneration Review and its "Cogeneration and Purchased Power Strategic Proposal", dated March 18, 1994 ("Strategic Proposal"), portions of which are attached as Exhibit No. __ (RJS-10). In these documents, FPC sets out its strategy to use 25-17.086 to obtain <u>at no cost</u> contract rights which it recognizes it does not have.

First, FPC acknowledges that, other than certain dispatch and scheduling rights FPC recently negotiated, its QF power purchase contracts are not dispatchable. Strategic Proposal, at 18 (Exhibit No. __ (RJS-10). However, FPC also recognizes that although it needs the QF capacity for meeting demand now, and perhaps even more so in the future (<u>see</u> Cogeneration Review, at 45 (Exhibit No. __ (RJS-8)), the current "energy needs from QFs is variable with load, maintenance outages, and fuel costs." Id. at 46 (Exhibit No. __ (RJS-8)). FPC further observes that "[i]deally, FPC would schedule, dispatch, and operate the various cogenerator units in the same manner its other plants are operated/dispatched." Id. (Exhibit No. __ (RJS-8)).

Second, FPC acknowledges that rule 25-17.086 has a "limited application" and was intended to address "extreme conditions only." Id. (Exhibit No. __ (RJS-8)). FPC further acknowledges that unilateral implementation of involuntary curtailments would "undoubtedly result in immediate cogenerator litigation" and that "[i]t has not been determined if FPC waived certain [curtailment] rights by signing contracts with the various parties." Id. (Exhibit No. __ (RJS-8)).

These documents reveal that FPC is knowingly using the Commission's curtailment rule to circumvent its contractual obligation to purchase power and to obtain contract rights it was unwilling to pay for during initial contract negotiations. Neither rule 25-17.086 of the Commission's rules nor section 292.304(f) of the FERC's regulations permit such abuse. As the Preamble to the FERC's regulations explicitly states, section 292.304(f) was not intended to "override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility." Preamble, at 12,228 (Exhibit No. (RJS-6)).

At the time it entered into the Negotiated Contracts, FPC committed itself to a long term bargain with the Cogens to be non-dispatchable based on the trade off of the value of dispatch versus the additional costs to obtain such rights. As part of this bargain, FPC explicitly assumed the downside costs of not having the capability to dispatch the Cogens. Presumably, FPC's decision was based upon the long term benefits it foresaw over the entire course of the Negotiated Contracts from lower payments versus the potential costs associated with not being able to dispatch the Cogens. Indeed, most of the Negotiated Contracts have terms of at least 20 years, and even FPC concedes that its alleged "minimum load" problem should be resolved within a few years. It is altogether inappropriate for FPC to now focus on those periods where it may be incurring some of the <u>anticipated costs it bargained for</u>, ignore all of the associated benefits that it has already received and will receive in the future, and use this as a justification for curtailment.

**SECTION B -- THE SECOND REQUIREMENT**

**Q. WOULD YOU EXPLAIN WHAT YOU MEAN WHEN YOU STATE THAT FPC MUST TAKE AVAILABLE MEASURES TO MITIGATE THE VERY**

**CIRCUMSTANCES GIVING RISE TO THE NEED TO CURTAIL QF POWER?**

A. Yes. Implicit in section 292.304(f) is the requirement that a utility seeking to be excused from its obligation to purchase QF power must first take available measures to mitigate the circumstances giving rise to the need for such curtailment. This requirement follows from the overall goal of PURPA to promote QFs, and from the more limited goal of PURPA to create a mandatory market for QF power by obligating utilities to purchase from QFs. Without such a requirement, section 292.304(f) could effectively frustrate both of these goals by allowing utilities to circumvent their mandatory purchase obligation.

It is clear that under both PURPA and the Negotiated Contracts, FPC has a direct obligation to purchase the firm power being sold by the Cogens. With respect to PURPA, it would make a mockery of section 292.304(f) of the FERC's regulations, if all FPC had to do to evade its contractual purchase obligation under the Negotiated Contracts was to over-commit generation resources or other utility purchases on its system and claim "operational circumstances." Similarly, with respect to the Negotiated Contracts, the "must run" firm purchase obligation that FPC has agreed to in these contracts would be rendered meaningless if FPC could simply evade this obligation by over-committing generation resources on its system and/or by failing to live up to its commitments. Yet, that is precisely the result FPC attempts to achieve in this proceeding under the guise of "curtailment." Prior to invoking the narrow exception for curtailment, FPC must attempt to comply with its contractual purchase obligations under the Negotiated Contracts by attempting to avoid the very "operational circumstances" which give rise to curtailment in the first place.

This is neither an extreme nor an unusual position. As a matter of course, one would expect that FPC would attempt to honor other firm take obligations such as minimum or must take contracts for fuel supplies such as coal. It is perfectly reasonable to expect that FPC should honor its firm purchase contracts with the Cogens with respect to which it has a strong regulatory obligation to purchase.

Q. **HAS FPC TAKEN ANY EFFORTS TO MITIGATE THE OCCURRENCE OF EXCESS GENERATION ON ITS SYSTEM?**

A. Yes. Under the Curtailment Plan, FPC is required to reduce peaking and intermediate output and cut back on base load production, all of which help to reduce excess generation on FPC's system.

**Q. AREN'T THESE EFFORTS ENOUGH?**

A. No. PURPA requires that FPC take available measures to mitigate the very circumstances that give rise to the need to curtail. There remain several measures available for FPC to take which would reduce the possibility of excess generation on its system.

**Q. WHAT TYPES OF ADDITIONAL MITIGATION EFFORTS SHOULD FPC BE TAKING?**

A. There are at least four general types of mitigation efforts that FPC can, and should, undertake to reduce the likelihood of excess generation occurring on its system. First, FPC can curtail its non-QF purchases during periods when generation is expected to exceed load. Second, FPC can modify its unit commitment practices to meet its expected load requirement. Third, FPC can properly price its offers of economy energy for sale either on or off the Energy Broker in order to encourage additional sales during periods when it forecasts that generation may exceed load. Fourth, FPC can reduce its retail price during periods of excess generation to encourage more consumption.

**Q. HAS FPC UNDERTAKEN ANY OF THESE MITIGATION EFFORTS IN A MEANINGFUL WAY?**

A. No. It appears that all FPC has done is attempt (i) to pursue additional sales on the Energy Broker during potential curtailment periods at prices which do not encourage such sales and (ii) to reduce (but not eliminate) the purchases that it makes under the Unit Power Sales Agreement ("UPS Agreement") under certain circumstances. Other than these very limited actions, I am rot aware of FPC having taken -- nor is FPC required to take under the Curtailment Plan -- any of the other types of mitigation efforts described above.

Q. **PLEASE EXPLAIN WHY FPC SHOULD CURTAIL ITS OTHER FIRM PURCHASES PRIOR TO REDUCING PURCHASES FROM THE COGENS.**

A. As an initial step in the mitigation process, FPC should curtail its other firm utility purchases prior to attempting to curtail purchases from the Cogens. This conclusion is required by PURPA and the regulations implemented thereunder.

In the proposed "curtailment" regulation discussed earlier, FERC identified the costs of other power purchases as a factor to be considered in justifying curtailment. NOPR, at 61,204 (Exhibit No. __ (RJS-4)). In the final regulation, however, this language was eliminated, and costs of purchases were no longer included as a justification for curtailment. Therefore, it seems clear that purchases, such as those from the Southern Companies under the UPS Agreement, should not be part of the FPC resources considered in determining whether "operational circumstances" exist.

This interpretation is also consistent with the meaning of "operational circumstances" as provided for in the Preamble:

> 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.

Preamble, at 12,227 (emphasis added) (Exhibit No. __ (RJS-6)). In no way can FPC claim that the "operational circumstances" referred to in the Preamble are created by purchases from another utility, because the FERC presumed that such purchases would not be made if the purchases would effect the operation of the utility's own must run units. It follows that such purchases should be curtailed prior to those from QFs.

This conclusion also makes sense in the broader context of PURPA. To allow QF purchases to be curtailed before purchases from another utility would essentially make the QF purchase obligation inferior to that of the purchase obligation between utilities. Such a result is contrary to the entire thrust of PURPA, which was to establish a clear preference for such QF sales.

Q. **ISN'T A CONSEQUENCE OF THIS CONCLUSION THAT FPC MIGHT BE REQUIRED TO PAY FOR POWER FROM ANOTHER UTILITY WHICH IT DOES NOT USE?**

A. Yes. However, this is purely a consequence of FPC's contractual obligations with the Southern Companies and does not justify involuntary curtailment of mandatory QF purchases. This is just one example of the possible downside costs that FPC bargained for when it entered into the minimum purchase contract with the Southern Companies. In this respect, it is no different than any other situation where a utility incurs short term costs in exchange for long term benefits in the context of a long term planning decision.

What is most significant in the current situation, however, is the special requirements imposed by PURPA on utilities to purchase QF power. It is unreasonable to believe that the very same legislation Congress adopted to promote QFs and overcome utilities' reluctance to purchase from QFs would also have been intended to subordinate firm generation by QFs to generation or purchases by utilities. As discussed above, this conclusion is supported by the fact that the term "operational circumstances" was not intended to cover utility purchases.

Q. **WITH RESPECT TO THE SECOND MITIGATION EFFORT, WOULD YOU EXPLAIN WHAT YOU MEAN BY MODIFICATION OF FPC'S UNIT COMMITMENT PRACTICES?**

A. Yes. In general, utilities go through a decision process to determine which of their generation units they will bring on line in order to meet their expected load requirements. This decision process is referred to as unit commitment. Typically, a utility considers the maximum load that it may be required to serve over a specific time frame or planning period. The utility then attempts to "turn on" or commit to operation the least cost combination of units that will allow it to meet those load requirements. This decision process would normally include considerations such as the start-up and operational costs of each unit, as well as its maximum generation capacity.

Q. **HOW SHOULD FPC MODIFY ITS UNIT COMMITMENT PRACTICES TO MITIGATE THE NEED TO CURTAIL QF PURCHASES?**

A. I will just comment briefly here about how FPC's unit commitment planning process can be modified to mitigate the need to curtail its firm QF purchase obligations. Mr. Slater will testify in significant detail on this subject. Typically, a utility making unit commitment decisions will only consider getting the cheapest generation on line to meet peak load requirements, and ignore minimum load conditions. Where light load periods are expected, however, a utility must modify its unit commitment planning process to take into account the implications of its minimum load problems.

Notwithstanding the fact that FPC has recognized for over two years the problems that might exist during light load periods, FPC does not appear to have modified its unit commitment planning process to recognize the implications of its minimum load problems. As Mr. Slater's analysis shows, the necessary adjustments are not difficult and, if made, could reduce or eliminate the occurrence of FPC's "minimum load conditions."

The other point that I would like to make here is that FPC must plan for and adjust its operations in recognition of the contractual obligations it has entered into with the Cogens. FPC has essentially ignored the fact that the Negotiated Contracts represent long term non-dispatchable purchase obligations. In particular, during the past two years there has been no indication that FPC has planned for or adjusted its commitment process in recognition of these firm purchase obligations, despite its awareness of potential low load conditions.

Having failed to properly plan for or accommodate its Cogen purchase obligations, FPC now seeks to escape its problems by curtailing these very same purchase obligations under rule 25-17.086. FPC's "minimum load conditions," however, remain fully subject to its control and can be rectified without recourse to involuntary curtailments of Cogen purchases. As discussed above, FPC must take available measures before seeking to curtail Cogen purchases. Until FPC has taken those actions, it cannot seek to solve its self-imposed problems through rule 25-17.086.

The simplest solution for FPC is to recognize that the Negotiated Contracts are firm, non-dispatchable purchase obligations and to plan and adjust its operations accordingly. Just as FPC apparently recognizes and plans around its minimum take obligation under the UPS Agreement, so it should recognize and plan around its minimum purchase obligations under the Negotiated Contracts. This means that FPC's unit commitment process should start with a recognition of its <u>total</u> minimum purchase obligations, and then seek to identify the best combination of its own units to meet total generation requirements. "Planning around" operational constraints is not unusual, and as Mr. Slater demonstrates, not that difficult with respect to avoiding the need to curtail.

Q. **ARE THERE ANY OTHER COMMITMENT TYPE ACTIONS THAT FPC COULD TAKE TO MITIGATE THE NEED FOR CURTAILMENT?**

A. Yes. The above discussion and Mr. Slater's analysis focus particularly on the short term (i.e., approximately one week) types of actions that FPC can employ to alleviate operational constraints. There are, however, several longer term actions which FPC could take. For example, FPC might consider putting a unit on reserve status on a seasonal basis. Alternatively, FPC might consider a mix of actions such as actually increasing purchased power that is fully dispatchable coupled with either seasonal reserve or adjusted maintenance schedule. The point to emphasize here is that there is a wide range of options open to FPC that are consistent with traditional utility planning practices, that apparently FPC has totally ignored.

Q. **WITH RESPECT TO THE THIRD TYPE OF MITIGATION YOU IDENTIFIED, WOULD YOU PLEASE EXPLAIN HOW FPC CAN MITIGATE THE NEED TO CURTAIL QF PURCHASES BY ADJUSTING THE PRICE AT WHICH IT OFFERS ENERGY ON THE ENERGY BROKER?**

A. Yes. By increasing off-system sales during potential light load periods, FPC can reduce the need to curtail Cogen purchases. FPC can increase such sales by lowering its offering price on or off the Energy Broker.

**Q. WHY HASN'T FPC LOWERED ITS PRICE ON THE ENERGY BROKER TO ENCOURAGE MORE SALES DURING PERIODS WHEN CURTAILMENTS WERE EXPECTED?**

A. FPC has stated that it is unable to reduce its price quotes on the Energy Broker because it is not permitted to sell economy energy below its incremental cost.

**Q. ARE YOU PROPOSING THAT FPC SELL ECONOMY ENERGY ON THE ENERGY BROKER BELOW ITS INCREMENTAL COST?**

A. No. The simple fact is that FPC is incorrectly calculating and significantly overstating its incremental costs during low load periods. As a result, FPC has been offering its energy on the Energy Broker at a price which discourages rather than encourages sales. By correctly understanding and calculating its incremental costs, FPC would be able to lower its offering price and increase its sales on the Energy Broker. My analysis of the limited empirical evidence available to date suggests that FPC could significantly reduce, if not eliminate, the need for curtailment if it were to lower its price for economy energy transactions on the Energy Broker to competitive levels. Based on what I have learned in the discovery process, FPC apparently would agree with my conclusions, but would disagree as to what constitutes its incremental costs during low load periods.

**Q. HOW DOES FPC SET ITS INCREMENTAL COSTS FOR PURPOSES OF**

**PRICING ITS SALES ON THE ENERGY BROKER?**

A. In a typical situation (e.g., not during light load periods) FPC would calculate its total production costs with the sale of power on the Energy Broker (say 100 MW) for an hour, and again calculate total production costs without the sale (e.g., operating at a lower level of production). The difference in total production costs divided by the 100 mWh would be FPC's estimate of its incremental costs for such sale, and, in turn, would be the price at which FPC would offer to make the sale on the Energy Broker. This method results in the calculation of the average incremental price over the 100 MW sales block of energy. During periods when FPC has the flexibility to increase its generation to meet additional economy sales this is an appropriate method to estimate incremental costs.

Q. **IS THIS METHOD APPROPRIATE TO ESTIMATE INCREMENTAL COSTS DURING PERIODS WHEN GENERATION IS EXPECTED TO EXCEED LOAD?**

A. No. FPC inappropriately uses this same method to calculate its incremental costs during periods of curtailment. It is very important to understand why the use of this same method is wrong when setting the incremental cost for a block of energy that, but for an additional sale, would constitute excess generation.

This may best be understood in the context of a hypothetical. Assume that FPC has 2100 MW of must run capacity on line, 1800 MW of its own base load units, 100 MW of must run Southern Companies purchases, and 200 MW of must run non-dispatchable Cogen power. Further, assume that FPC has only 2000 MW of load on its system. This means that it has 100 MW of excess generation. In this situation, FPC calculates its offer price for sales on the Energy Broker as the average incremental cost of serving megawatts 2001 through 2100 by increasing the output of its own units.

This calculation is clearly wrong, because it incorrectly assumes that FPC has some discretion in generating incremental energy at less than 2100 MW. IF FPC had such discretion, however, there would be no need for curtailment because FPC would simply reduce generation to meet load. What is being offered for sale on the Energy Broker in this surplus situation is the output between megawatts 2001 and 2100, during a period when FPC has no ability to reduce its output below 2100 MW. In this context, FPC can not save any money by producing less, because it cannot produce less. Thus, the true marginal cost that should be associated with the surplus 100 MW is at most zero.

**Q. IS IT A SURPRISING RESULT THAT MARGINAL COSTS WOULD BE AT**

**MOST ZERO UNDER THESE CIRCUMSTANCES?**

A. No. It is perfectly logical that marginal costs would be at most zero when "must take" supplies exceed demand. In such a situation there is no cost to serving the next increment of demand that falls below the "must take" level.

This is a common situation with respect to take or pay fuel contracts. For example, if a utility had a take or pay requirement that obligated it to buy 10 tons of coal, but it only needed 9 tons, the <u>incremental</u> cost for the last ton would be zero because it could not purchase less than 10 tons. In a fuel cost recovery proceeding, FPC witness Karl Wieland supported this conclusion by observing: "The true economic cost of the take or pay [coal] contract is zero . . . . I mean once you have an obligation to buy a certain tonnage, the incremental cost of burning . . . half of it or all of it is zero." <u>See</u> Docket No. 870001-EI, Direct Testimony and Exhibits of FPC Witness Karl H. Wieland, transcript of cross examination, at 400 (1987), a copy of which is attached as Exhibit No. __ (RJS-11). The situation is exactly the same here when FPC has firm purchase obligations for more generation than load

This is also not that unusual in the context of electric utility operations and generation. T'pically, where generation exceeds load, the excess is regarded as "dump" energy, and often sold at a zero cost basis. This type of pricing of "dump" energy applies with respect to transactions between utilities in the New York Power Pool during periods of excess generation.

Q. **WITH RESPECT TO THE LAST TYPE OF MITIGATION YOU IDENTIFIED, HOW WOULD MODIFYING FPC'S RETAIL PRICING DURING PERIODS OF EXCESS GENERATION HELP MITIGATE THE NEED TO CURTAIL COGEN PURCHASES?**

A. The situation is very similar to that discussed above with respect to pricing additional economy sales on the Energy Broker. During periods of low load, the incremental cost for the block of power that would have been excess is zero or less. If FPC can encourage retail customers to take more of their requirements during this period, it should be prepared to sell it down to a price of zero. In turn, the increased load can reduce or even eliminate the level of excess generation. Thus, to properly mitigate, FPC should offer such energy to retail customers who can increase their loads at the reduced rate.

For example, any industrial companies which operate cogeneration facilities to meet their own loads could, during light load periods, be offered power at a price which encouraged them to turn off their plants and to purchase from FPC. To further encourage such sales, FPC could offer the power in advance for a fixed block of time consistent with its forecast of the low load periods, in much the same way that FPC currently bids economy sales to the Carter facility in the South Eastern Power Authority. Of course, this would require FPC to file the appropriate retail tariff with the Commission.

**SECTION C -- THE THIRD REQUIREMENT**

**Q. WHY IS THE CONCEPT OF "NEGATIVE AVOIDED COSTS" IMPORTANT IN THE CONTEXT OF THE POTENTIAL CURTAILMENT OF QF PURCHASES UNDER SECTION 292.304(f) OF THE FERC'S REGULATIONS?**

A. This concept is central to the determination of when the curtailment of QF purchases is permitted. Specifically, section 292.304(f)(1) excuses utilities from their obligation to purchase QF power during

> any period during which, due to operational circumstances, <u>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</u>.

18 C.F.R. § 292.304(f)(1) (1994) (emphasis added). The underscored text reflects the concept of "negative avoided costs."

Q. **IS A FINDING OF "NEGATIVE AVOIDED COSTS" ENOUGH TO TRIGGER CURTAILMENT UNDER SECTION 292.304(f)?**

A. No. Section 292.304(f) requires that a utility seeking to curtail QF purchases not only establish "negative avoided costs," but also establish that such "negative avoided costs" are "due to operational circumstances." Moreover, as discussed above, a utility cannot curtail QF purchases pursuant to section 292.304(f) unless it can first demonstrate that it has taken available measures to mitigate the very circumstances giving rise to the need for curtailment.

Q. **WHAT ARE "NEGATIVE AVOIDED COSTS"?**

A. In the context of section 292.304(f), "negative avoided costs" occur when the cost that the utility would incur to generate with the QFs (e.g., with QF energy priced at zero) exceeds the cost that it would incur to generate without the QFs (e.g., with the QFs curtailed). This differential comparison of what would occur with versus without the operation of the QFs reflects the basic concept of avoided costs. This concept is explained in the Preamble's discussion of the definition of avoided costs:

> 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, excluding the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility.

Preamble, at 12,216 (citations omitted) (emphasis in original) (Exhibit No. __ (RJS-6)).

Thus, in order to determine the existence of "negative avoided costs," FPC must calculate its avoided costs, which represent the costs that it would have incurred but for the existence and operation of the QFs. In general, where those costs are negative (e.g., FPC's costs increase due to the QFs), FPC will have incurred "negative avoided costs" with respect to the QF purchases.

Q. **IN ATTEMPTING TO DEMONSTRATE THE EXISTENCE OF "NEGATIVE AVOIDED COSTS," HAS FPC PROPERLY CALCULATED ITS AVOIDED COSTS CONSISTENT WITH PURPA?**

A. No. Although FPC does follow the basic with/without methodology used in PURPA to calculate avoided costs, its assumptions regarding the basis for its calculation of avoided costs are flawed. Basically, FPC incorrectly assumes the wrong system operations over the wrong period of time, and includes inappropriate costs in its calculations. These errors in FPC's methodology completely invalidate its results.

Q. **WHAT IS THE PROPER METHODOLOGY FOR DETERMINING THE EXISTENCE OF "NEGATIVE AVOIDED COSTS"?**

A. The determination of "negative avoided costs" in the context of section 292.304(f) should be viewed as a two-step process. The first step is essentially a pre-condition to the utility's calculation of avoided costs. It recognizes that prior to evaluating the existence of "negative avoided costs," the base line configuration of the utility's system operations must reflect the full effect of the efforts the utility has or, as discussed above, should have taken to mitigate the need for curtailment.

As discussed earlier in my testimony, it is clear that the FERC intended section 292.304(f) to relieve utilities of their obligation to purchase QF power only under very limited circumstances. It follows that the method of determining the existence of "negative avoided costs" must be consistent with the limited nature of section 292.304(f). In order to achieve this consistency, the calculation of the utility's avoided costs must be made in the normative conditions of what the utility should have done to operate its system consistent with its obligations under PURPA and the regulations implemented thereunder. Under any other conditions, the determination of the existence of "negative avoided costs" in the context of section 292.304(f) would be meaningless.

For example, it would be unreasonable to allow FPC to ignore its obligations to mitigate and then conclude the existence of "negative avoided costs" based on the resulting adverse operational conditions that it had brought upon itself. In fact, failing to measure avoided costs under normative conditions could encourage FPC to inappropriately operate and commit its system in order to effectively achieve contract rights in the Negotiated Contracts that it had failed to negotiate or pay for.

Clearly, neither PURPA, the FERC's regulations nor this Commission's rules contemplate such a result.

Q. **WHAT WOULD BE AN EXAMPLE OF THE KIND OF ADJUSTMENTS THAT FPC WOULD BE REQUIRED TO MAKE IN ORDER TO REFLECT THE NORMATIVE CONDITIONS REQUIRED TO ACCURATELY MEASURE AVOIDED COSTS?**

A. A simple example would be with respect to sales by FPC on the Energy Broker. Assume FPC had made no sales during a curtailment period because it failed to properly price their excess generation on the Energy Broker at a competitive rate. In this situation, the calculation of avoided costs should be adjusted to reflect the level of sales that could have been achieved had FPC taken the proper mitigation efforts as discussed above and priced the economy power at a market-clearing price. Similar adjustments would be required with respect to each of the other mitigation efforts that I discussed earlier.

Q. **WHAT IS THE SECOND STEP IN THE PROCESS FOR DETERMINING THE EXISTENCE OF "NEGATIVE AVOIDED COSTS"?**

A. The second step involves defining the period of time over which the avoided costs analysis will take place and the proper cost information which will be used consistent with such time frame.

Q. **WHAT IS THE APPROPRIATE TIME FRAME FOR CONDUCTING SUCH AN AVOIDED COSTS ANALYSIS?**

A. The time frame should be consistent with the context within which the utility is taking its actions. That is, the with and without avoided costs comparison should be over a period long enough to capture the full impacts of the potential perturbation of a curtailment, as well as the potent'al range of pertinent mitigation impacts.

Q. **AS AN EMPIRICAL MATTER, WHAT WOULD BE THE APPROPRIATE TIME FRAME FOR CALCULATING FPC'S AVOIDED COSTS DURING A POTENTIAL CURTAILMENT PERIOD?**

A. All the information furnished in this proceeding suggests that a time frame of not less than a week is appropriate for purposes of FPC's avoided cost calculations. This is supported by FPC's own comments regarding operational planning and unit commitment and explained further by Mr. Slater in his testimony.

Q. **WHY DO YOU STATE THAT THE COSTS CONSIDERED MUST ALSO BE CONSISTENT WITH THE EVALUATION TIME FRAME?**

A. This is a logical requirement of any costing analysis. That is, the costs considered should only be those incurred that are directly related to the events under analysis. For example, it makes no sense to consider long term life cycle costs in the context of an event that only lasts hours or weeks.

Q. **HAS FPC USED THE APPROPRIATE TIME FRAME AND ASSOCIATED COSTS IN ITS AVOIDED COSTS CALCULATIONS?**

A. No. The studies sponsored by Mr. Southwick all use much too short a time frame, and only consider the period associated with the cycle response time of a curtailed utility unit, rather than the longer one week period of time which the utility considers in making its own unit commitment and sales decisions.

In addition, FPC has included costs in its calculation of avoided costs which span much too long a period of time. The costs identified by Mr. Lefton represent long term life cycle expenses that may be associated with the continued cycling of a plant over the remainder of its useful life. They do not reflect marginal operational costs consistent with the shorter time frame used by either Mr. Southwick or Mr. Slater. If Mr. Lefton's costs were to be sustained as reliable, the only appropriate avoided cost analysis that would include such costs would be one that considered the avoided cost savings from the Cogens over the full lifetime of their contracts, a period consistent with the time frame of the measurement of Mr. Lefton's costs. Virtually by definition such a time frame would never result in "negative avoided costs" because the same time frame would have been considered in the determination that the contracts are cost effective compared to the utility's expansion plan.

**Q. HAS OCL REVISED THE AVOIDED COST CALCULATIONS CONDUCTED BY FPC TO PROPERLY REFLECT THIS TWO STEP PROCESS?**

A. Yes. Mr. Slater has critiqued FPC's avoided cost calculations and discussed both the necessary mitigation efforts and the correct time frame and associated costs for such analysis. Mr. Slater concludes that no "negative avoided costs" exist during the low load periods where FPC has declared curtailments if the analysis period (even absent mitigation) is extended to include a period of less than two days.

**Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

A. Yes.

EXHIBITS

OF

ROY J. SHANKER, PH.D.

# QUALIFICATIONS
# OF
# DR. ROY J. SHANKER

## EDUCATION:

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
Ph.D., Industrial Administration, 1975
MSIA Industrial Administration, 1972

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

## EXPERIENCE:

1981 - Present
Independent Consultant
9113 Burning Tree Road
Bethesda, MD

Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.

1979-81
Hagler, Bailly & Company
2301 M Street, N.W.
Washington, DC

Principal and founding partner of the firm; director of electric utility practice area. The firm conducts economic, financial, and technical management consulting analyses in the natural resource area.

1976-79
Resource Planning Associates, Inc.
1901 L Street, N.W.
Washington, DC

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

1994 American Arbitration Association, Case No. 11-Y198-00352-94. Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a non-utility generator ("NUG") facility.

Florida Public Service Commission, Docket No. 941101-EQ. Analyses of the proper procedures for the determination and measurement of the need to curtail purchases from qualifying facilities.

New York Public Service Commission, Case No. 93-E-0272. Testimony regarding Public Utility Regulatory Policy Act of 1978 ("PURPA") policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

Circuit Court for the City of Richmond, Case No. LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

New York Public Service Commission, Case No. 93-E-0958. Analyses of stand-by, supplementary and maintenance rates of Niagara Mohawk Power Corporation for qualifying facilities .

New York Public Service Commission, Case No. 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

American Arbitration Association, Case No. 55-198-0198-93. Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power production facility.

1993 United States District Court, Southern District of New York, Case No. 92 Civ. 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

Virginia State Corporation Commission, Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

Federal Energy Regulatory Commission, Docket No. ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

Federal Energy Regulatory Commission, Docket Nos. EL93-45-000 and QF83-248-002. Analyses related to the qualifying status of a cogeneration facility.

Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida, Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

New Jersey Board of Regulatory Commissioners, Docket No. EM 91010067. Testimony regarding the revised GPU/Duquesne Light Company 500 MW power sales agreement and associated transmission line.

North Carolina Utilities Commission, Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992 ("EPA").

New York Public Service Commission, Case Nos. 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

Pennsylvania Public Utility Commission, Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne Light Company 500 MW power sales agreement and associated transmission line.

1992 Pennsylvania Public Service Commission, Docket Nos. P-870235, C-913318, P-910515 and C-913764.

Testimony regarding the calculation of avoided costs for GPU/Penelec.

Maryland Public Service Commission, Case Nos. 8413 and 8346. Testimony on the appropriate avoided costs for PEPCO, and appropriate procedures for contract negotiation.

1991 New Jersey Board of Regulatory Commissioners, Docket No. EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

Wisconsin Public Service Commission, Docket No. 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

Virginia State Corporation Commission, Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service.

Virginia State Corporation Commission, Case No. PUE910048. Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

Virginia State Corporation Commission, Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

Maryland Public Service Commission, Case No. 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

Maryland Public Service Commission, Case No. 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design.

1990 California Public Utility Commission, Application No. 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed qualifying facility.

Montana Public Service Commission, Docket No. 90.1.1. Testimony and analyses related to natural gas transportation, services and rates.

Virginia State Corporation Commission, Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

District of Columbia Public Service Commission, Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

Virginia State Corporation Commission, Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

Virginia State Corporation Commission, Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

Maryland Public Service Commission, Case No. 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

Virginia State Corporation Commission, Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

Federal Energy Regulatory Commission, Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and EL90-9-000. Analyses of the implications of Northeast Utilities Service Company and Public Service Company of New Hampshire merger on electric supply and pricing.

Maryland Public Service Commission. Contract with Advanced Power Systems, Inc. and PEPCO.

Puerto Rico Electric Power Authority ("PREPA"), Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing qualifying facilities.

Virginia State Corporation Commission, Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989 Oklahoma Corporation Commission, Case No. PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

Virginia State Corporation Commission, Case No. PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

Federal Energy Regulatory Commission, Docket No. RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

Circuit Court of the Fifth Judicial Circuit, Dade County, Florida, Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

Florida Public Service Commission, Docket No. 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988 Virginia State Corporation Commission, Case No. PUE870081. Testimony on the implementation of the differential revenue requirements of avoided cost methodology recommended by the Virginia State Corporation Commission Task Force.

Virginia State Corporation Commission, Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

Virginia State Corporation Commission, Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

Montana Public Service Commission, Docket No. 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

Oklahoma Corporation Commission, Cause Pud. No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

Florida Public Service Commission, Docket No. 8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

Arizona Corporation Commission, Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987 Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factor application and relationship to avoided costs.

District of Columbia Public Service Commission, Formal Case No. 834, Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

Virginia State Corporation Commission, Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

Virginia State Corporation Commission, Case No. PUE870025. Testimony addressing the proper design of rates for stand-by, maintenance and supplement power sales to cogenerators.

Florida Public Service Commission, Docket No. 860004-EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986 Florida Public Service Commission, Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

Florida Public Service Commission, Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

United States Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

New Hampshire Public Utility Commission, Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and qualifying facilities.

Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of stand-by rates for qualifying facilities.

Virginia State Corporation Commission, Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

Virginia State Corporation Commission, Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

Bonneville Power Administration, Case No. VI86. Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

Virginia State Corporation Commission, Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

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1985 Virginia State Corporation Commission, Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

Louisiana Public Service Commission, Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

Connecticut Public Utility Control Department, Docket No. 85-08-08. Assist in the development of testimony for industrial natural gas transportation rates.

Oklahoma Corporation Commission, Cause No. 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

Florida Public Service Commission, Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

Virginia State Corporation Commission, General Rate Application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

Virginia State Corporation Commission, Case No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

New York State Public Service Commission, Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

Vermont Public Service Department, Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984 Virginia State Corporation Commission, Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

Bonneville Power Administration 1985 Wholesale Rate Proceedings, Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

Virginia State Corporation Commission, Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities, Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

Virginia State Corporation Commission, Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

Bonneville Power Administration 1985 Wholesale Rate Proceedings, Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of Bonneville Power Administration; interactions between rate design, demand, system expansion and operation.

1983 Virginia State Corporation Commission, Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

Vermont Public Service Department, Case No. 4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

Bonneville Power Administration Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of Bonneville Power Administration;

interactions between rate design, demand, system expansion and operation.

Idaho Corporation Commission, Docket No. PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

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95TH CONGRESS } HOUSE OF REPRESENTATIVES { REPORT
2d Session } { No. 95-1750

# PUBLIC UTILITY REGULATORY POLICIES ACT

OCTOBER 10, 1978.—Ordered to be printed

Mr. STAGGERS, from the committee of conference, submitted the following

## CONFERENCE REPORT

[To accompany H.R. 4018]

The committee of conference on the disagreeing votes of the two Houses on the amendment of the House to the amendment of the Senate to the bill (H.R. 4018) entitled "An Act to suspend until the close of June 30, 1980, the duty on certain doxorubicin hydrochloride antibiotics", having met, after full and free conference, have agreed to recommend and do recommend to their respective Houses as follows:

That the Senate recede from its disagreement to the amendment of the House to the amendment of the Senate to the text of the bill and agree to the same with an amendment as follows:

In lieu of the matter proposed to be inserted by the House amendment insert the following:

***SECTION 1. SHORT TITLE AND TABLE OF CONTENTS.***

*(a) SHORT TITLE.—This Act may be cited as the "Public Utility Regulatory Policies Act of 1978".*

*(b) TABLE OF CONTENTS.—*

# JOINT EXPLANATORY STATEMENT OF THE COMMITTEE OF CONFERENCE

The managers on the part of the House and Senate at the conference on the disagreeing votes of the two Houses on the amendment of the House to the amendment of the Senate to the bill (H.R. 4018) entitled "An Act to suspend until the close of June 30, 1980, the duty on certain doxorubicin hydrochloride antibiotics" submit the following joint statement to the House and Senate in explanation of the effect of the action agreed upon by the managers and recommended in the accompanying conference report:

The Senate amendment to the text of the House bill (H.R. 4018) struck out all of the bill after the enacting clause and inserted a substitute text which contained two titles. Title I (the "Public Utilities Regulatory Polices Act of 1977") contained the taxt of S. 2114, as amended by the Senate. Title II was identical, except for clerical and conforming changes, to part V (Public Utility Regulatory Policies) of title I of H.R. 8444, as passed by the House.

The House amendment to the Senate amendment struck out the text of the Senate amendment and substituted the text of title I of H.R. 8444 as passed by the House.

The Senate recedes from its disagreement to the amendment of the House with an amendment which is a substitute for both the Senate amendment and the House amendment. The differences between the Senate amendment, the House amendment, and the substitute agreed to in conference are noted below, except for clerical correction, conforming changes made necessary by agreements reached by the conferees, and minor drafting and clarifying changes.

Since the Senate and House amendments both substituted new texts for the House bill, H.R. 4018 (which was unrelated to electric and gas utility matters when it originally passed the House), references in the explanation below to "the House bill" are not intended to serve as references to H.R. 4018 as originally passed by the House but as references to Part V of title I of H.R. 8444 as passed by the House. Similarly, since the Senate amendment contained both the texts of S. 2114 as amended by the Senate and the text of Part V of title I of H.R. 8444, as passed by the House, references to the Senate amendment in the explanation below are intended to serve as references to S. 2114 as passed by the Senate.

No action was taken by the conferees with respect to that portion (title II) of the Senate amendment which contained the text of Part V of title I of H.R. 8444 or with respect to that portion of the House amendment to the Senate amendment as contained in other titles of H.R. 8444.

*House bill*

The House bill contained provisions designed to encourage the conservation of resources by electric utilities and to carry

*Section 209. Reliability*

The purpose of this section is to require the Secretary of Energy to study ways to improve the reliability of service to electrical consumers, to authorize the Secretary to request appropriate persons to examine and report to him on reliability issues, to authorize the Secretary to recommend to the electric utility industry standards for reliability, and to require that the Secretary, in his annual report, make recommendations concerning reliability of service to electrical consumers.

*Section 210. Cogeneration and small power production*

Section 210, as agreed to by the conferees, is a compromise of the House and Senate positions on cogeneration and small power production. In lieu of the Senate guideline approach, this section requires that States and utilities follow rules which the Federal Energy Regulatory Commission is to prescribe within one year after the date of enactment of this legislation.

Subsection (a) of this section states that the rules the Commission is required to prescribe under this section require electric utilities to offer to sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and require electric utilities to offer to purchase electric energy from these facilities.

Subsection (a) also contains procedural requirements with respect to the hearings to be conducted prior to final promulgation of the rules and limits the authority of the Commission to authorize in these rules cogeneration facilities or small power production facilities to make any sale for purposes other than resale. The conferees do not intend that this limitation on the Commission's authority will limit the States from allowing such sales to take place. The cogenerator or small power producer may be permitted to make retail sales pursuant to State law.

Subsection (b) of this section deals with the requirements that the Congress places on the Federal Energy Regulatory Commission in prescribing the rules under subsection (a). These rules shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualified cogenerator or qualified small power producer, the rates for this type of purchase are to be just and reasonable to the electric consumers of the utility, in the public interest, and are not to discriminate against cogenerators or small power producers. The conferees intend that the phrase "just and reasonable to the electric consumers of the utility" be interpreted in a manner which looks to protecting the interests of the electric consumer in receiving electric energy at equitable rates. It is not the intention of the conferees that cogenerators and small power producers become subject, by virtue of this language, and the rules promulgated under this section, 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. The conferees recognize that cogenerators and small power producers are different from electric utilities, not being guaranteed a rate of return on their activities generally or on the activities vis a vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise is not guaranteed to be recoverable.

The conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production.

This subsection further states that the utility would not be required to purchase electric energy from a qualifying cogeneration or small power production facility at a rate which exceeds the lower of the rate described above, namely a rate which is just and reasonable to consumers of the utility, in the public interest, and nondiscriminatory, or the incremental cost of alternate electric energy. This limitation on the rates which may be required in purchasing from a cogenerator or small power producer is meant to act as an upper limit on the price at which utilities can be required under this section to purchase electric energy. The conferees do not intend cogenerators or small power producers to be subject, under the commission's rules, to utility-type regulation.

Subsection (c) deals with the requirements with respect to sales by utilities to cogenerators and small power producers and requires that these rates be just and reasonable and in the public interest and do not discriminate against cogenerators or small power producers. Here the phrase "just and reasonable" is intended to refer to traditional utility ratemaking concepts. The conferees do not intend that the cogenerator or small power producer pay any more or any less than is otherwise just and reasonable in terms of the utility receiving the reasonable rate of return for providing service to those kinds of users. However, unreasonable rate structure impediments, such as unreasonable hook up charges or other discriminatory practices, would not be allowed.

The conferees use the phrase "not discriminate against cogenerators or small power producers" because they were concerned that the electric utility's obligations to purchase and sell under this provision might be circumvented by the charging of unjust and non-cost based rates for power solely to discourage cogeneration or small power production. This phrase should not be construed to permit discrimination against the electric consumers of an electric utility in formulating rates under this provision. The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.

Subsection (d) deals with the definition of the term "incremental cost of alternative electric energy" as used in the last sentence of subsection (b). This term is defined as the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. In interpreting the term "incremental cost of alternative energy", the conferees expect that the Commission and the States may look beyond the cost of alternative sources which are instantaneously available to the utility. Rather, the Commission and States should look to the reliability of that power to the utility and the cost savings to the utility which may result at some later date by reason of supply to the utility at that time of power from the cogenerator or small power producer: for example, an electric utility which owns a source of hydroelectric power and which is offered the sale of electric energy from a cogenerator or small power producer might, if measured over the short term, have a low incremental cost of alternative power because of its access to hydropower: however, it may be the case that by purchasing from the cogenerator or small power producer and saving hydropower for later use, the utility can avoid the use of expensive electric energy generated by fossil fired units during later months of its seasonal generation cycle. Thus, viewed over the longer period of time, the incremental cost of alternative electric energy might be substantially higher than that measured by the instantaneously available hydropower.

In providing that the 30–80 megawatt class of small power production facilities may not be exempt from the Federal Power Act under subsection (e), the conferees intended that where such facilities are subject to Federal Power Act jurisdiction, the Commission must set the rates for the sale of power by such facilities in accordance with the requirements of this section.

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 enforcible obligation of such cogenerator or small power producer to supply firm power to the utility.

*Section 211. Interlocking directorates*

This section amends section 305 of the Federal Power Act, by adding a new subsection. The conferees agreed to adopt with some revisions the disclosure provisions contained in the House bill. The provisions in the House bill authorizing the Commission to prohibit an officer or director of a public utility from holding other positions were not adopted. The Senate amendments contained no comparable provision.

In paragraph (2)(D) of this new subsection, the conferees intend that the 20 purchasers of electric energy be measured in terms of electric energy bought from the utility.

The definition of the word "controlled" in paragraph (2)(F) of new subsection (c) is, the conferees intend, to be defined by the Commission. The conferees were reluctant to establish a single arbitrary percentage of stock ownership as the yardstick for measuring control. Rather, it is anticipated that after appropriate consideration, the Commission will arrive at a definition that takes into account the nature and extent of control of one firm by another.

*Section 212. Public participation before Federal Energy Regulatory Commission*

The House bill contained a provision creating an Office of Public Counsel and provided that the Director of the Office would administer 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)(1), if the State approves some manner of amortization, it might consider assignment of uncollected interconnection costs to the class for which the rate is established.

*§ 292.307 System emergencies.*

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

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

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

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

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

*§ 292.308 Standards for operating reliability.*

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

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

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

*Subpart D—Implementation*

*Summary of this Subpart*

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

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

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the maritime unions and related interests.

Various internal memorandums suggest that the decision by the administration was merely for the purpose of paying the President's political debts to the maritime interests.

The American people are entitled to know the real reasons for an administration policy that would cost the consumer millions in unnecessary costs. And they are entitled to know the extent to which such policies are the result of an unholy alliance between the President and the maritime unions, both of which may be seeking this legislation for reasons that have absolutely nothing to do with the public interest.

It is therefore essential that the Senate, through the appropriate committees, fully explore every aspect of the cargo preference decision. That consideration should include indepth discussions with many, if not all, of the key administration officials who played a part in this decision. It is essential that we know whether cargo preference will stand on its own merits or if it is just a political deal with a special interest group.

If we find, as I expect we will, that cargo preference legislation will not stand on its own merits, then we should insist that the President repudiate any deal with the maritime interests and withdraw this legislation. Given the President's willingness to repudiate promises made to the American people, such as the one he made last year regarding the deregulation of natural gas, I should think he would be most willing to reconsider an ill-advised private deal made with a special interest group, if that is the case.

I realize that some of my colleagues may have more enthusiasm for investigating the sour odors of a milk fund scandal than they do for investigating the bubbling bilge of a maritime bailout. But our responsibilities as Senators require that we fully and forthrightly address the issues which have been raised about cargo preference legislation before we even consider enacting it into law.

Mr. President, I suggest the absence of a quorum.

The PRESIDING OFFICER. The clerk will call the roll.

The second assistant legislative clerk proceeded to call the roll.

Mr. JOHNSTON. Mr. President, I ask unanimous consent that the order for the quorum call be rescinded.

The PRESIDING OFFICER. Without objection, it is so ordered.

## ROUTINE MORNING BUSINESS

Mr. ROBERT C. BYRD. Mr. President, I ask unanimous consent there be a period for the transaction of routine morning business.

The PRESIDING OFFICER. Without objection, it is so ordered.

## CONCLUSION OF MORNING BUSINESS

Mr. ROBERT C. BYRD. Mr. President, is there further morning business?

The PRESIDING OFFICER. Is there further morning business? If not, morning business is closed.

## PUBLIC UTILITIES REGULATORY POLICY ACT OF 1977

The PRESIDING OFFICER. Under the previous order, the Senate will now proceed to the consideration of S. 2114, which the clerk will state by title.

The legislative clerk read as follows:

A bill (S. 2114) to authorize Federal action to encourage energy conservation, efficiency, and equitable rates in public utility systems, and for other purposes.

The Senate proceeded to consider the bill which had been reported from the Committee on Energy and Natural Resources.

Mr. JOHNSTON. Mr. President, I ask unanimous consent that Deborah Merrick, Marjorie Gardner, Mike Harvey, Dan Dreyfus, Ben Cooper, Jim Bruce, and Bob Szabo be accorded the privileges of the floor during consideration of S. 2114, the Public Utilities Regulatory Policy Act of 1977.

I also request unanimous consent that the following staff members be given floor privileges during the consideration of and voting on S. 2114:

Jack Odegard, Fred Craft, Danny Boggs, Tom Imeson, Carol Bocchi, Faye Widenmann, Judy Petey, and Mary McKenna.

The PRESIDING OFFICER. Without objection, it is so ordered.

Mr. BARTLETT. Mr. President, I ask unanimous consent that Erich Evered, of my staff, be granted the privileges of the floor during the consideration of this bill.

The PRESIDING OFFICER. Without objection, it is so ordered.

Mr. DOMENICI. Mr. President, I ask unanimous consent that Kathy Bruner, of Senator HAYAKAWA's staff, have the privilege of the floor during the debate and votes on this bill.

The PRESIDING OFFICER. Without objection, it is so ordered.

Mr. JOHNSTON. Mr. President, I ask unanimous consent that Tom Graham, of Senator DURKIN's staff, have the privilege of the floor during the debate on this measure.

The PRESIDING OFFICER. Without objection, it is so ordered.

Mr. DOMENICI. Mr. President, will the Senator from Louisiana yield for a question?

Mr. JOHNSTON. I yield.

Mr. DOMENICI. Will the Chair tell the Senator from New Mexico what the unanimous-consent agreement is on this bill?

The PRESIDING OFFICER. Time for debate on this bill is limited to 4 hours, to be divided and controlled by the Senator from Louisiana (Mr. JOHNSTON) and the Senator from New Mexico (Mr. DOMENICI), with 2 hours on any amendment in the first degree, except for one amendment each by Mr. GRIFFIN, Mr. GLENN, and Mr. JOHNSTON, and on two amendments by Mr. TOWER, on each of which there will be 1½ hours, on one amendment by Mr. MELCHER, on which there shall be 1½ hours, and on one amendment each by Mr. DURKIN and Mr. FORD, on each of which there shall be 1½ hours, with 30 minutes on any amendment in the second degree, and 20 minutes on any debatable motion, appeal, or point of order.

Mr. DOMENICI. I thank the Chair.

Mr. JOHNSTON. Mr. President, I yield myself such time as I may require.

Mr. President, the Public Utilities Regulatory Policy Act of 1977 is the fifth and last major portion of President Carter's proposed National Energy Act reported by the Committee on Energy and Natural Resources this session.

S. 701, providing energy conservation assistance to schools and hospitals, was passed by the Senate on July 20, 1977;

S. 977, the coal conversion bill, was passed on September 8, 1977;

S. 2057, the omnibus energy conservation bill, passed on September 14, 1977; and

S. 2104, providing for a natural gas pricing policy, passed on October 4, 1977.

The Committee on Energy and Natural Resources completed action on the Public Utilities Regulatory Policy Act on September 19, 1977, and filed its report on September 26, 1977.

I ask unanimous consent that a summary of the bill and a copy of the cost estimate provided by the Congressional Budget Office be printed in the RECORD at this point.

There being no objection, the material was ordered to be printed in the RECORD, as follows:

### SUMMARY OF S. 2114: THE PUBLIC UTILITIES REGULATORY POLICY ACT OF 1977

S. 2114 requires State regulatory authorities and each nonregulated utility above a certain size to report biannually to the Secretary of Energy information about variations in the demand for electricity or gas among various classes of customers as well as information on the costs of serving these classes of customers. If the information requested is not already available in the files of these institutions, the Secretary must reimburse the authority or utility for the cost of gathering any additional information required.

The Secretary of DOE is authorized to intervene on his own initiative in any utility rate or rate design proceeding held before a State regulatory authority. However, the purpose of the intervention is limited to advocating: (1) energy conservation, (2) efficient use of facilities and resources, or (3) equitable rates to consumers. The Secretary would have the same rights as any other party in the proceeding, except that he could not initiate or join in an appeal using authority under this Act. Authority to participate in ratemaking proceedings granted to the Administrator of the Federal Energy Administration in Title II of the Energy Conservation and Production Act (which will be vested in the Secretary of Energy on October 1, 1977) is not affected by the bill.

In the case of a nonregulated utility, the Secretary could intervene in any convenient proceeding dealing with rates or rate design. If no such proceeding is available, the Secretary may review the utility's rates and make recommendations to promote the three purposes cited above.

The Act instructs the Secretary to examine the methods electric utilities use in determining rates in order to assess how well their rates reflect variations in cost of service due to daily and seasonal time of use as well as the relationship between rates and the marginal cost of providing service to customers. He is also to consider to what extent the three purposes cited above may

The PRESIDING OFFICER. The amendment will be so modified, when received at the desk.

Mr. JOHNSTON. I should like to see the amendment when the Senator has prepared it. I will move on, in the meantime.

Why does the Senator pick the figure of $100 million? That is a great deal of money. What kind of basis does he have for determining that total sum?

Mr. DURKIN. Our research indicated that the loan guarantees might ultimately result in very little expenditure of Federal moneys. That would provide for 50 projects over a 3-year period. That would be roughly—I am sure it will not break down this way—one per State. By the time we have 50 projects coaxed along and encouraged by the Federal loan guarantee, with the increase in the price of oil and gas and the supply problem and the coal conversion problem, the European turbine will have proved itself, and there is money in the ERDA 1978 authorization to do studies and research upon even more advanced turbines than the American turbines. So by that time, with that combination of circumstances, the thing will fly by itself, and private financing will find it economically advantageous. But right now, it does need the boost of the Federal loan guarantee.

Mr. JOHNSTON. I yield to the distinguished Senator from New Mexico.

Mr. DOMENICI. First, I say to my good friend that I do not know much about this kind of energy production, but I understand that it is available. It certainly is going to be clean, and it is something we should attempt to develop. I just have a couple of basic questions.

Can the Senator explain to me why we need loan guarantees in this situation? I assume the Senator is saying that, but for this, some projects will not get ordinary marketplace funding, be it general obligation bonds or revenue bonds or private capital; that some of these kinds of projects will not find their way into feasibility and completion. I do not understand why.

Mr. DURKIN. That is correct. The language in the other body refers to hard loans—solid Federal cash. We adopted the loan guarantee approach because we felt that that gave the incentive, that gave the security, without putting up Federal cash per se, at least from the outset. We think most of these projects will be successful and that the loan guarantee will not be used. The reason why the Federal incentive is needed is that the utility companies, as a rule, turn up their noses at low-head hydro. So there is a disincentive in the utility industry to turn to low-head hydro.

That, combined with the reluctance of the banking community to bankroll something that some of the utilities frowned upon, has been one of the reasons why there is not more low-head hydro generation.

All the recent studies have shown that there is tremendous potential. Once we can demonstrate it to the utilities, demonstrate it to the environmental groups which have some concerns about this type of generation of power, as well as the financial community, and with the increase in oil and gas and coal conversion, this will take off by itself. This will have impact not just in New England but in the South and West as well.

Mr. THURMOND. Mr. President, I ask unanimous consent that Mr. Robert Lyon of my staff be allowed on the floor during the consideration of S. 2114.

The PRESIDING OFFICER. Without objection, it is so ordered.

Mr. DOMENICI. Is the Senator saying because this is not very typical and has not been for quite a few years, that the typical marketplace is reluctant to recognize it and, therefore, we need some kind of guarantee program to get it started?

Mr. DURKIN. To demonstrate on-site generation of power at a lowhead hydrosite. That will convince the utilities, the banking community, and the public as a whole.

Mr. DOMENICI. On page 11 of the amendment——

Mr. DURKIN. Excuse me. There is tremendous potential here. When you take a remote site solar installation and a cogeneration installation, and take the paper industry which is on a stream, and then add a lowhead hydrodam with that paper facility, whether it be in New Hampshire or Maine or Georgia, or wherever, out in the Pacific Northwest, that will become almost energy self-sufficient with the combination of cogeneration, remote site solar, and lowhead hydro. We have to demonstrate to the financial community and others. Now it is a small band of people pushing it. But once we can demonstrate it is economically and environmentally sound—even the environmentalists are scared about it, putting another dam and Grand Coulee built on top of each other.

It is so that we can demonstrate to the environmental, economic and financial communities that this is a viable way to go.

Mr. DOMENICI. I am not opposed to all of these new approaches, and I think we will see 10 or 15 years from now precisely what you have said in many areas where there are just little localized, isolated ways to develop local energy which we have just completely abandoned in the last 30 years.

On the other hand, I am not adverse to Federal loan guarantees to develop new sources of energy. I just want to be sure that I, for one, am convinced it is needed, and that the marketplace will take care of it. Not because I do not want the Government involved, but I have a tendency to think when we do get involved we usually buy projects that do not work. We either accumulate an inventory of pink elephants, or whatever you call them, or we put our money in and they do not work. I just wanted the Senator's explanation of how this is it and why.

One technical question: On page 11 you talk about the "commission shall take such steps as are necessary," and then you say "within its existing authority to require," and then you enumerate "each utility within its jurisdiction will establish physical connection with all small hydropower projects; second, to establish conditions of service which require that any small hydroelectric project shall be provided with backup generation service from a utility at reasonable prices which do not discriminate," et cetera.

Do they already have that authority or not?

Mr. DURKIN. Well, the reason for that, Senator, is this is one of the problems. Again, the cogenerators, the small sources of generating capacity, whether they be remote sites solar or lowhead hydro, the utility will not buy the excess power for them or will not provide them backup power. That, plus the lack of assurance in the financial community, has left most of these programs with feasibility site studies. This does not abrogate State law because not only do I share the Senator's concern with another C-5A, and all the list of, the parade of, horribles the Federal Government has bought several times over, but I do not want to abrogate State law with respect to the regulation of utilities, at least not at this time, until we have given them a chance to reply and the Secretary to intervene.

So this does not get into the interconnection question. That has been raised before, that we were getting into the whole question of wheeling, pooling, interconnection, and all these exotic things we discussed in committee.

This just says if you have that—and we put this in the cogeneration and the other program as well, that they cannot, the utility cannot, deny the lowhead hydrosource backup power or they have to buy the excess power at cost, at not any subsidized rate.

Mr. DOMENICI. Well, the Senator did not answer my question. I understand the Senator's explanation. Does the Federal Power Commission have the authority to do these things now or are we giving them this authority in the Senator's amendment?

Mr. DURKIN. We do not give them any new authority.

Mr. DOMENICI. Why do we need it in the bill?

Mr. DURKIN. Because to get around the concern I mentioned before. If you have that lowhead hydrodam and turbine, and there is no place to peddle the power, and if the utility wants to cause difficulties, they will not buy it. We did not intend to give them any additional authority. But, to be honest with you, I am not sure of the extent of their authority today.

Mr. DOMENICI. I would say to the Senator I do not know whether I will end up supporting his amendment or not, but I might say I really would object to putting this kind of authority in as a mandate. I would support, if you would strike it, I would support the language that would indicate the extent of this power since this is a policy of our Government to encourage these, that we would expect the Federal Power Commission to see to it that they are not discriminated against in terms of their needs which, I think, is what the Senator is trying to get at.

Mr. DURKIN. I would have no objection to it, and I would be happy to accept the suggestion of the Senator products like paper, glass, chemicals, textiles, and petroleum. Again, two-thirds of this energy is wasted. But cogenerating industries use their waste steam to also generate electricity—at less than half the usual cost.

The amendment I offer now sets this country on a rational course for a better future in this regard.

First, a comprehensive series of policy analyses are required, with Federal Trade Commission and Environmental Protection Agency participation. The goal of these analyses is to propose within 2 years a range of alternative courses of action for establishing a national waste heat recovery policy.

Industrial cogeneration is only a part of any real effort to recover waste heat. My amendment provides for an analysis of not only cogeneration, but also district heating, energy cascading, and the concept of total energy systems. District heating lets us use otherwise wasted steam to heat homes and even farmland so that fields can be productive year-round. Total energy systems combine presently separate industrial processes in order to squeeze out the total energy value from fuel.

Second, an oversight mechanism is created within the Department of Energy. My amendment would direct the Secretary to make annual reports to Congress on the progress of the waste heat recovery policy, including proposals to improve it.

Third, my amendment gives specific statutory authority for the successor agency to the Energy Research and Development Administration to commence an intensive research, development, demonstration, and technology transfer program. The first year authorization for the program is $5 million—this figure is five one-hundredths of 1 percent of the annual savings from cogeneration alone in a decade.

This amendment has the full support of industry and environmental groups. It has the support of the National Rural Electric Cooperative Association. It is supported by the Governor of Tennessee, the scientific community, and even some State regulatory commission members nationwide.

This amendment does nothing controversial. It studies waste heat recovery—not just industrial electricity generation. It provides answers for us, and will give us a range of options from which to choose for enacting a national waste heat recovery policy. And it provides for an automatic oversight mechanism to make sure that what we intend to have happen does, indeed, happen.

To speed up the development and application of improved ways to use waste heat, the amendment provides for an extremely modest R. & D. program.

Mr. President, I hope the Committee will see its way clear to support this very straightforward amendment. One which will help pave the way for a very sound national policy in the very near future to help recapture some of this country's needlessly wasted energy.

I ask unanimous consent to have printed in the RECORD a statement setting forth further facts in support of the amendment.

There being no objection, the statement was ordered to be printed in the RECORD, as follows:

STATEMENT

Cogeneration doubles the usefulness of fuel. A study for the Federal Energy Administration concludes that we can save 1.86 million barrels of oil-equivalent every day by 1985 if only 3 industries—paper, chemicals and petroleum—cogenerate. At $15 a barrel that equals a savings of nearly $28 million dollars every day, or over $10 billion every year. And this $10 billion a year savings is in reduced fuel costs alone.

Cogeneration could cut the environmental damage of our present, wasteful practices substantially.

Cogeneration could alleviate the need for some additional nuclear powerplants. If only half of all the new industrial steam-raisers coming on-line in the next ten years also cogenerate electricity, the Library of Congress states that enough power would be produced to replace the need for between 10 and 14 giant new nuclear powerplants. Experts at Princeton University write that cogeneration can reduce ERDA's estimate for needed nuclear power capacity in the year 2000 by exactly one-half.

The cogeneration saves our capital resources. A study by Dow Chemical Company states that cogeneration can cut the need for new capital investments to make electricity by about $5 billion every year in the next decade.

Cogeneration can save consumers money. The same Dow Chemical study concludes that cogeneration can save household consumers as much as $3.6 billion every year in reduced utility bills.

Why are they cogenerating in Sweden, Denmark and every other industrialized country except the United States?

Fifteen years ago, 15 percent of our electricity was cogenerated. Today we are down to about 4 percent.

The reasons for this reduction fall into 4 categories:

First, there are technological barriers. Coal-burning cogenerators can produce only a quarter of the electric power that oil- or natural gas burners can make.

There are promising solutions to this problem, however.

Fluidized bed combustors have operated successfully in Europe, and even in this country. These combustors can burn coal or any other organic material for fuel, virtually pollution free. Connect a fluidized bed to a cogeneration system, and you match the electrical production of an oil-burner.

Is there any widespread effort to apply the fluidized bed concept to waste heat recovery? No, not in this country.

The artificially low price of energy means that it is not profitable for industry to develop waste heat recovery systems. It will be profitable in a few years, but can we afford to wait at a cost of $10 billion a year?

It is in the public interest to develop more and better ways to recover and re-use our waste heat energy resources—totaling over 8 million barrels a day. Clearly, the Federal government has a duty to help push fluidized beds and other promising waste heat recovery technologies to the marketplace. But there exists no statutory authority for such a development effort.

My amendment provides long-needed statutory authority and authorizes a modest sum to begin an intensive waste heat recovery R&D effort—$5 million in fiscal year 1979. If we devoted as much money to find ways to recover and re-use waste heat as we will save in the future from cogeneration alone, the technological barriers to waste heat recovery would be eliminated in short order.

Second, there are economic barriers to cogeneration. Until we find a way to reflect the real benefits of conservation on corporate balance sheets, we cannot realistically expect industries or utilities to conserve.

The best way to resolve the economic barrier? We do not know, precisely. President Carter and I support granting an additional 10 percent investment tax credit for purchases of waste heat recovery equipment. My amendment to the energy tax bill would have the credit automatically expire at the end of 3 years. By that time Congress will have absorbed the range of solutions that the study required by this amendment will have proposed.

Third, there are regulatory barriers to cogeneration. Industries are prohibited from cogenerating in some places. Federal laws are ambiguous about cogeneration, and some provisions of the Federal Power Act and the Public Utility Holding Company Act are too burdensome for small power producers to cope with. The bill, as reported by the Committee, addresses this problem by authorizing the Secretary of Energy to exempt cogenerators from these two Acts.

Fourth, and the most difficult obstacle to overcome, are institutional barriers.

The fact is that private utility companies have historically REFUSED to permit cogeneration in their service areas. Lower electricity and capital costs mean less gross profits.

The study required by my amendment will give us a broad range of choices from which to select for addressing the institutional barriers to cogeneration and other ways to recover and re-use waste heat.

But at a potential future cost of $10 billion a year, we cannot afford to delay addressing this critical issue. This can be best accomplished, on an interim basis, by a moderate amendment I support to the energy bill now pending in the Finance Committee.

COGENERATION

Mr. SASSER. Mr. President, I would like to express my strongest possible support for the approach to cogeneration advanced by my colleague from Colorado (Mr. HART). The reasons for adopting these amendments are compelling, and I would like to commend the Senator for his fine amendment.

First, let us consider carefully and judiciously how crucial the actions of the Federal Government are in promoting a greater degree of waste heat recovery and onsite generation of electricity. We should examine the issue from its broadest possible perspective.

A few statistics should make abundantly clear the centrality of waste heat recovery strategy to our national energy policy.

First, the production of steam for generating electricity and for use in industrial processes accounts for a staggering proportion of our national energy budget. Fifty percent of our Nation's energy consumption results from just these two energy intensive activities.

Second, due to the second law of thermodynamics, only one-third of the steam which industry creates is ever used for the purpose for which it is created. Two-thirds of this steam is literally wasted. The amount of this daily waste is about equal to the energy value of the foreign oil our Nation imports each day. Mr. President, on this day alone we are discharging into rivers and into the sky the thermal equivalent of 8 million barrels of oil.

Third, a moment ago I mentioned that utility and industrial generation of procthe appropriate time if the Senator wishes to raise the point of order he can raise the point of order. But I wish to proceed with my amendment.

Mr. HASKELL. Mr. President, will the Senator yield?

Mr. BROOKE. I yield to the Senator from Colorado.

Mr. HASKELL. Mr. President, I thank the Senator from Massachusetts for yielding to me.

The PRESIDING OFFICER. The Senator from Colorado.

UP AMENDMENT NO. 873

(Purpose: To prevent discrimination by utilities against certain energy consumers utilizing alternative energy sources)

Mr. HASKELL. Mr. President, I send an unprinted amendment to the desk and ask for its immediate consideration.

The PRESIDING OFFICER. The amendment will be stated.

The second assistant legislative clerk read as follows:

The Senator from Colorado (Mr. HASKELL) proposes an unprinted amendment numbered 873.

Mr. HASKELL. Mr. President, I ask unanimous consent that the reading of the amendment be dispensed with.

The PRESIDING OFFICER. Without objection, it is so ordered.

The amendment is as follows:

On page 12, line 8, after "COGENERATION" insert a comma and "BACK-UP POWER,".

On page 13, between lines 16 and 17, insert the following new paragraph:

"(c) Not later than one year after the date of enactment of this Act, the Secretary of Energy shall, after consultation with representatives of State regulatory authorities, electric utilities, and alternative energy industries and consumers, recommend to State regulatory authorities guidelines for the purpose of preventing utilities from engaging in any conduct which results in unreasonable or discriminatory rate or pricing structures or practices against consumers that utilize power facilities other than those provided or otherwise supplied by any such utility including, but not limited to solar, geothermal, photovoltaic, wind, and other power sources as the Secretary may decide.".

Mr. HASKELL. Mr. President, a problem which is not addressed in the pending Public Utilities Regulatory Policy Act, S. 2114, is the matter of discrimination by utilities against certain energy consumers who utilize alternative energy systems. Although section 12 requires guidelines for prohibiting discrimination against cogenerators and small power producers, this section does not address the problem of discrimination against other alternative energy systems which require backup power for varying periods of time, such as solar hot water and space heating systems. Unless backup power is available for these systems at reasonable rates and under equitable conditions, the economic feasibility and marketability of many alternative energy systems will be inhibited. As a result, the widespread use of these alternative energy systems which have the potential to conserve large quantities of nonrenewable fuels will not be realized.

Although reports of discrimination are not widespread yet, they are numerous enough to cause concern, especially if we are serious about expanding the utilization of alternative energy systems in the near future. The most recent example of discrimination was reported in the September 30 issue of New Times in an article entitled "Sun Wars." In this instance a builder had installed solar units in a large residential complex and the local gas utility arbitrarily changed the development's classification to "nonresidential." In essence, this means that unlike other housing developments this one would be subject to having its fuel supply interrupted or curtailed in times of shortages.

In addition to this instance, we have received information from a number of State energy offices recounting cases of alleged discrimination. While alternative energy systems which require backup power should pay their fair share, they should not be discriminated against. This amendment will require that the Secretary of DOE recommend guidelines for utilities which are designed to insure that practices and rate structures do not arbitrarily discriminate against these promising new technologies. The Secretary would develop guidelines for utilities, not rules, which would thus insure responsiveness to regional differences and be consistent with the position adopted by the committee in reporting S. 2114. Moreover, a provision similar to this one passed in the House.

Mr. President, it is my understanding that this amendment has been cleared with both sides of the aisle.

Basically what it does is say that the Secretary of DOE is required to recommend guidelines to State public utility commissions so that there will not be any discrimination in their ratemaking or other practices which has an adverse effect on alternate energy systems, such as solar hot water and space heating systems. There have been examples of discrimination reported in California and Massachusetts and one close call in Colorado where the utility eventually rescinded its order.

I think we all agree that this goes directly against the national energy policy goals.

Mr. President, I, therefore, ask that my amendment be adopted.

Mr. JOHNSTON. Mr. President, this amendment is consistent with the general thrust of the committee's consideration of this bill. It provides for guidelines relating to nondiscriminatory practices. It does not put a Federal mandate on the State, but rather requires them to come up with their own guidelines.

Mr. HASKELL. That is correct.

Mr. JOHNSTON. We think it is an excellent amendment and we support it.

The PRESIDING OFFICER. Is all time yielded back?

Mr. BARTLETT. Mr. President, I shall make a very short statement.

I concur with my colleague who is managing the bill. This permits the Federal Government to make recommendations, but those recommendations are not binding on the agencies which regulate the utilities.

I think this is the understanding and I support this amendment and accept it.

Mr. JOHNSTON. Mr. President, I yield back the remainder of my time.

Mr. BARTLETT. Mr. President, I yield back the remainder of my time.

The PRESIDING OFFICER. All time is yielded back. The question is on agreeing to the amendment of the Senator from Colorado.

The amendment was agreed to.

Mr. HASKELL. Mr. President, I thank my friend from Massachusetts very much.

The PRESIDING OFFICER. The Senator from Massachusetts.

Mr. BROOKE. Mr. President, I ask unanimous consent that Meg Powers, of my staff, be accorded the privilege of the floor during the consideration of the bill presently before the Senate and any and all votes thereon.

The PRESIDING OFFICER. Without objection, it is so ordered.

Mr. BROOKE. Mr. President, there is no longer any question that the availability and management of electric utilities——

The PRESIDING OFFICER. Who yields time to the Senator from Massachusetts?

Mr. DURKIN. Mr. President, how much time does the Senator need on the bill?

Mr. BROOKE. I need 30 minutes.

The PRESIDING OFFICER. Who yields time?

Mr. DURKIN. How much time remains on the bill?

The PRESIDING OFFICER. The Senator from Louisiana has 36 minutes, and the Senator from New Mexico has 57 minutes.

Mr. BROOKE. Mr. President, under those circumstances——

Mr. DURKIN. How about 5 minutes?

Mr. President, I reserve my right to object to any Senator's request.

The PRESIDING OFFICER. The Senator always has a right to object. No unanimous-consent request is pending.

Mr. BARTLETT. Mr. President, will the Senator yield?

Mr. BROOKE. I am very pleased to yield.

Mr. BARTLETT. Is the Senator handling the time or if he is not handling the time, I shall yield? I wish to make sure the Senator has time.

Mr. BROOKE. I was asking for 30 minutes.

The PRESIDING OFFICER. The Chair is inquiring who yields time to the Senator from Massachusetts.

Mr. BARTLETT. I yield 30 minutes to the Senator from Massachusetts.

The PRESIDING OFFICER. Thirty minutes is yielded to the Senator from Massachusetts.

Mr. BROOKE. Mr. President, there is no longer any question that the availability and management of electric utility energy is a matter of national concern. Energy resources in general did not become a matter of public policy with the introduction of the President's energy program. For over 2 years, the Nation has been implementing laws whose sole 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 rulemaking 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 28, 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."

**§ 708.8 [Amended]**

3. Paragraph (a) of 12 CFR 708.8 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, notwithstanding 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. 79-32789 Filed 10-23-79; 8:45 am]
BILLING CODE 7535-01-M

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**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 18, 1979.

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

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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.

## 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

[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.

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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 § 292.200 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.[1]

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.[2]

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

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[1] "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.

[2] Conference Report on H.R. 4018, Public Utilities Regulatory Policies Act of 1978, H. Rep. No. 1750, 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 1978 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 § 292.106(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.[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.

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[4] For example, § 290.303(b) 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 290.306(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 8, 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.[9] 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 § 292.108, 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.

§ 292.106 *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 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 and the

[9] Staff discussion paper, *supra*, at 10-14.

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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 often 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.[9] 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,

[9] Comments of American Electric Power, filed August 1, 1979, at 3-4; 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 3-6.

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 certainty 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 preceding 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. §§ [illegible], November 9, 1978.

[13] 26 U.S.C. § 46(e)(3)(b).

[14] Treasury Reg. § 1.46-[illegible], T.D. [illegible] (March 22, 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 16–20.

[16] Comments of ELCON (Electricity Consumer Resources Council), filed August 1, 1979, at 3.

[17] Comments of Consumers Power Company, filed August 1, 1979, at 3.

[18] Staff discussion paper, supra at 24–28.

**§ 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.[illegible]

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.[illegible]

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

[illegible] Comments of The Southern Company, filed July 30, 1979, at 5.

[illegible] 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 cogeneration 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 authorised 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 required 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. RM79-8, issued September 6, 1979, and Application for License for Major Project—Existing Dam, Docket No. RM79-36, 44 F.R. 24086 (April 23, 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**



**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 i  this part.

(b) *De  uitions:* For purposes of this part:

(1) "Q ualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under § 292.206 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 § 292.106(e), each electric utility shall purchase in accordance with § 292.106 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 § 292.108.

(c) *Obligation to Interconnect.* Any electric utility shall make all interconnections with any qualifying facility as may be necessary to accomplish pu-chases 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;

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(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.

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## 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 2(a)(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. 79-32856 Filed 10-23-79; 8:45 am]

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## 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.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

# SUMMARY OF COMMENTS ON COGENERATION AND SMALL POWER PRODUCTION

DOCKET NO. RM79-55

FOR FURTHER INFORMATION CONTACT:

Christine Benagh
Office of the General Counsel
357-8033

or

Glenn Berger
Office of the General Counsel
357-8033

need be made. The commenter disagrees with this proposition. It states that if the time of purchase cannot be recorded it should be assumed that all utility purchases are made off-peak. In this way the qualifying facility, not the utility's other customers, would bear the consequences of uncertainty. 249/

Decreased Revenues. One commenter states that the rules regarding rates for purchases should permit consideration of decrease in revenue to the utility as a result of conversion by full requirement customers to self-generation without simultaneous cost reduction which would result in increased charges to other customers in order to recover fixed and administrative costs. The commenter recommends that a new section 292.105(d)(4) be added to permit consideration of "the effect of revenue detriments as a result of the conversion of full requirement customers to either cogeneration or small power production which are greater than simultaneous cost reduction." 250/

§ 292.105(e) Periods During Which Purchases Not Required.

Several commenters who address this subsection state that the provision is unnecessary. It is pointed out that the Commission's regulations which tie the price of energy sold by qualifying facilities to the utility's avoided cost will require the qualifying

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249/ Commonwealth Edison, et al.

250/ Arizona Public Service.

facility to pay the utility for accepting its energy output. Such a situation will make the facility reluctant to supply the utility. For example, two commenters point out that the Commission's regulations require that the qualifying facility pay a negative avoided cost if these, in fact, are incurred by the utility. 251/ Another commenter notes that this provision can be eliminated by the proper application of avoided cost and negative avoided cost and should, therefore, be eliminated. 252/ Another agrees that because of the negative avoided cost, § 292.105(e) is unnecessary. 253/

Some commenters feel that the section is vague, permitting utility great latitude in determining when purchases are not required. One commenter states that the negative avoided costs formula should only be permitted to the extent that the utility can demonstrate that it took into account currently available or projected qualifying facility output in its system planning before proceeding with the construction of its excess baseload capacity. 254/ Others maintain that utilities should only be permitted to cease purchase obligations when these conditions

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251/ MIT, Energy Consumers of New Mexico, Inc.

252/ Energy Law Institute.

253/ New York State Energy Office.

254/ Institute for Local Self-Reliance.

are actually shown to exist. 255/ Two commenters state that utilities should not be able to use this section if they have constructed new capacity in the face of declining demand. 256/ One commenter recommends that an individual state should be permitted the flexibility to allow qualifying facilities to continue in operation for an extended time period so long as the overall rates charged are economical on an average basis. 257/ One commenter simply states that the Commission should more clearly define which costs are to be considered in determing whether the utility would incur greater costs by purchasing such energy. 258/

From the utilities' standpoint, one commenter points that it is difficult to identify in advance periods during which utilities can avoid purchases. Another notes that reducing generation from facilities to allow for purchases from a qualifying facility could require the taking of the facilities coal-fired generation out of service. This could require the use of more oil to restart the generator and for flame stabilization when operated at low load levels. Under these circumstances

255/ MIT, New York State Energy Office.

256/ California Public Utility Commission, California Energy Commission.

257/ Massachusetts Energy Office.

258/ Colorado - UTE Electric Association.

the utility would be required to use more oil than would otherwise be necessary. The commenter suggests that the rules permit utilities not to purchase energies when to do so would increase net oil usage. They recommend that the following sentence be added to § 292.105(e): "An electric utility shall not be required to purchase energy or capacity during any period in which such purchases from a qualifying facility might result in a degradation of the security and reliability of the utility's system or violate good operating procedures." 259/ Another commenter supports § 292.105(e) with regard to periods during which electric utilities are not required to accept deliveries of power from qualifying facilities.

The commenter refers to "light-load" problems which develop when energy would be delivered during off-peak times. The commenter recommends that qualifying facilities should either be charged for off-peak deliveries under such conditions or that, when a utility can show that such conditions exist, no payments should be required. 260/

Another utility recommends expansion of the section, noting that this section relies exclusively on cost as a criteria to determine the periods when purchases are not required. The commenter suggests that, during periods of extremely low demand,

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259/ Southern Company.

260/ American Electric Power.

reliability constraints may be require a utility to operate its generating plants at minimum load. In such cases the utility generation cannot be backed off to accommodate purchases of energy even at lower costs. 261/ It also suggests that utilities not be required to make purchases during any period during which the utility generates or purchases an equivalent amount of electric energy generated from renewable resources or from plants designated for operation of minimize air pollution or during periods of minimum system operations. 262/

Two public utility commissions recommend that the utility which is refusing energy from a qualifying facility under this subsection be required to endeavor to resell the energy to interconnected utilities and to wheel the energy. 263/ One commenter points out that the provisions in § 292.104(d) (wheeling) requires other uuilities to accept power wheeled to them from qualifying facilities. As a result electricity would only be provided free if the transmission cost to the second utility exceeds the avoided cost to every utility in the United States. 264/

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261/ Pacific Gas & Electric Company.

262/ Id.

263/ Oregon Department of Energy, California Energy Commission.

264/ New York State Energy Office.

Finally, two public service commissions recommend that this subsection not be permitted to override contracts for purchases of electrical power. One commenter states its concern that this paragraph might undermine contractual arrangements by relieving a contractually bound utility from its obligation to make the purchase. It suggests that this section be amended to make it clear that it does not override existing contracts. 265/ Another suggests adding the following sentence to this paragraph "capacity and energy purchases which result from a legally enforceable obligation for firm power deliveries are not subject to option by the utility of not purchasing such electricity during such periods identified by the state regulatory authority." 266/

§ 292.106 Rates for Sales.

General. One commenter believes the proposed rule to be equitable in its present form. 267/ Another commenter also believes the Commission has proposed "proper and effective criteria" for rates of sales by utilities to qualifying facilities. 268/

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265/ New York State Public Service Commission.

266/ State of California Public Utility Commission supported by the Solar Energy Research Institute.

267/ Jet Propulsion Laboratory.

268/ American Paper Institute.

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structural failure of the airframe, accomplish a comprehensive inspection of all areas modified by The Raisbeck Group, as follows:

A. Before further flight, inspect for deviations from the supplemental type design in accordance with Paragraphs I through IV, and VI, of FAA approved Raisbeck Service Bulletin No. 25. Inspect for discrepancies such as:

1. Plugged holes
2. Oblong, egg-shaped, oversized, or irregular holes
3. Tapered holes
4. Excess holes
5. Inadequate edge distances
6. Gouges
7. Improper fasteners (type and number)
8. Improper clearances
9. Any other irregularities which are not consistent with standard aircraft practice.

B. Before accumulation of 2,000 flight hours time-in-service after modification by STC SA887NW inspect the horizontal stabilizer and elevator in accordance with Paragraphs V(A) and V(B) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 5,000 flight hours time-in-service thereafter.

C. Before accumulation of 2,000 flight hours time-in-service after modification by STC SA887NW or STC SA847NW, inspect the wing leading edge in accordance with Paragraph V(D) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 5,000 flight hours time-in-service thereafter.

D. Before accumulation of 10,000 flight hours time-in-service after modification by STC SA887NW or STC SA847NW, inspect the overwing modification in accordance with Paragraph V(C) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 10,000 flight hours time-in-service thereafter.

E. Inspections are to be conducted at facilities specifically authorized by the Chief, Engineering and Manufacturing Branch, FAA Northwest Region.

F. Discrepancies discovered as a result of the inspections are to be reported to the Chief, Engineering and Manufacturing Branch, FAA Northwest Region. Repair or modifications required because of these problems are to be FAA approved by the Chief, Engineering and Manufacturing Branch, FAA, Northwest Region or specifically authorized DERs.

G. Airplanes may be ferried, in accordance with FAR 21.199, to a maintenance base, for the purpose of complying with this AD.

H. The inspections noted herein may be accomplished as noted or in a manner approved by the Chief, Engineering and Manufacturing Branch, FAA, Northwest Region.

I. Areas previously inspected in accordance with Amendment 39-3640 may be excluded from the inspections required by this AD.

The manufacturer's specifications and procedures identified and described in this directive are incorporated herein and made a part hereof pursuant to 5 U.S.C. 552(a)(1).

All persons affected by this directive who have not already received these documents from the manufacturer, may obtain copies upon request to The Raisbeck Group, 7777 Perimeter Road, Seattle, Washington 98108.

This amendment becomes effective upon publication in the Federal Register and was effective earlier to all recipients of the telegraphic AD T80-NW-2 dated January 17, 1980.

(Secs. 313(a), 601, and 603, Federal Aviation Act of 1958, as amended (49 U.S.C. 1354(a), 1421, and 1423) and Section 6(c) of the Department of Transportation Act (49 U.S.C. 1655(c)); and 14 CFR 11.89)

Note.—The FAA has determined that this document involves a regulation which is not considered to be significant under the provisions of Executive Order 12044 and as implemented by Department of Transportation Regulatory Policies and Procedures (44 FR 11034; February 26, 1979).

Issued in Seattle, Washington, on February 13, 1980.

Note.—The incorporation by reference provisions in the document were approved by the Director of the Federal Register on June 19, 1967.

C. B. Walk, Jr.,

*Director, Northwest Region.*

[FR Doc. 80-5555 Filed 2-22-80; 8:45 am]

BILLING CODE 4910-13-M

## OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE

### 15 CFR Chapter XX

### CFR Chapter Heading and Nomenclature Change

February 19, 1980.

**AGENCY:** Office of the United States Trade Representative.

**ACTION:** Final rule.

**SUMMARY:** This rule changes Chapter XX of Title 15, Code of Federal Regulations, from "Office of the Special Representative for Trade Negotiations" to "Office of the United States Trade Representative." Within the body of the Chapter XX, all references to the "Office of the Special Representative for Trade Negotiations", to the "Special Representative for Trade Negotiations" and to the "Special Representative" or "Deputy Special Representative" are changed to the "Office of the United States Trade Representative", to "the United States Trade Representative" and the "Trade Representative" or "Deputy Trade Representative" respectively. These changes are authorized as part of Reorganization Plan No. 3 of 1979 (44 FR 69273) which was implemented by Executive Order No. 12188 of January 2, 1980 (45 FR 989).

**EFFECTIVE DATE:** February 25, 1980.

**FOR FURTHER INFORMATION CONTACT:** Alice Zalik, General Council's Office, Office of the United States Trade Representative, 1800 G Street, NW., Washington, D.C. 20506. (202) 395-34..

Accordingly, each reference to "the Office of the Special Representative for Trade Negotiations" contained within Chapter XX of Title 15 of the Code of Federal Regulations, including the heading, is changed to "the Office of the United States Trade Representative". Each reference to "the Special Representative for Trade Negotiations" contained within the chapter is changed to "the United States Trade Representative". Each reference to the "Special Representative" and to the "Deputy Special Representative" is changed to the "Trade Representative" and to the "Deputy Trade Representative" respectively.

Robert C. Cassidy,

*General Counsel.*

[FR Doc. 80-5880 Filed 2-22-80; 8:45 am]

BILLING CODE 3190-01-M

## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

### 18 CFR Part 292

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

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

**AGENCY:** Federal Energy Regulatory Commission.

**ACTION:** Final rule.

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

**EFFECTIVE DATE:** March 20, 1980.

**FOR FURTHER INFORMATION CONTACT:**

Ross Ain, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8440.

John O'Sullivan, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8477.

Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8033.

Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-376-9204.

SUPPLEMENTARY INFORMATION:

Issued February 19, 1980.

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

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

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

Small power production facilities use biomass, waste, or renewable resources, including wind, solar 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 facilities which obtain qualifying status under section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act.

## I. Procedural History

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

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

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

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

After consideration of the comments, the Commission Staff made available a final draft rule on January 29, 1980. State public utility commissioners were invited to comment on the draft at a public meeting held on February 5, 1980. Representatives of electric utilities were invited to comment at a public meeting held on February 6, 1980. The Commission Staff also made itself available to any other interested parties who wished to comment. All of the comments were considered in the formulation of this final rule.

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

## II. Summary

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

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

[1] 44 FR [illegible], July 3, 1979.
[2] 44 FR [illegible], November 15, 1979.
[3] 44 FR [illegible], July 3, 1979.
[4] 44 FR [illegible], October 24, 1979.

[5] 44 FR 61877, October 26, 1979.

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

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

### III. Section-by-Section Analysis

*Subpart A—General Provisions*

**§ 292.101 *Definitions.***

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 292.301 *Scope.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**§ 292.303 Electric utility obligations under this subpart.**

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

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

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

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

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

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

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

*Transmission to Other Facilities*

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

This would not appear to be the case if the qualifying facility offers to supply capacity and energy to 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(e) 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.[22] The Commission has therefore provided that the rate for purchases meets the statutory requirements if it equals avoided costs, and has eliminated the reference to the "rebuttable presumption".

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

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

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

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

Moreover, several utilities commented that, for the forseeable future, they are inextricably tied to the use of oil to produce electricity. They 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 of scarce fossil fuels, such as oil and gas, and the more efficient use of energy.

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

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

> It is not the intention of the Conferees that cogenerators and small power producers become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[23]

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

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

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

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

§ 292.304(b) *Relationship to avoided costs.*

*"New Capacity"*

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

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

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

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

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

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

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

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

§ 292.304(c) *Standard rates for purchases.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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§ 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 purchases 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.[55]

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.[56]

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

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

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

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

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

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

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

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

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

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

[56] *Id.*, at 98.

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

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

*§ 292.304(e) Factors affecting rates for purchases.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

*Tax Issues*

The Conference Report states that:

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

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

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

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

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

**§ 292.305 Rates for sales.**

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

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

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

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

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

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

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

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

[19] 26 U.S.C. § 48(l)(3)(B).

[20] Treasury Reg. § 1.46-3(g)(2); T.D. 7602 (March 23, 1979).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

### § 292.306 *Interconnection costs.*

Paragraph (a) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs, on a nondiscriminatory basis with respect to other customers with similar load characteristics. The Commission finds

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

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continuing process and that oversight will be ongoing.

§ 292.402 *Implementation of reporting objectives.*

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

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

§ 292.403 *Waivers.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[21] See Order No. 11, Simplified Procedures for Certain Water Power Licenses, Docket No. RM79-4, issued September 5, 1979, and Application for License for Major Projects—Existing Dam, Docket No. RM79-38, 44 FR 24095 (April 23, 1979).

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

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

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

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

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

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

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

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

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

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

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

## IV. Effective Date

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

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

Kenneth F. Plumb,
*Secretary.*

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

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

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

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

### Subpart A—General Provisions



### 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



### Subpart D—Implementation



* * * * *

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

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

## Subpart A—General Provisions

### § 292.101 Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

## Subpart B—[Reserved]

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

### § 292.301 Scope.

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

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

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

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

### § 292.302 Availability of electric utility system cost data.

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

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

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

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

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

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

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

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

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

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

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

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

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

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

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

**§ 292.303 Electric utility obligations under this subpart.**

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

(1) Directly to the electric utility; or

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

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

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

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

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

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

**§ 292.304 Rates for purchases.**

(a) *Rates for purchases.* (1) Rates for purchases shall:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**§ 292.305 Rates for sales.**

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

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

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

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

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

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

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

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

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

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

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

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

**§ 292.306 Interconnection costs.**

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

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

**§ 292.307 System emergencies.**

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

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

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

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

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

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

**§ 292.308 Standards for operating reliability.**

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

## Subpart D—Implementation

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

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

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

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

**§ 292.402 Implementation of certain reporting requirements.**

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

**§ 292.403 Waivers.**

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

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

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

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

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

(1) qualifying cogeneration facilities: and

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

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

(1) Sections 1–30;

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

(3) Sections 305(c); and

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

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

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

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

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

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

(i) The rates of electric utilities; and

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

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

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

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

[FR Doc. [illegible] Filed [illegible]]

BILLING CODE [illegible]

## DEPARTMENT OF JUSTICE

**Parole Commission**

**28 CFR Part 2**

**Parole, Release, Supervision and Recommitment of Prisoners, Youth Offenders, and Juvenile Delinquents**

**AGENCY:** U.S. Parole Commission.

**ACTION:** Final rule.

**SUMMARY:** The Parole Commission has adopted a rule that contains both procedural and substantive changes in the handling of parolees who are serving sentences of imprisonment for new criminal offenses committed while on parole. Procedurally, parole violators incarcerated in state or local facilities will be afforded revocation hearings after completion of 18 months of confinement on the new sentence, or on the docket following their arrival at a federal institution, whichever comes first. For parole violators serving new sentences in federal facilities, the revocation hearing will be held within 120 days after the Commission has been notified of the new incarceration, or as soon thereafter as practicable. The rule also establishes a substantive change from past Commission policy by providing for a customary policy of partially concurrent service of the parole violator term and the new sentence starting either upon release from confinement on the new sentence, or after 18 months of confinement on the new sentence, whichever comes first. A departure from this customary policy would require the concurring votes of two Commissioners. The purpose of this rule is to reduce the period of uncertainty for incarcerated parolees as to the Federal disposition of his/her case.

**EFFECTIVE DATE:** July 1, 1980, following the procedure described below.

**FOR FURTHER INFORMATION CONTACT:** Barbara Meierhoefer, Research Unit, U.S. Parole Commission, 320 First Street, NW., Washington, D.C. 20537; telephone (202) 724–3183.

**The Proposal and Its Purpose**

On June 5, 1979, the U.S. Parole Commission published in the Federal Register (44 FR 32253) a proposed rule which dealt with the time of revocation hearings for parole violators serving new sentences.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

| | | |
|---|---|---|
| Small Power Production and Cogeneration Facilities Qualifying Status | ) | Docket No. RM79-54 |
| Small Power Production and Cogeneration Facilities Rates and Exemptions | ) | Docket No. RM79-55 |

PUBLIC HEARING

Wednesday, November 28, 1979
New York, New York

PANEL:

ROSS AIN, Hearing Officer

JACK HEINEMANN

ADAM WENNER

JOHN O'SULLIVAN

JAMES LILES

resources.

MR. AALTO: Is the question then, what do I think of the idea of not letting an old --

MR. O'SULLIVAN: It seemed to me you had a misunderstanding of what the rule was designed to do.

HEARING OFFICER: Thank you very much for your patience.

Is Maura O'Neil of Consumer Action here? Please give your name, address and who you represent for the record.

MS. O'NEIL: My name is Maura O'Neil. I am with Consumer Action Now, 355 Lexington Avenue, New York City, 10017.

I am submitting this testimony on behalf of Consumer Action Now on Notice of Proposed Rulemaking regarding implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978.

Consumer Action Now was founded in 1970 to translate technical information on environmental and consumer issues into laypersons' language.

CAN has been involved exclusively with energy issues for the past five years, and has been at the forefront in promoting energy conservation in the use of clean renewable resources.

We support efforts to move this country toward a safe and sustainable energy future.

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Does anyone on the panel have any questions or remarks? Mr. Wenner.

MR. WENNER: You mentioned the possible ambiguity between two sections, 105(c)(2) it says in the paper, you said "3" and I think you meant "2," and 292.105(e).

I think there is not an ambiguity and I would like to explain to you my understanding, and then if there is still one, I would like to know if there is something we have missed.

The second section deals with periods when some utilities have advised us they have baseload units operating on the margin, it's their most expensive plants, and that if they cut back out from those plants that when they do have to increase it to match load there will be a net increase in cost to customers.

The other section deals with the ability of a qualifying facility to deliver power as available.

I agree that there is a conflict between those two sections and it would be our understanding that the first would override the second, that is, if there is such a period identified by the state regulatory authority, during that period one would not be able to make as available sales to the utility.

That would be just a reconciliation between the two sections, and with that in mind, I'm not quite sure how to interpret your comments with regard to taking the potential of the capacity and energy displacement into account.

Could you elaborate on that?

MS. O'NEIL: Yes. I know that there was probably not ambiguity in your intent in writing it, but in reading it, I understand that there are certain times of the year when utilities do have baseload on the margin, but I think that also the way that we have read it is that it could be used as an escape clause or an out for the utilities at any point during the year to not buy power, so we just wanted to point this out, that if there is going to be that allowance of utilities not to be able to refuse to buy power in certain periods that it be made very clear that that and the capacity of the small generators be taken into consideration in all the facilities.

HEARING OFFICER: Thank you very much.

The next witness is Richard Napoli. Please give your name, address, and who you represent.

MR. NAPOLI: My name is Richard Napoli. I am the Deputy Director of the Center for Regional Technology and Solar Energy Applications Center at the Polytechnic Institute of New York, at 333 Jay Street, Brooklyn, New York

The Polytechnic Institute is a unification of two of the oldest engineering and science institutions in New York State and, for that that matter, the country -- the

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the Matters of:

SMALL POWER PRODUCTION AND COGENERATION FACILITIES -- QUALIFYING STATUS — Docket No. RM79-54

SMALL POWER PRODUCTION AND COGENERATION FACILITIES -- RATES AND EXEMPTIONS — Docket No. RM79-55

- - - - - - - - - - - - - - - - - - -x

Hearing Room 9306
Federal Energy Regulatory Commission
825 North Capitol Street
Washington, D. C.
Wednesday, December 5, 1979

The above-entitled matters convened for public hearing, pursuant to adjournment, at 9:00 a.m.

BEFORE:

ROSS AIN, Esq. Presiding

PANEL MEMBERS:

JAMES LILES
BERNARD CHEW
DR. JACK HEINNEMAN
ADAM WENNER
JOHN O'SULLIVAN
DEBORAH GOTTHEIL

ALSO PRESENT:

COMMISSIONER HALL
MR. NORDHAUS

- - -

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question the witness?

I would just like to say and comment to you that it is a very difficult problem, the one of providing enough direction from this Commission to the states in implementing this to minimize problems without creating problems. In other words, the diversity out there is such that if we go too far, the existance of benign legislation in New Hampshire, Maine and other states that have been pointed out to the Commission, we have a balance there and we will try to do our best in this regulation to give, where we can, guidance and certainly, where we must, flexibility and allow for innovation and I think it is going to be a process of revising these rules in the future.

I think some of us have perceived that the worst thing we can do is to give so much clarity that we set back good programs that are existing in the states.

MR. WOLFF: I am just suggesting that perhaps that support should come or could potentially come not so much in the form of restrictive regulations as in the form of technical support.

MR. AIN: I understand.

MR. WOLFF: Thank you.

MR. AIN: Our penultimate witness is John Plunkett from the Institute for Local Self Reliance.

MR. PLUNKETT: Good afternoon. My name is John Plunkett and I am a staff economist with the Institute for Local Self Reliance, a non-profit technical assistance and research firm based in Washington, D. C. Our address is 1717 18th Street, Northwest, Washington, D. C. 20009. I thank the Commission's staff for this opportunity to participate in these, the final hearings, on federal rules governing the purchase and sale of power between electric utilities and small producers.

At the outset, I wish to state that this is my second appearance before this Commission concerning the evolution of the PURPA rules on non-utility power generation. I feel the Staff has done a splendid job in dealing with the complicated set of economic issues raised by Congress in directing this regulatory mandate to FERC. The proposed rules embody fairness in the tradeoffs between equity and efficiencies among QFs as well as utility customers and shareholders.

MR. AIN: I might interrupt to state that I do remember your earlier testimony which I also greatly appreciate. I think the staff did. It was very well done.

MR. PLUNKETT: Thank you.

I also think it would be niave to ignore the obvious trepidation with which most, if not all, investor-owned utilities view the proposed rules regarding Section 210 of PURPA. Many show legitimate if exaggerated concern for the potential compromise of future service reliability to their customers;

that the only thing that is going to be necessary is a main breaker installed at the facility with some kind of lock and the cost of that thing installed shouldn't be any more than around $150 for a small system. We are talking about under the ten kilowatt range and that also these -- both induction motors will cut out automatically once there is a line failure and, again, for a serviceman with that main breaker and lock assembly and the automatic cut-out of the system, you should be well protected.

I understand that Southern California Edison -- I had a conversation with them. They have basically the old backup, old backup cliche which seems to be kind of excessive. We basically have a double thing going on here. They want triple and I don't know what that third level is but it seems to me unnecessary.

Another thing is that this comes to my third topic, what I perceive to be a baseload escape clause posed by the -- I forget what section it is in.

MR. AIN: 292.105(e).

MR. PLUNKETT: You have got it. Okay.

First of all, I don't agree that I could feel strongly that a utility should never be able to refuse purchases. I would much rather see them be able to charge, as I think the Edison Electric Utility suggested, for power, basically the utility allowing them to charge QF for the ability to dispose of, if you will, the power that you -- that he produces. The reason I see this as an escape clause is that while utilities might be talking about, you might be talking about capacity credits, they might, in fact, not defer capacity and so that they can, the way I see it is that utility can take on all of these QFs as kind of captive sellers and then keep, go ahead and stick in thier nice baseload units and say in 1995 all bets are off. We have got to take you guys on. We have got this massive baseload and suddenly you might have sized your equipment to produce a certain level of output and suddenly it has negative or no value. I think a remedy for that would be to suggest, first of all, make sure that the utilities are somehow -- makes them take into account in a planning perspective and that somehow, they insure that -- first of all, ratepayers would be footing the bill if utilities brought up the point of if capacity isn't deferred and you are getting capacity credits, you are going to have some redundant costs being borne by the consumers and from the other hand, it is clearly inefficient to talk about capacity credits and not defer any capacity. I don't see that that is necessarily going to be taken care of.

The way the rules have set out -- alternatively, I would say that this particular section would be null and void if it could be shown that they were not taking it into account in their explanations.

NOTE: While the documents which comprise Exhibits RJS-8, RJS-9, and RJS-10 bear a "confidential" mark, counsel for FPC has confirmed that these documents -- some of which are excerpts from larger documents -- need not be treated as confidential.

R.J. Rocha

Florida Power
CORPORATION

# COGENERATION REVIEW

An Assessment of Florida Power's Qualifying Facility
(Cogeneration) Purchases

PRELIMINARY

Energy Distribution Department
December 1993

Confidential Material
FPC Use only

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# CURRENT OF STRATEGY

## Need For New Capacity

The desirability of Florida Power Corporation buying out its existing cogeneration contracts is highly dependent upon FPC's need for additional generation capacity. In turn, the need for capacity is a function of several major assumptions. These include:

1. The Long-Term Demand and Energy Forecast.
2. The approved additions and retirements of FPC's generation capacity.
3. The planned additions and maintenance of FPC's Demand-Side Management (DSM) programs.

Depending upon what assumptions are made, FPC's need for capacity can vary a great deal. The Load and Capacity Report in Appendix 11 provides the details of FPC's need for capacity through 2003 for strategic planning purposes. (Generally, FPC's need for capacity is driven by a need to satisfy the 15% winter reserve margin. Additionally, all results must be verified to ensure that the 0.1 days/year Loss of Load Probability criterion is not violated.)

The Load and Capacity report assumes that DSM programs are expanded by 40 MW each year from 1993 levels, the Siemens and Polk County units are completed on schedule, the Turner and Higgins steam plants are placed in extended cold shutdown, and all 1,100 MW of cogeneration comes on-line as planned.

The column of the Load and Capacity report titled "New FPC capacity (MW)" indicates the capacity additions necessary to maintain the 15% winter reserve margin. These capacity additions are not cumulative, therefore the additions are those required for each year. These results identify a need for additional capacity in the winter of 1999/2000, as well as in the winter of 2001/2002.

If the present DSM programs are modified, FPC could require additional capacity by the end of 1999. This would mean that the cancellation of a purchased power contract would cause a need to build or buy additional capacity. With the current FPSC position on bidding, it is highly likely that this new capacity need would be met through a competitive bidding process.

The elimination of any of the existing cogeneration contracts could cause a need for additional capacity. A possible buy out proposal should consider the cost involved in replacing the existing capacity. The need for new capacity makes a buy out very difficult. In states were cogeneration buy outs have been successful, no replacement capacity has been required.

## Operational Strategy

The energy needs from QFs is variable with load, maintenance outages, and fuel costs. When only variable energy costs are considered in production cost simulation studies, the various cogeneration contracts dispatch at approximately a 70% capacity factor. This is less than the contracted capacity factor, but significant nonetheless. At minimum load conditions, hourly deterministic computer simulations have shown a need to load follow (adjust cogenerator output to the system load) as well as cycle (turn cogenerator off or on) on a daily basis.

Ideally, FPC would schedule, dispatch, and operate the various cogenerator units in the same manner its other plants are operated/dispatched. There is a certain need to load follow with at least 300-600 MW of cogeneration capacity over the course of a typical day. Additionally, there is a fast approaching regular need to cycle some cogenerators and FPC base load capacity during minimum load hours (i.e. 2 AM to 6 AM). When these cogeneration contracts were negotiated it was forecasted that load, including minimums, would increase at a higher rate than has actually occurred. In addition, it was anticipated that the economic incentives for not generating during low load conditions would also address these concerns.

Since the various cogenerators have a wide cost structure range, some would elect to generate energy even when FPC's as available costs are as low as $16/MWh. Therefore, many of the cogenerators would not voluntarily curtail their output.

FPC has been engaged in renegotiations with some cogenerators, without additional costs to FPC's ratepayers, to obtain dispatch and scheduling or cycling rights. Niagara Mohawk and PG&E have been forced to pay QFs to obtain dispatch rights during minimum load periods utilizing an auction type approach. FPC is actively pursuing these negotiations through the FPSC rule 25-17.086 "Periods During Which Purchases Are Not Required". This regulation has limited application during extreme conditions only. The implementation of this regulation by FPC would undoubtedly result in immediate cogenerator litigation. The regulation speaks to curtailments when "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." However, the same regulation requires the utility to verify the claim to the FPSC on each occurrence. FPC has decided to implement an actual curtailment prior to a hearing at the FPSC. It has not been determined if FPC waived certain rights by signing contracts with the various parties.

The cogeneration contracts based on a FPC avoided coal unit (62% of the total QF contract capacity) receive firm energy payments when a unit of this type would have been scheduled on. FPC is currently negotiating certain dispatch and scheduling rights during these hours which will result in a very limited requirement (if at all) to cycle any of FPC's coal units. These include Orlando CoGen (79.2 MW), and Auburndale (114.2 MW). Also, FPC has concluded negotiations with Tiger Bay (220 MW), Mulberry (110 MW), and Dade County (43 MW). Informal agreements have been made with Pasco Cogen (106 MW) and Lake

X261

Florida Power
CORPORATION

# INTEROFFICE CORRESPONDENCE

| System Planning | KBL | 5539 |
|---|---|---|
| Office | MAC | Telephone |

SUBJECT: Cogeneration Dispatchability Study

TO: Ed Bassford

DATE: March 7, 1991

Enclosed are the results of a study to determine the benefit to Florida Power Corporation (FPC) of having the ability to dispatch a 400 MW block of cogeneration. This is contrasted to a base case where the cogenerator is modelled as a firm transaction.

These scenarios were selected at our February 27 meeting. The firm transaction is the one we called the "Cheap Fuel" case and is a worst case scenario. We were not able to model the "Expensive Fuel" case properly in PROMOD.

Assumptions:

| | |
|---|---|
| General | Term 1994 - [illegible]<br>1990 Facility Plan |
| Base Case | 400 MW Firm Transaction<br>83% Capacity Factor |
| Dispatchable | 400 MW Coal Unit<br>8% Forced Outage Rate<br>92% Availability<br>Heat Rate for Reference Coal Plant<br>Dispatched on CR 1 & 2 spot<br>Priced on average coal<br>5.2 weeks maintenance per year |

Results:

Over the specified term, the cogenerator operates the same, whether it is dispatchable or not. Therefore, the study indicates no justification for having dispatch control on the unit.

In some years, the dispatchable case is more expensive than the transaction. This is not a logical result. Based on a levelized annual fuel cost of over one billion dollars, the savings or loss shown are outside of the accuracy expected from the model. Therefore, the differences in cost between the cases cannot be attributed solely to the ability to dispatch the unit and could be due to the accuracy of the calculations. Were the savings to the company very significant, they would be inside these accuracy bounds.

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The dispatchable cogenerator is modelled as a small coal unit with an excellent heat rate and relatively inexpensive fuel. PROMOD dispatches this unit as base load, just as we would if an FPC unit with these characteristics existed. As a result, the capacity factor is always around 80%, which is the maximum.

This conclusion is only relevant for the twelve year term of the study. It uses assumptions made in the 1990 Facility Plan regarding load growth, construction of future FPC facilities, etc. No assumptions were made concerning future conditions where a coal unit with the Reference Unit heat rate is not desirable as a base load unit. Also, no consideration is given to an increase in O & M costs for FPC units which are cycled more due to the operation of the cogenerator.

Art Nordlinger

ALN:91-MAR-Cogen-1/bhl

Attachments

cc: W. B. Foley, Jr.
R. D. Hickam
G. D. Nagel
J. L. Seelke, Jr.

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## COGENERATION DISPATCHABILITY

### FIRM TRANSACTION VERSUS DISPATCHABLE UNIT

| YEAR | PRODUCTION COST FIRM 83% | DISPATCHABLE | C.F. | SAVINGS (LOSS) |
|---|---|---|---|---|
| 1994 | 834,433,680 | 834,153,764 | 83 | 279,916 |
| 1995 | 984,911,460 | 984,713,123 | 82 | 198,337 |
| 1996 | 1,090,945,214 | 1,091,252,235 | 83 | (307,021) |
| 1997 | 1,183,885,928 | 1,184,758,630 | 83 | (872,702) |
| 1998 | 1,301,994,348 | 1,302,530,283 | 83 | (535,935) |
| 1999 | 1,339,399,108 | 1,340,429,125 | 82 | (1,030,017) |
| 2000 | 1,466,092,610 | 1,466,648,938 | 82 | (556,328) |
| 2001 | 1,555,280,761 | 1,554,456,508 | 82 | 824,253 |
| 2002 | 1,696,768,476 | 1,695,175,997 | 82 | 1,592,479 |
| 2003 | 1,785,176,211 | 1,783,262,492 | 82 | 1,913,719 |
| 2004 | 1,945,232,151 | 1,942,976,606 | 82 | 2,255,545 |
| 2005 | 2,090,964,759 | 2,089,994,264 | 82 | 970,495 |
| LEVEL | 9.82% | | | |
| | 1,325,331,495 | 1,325,139,270 | | 192,224 |

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FPSC Docket No. 941101-EQ
OCL/Pasco Witness: SHANKER
Exhibit No. ___ (RJS-9)
Page 5 of 13

TX26

Florida Power Corporation

# INTEROFFICE CORRESPONDENCE

COGENERATION / SYSTEM PLANNING — [illegible] — 232-4205

SUBJECT: Cogeneration Dispatchability Study

TO: G. E. Bamford
L. D. Brousseau
A. I. Henry
G. D. Nagel
R. D. Nielsen
A. L. Nerdlinger
L. A. Welsh
T. I. Washington

DATE: March 26, 1991

Mike Foley asked me to continue our previous efforts to develop a cogeneration contract that includes dispatchability.

The task that I believe needs to be performed are listed on the attachment. Please review this list and add any others you feel we should address. I have scheduled a meeting on April 23, 1991 starting time 8:30 A.M. in conference room #5 E0 to discuss our approach to this dispatchability study and to agree to a timetable for completing the necessary tasks.

J. L. Snelica

JLS/[illegible]

cc: M. B. Foley, Jr.

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TX 252



Subject: Assessment of Criteria for Cogeneration Payments

To: C. D. Nagel
S. F. Nixon, Jr.
J. L. Seelke, Jr.

Date: October 18, 1990

At the last meeting on October 12, John Seelke authorized the formation of a subcommittee to develop a methodology to calculate a cogeneration equivalence factor and a ranking system for different types of cogeneration contracts as compared to a utility dispatchable unit. The equivalence and ranking system would be used to determine the payments to the cogenerator. I am requesting that you or a designated person in your group assist me in developing a methodology to calculate a generator equivalence factor.

I have contacted EPRI, Charles Rivers and Associates, and a couple of other utility companies to discuss scoring systems and ranking systems that have been used to evaluate IPP's and cogenerators. To date I have not found a study that is exactly like the one mentioned but several studies have been made that indicate a relative worth of desired criteria. Several papers and studies show that dispatchablity, on-peak performance, curtailablity, and reliability are extremely important factors in the development and pricing in contracts so that the customers win, the cogeneration project wins and the utility wins. Attached is a story about a very disappointing experience that United Illuminating Company had with cogenerators where they were producing less than 5% of there nameplate capacity during a critical time period. Also a couple of example tables are attached that show part of a sample scoring system.

In conclusion, I am convinced that it is very important that FPC provide the proper price incentives and signals to the cogenerators so that FPC will receive the power when it is needed at a price that is at or below the costs of our avoided units. At the same time we need adequately reward cogenerators that are dispatchable, curtailable and reliable.

Please contact me and let me know the person in your area will be willing and able to assist this subcommittee in the development of a methodology to evaluate different performance criteria and the relative value to our system. Thank you in advance for your cooperation.

C. E. Bassford

cc. E. H. Coffin
T. I. Wetherington
K. M. Wieland

Attachments

# DISPATCHABILITY STUDY OUTLINE

1. **Benchmark PROMOD and EVALUATOR**

   PROMOD simulations by Art Nordlinger indicated no justification for dispatchability with a base loaded coal unit. However, previous EVALUATOR runs by Linda [illegible] showed some benefit. We need to run the same scenario under both models and agree on one model for the purpose of future analysis.

2. **Evaluate how the Performance Adjustment would apply to a QF if it (the QF) simulated an FPC dispatched unit.**

   The Performance Adjustment in the current contract encourages to maximize performance when our avoided cost is highest. Does the adjustment properly reimburse the QF? We must determine the best way to evaluate this.

3. **Develop contract provisions for a dispatchable FPC unit.**

   We must develop provisions which address how an FPC dispatch unit would operate and incorporate this into a contract. The provisions should address as many of the parameters of the FPC dispatched unit as practical, such as:

   a. Scheduled outages
   b. Unscheduled outages
   c. Heat rate (including degradation)
   d. Variable O&M
   e. Seasonal capacity and heat rate changes
   f. Dispatch fuel cost vs. average fuel cost

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- TX259

RCV BY:CARLTON FIELDS : 3-18-94 ; 8:31AM ; ST. PETE:# 3

Florida Power Corporation

# INTEROFFICE CORRESPONDENCE

ENERGY CONTROL | EC37 | 226-7389
Office | MAC | Telephone

SUBJECT: 100 MW Cogenerator/Dispatchable Unit Study

TO: G. E. Bassford DATE: February 18, 1991

As requested in our February 6, 1991, conversation with R. D. Niekum, I re-ran the EVALUATOR model with the appropriate changes. The assumptions and/or conditions of the study are as follows:

- Study period is 01/05/91 - 12/27/91
- Corporate goal forced outage rates used
- Actual 1990 loads increased by three percent
- Fuel costs from FCP9003
- Cogenerator - 100 MW unit with 83 MW available on-peak hours and 67 MW available off-peak hours
- Dispatchable Unit - 100 MW unit with an eight percent forced outage rate and a five week one-day scheduled outage beginning 03/02/91
- Both the Dispatchable Unit and the Cogenerator had the same fuel cost as Crystal River units 1 and 2

To provide a sensitivity analysis, I ran three scenarios. These scenarios compared the effects of forced outage rate treatment which did not apply to the cogenerator. The first scenario used the forced outage rates to produce discrete forced outages throughout the study period. The second scenario used the forced outage rate to derate the maximum capacity for the entire study period. The third scenario ignored the forced outage rates and assumed 100 percent availability except for the scheduled maintenance outages. The attached table provides a summary of the results.

I believe the discrete forced outage scenario is more realistic from an operations view, therefore, the savings of $1,390,000 represents the yearly value that can be attributed to the dispatchable unit.

If you have any questions or comments, please do not hesitate to give me a call.

Linda D. Brousseau

L. D. Brousseau

LDB:fv#18

cc: D. R. Karp
G. D. Nagel
R. D. Niekum
R. W. Schooley
J. L. Seekle, Jr.

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**DISCRETE FORCED OUTAGES**

| | Cogen | Dispatchable |
|---|---|---|
| MWH | 637,200 | 677,200 |
| AVG. BTU/KWH | 9.92 | 9.94 |
| CAP. FACTOR | 74 | 79 |
| AVG. $/MWH | 17.61 | 17.63 |
| TOTAL $ | 654,906,600 | 653,516,600 |
| SAVINGS | $1,390,000 | |

**DERATED CAPACITY**

| | Cogen | Dispatchable |
|---|---|---|
| MWH | 639,600 | 692,700 |
| AVG. BTU/KWH | 9.88 | 9.86 |
| CAP. FACTOR | 75 | 81 |
| AVG. $/MWH | 17.61 | 17.44 |
| TOTAL $ | 642,559,400 | 641,432,000 |
| SAVINGS | $1,127,400 | |

**100 PERCENT AVAILABILITY**

| | Cogen | Dispatchable |
|---|---|---|
| MWH | 634,400 | 737,600 |
| AVG. BTU/KWH | 9.98 | 9.87 |
| CAP. FACTOR | 74 | 86 |
| AVG. $/MWH | 17.61 | 17.46 |
| TOTAL $ | 588,255,100 | 586,566,100 |
| SAVINGS | $1,689,000 | |

CC 251348

II X2

Florida Power Corporation

# INTEROFFICE CORRESPONDENCE

| Office | MAC | Telephone |
|---|---|---|
| Economic Research | B3N | 4367 |

SUBJECT: Information on Dispatchability

TO: E. H. Coffin
G. O. Nagel
S. F. Nixon
J. L. Seelke, Jr.

DATE: November 2, 1990

Attached is some information on dispatchability. As you can see, most utilities assign a value to dispatchability.

Ed Bassford

G. E. Bassford

GEB:csj

cc: K. H. Wieland

Attachment

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EPRI

Leadership in Science and Technology

# REPORT SUMMARY

**SUBJECTS** Utility planning methods / Power system planning and engineering

**TOPICS** Bidding; Resource planning; Independent power producers; Power generation planning; Cogeneration

**AUDIENCE** Corporate, generation, and demand-side planners / Power contracts managers

## Competitive Procurement of Electric Utility Resources

Competitive procurement has rapidly grown into an important means for many utilities and states to acquire new electric resources. This document synthesizes the wealth of knowledge and experience in the marketplace into a comprehensive reference on the procurement life cycle.

by P. Fox-Penner, P. O'Rourke, and P. Spinney

**BACKGROUND** Utilities and other firms have used competitive methods to select suppliers for many years. However, the use of bidding to purchase electric resources represents a new development with unique attributes. This report can help utilities quickly develop a thorough understanding of the competitive procurement process, providing a broad picture of various bidding methods used today in combination with the best current knowledge on the subject.

**OBJECTIVES**

- To explain the competitive procurement process, enabling readers to gain insight from other utility experience.
- To help utility planners and managers select, refine, and successfully implement bidding methods suited to their particular environments and resource needs.

**APPROACH** The project team compiled information on competitive resource procurement experience, including requests for proposals (RFPs), sample bids and purchase contracts, and various publications. They also interviewed utilities currently active in competitive bidding and conducted a two-day workshop with key managers of most U.S. utility procurement programs.

**RESULTS** This report contains detailed information on each stage of the competitive procurement process for acquiring new electric resources. Major sections of the report address bidding and resource planning, RFP design, price and nonprice factor evaluation, RFP issuance and evaluation logistics, awards and contract negotiations, and postcontract follow-up. In each section, a variety of approaches are described, based on utility experience; where appropriate, checklists for areas ranging from fuel supply to permits and licenses are provided. Additionally, the report features a bibliography of pertinent literature on bidding.



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Florida Power

# INTEROFFICE CORRESPONDENCE

Economic Research | [illegible] | 4367
Office | Mail | Telephone

SUBJECT: Request to Study the Value of Dispatchable Cogeneration

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TO: W. L. [illegible], Jr.

DATE: January 24, 1991

First, I would like to thank you for the opportunity to meet with you concerning the value of dispatchability for cogeneration. I appreciate your openness and your willingness to listen to my concerns and suggestions. With your leadership, I believe that Florida Power will be a model company for "Partners in Energy" that will help our customers and our stockholders. As you requested, I am making a summary statement of our meeting and I am listing sources of the information that was presented. At this point a conclusion cannot be drawn from the data. However, the data does indicate that Florida Power should study three areas so that the most value can be obtained for our customers from cogeneration.

1. In my opinion the single most important factor that we are missing in our cogeneration contracts is dispatchability. Some of the reasons to study the value dispatchability and have dispatchability in our contracts are:

   - Common sense tells you that a cogeneration plant under the control of our energy control center and its multimillion dollar computer system is going to be of more value to our customers than a cogenerator providing power its convenience.

   - Florida Power Corporation has studied and economically justified the expenditure of millions of dollars for improved dispatchability. With over a million dollars a day in fuel costs and billions being spent for capacity, a small percentage of improvement could provide large savings.

   - Other sources of information such as EPRI publications indicate that dispatchability and curtailability are important factors in the evaluation of NUG's. Other utilities such Virginia Power are already negotiating dispatchable contracts. Consulting firms such as Charles Rivers Associates have studied dispatchability and published documents stating that weight should be given to dispatchability.

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2. A second area that data indicates that we may be underestimating our requirements is in the area of the capacity factor. A statistical analysis was performed on the unit performance "UPIS" data base. The past two years of measured output for FPC's units Crystal River 4 & 5 was analyzed. By performing a statistical analysis on approximately [illegible] data points the following data was computed. A summary table is as follows:

FPC OBTAINED CAPACITY FACTORS:

| | |
|---|---|
| Annual on-peak hours capacity factor | [illegible]% |
| Peak months and on-peak hours capacity factor | [illegible]% |
| All hours (peak & off-peak) capacity factor | [illegible]% |

STANDARD OFFER

| | |
|---|---|
| On peak hours capacity factor | [illegible]% |
| Off-peak hours capacity factor | 7[illegible]% |

3. A third area that the data indicates that we may be making too high of payments is O & M. Two years of O & M expenses for FPC's coal units was analyzed. A summary table is shown below:

ACTUAL FPC O&M EXPENSES

| | |
|---|---|
| Crystal River 1,2,4 & 5 | $[illegible]/KW |

CONCEPTUAL DATA WHICH IS THE BASIS FOR THE STANDARD OFFER

| | |
|---|---|
| Fixed O & M Costs | $[illegible]/KW |
| Variable O & M Costs with [illegible] Capacity | $[illegible]/KW |
| | ------ |
| | $[illegible]/KW |

The historical O & M expense is difficult to compare for several reasons. The accounting process for capitalization and O&M makes it difficult to determine how much is actually spent for the maintenance of plants. On the other hand some historical expenditures made at plants were for improved efficiency and life extension. Also, with Florida Power's desire to minimize its costs to our customers, we do not always perform maintenance with the frequency specified by the manufacturer. Due to the large difference in the actual versus projected, I feel that we should study the O&M payment.

In summary, I am not criticizing our existing contracts or any of the past efforts but it is my intention to suggest areas for study that will make our contracts even better. By studying the three areas I believe that we will save our customers millions of dollars, will have more power when it is needed, and will be able to help the cogenerators by compensating them for potential costs that are not currently covered in our contracts such as the costs of extra cycling and compensation for heat rate changes due to dispatch.

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If I can be of further assistance or if you have any questions, please let me know. Again, thank you for your consideration.

Ed Sanford

G. E. Sanford

[illegible]

cc: K. M. Wieland

Attachments

# Energy Delivery Strategy Team

## Cogeneration and Purchased Power Strategic Proposal

March 18, 1994

CONFIDENTIAL 400580

## Strategy #6: Obtain Dispatch and Cycling Rights from QFs and Prepare for QF Curtailments

Due to the large influx of QF capacity, FPC may have to curtail deliveries from the QF's in 1994 to prevent cycling our coal facilities during minimum load conditions. FPC's minimum load can typically be as low as 1800 MW at 5 A.M. with an afternoon peak of 4200 MW at 5 P.M. The cycling of FPC's units will increase the cost to the ratepayers because FPC's coal units are needed to economically serve the afternoon peak. Pursuant to the FPSC rules, FPC will need to demonstrate that cycling the QF's is due to operational circumstances or for economic reasons and is in the best interest of the ratepayer as required by FPSC Rule 25-17.086, Periods During Which Purchases are not Required:

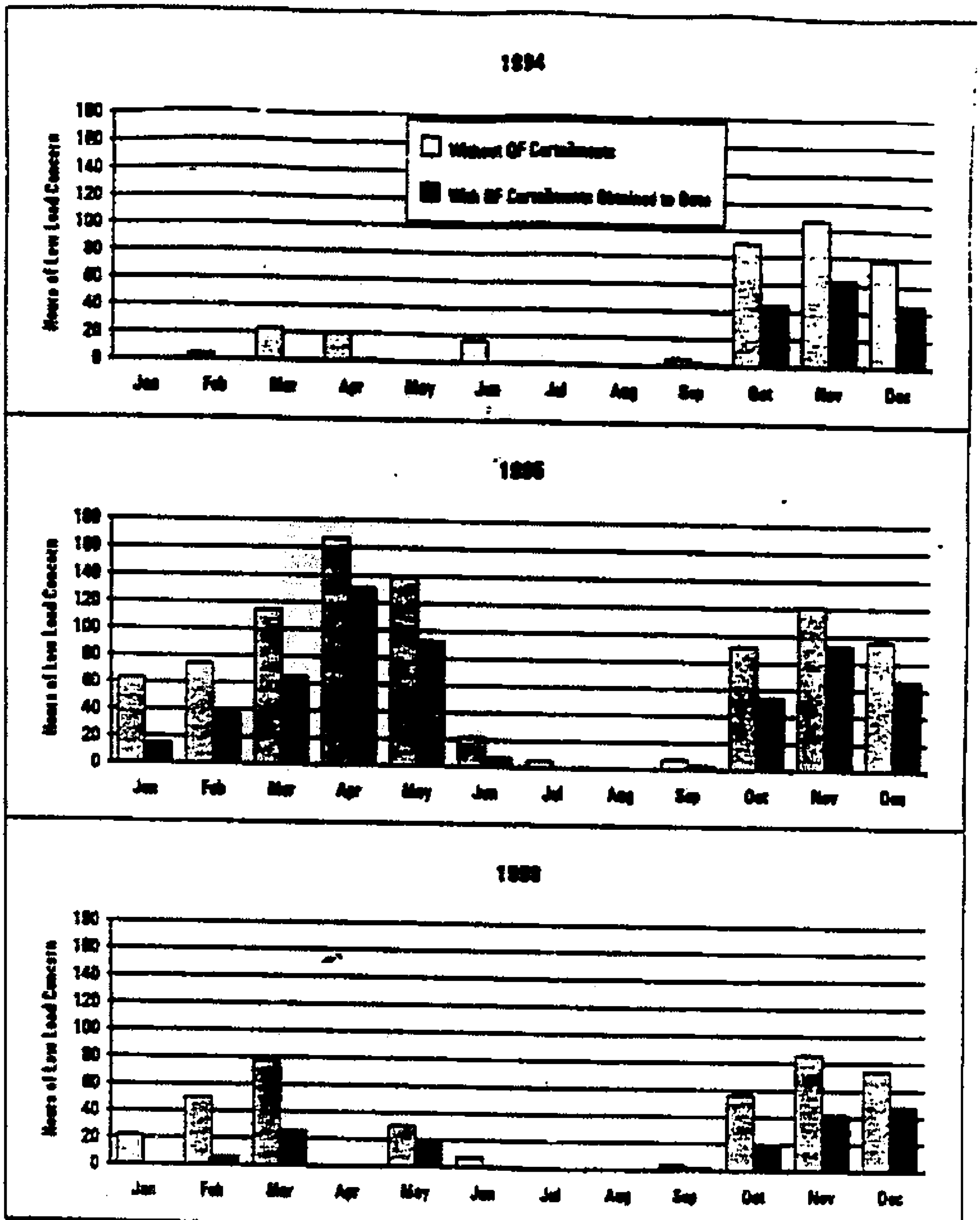
> *"Where purchases from a qualifying facility will impair the utility's ability to give adequate service to the rest of its customers or, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, or otherwise place an undue burden on the utility, the utility shall be relieved of its obligation under Rule 25-17.082 to purchase electricity from a qualifying facility. The utility shall notify the qualifying facility(ies) prior to the instance giving rise to those conditions, if practicable. If prior notice is not practicable, the utility shall notify the qualifying facility(ies) as soon as practicable after the fact. In either event the utility shall notify the Commission, and the Commission staff shall, upon request of the affected qualifying facility(ies), investigate the utility's claim. Nothing in this section shall operate to relieve the utility of its general obligation to purchase pursuant to Rule 25-17.082."*

To mitigate some of the operational problems resulting from non-dispatchable QF capacity, FPC has negotiated certain dispatch and scheduling rights. The bulk of the QF contracts remain non-dispatchable. These negotiations will probably not prevent cycling of FPC coal units or the QF's in all cases. FPC is actively pursuing these negotiations through the rule cited above and through aggressive enforcement of the QF contracts (see strategy #3). The table on pages 22 and 23 summarizes the dispatch and scheduling agreements that have been negotiated with the QFs at no cost to FPC's ratepayer. The capacity shown represents the total capacity contracted to FPC.

The impact of the scheduling rights obtained to date can be seen in the graphs on page 19. The graphs illustrate the number of hours per month that the minimum load is forecasted to be less than the minimum generation with and without the rights obtained to date for 1994, 1995, and 1998. The maximum expected minimum load and generation mismatch for these years are 240 MW in 1994, 450 MW in 1995, and 230 MW in 1998.

It should be noted that additional efforts have been made to reduce the difference between FPC's minimum load and generation. These efforts include the encouragement of off-peak sales, reduction in the minimum generation levels for FPC's plants, and exploring the reduction of minimum capacity taken by FPC from the Southern Company Miller contract.

## Periods When Minimum Generation Exceeds Minimum Load



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In order to strengthen FPC's position during hearings resulting from the curtailment of the QFs due to economic or operational problems, a curtailment procedure must be developed and documented prior to any QF curtailments. This development and documentation are required to ensure approval by the FPSC. Prior to the development of a curtailment procedure the scheduling of the avoided units must be established (see strategy #5). In addition, the unit commit, evaluator and PROMOD dispatch models must be updated to include variable O & M. This is due to the significant difference in variable O&M for some of the QF contracts ($5.45/MWH) versus FPC's units ($1.00/MWH).

## Assumptions and Risks

1. The QFs will be willing to negotiate to give FPC dispatch and/or cycling rights. The QFs that have not come to a formal agreement already with FPC could opt to fight FPC at the FPSC or in the courts rather than give FPC dispatch and cycling rights.

2. FPC can adequately determine which type of dispatch and cycling rights will properly address not only the problems in the next few years, but also over the term of the QF contracts. These contracts can be for as long as 30 years. The rights FPC is negotiating for now may be detrimental to FPC in the future as system conditions and constraints change.

3. The FPSC may not approve the curtailment of the QFs even if FPC can demonstrate the development of a curtailment procedure and show that the curtailment is in the best interest of our ratepayers. This seems to be very unlikely.

## Financial Impacts and Resources Required

FPC is currently attempting to negotiate for dispatch and cycling rights without any additional cost to FPC and our ratepayer. If FPC is unable to get enough dispatch and cycling rights without additional cost, then FPC may be required to obtain these rights at some cost to FPC. These costs will have to be reviewed to ensure that they are acceptable to FPC and our ratepayer in exchange for the additional rights they provide. The magnitude of these costs cannot be defined until the negotiations determine the type of costs that are attractive to the QF.

The development of a curtailment procedure should not require any additional resources other those outlined in strategy #5. However, during the hearings that follow QF curtailments it may be necessary to utilize outside engineering services to provide expert testimony.

## Action Steps and Milestones

| Action Step | Responsible | Time Complete | Milestone |
|---|---|---|---|
| 1) Negotiate dispatching rights with QFs that reduce costs and maintain operational reliability. | Robert Dolan | Q2 1994 | Identify requirements. |
| | | Q1 1995 | Negotiate 500 MW of scheduling and dispatchability. |
| 2) Prepare QF curtailment procedures. | Linda Brousseau | Q3 1994 | Document curtailment procedures. |

## Confidence of Team

<u>Confidence Level = 4:</u> The team feels that significant progress has been made in obtaining scheduling and dispatch rights from the QFs and that this progress will continue. Payment for scheduling and dispatch rights from the QFs where appropriate should ensure that the goals are met. The team also feels that a curtailment procedure can be developed in a timely manner to allow the curtailment of the QFs when necessary.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Fuel and purchase power cost recovery clause with generating performance incentive factor. | Docket No. 870001-EI<br><br>For filing on July 9, 1987 |

# FLORIDA POWER CORPORATION

## LEVELIZED FUEL COST FACTORS
## OCTOBER 1987 THROUGH MARCH 1988

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DIRECT TESTIMONY AND EXHIBITS OF

KARL H. WIELAND

---

FLORIDA POWER CORPORATION

DOCKET NO. 870001-EI

Re: Levelized Fuel Cost Factors for

October 1987 through March 1988

**DIRECT TESTIMONY OF**

**KARL H. WIELAND**

Q **Please state your name and business address.**

A My name is Karl H. Wieland. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

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

A I am employed by Florida Power Corporation as Director of the Company's Economic Research Department.

Q **Have your duties and responsibilities with the Company remained the same since you last testified in these proceedings?**

A Yes they have.

**What is the purpose of your testimony today?**

# EXHIBITS TO THE TESTIMONY OF

# KARL H. WIELAND

---

Parts A through D

---

A I knew Florida Power and Light buys a lot of gas, but I do not know the specifics of their contracts.

MS. PERRIN: That's all we have for this witness.

CHAIRMAN NICHOLS: Thank you. Mr. McGlothlin?

CROSS EXAMINATION

BY MR. McGLOTLIN:

Q Mr. Weiland, my questions relate to the decision of Florida Power Corporation to use the spot price of coal for the basis of dispatching its coal-fired units, and also as a component in the calculation of payments to qualifying facilities for as-available energy. That practice was implemented in June of 1986, is that correct?

A Yes.

Q As I understand it, Mr. Weiland, the decision as to which unit should be used to generate the next kilowatt hour is typically made by means of a dispatch computer into which has been fed the various heat rates associated with the units and the fuel costs associated with the units, is that correct?

A Essentially, yes.

Q And the rationale for using the so-called incremental price of fuel in determining which unit to use is that if the incremental cost of fuel is used that will lead to the lowest overall generation cost for the ratepayers, is that correct?

A Yes.

Q Assume for a moment that your arrangement or contract

And the spot price of coal, for whatever anonymous reason, was 45. On what basis would you have dispatched your units in that situation?

A Okay. Let me make sure I've got all your numbers straight. Spot coal is how much?

Q 45.

A 45. Contract coal was 40. And oil prices —

Q Equivalent of 30.

A You'd burn oil. I'd hope you'd always burn the cheapest fuel.

Q You would burn oil and incur the penalty of buying the long term contract coal that you couldn't burn?

A No, no. The true economic cost of the take or pay contract is zero, okay. I mean once you have an obligation to buy a certain tonnage, the incremental cost of burning, you know, half of it or all of it is zero. I mean it's just — you know, there is so many dollars that you have to pay, and those dollars don't change whether you burn zero tons of that committed or whether you burn all of it. And, you know, so in terms of an incremental dispatch, that coal is paid for, it's free. So it would be the first thing to get burned even before the nuclear unit. After that commitment is taken care of, then you get to the $30 oil.

Q Under the situation that I've hypothesized, what would be the cost of fuel that you would ascribe to your coal-fired

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony and Exhibits of Roy J. Shanker, on behalf of Orlando CoGen Limited, L.P., and Pasco Cogen, Ltd., has been furnished by hand delivery*, by Federal Express**, or by U.S. Mail to the following parties of record, this 10th day of April, 1995.

Martha Brown*
Division of Legal Services
Florida Public Service Commission
101 East Gaines Street
Fletcher Building, Rm. 212
Tallahassee, FL 32399

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Florida Power Corporation
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St. Petersburg, FL 33733

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Joseph A. McGlothlin

Joseph A. McGlothlin

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