

Report of The Committee On Cogeneration and Small Power Production Facilities

Significant developments have occurred at the federal and state levels since preparation of the Committee's previous report.¹ The Supreme Court sustained the FERC's interconnection and full-avoided-cost rules and thereby restimulated state commission activity. This report therefore attempts to sample state level developments as well as covering federal developments.

I. JUDICIAL DEVELOPMENTS

A. Federal

1. *American Paper Institute, Inc. v. American Electric Power Service Corporation*, 51 U.S.L.W. 4547, 103 S. Ct. 1921 (1983). In a decision with major ramifications for the nation's policy on renewable energy sources, the Supreme Court affirmed in full the Federal Energy Regulatory Commission's ("FERC") regulations, promulgated under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), governing the purchase by electric utilities of electricity produced from cogeneration and small power production facilities. The Court resolved two fundamental issues: first, it upheld the FERC's full-avoided-cost rule and second, it held that the FERC can order utilities to interconnect with qualifying facilities without holding an evidentiary hearing.

The Supreme Court's May 16, 1983 decision reversed a federal appeals court decision² which had vacated two rules promulgated by the FERC pursuant to Section 210 of PURPA.³ These rules require electric utilities: (1) to purchase electricity from a qualifying cogeneration or small power production facility at a rate equal to the utility's "full avoided cost" — the utility's incremental cost of generating the electricity itself or otherwise acquiring the power from another source;⁴ and (2) to interconnect with any cogenerator or small power producer designated by the FERC.⁵ The appellate court had held that the FERC failed to demonstrate adequately that the full avoided cost rule is consistent with the requirements of Section 210(b) of PURPA⁶ and exceeded its authority in promulgating an interconnection rule in view of the requirements of Section 210(e)(3) of PURPA.⁷

¹4 Energy L. J. 279 (1983).

²*American Electric Power Service Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982).

³Section 210 of PURPA, 16 U.S.C. § 824a-3 (Supp. V 1981), intended to encourage the development of cogeneration and small power production facilities, directs the FERC to promulgate rules requiring utilities to sell electricity to, and purchase electricity from, qualifying cogeneration and small power production facilities. Each state regulatory authority and non-regulated utility is required to implement the rules adopted by the FERC. Section 210 also directs the FERC to promulgate rules exempting cogeneration and small power production facilities from certain state and federal laws governing electric utilities. Section 210(b) of PURPA requires that in promulgating rules prescribing rates for purchases of electricity by electric utilities, the FERC must insure that such rates are "just and reasonable" to the electric consumers of the utility, in the public interest, do not discriminate against qualifying cogenerators or qualifying small power producers," and do not exceed "the incremental cost to the electric utility of alternative electric energy." Section 210(e)(3) of PURPA provides that no qualifying small power production facility or qualifying cogeneration facility may be exempted under that subsection from specified provisions of the Federal Power Act (FPA) which require the FERC to afford the opportunity for a hearing before ordering an interconnection.

⁴18 C.F.R. § 292.304(b)(2) (1983).

⁵18 C.F.R. § 292.303 (1983).

⁶675 F.2d at 1232.

⁷*Id.* at 1240.

Justice Marshall, writing for a unanimous Court, reversed the appellate court, thereby upholding the FERC's rules.⁸ The Court held that the FERC had acted neither arbitrarily nor capriciously in promulgating a full avoided cost rule, concluding that the "just and reasonable" language in Section 210(b) was not intended by Congress to impose traditional cost-of-service utility ratemaking requirements on qualifying facilities and that the FERC had adequately considered and explained the interests of electric utility consumers in receiving electric energy at equitable rates. The Court therefore held that the FERC "considered the relevant factors and deemed it most important at this time to provide the maximum incentive for the development of cogeneration and small power production, in light of the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the nation's dependence on fossil fuels."⁹

The Court further held that the FERC did not exceed its authority in promulgating the interconnection rule because the authority granted the FERC by Section 210(a) of PURPA to promulgate such rules as are necessary to require utilities to sell electricity to, and purchase electricity from, qualifying facilities "plainly encompasses the power to promulgate rules requiring utilities to make physical connections with qualifying facilities in order to consummate purchases and sales authorized by PURPA."¹⁰ Therefore, the FERC reasonably interpreted Section 210(e)(3) as allowing it to grant qualifying facilities the right to obtain interconnections under PURPA without applying for an order under the Federal Power Act. As with the full avoided cost rule, the Court gave considerable weight to the FERC's purpose: to provide an incentive for the development of qualifying facilities, consistent with Congressional intent. As the Court observed, "Providing an opportunity for evidentiary hearings before the Commission for every interconnection necessary to complete a purchase or sale under PURPA would seriously impede the very development of cogeneration and small power production that Congress sought to facilitate."¹¹

Aside from the affirmance of the FERC's specific regulations, the most significant aspect of the Court's decision was its pronouncement of the standard of review which applies under PURPA. In a lengthy footnote, the Court observed that "it appears that the [appeals] court may have erroneously employed the substantial-evidence standard," when it "should have applied only the arbitrary-and-capricious standard." The Court went on to draw a critical distinction between the Federal Power Act's specification of the substantial evidence test and PURPA's silence on this point. It concluded "In the absence of a specific command in PURPA to employ a particular standard of review, the full-avoided-cost rule must be reviewed solely under the more lenient arbitrary-and-capricious standard prescribed by the Administrative Procedure Act. . . ." In so doing, the Court may have brought a halt to the growing thought, expressed from time to time by federal appellate courts, among others, that the distinction between the substantial evidence and arbitrary and capricious standards is narrowing.

2. In *Florida Power & Light Co. v. FERC*, 711 F.2d 219 (D.C. Cir. 1983), an electric utility challenged the right of a private corporation to self-certify a small power production facility at the FERC, on the ground that pre-existing contractual arrangements existed which provided for Dade County, Florida and the utility to

⁸ Justice Powell took no part in the consideration or decision of this case.

⁹ 103 S. Ct. at 1930.

¹⁰ *Id.* at 1930-31.

¹¹ *Id.* at 1931.

own the facility and the private corporation merely to operate the solid waste processing portion of the facility and sell its steam to the utility. The utility argued that where such a conflict existed, the Commission was required under the *Mobile-Sierra* doctrine to examine the underlying contracts before allowing qualification and its attendant avoided cost rates to go into effect. In addition, the utility argued that the FERC's own regulations required an application for certification to be submitted, not simply a notice of qualification. The court upheld the Commission's acceptance of the self-certification notice and subsequent rate filing, subject to revocation of qualifying status and refund of rates should a state forum resolve the commercial dispute in favor of the utility. The court found that the *Mobile-Sierra* doctrine did not apply to a claim of qualifying status and that the Commission was not required to look behind a facially valid self-certification, and deferred to the Commission's interpretation of its own regulations.

B. State

State courts grappled with issues of federal and state law and application of U.S. Supreme Court precedents.

1. Florida

The Florida Supreme Court, upsetting the Florida Public Service Commission's ("FPSC") 1981 order adopting rules implementing PURPA, held, *inter alia*, that the FPSC may not exercise general rulemaking authority for the purpose of implementing a federal law, PURPA, absent a state statute empowering the FPSC to encourage cogeneration. *Florida P & L Co. v. PSC of Florida*, No. 60,671, (Fla., March 17, 1983) petitions for rehearing pending. The majority also held that the FPSC failed to follow requisite evidentiary type hearing procedures in adopting a full-avoided-cost rule; one justice would also have struck down that rule on substantive grounds, akin to the court of appeals' reasoning in *AEP v. FERC*. Subsequent passage of a State mini-PURPA, as well as adoption of new rules by the FPSC, may moot the Supreme Court opinion.

2. Idaho

In *Afton Energy, Inc., et al., v. Idaho Power Company*, No. 14777 (Idaho, January 11, 1984), the Idaho Supreme Court upheld a State Public Utilities Commission (PUC) order requiring Idaho Power Company (Idaho Power) to enter into a long-term, fixed rate contract with a cogeneration facility developed by Afton Energy, Inc. The PUC had ordered Idaho Power to pay Afton for the output of its wood-waste cogeneration facility for a term of 35 years at avoided cost rates previously approved by the PUC for the Idaho Power & Light Company. The question of the reasonableness of the established avoided cost rates of 6.0¢ and 6.7¢ per kWh under various options was not before the Court on appeal.

Afton had sought the order by the PUC in a complaint alleging that Idaho Power had deliberately protracted negotiations and had attempted to hinder Afton's efforts to complete financing of its project. Idaho Power maintained that the PUC had no jurisdiction under state law to order it to enter into a long-term, fixed rate contract. The PUC, however, issued the order pursuant to authority it claimed under § 210 of PURPA.

Idaho Power strenuously opposed setting a fixed rate over the term of the contract. Idaho Power had argued in the PUC proceeding that such rates were too

high given the excess capacity in the Pacific Northwest and its own lower growth forecasts. After making a compliance filing prior to the appeal, Idaho Power had attempted to amend its contract with Afton to provide that its terms and conditions would be "subject to the continuing jurisdiction of the Commission" in order to secure more favorable rates in the future. The Court, however, noted that FERC's regulations implementing PURPA (especially 18 C.F.R. 292.304(d)) gave the qualifying facility the option of having its power purchased at avoided costs levels calculated either at the time of delivery or at the time the legally enforceable obligation (i.e., its contract) is incurred.

After a discussion of PURPA's legislative history, the court concluded:

[W]e reject Idaho Power's argument that the commission does not have any authority to establish an avoided-cost rate which is fixed for the duration of the contract and which is not subject to the Commission's continuing jurisdiction. It is clear that both Congress and FERC, through its implementing regulations, intended that [cogenerators and small power producers] should not be subject to the pervasive utility-type regulation which would result if the contract language proposed by Idaho Power were approved by the Commission. In fact, one of Congress' main objectives in enacting [PURPA] was to encourage cogeneration and small power production by exempting [cogenerators and small power producers] from pervasive state rate regulation. Slip. op. at 14-15.

In addition, Idaho Power had maintained that the PUC had no authority under state law to require it to contract with Afton and that absent such authority, PURPA could not confer such authority on the PUC. The Court rejected this argument noting that state law granted broad authority to the PUC including the power "to regulate those matters which impact utility rates," and noting further that the U.S. Supreme Court in *FERC v. Mississippi*, 456 U.S. 742, (1982), had interpreted PURPA as imposing requirements on state regulatory authorities in excess of their duties under state law where the state authorities "[have] jurisdiction to entertain claims analogous to those granted by PURPA," 456 U.S. at 760. Concluding that the PUC's actions were "similar to its every day ratemaking functions," the Court held that the PUC acted within its authority in requiring Idaho Power to contract with Afton.

3. Maine

In *Central Maine Power Co. v. Public Utilities Commission*, 455 A.2d 34 (Me. 1983), the Supreme Judicial Court of Maine affirmed an order of the Maine Public Utilities Commission ("MPUC") which, *inter alia*, deducted 0.1 percent from Central Maine Power Company's ("CMP") allowed rate of return on equity because "with respect to the promotion of conservation and cogeneration, the Company has not been operating as efficiently as possible nor has it been utilizing sound management practices." Commission Decision and Order, Docket Nos. 81-127, 81-206, Slip op. at 15-16 (March 27, 1982). The MPUC explicitly held that it would have allowed a rate of return of 15.5 percent, except for CMP's failure adequately to promote conservation and cogeneration. However, the Commission also determined that a rate of return between 15.4 percent and 15.6 percent was in the reasonable range. CMP did not dispute this conclusion, meaning that even with the 0.1 percent deduction, all parties agreed that the allowed rate of return fell within the reasonable range.

On appeal, the Supreme Judicial Court held that any rate within the area of reasonableness was not to be disturbed, citing *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944); *Bluefield Water Works and Improvement Co. v. Public Service Commission*, 262 U.S. 679, 692-93 (1923); and *New England Telephone and Telegraph Co. v. Public Utilities Commission*, 39 A.2d at 8, 31 (Me. 1978). The

majority held that "the Commission's determination of CMP's cost of equity in this case is independently supported by the record and falls within a range we find to be reasonable." 455 A.2d at 39. Accordingly, the majority did not reach the question of whether it was proper under Maine or federal law for the Commission to deduct 0.1 percent for failure to encourage cogeneration and conservation properly.

Three of the seven Justices dissented from this portion of the Court's opinion. Justices Nichols and Roberts simply stated that in their view the legislature had not condoned the Commission's implementation of public policy regarding conservation and cogeneration in the manner utilized in this case. Justice Carter wrote a much longer dissent, analyzing the history of rate regulation in Maine and nationally, and determining that the return on equity provision under Maine law "excludes from the process's parameters the consideration of achievement of other independently established policy goals devolving upon the Commission as constituent parts of its general regulatory function." 455 A.2d at 48 (emphasis in original).

4. New York

Consolidated Edison Company of New York, Inc. v. Public Service Commission of the State of New York, No. 44910 (N.Y. Sup. Ct., App. Div. 3rd Dept., December 30, 1983). On December 30, 1983, the New York Supreme Court, Appellate Division, Third Department, struck down certain aspects of New York State's Public Service Law governing sales from cogeneration and small power production facilities. The decision also invalidated the New York Public Service Commission's ("NYPSC") implementation of rates for the sale of electric energy from small power production facilities and cogeneration facilities to electric utilities.

The Court addressed three issues, ruling against the NYPSC's action on two points and upholding it on the third. First, the Court held that New York State's law, to the extent that it regulates rates for the sale of electric energy produced from facilities which are not qualifying facilities under PURPA and the FERC's regulations, constituted an impermissible intrusion into an area which is preempted by Federal law. The State law went beyond merely establishing rates for PURPA-qualifying facilities, and required utilities to purchase electricity (for resale) from state-defined facilities which do not meet federal criteria for qualifying facilities. The Court held that this aspect of the law improperly invaded the FERC's exclusive jurisdiction of wholesale (sales for resale) sales of electricity, conferred by the Federal Power Act, and that the NYPSC consequently has no authority to act in this area.

Second, the Court voided the state law's establishment of a \$.06 per kWh minimum rate for sales from qualifying facilities. It was held that this portion of the state law has also been preempted by federal law, because the federal "avoided cost" limitation on such rates is meant to act as an upper limit. Congress did not intend for states to establish rates in excess of the Federal statute's avoided cost maximum. Since New York's 6 cent rate may exceed the federal maximum at times, the Court said, "it has been preempted and cannot be enforced."

Third and finally, the Court upheld the NYPSC's requirement that qualifying facilities be given a capacity credit of \$21 per kW for electricity sold during the summer peak period. The Court essentially found that there was sufficient evidence to uphold such a determination. The NYPSC has appealed the case to the New York Court of Appeals, where a final decision is expected in the Fall of 1984.

In *Occidental Chemical Corporation v. Public Service Commission of the State of New York*, the State of New York Supreme Court (Albany County Special Term, Calendar No. 27, April 19, 1983) considered the issue of whether a cogeneration facility was "developed on or after June 26, 1980" so as to be entitled to the New York statutory

minimum rate of 6¢ per kWh for alternate energy production facilities under Section 66-c of the New York Public Service Law. The Court there considered an order of the NYPSC¹² which had rejected Occidental's request for the statutory minimum rate based upon its finding that the statutory term "developed" meant "substantially designed and constructed." The Commission determined that some of the factors to be considered in deciding whether a facility was developed prior to the statutory date were the amount of money spent in proportion to the estimated cost of completion, the extent to which the facility had been designed and the amount of construction that had been completed. The Commission found that construction of the Occidental facility began April 10, 1978, that initial testing began after the critical statutory date of June 26, 1980, and that the facility did not have the capability of producing commercial quantities of electricity until September 18, 1980. Applying the tests it had devised to Occidental's facility, the Commission determined that it did not qualify for the statutory rate.¹³

The Court found that under the New York statutory definition of a "co-generation facility,"¹⁴ the existence of such a facility "must be measured from the moment it produced electricity for industrial or commercial purposes."¹⁵ Accordingly, the Court found "no reasonable basis in law for the Commission's adoption of its own test," and ordered the NYPSC on remand to issue an order declaring the Occidental facility qualified for the statutory minimum rate.¹⁶

Occidental's victory was short-lived, however. Niagara Mohawk, the purchasing utility, appealed to the Appellate Division.¹⁷ In a one-page Memorandum Decision issued on December 30, 1983,¹⁸ the Court remitted the Occidental case to Special Term for reconsideration in light of the *Consolidated Edison Company* decision issued that same day (see immediately preceding discussion). The appellate court withheld a decision regarding the meaning of the term "developed." Should the *Consolidated Edison Company* decision be overruled, this issue will reappear.

5. Kansas

Kansas City Power & Light Company v. The State Corporation Commission of the State of Kansas, No. 55,844, (Kan. February 18, 1984).

On appeal of Kansas City Power & Light Company ("KCPL"), the Kansas Supreme Court overturned an order of the District Court of Linn County, Kansas which had upheld orders of the Kansas Corporation Commission ("Commission") fixing rates to be charged for the sale of electricity by cogeneration and small power production facilities to electric utilities.

On April 28, 1982, the Commission issued an order on cogeneration and small power production. Stating it was impossible to determine a rate based on avoided costs, the Commission determined rates on a different basis, which exceeded avoided costs. Although, according to the Commission, Kansas electric utilities have surplus capacity now and for the indefinite future and no additional generation facility construction was anticipated, the Commission order provided for a capacity

¹² NYPSC Case No. 28164, Declaratory Ruling and Order (July 6, 1982), *Reh'ing denied* by order adopted on September 22, 1982.

¹³ See slip op. at 4.

¹⁴ New York Public Service Law, Section 2, subd. [2-a].

¹⁵ Slip op. at 5 (emphasis in the original).

¹⁶ *Id.*

¹⁷ *Occidental Chemical Corporation v. Public Service Commission of the State of New York*, No. 45914.

¹⁸ *Occidental Chemical Corporation v. Public Service Commission of the State of New York*, A.D.2d N.Y.S.2d

credit. At a rehearing held on November 5, 1982, the Commission generally affirmed its original order and adopted the position that it was not preempted from acting under Kansas statutes and that it could adopt rates which were not based on a utility's avoided costs.

The Kansas Supreme Court held that the federal government has preempted the field in the area of cogeneration and that the Commission's orders requiring KCPL to purchase electricity from cogenerators at a rate exceeding the federally-approved avoided cost violates PURPA and FERC regulations. The Court stated that a rate other than an avoided cost-based rate can be used if there is a specific agreement between the parties setting a price that is lower than the avoided cost rate or if the state regulatory authority has received from the FERC a waiver of the avoided cost rule. No waiver has been obtained by the Commission from the FERC.

II. FERC DEVELOPMENTS

A. Rules

User Fees. An issue which is still pending and which could have serious impacts on cogenerators and small-power producers is that of user fees. The FERC proposed to establish such fees with respect to electric utilities, cogenerators, and small-power producers in Docket No. RM82-38-000 in a Notice of Proposed Rulemaking issued September 1, 1982. The proposed rulemaking would require payment of fees for various functions performed by the Commission under the FPA and PURPA including:

1. Review of applications for an order directing the establishment of physical interconnection of facilities or wheeling under the FPA (\$6,200 without hearing and \$57,400 with hearing);
2. Review of applications for certification of qualifying status as a small power production cogeneration facility under PURPA (\$2,600).

The Commission has recently reported that final rules are expected in 1984.

B. Policy Statements and Interpretations

1. *Enforcement Policy.* On May 31, 1983, the FERC issued a policy statement clarifying the FERC's enforcement role under Section 210 of PURPA.¹⁹ The policy statement, which has "no legal effect, is not a rule or binding norm, and imposes no rights or obligations," was intended simply to "further inform the public of our views and the course we intend to follow in future proceedings," although the FERC acknowledged that on a case-by-case basis "the validity and application of the policies enunciated herein may be subject to further consideration."²⁰

The policy statement seeks to clarify the appropriate forum for judicial review, and to explain the relationship between the enforcement roles of the FERC, on the one hand, and the states on the other hand under Sections 210(g) (judicial review and enforcement) and 210(h) (FERC enforcement) of PURPA.²¹ The FERC addresses these issues in a variety of contexts.

¹⁹ Docket No. PL83-4-000, 23 FERC ¶ 61,304 (1983), 48 Fed. Reg. 29,475 (June 27, 1983).

²⁰ 23 FERC ¶ 61,304 at p. 61,644.

²¹ 16 U.S.C. §§ 824a-3(g) and 824a-3(h).

First, as to the states' obligations under Section 210(f) of PURPA²² to implement the FERC purchase-and-sale rules²³ promulgated under Section 210(a) of PURPA,²⁴ the FERC notes that it is authorized under Section 210(h)(2)(A)²⁵ to enforce not only the commencement of implementation by state regulatory authorities or non-regulated utilities but also to address situations in which duly promulgated regulations are alleged to be inconsistent or violative of the FERC regulations.²⁶ The FERC adds that its authority to review and enforce this initial implementation requirement is not exclusive, and that it "would anticipate that generally proceedings would be initiated at the State level."²⁷

Second, as to implementation procedures, the FERC notes that it has authority under Sections 210(h)(2)(A) of PURPA to enforce PURPA procedural requirements as to notice and opportunity for hearing in the promulgation of rules by states or nonregulated electric utilities.²⁸ The FERC further notes that any person — without petitioning the FERC — may seek judicial review under Section 210(g)(1) of any proceeding conducted by a State or nonregulated electric utility.

Third, as to challenges to the *application* of rules promulgated by states or nonregulated electric utilities, the FERC specifically limits its role, stating that the "primary enforcement authority" lies before a State judicial forum in actions brought by "any person" under authority of Section 210(g)(2) of PURPA.²⁹ Such actions could include, for example, a complaint by a qualifying facility that a utility refuses to negotiate a purchase rate where such a negotiation requirement is mandated by the state's PURPA implementation regulations.

Finally, with regard to 30-80 mW qualifying small power production facilities which are subject to FERC regulation under the Federal Power Act, the FERC notes that Section 210(h)(1) of PURPA gives the FERC exclusive enforcement authority as to such facilities, including the authority to approve or disapprove rates.³⁰

The FERC summarizes its general enforcement policy as follows:

With regard to review and enforcement, the [FERC's] role is generally limited to ensuring that the State regulatory authority — or non-regulated electric utility — established implementation plan is consistent with Section 210 of PURPA and with the [FERC's] regulations. Once this is ensured, the State judicial forums are available to ensure that electric utilities and qualifying facilities are dealing in good faith and in a manner consistent with locally-established regulation.³¹

2. *Interpretations.* Recent interpretations of the FERC General Counsel have attempted to clarify that sales by qualifying cogeneration facilities (sales not for resale) to non-utility (i.e., industrial) purchasers do not affect the qualifying status of the cogeneration facility. In one instance, a qualifying cogeneration facility wished to make sales at wholesale to a remote non-generating utility, and sales at retail (not for resale) to an industrial facility adjacent to the qualifying facility. In the opinion of the

²² 16 U.S.C. § 824a-3(f).

²³ 18 C.F.R. Part 292.

²⁴ 16 U.S.C. § 824a-3(a).

²⁵ 16 U.S.C. § 824a-3(h)(2)(A).

²⁶ 23 FERC ¶ 61,304 at p. 61,644.

²⁷ *Id.* The FERC may undertake such enforcement on its own motion, or upon petition by electric utilities or qualifying facilities. See Sections 210(g)(2) and 210(h)(2)(A) of PURPA. Further, under Section 210(h)(2)(B), where the FERC does not initiate enforcement action within 60 days after receipt of a petition, the petitioner may file an action in the appropriate United States district court.

²⁸ *Id.* at p. 61,645.

²⁹ *Id.*

³⁰ *Id.* at p. 61,646.

³¹ *Id.*

General Counsel, the transactions described would not affect the qualifying status of the facility under Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA). As the General Counsel pointed out, Section 210(a) of PURPA states that the Commission's "rules may not authorize a qualifying cogeneration facility or qualifying small-power production facility to make any sale for purposes other than resale." The Conference Report accompanying PURPA states that "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." (H. Rep. 95-1750, 95th Cong., 2d Sess. 197). As the General Counsel concluded, although the Commission's regulations do not authorize retail sales, neither do they prohibit such sales. Thus, retail sales would not affect the qualifying status of a qualifying cogeneration facility or the benefits flowing from that status. *Arent Fox*, April 13, 1983.

This interpretation is consistent with others issued in recent years. In another instance, the owner of a hydro-electric generating project would no longer be considered a qualifying small-power production facility for purposes of Section 210(e)(1) of PURPA if the owner sold power produced by the facility to a purchaser other than an electric utility where the power would not be offered for resale. The General Counsel explained that the sale described would not affect the qualifying status of the facility. *Energenics Systems, Inc.*, June 28, 1982. In the same opinion, the General Counsel explained that a qualifying facility is only exempt from State regulation for certain purposes. The particular facility described would not be exempt from State regulation in non-rate matters, and the transaction described would not be exempt from state retail rate regulation. The General Counsel emphasized that Section 210(a) of PURPA directs the Commission to prescribe rules to require electric utilities to offer to sell electric energy to, and purchase electricity from, qualifying facilities. The rules may not authorize a qualifying facility to make any sale for purposes other than resale. The Conference Report on this provision of PURPA specified:

(a) . . . 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. Federal Energy Guidelines, Vol. I, ¶ 5151, p. 5105.

Furthermore, it was pointed out that nothing in PURPA or the Commission's implementing regulations (18 C.F.R. Part 292) exempts a qualifying facility from State regulation of matters other than rates or financial and organizational regulation. For example, State regulation of environmental matters, licensing, and construction would not be pre-empted by the Commission's regulations.

In another instance, the FERC made clear that a private company, as the owner of a cogeneration project, may sell electricity to a nearby industry and not endanger the facility's qualifying status. The Commission emphasized that its rules apply only to wholesale transactions (sales of electric energy to a utility which will in turn resell that power), and they do not apply to direct retail sales. Thus, any direct retail sales made by the private owner may render the owner a utility under State law and such sale may be subject to State electric rate regulation. *Senator Bennett Johnston*, July 9, 1981.

Finally, in a recent order the Commission reaffirmed its narrow view of its limited jurisdiction over sales of a local nature *albeit* interstate in character. In *City of Oakland, California v. Pacific Gas and Electric Company*, 24 FERC ¶ 61,010 (1983), the City of Oakland, through its Board of Port Commissioners, argued that its purchases

of its total electric requirements for Metropolitan Oakland International Airport (the Airport) from PG&E, most of which energy was sold by the Port to its tenants, were sales for resale and that it should be given a wholesale rate by PG&E. The Commission found, however, that although the Board owns and maintains its own distribution and transmission system over the Airport complex for service to its own facilities and to approximately 103 tenants, which system included a metering system which the Port maintains for those tenants whom it bills directly, the billing for electricity by the City's Port Authority to its tenants more closely resembled an "equitable, internal allocation of costs between landlord and tenant rather than a "sale for resale" as contemplated by the Federal Power Act." The Commission further characterized the sale in question as "a direct sale to the Port for its own use, which use includes the operation of the airport and the provision of services to Port tenants, including the availability of electricity." The Commission further stated that the Port "is therefore like the operator of a shopping center, apartment or commercial office building, or like any other landlord who provides electricity as a necessary incident of providing space to tenants. We do not believe that it was the intent of Congress in enacting the Federal Power Act to involve the Federal government in direct sales to landlords."

Therefore, for those owners and operators of small power production facilities and cogeneration facilities who would make sales similar to those discussed within the case interpretations, the Commission has offered some guidance in framing such transactions. However, in *City of Oakland* both sales to the airport and the bills to the airport customers were regulated by the California Public Utilities Commission and the rates to sub-metered tenants were also regulated by state rules and monitored and audited by PG&E as required by the state.

C. Decisions

The Commission issued several opinions in 1983 which interpret the regulatory criteria that a small power production facility must meet to become a "qualifying facility" within the meaning of Section 3(17)(C) of the Federal Power Act,³² as amended by Section 201 of the Public Utility Regulatory Policies Act ("PURPA").³³

1. In *Energy Cogen Corporation*³⁴, the Commission analyzed the permissible energy input requirement.³⁵ This requirement limits the use of oil, natural gas or coal for power production at a qualifying small power production facility during any calendar year to no more than 25 percent of the total energy input of the facility.

Energy Cogen filed an application for certification of "turboexpanders" as qualifying small power production facilities. Turboexpanders consist of turbine generator sets which are driven by the energy released when the pressure of natural gas is reduced and gas expands. Energy Cogen proposed to locate its turboexpanders at five powerplants of the Southern California Edison Company. Then, as natural gas enters the powerplants and the delivery pipeline pressure is reduced to accommodate the lower pressure at which gas is supplied to the powerplant boilers, the turboexpanders would be utilized to capture the "waste" energy released during the pressure reduction process. To prevent operational problems associated with a decrease in temperature as the gas passes through the turboexpanders,³⁶ Energy Cogen proposed to heat the gas with steam derived from

³² 16 U.S.C. § 796 (17)(C).

³³ Public Utility Regulatory Policies Act of 1978, P.L. 95-617, 92 Stat. 3117, § 201.

³⁴ 25 FERC ¶ 61,417 (1983).

³⁵ 18 C.F.R. § 292.204(b)(2).

³⁶ One such operational problem was freezing of moisture in the gas as temperature dropped during pressure reduction.

the combustion of natural gas at the powerplant boilers. The only question before the Commission was whether the use of the steam to prevent operational problems would result in a violation of the permissible energy input test.³⁷

The Commission found that it would. In reaching this conclusion, the Commission stated that "energy input" for purposes of this type of energy-producing process is the energy available from a perfect expansion of the gas without losses from the initial temperature and pressure to the final pressure. Under this analysis, the Commission determined that the use of steam as a pre-heat would mean that 48 percent of the total energy input of the turboexpanders would be derived from natural gas.³⁸ Accordingly, the Commission denied Energy Cogen's applications for certification of the turboexpanders as qualifying small power production facilities under Section 201 of PURPA.

2. In *El Dorado Water Agency and El Dorado Irrigation District*,³⁹ the Commission upheld its criteria for determining whether small power production facilities are located at the same site and, accordingly, must not exceed in the aggregate a production capacity of 80 megawatts. The regulatory site criteria are derived from Section 201 of PURPA, which provides that a facility can qualify as a small power production facility only if it has a production capacity "which, together with any other facilities located at the same site (as determined by the Commission) is not greater than 80 megawatts."⁴⁰ Section 292.204(a)(2) of the Commission's regulations⁴¹ sets out the site criteria. In general, facilities are considered to be located at the same site if they are within one mile of one another and, in the case of hydroelectric facilities, use water from the same impoundment for power generation.

In *El Dorado*, the County water agency and irrigation district (referred to herein as "El Dorado") filed applications for certification of three hydroelectric power generating facilities as individual small power production facilities. The three facilities were part of a larger hydroelectric project for which only a single FERC project license was sought. Furthermore, the three facilities used water from the same impoundment for power generation. El Dorado nonetheless asserted that the facilities were distinct and should be treated as individual qualifying facilities because (1) each facility did not exceed the 80 megawatt size limitation; and (2) each facility was located more than a mile apart from the other facilities. A nonprofit organization, Friends of the River, Inc. ("Friends"), filed a timely protest and motion to intervene in the certification proceeding. Friends contended that the Commission should deny the application for certification since the aggregate megawatt capacity of the three facilities exceeded 80 megawatts. Friends also requested, pursuant to Section 292.204(a)(3) of the Commission's regulations,⁴² that the Commission "modify" the one-mile rule of the regulations to ensure that the facilities did not achieve qualifying status. To support its request, Friends contended that the three facilities were part of an integrated hydroelectric project and, thus, strict adherence

³⁷ Another issue raised by the application concerned the classification of the energy released during pressure reduction as "waste" which can be used as the primary energy source of a small power production facility under 18 C.F.R. § 292.204(b)(1)(i). The Commission did not reach this issue, however, when it determined that Energy Cogen would be unable to meet the permissible energy use requirement set out in 18 C.F.R. § 292.204(b)(2).

³⁸ 25 FERC ¶ 61,417 at p. 61,932.

³⁹ 24 FERC ¶ 61,280 (1983).

⁴⁰ PURPA § 201, codified at 16 U.S.C. § 796 (17)(C)(i).

⁴¹ 18 C.F.R. § 292.204(a)(2).

⁴² 18 C.F.R. § 292.204(a)(3), which provides that "[t]he Commission may modify the application of paragraph (a)(2) of this section (i.e., the site criteria), for good cause."

to the one-mile rule would cause arbitrary and "illogical"⁴³ results in violation of the spirit of PURPA.

The Commission was not persuaded by Friends' contentions and granted the requested certifications. In reaching its decision, the Commission found that aggregation of the facilities for purposes of the hydroelectric project license had no precedential effect on the Commission's authority to consider each facility as an individual unit for purposes of certification under Section 201 of PURPA.⁴⁴ Since the facilities met all regulatory criteria for separate certification as qualifying facilities, the Commission determined that it was bound to grant El Dorado's application.

The Commission expressly declined to exercise its waiver authority under Section 292.204(a)(3) of its regulations to avoid application of the one-mile rule.⁴⁵ It determined that Friends' waiver request was in reality a collateral attack on the one-mile requirement itself. Accordingly, the Commission denied Friends' protest and certified the three hydroelectric facilities as "qualifying facilities" within the meaning of Section 201 of PURPA. A petition for rehearing was denied.⁴⁶

3. In *Kenvil Energy Corporation*,⁴⁷ the Commission reviewed the regulatory criteria for determining whether a fuel qualifies as "waste" under Section 292.204(b).⁴⁸ The case arose from an application made by Kenvil Energy Corporation ("Kenvil") for an order granting certification to a 15 megawatt generating unit. As the primary energy source for the unit, Kenvil proposed to use a refuse material consisting of unused anthracite coal mixed with rock material. Some "saleable" coal would be used to improve combustion and fuel oil also would be used for start-up of the incinerator. However, the combined use of "saleable" coal and fuel oil would not exceed 25 percent of the total heat input of the facility.

The Commission employed a two-part test in determining whether the anthracite-based fuel could qualify as "waste." Under the test, a fuel is "waste" only if it is (1) byproduct material and (2) has no current commercial value. The Commission held that the anthracite-based fuel (hereinafter referred to as "refuse material") met both tests and therefore qualified as "waste" under its regulations.

The Commission stated that material is properly characterized as "byproduct material" if it is an unavoidable, incidental product of an industrial operation whose costs of salvage and marketing exceed its costs of disposal.⁴⁹ On this basis, the Commission found that the anthracite-based refuse constituted byproduct material since it was "an unsought but necessary result of the coal processing."⁵⁰

The Commission also found that the refuse met the commercial value test. To reach this finding, the Commission reviewed past, current and predicted marketability of the refuse material. It noted that the accumulation of the refuse in a pile for a number of years suggested that it had no commercial value in the past. It further noted that the refuse material was not currently marketable since it contained less than 35 percent combustible materials — the minimum level necessary for upgrading and use by electric utilities or other combustion facilities.⁵¹ Indeed, the refuse material could be burned as fuel at the Kenvil facility only because Kenvil proposed to employ a new technology which was capable of

⁴³ 24 FERC ¶ 61,280 at p. 61,577.

⁴⁴ *Id.* at pp. 61,577-78.

⁴⁵ *Id.* at p. 61,578.

⁴⁶ 26 FERC ¶ 61,185 (1984).

⁴⁷ 23 FERC ¶ 61,139 (1983).

⁴⁸ 18 C.F.R. § 292.204(b).

⁴⁹ 23 FERC ¶ 61,139 at pp. 61,302-03.

⁵⁰ *Id.* at p. 61,303.

⁵¹ *Id.*

tolerating a high percentage of non-combustible materials.⁵² For these reasons, the Commission found that there was no market demand for the refuse and, consequently, it had no current commercial value.

In a separate opinion, Commissioner Sheldon concurred in the result reached by the Commission, but dissented from the use of the two-part economic test for qualification of fuel as "waste." Commissioner Sheldon observed that, under the Commission's commercial value test, material can qualify as "waste" only if it has no commercial value both at the time it was originally produced and at the time certification is sought. Commissioner Sheldon urged the Commission to reject this economic test, noting that a fundamental purpose of Section 210 of PURPA is to encourage the development of small power production.⁵³ Accordingly, Commissioner Sheldon would have permitted the use of the refuse material as a primary energy source whether or not it had commercial value.

4. In *American Lignite Products Co.*,⁵⁴ decided some six months after the decision in *Kenvil Energy Corporation*, the Commission again reviewed the criteria for determining if a fuel qualifies as "waste." The case arose when American Lignite Products Company ("American Lignite") applied for certification of a fluid bed combustion unit as a qualifying small power production facility. As fuel, American Lignite proposed to burn a high ash lignite residue produced in the course of its montan wax extraction process. For many years, American Lignite stored the lignite residue in a waste storage pile. It proposed to burn the stored residue ("existing residue") along with the waste produced as a result of the ongoing wax production process ("annual residue"). The residues would produce super-heated steam to drive an extraction turbine and generate electricity. American Lignite estimated that its total supply of existing residue would be exhausted in 1994. At that time, it proposed to fuel the combustion unit with low wax or non-wax lignites that existed in the geologic formation over the wax-bearing lignites.

The Commission examined each fuel source (*i.e.*, the existing residue, the annual residue and the low wax lignite) to determine whether each qualified as "waste" under Commission regulations. Relying on the tests employed in *Kenvil Energy Corporation*, the Commission determined that the existing and annual residue qualified as byproduct materials since both are unessential and undesired products of the montan wax extraction process.⁵⁵ The Commission declined, however, to find that the low wax lignite also qualified as byproduct material on the grounds that American Lignite failed to provide sufficient factual data showing that low wax lignite is an unessential and unwanted product of the wax extraction process.⁵⁶

The Commission then considered the commercial value test employed in *Kenvil*. It observed that the storage of the residue in a "waste" storage pile for a number of years suggested that the existing residue had no commercial value in the past. The Commission further found that the residue had little or no existing current market value because of a high moisture content in the residue which made it extremely expensive to transport, thereby increasing its cost in comparison to other types of coal.⁵⁷ The Commission also observed that environmental requirements created additional potential impediments to the use of the residue as a commercial fuel. Finally, the Commission found that the low quality of lignite as a fuel had constrained

⁵² *Id.*

⁵³ 23 FERC ¶ 61,139 at p. 61,305.

⁵⁴ 25 FERC ¶ 61,054 (1983).

⁵⁵ 25 FERC ¶ 61,054 at p. 61,229.

⁵⁶ *Id.*

⁵⁷ *Id.*

its commercial value.⁵⁸ For all of these reasons, the Commission determined that the existing and annual residue could qualify as "waste" under Section 292.202(b) of its regulations. It declined to make such a finding for the low wax lignite.

Although the Commission granted the application for certification of the fluid bed combustion unit as a small power production facility, it did so subject to a limitation on the use of lignite. Specifically, lignite (other than that derived from the existing and annual residues), along with the use of natural gas, coal or oil, was limited to 25 percent of the annual heat input of the facility to insure compliance with the permissible use test set out in Section 292.204(b)(2). Commissioner Sheldon dissented.

5. In *The Lawrence Park Heat, Light & Power Co.*, 25 FERC ¶ 61,315 (1983), the Commission applied Federal Power Act Section 3(17)(C)(ii), 16 U.S.C. § 796(17)(C)(ii), and 18 C.F.R. § 292.206(a), both of which state that a qualifying facility may not be owned by a person "primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)." The applicant in *Lawrence* was a generator and seller of electric power, but all of the power it generated and sold was derived from cogeneration facilities. The FERC thus held that the exception of Section 292.206(a) and the Commission's regulations applied, and granted Lawrence Park's application for certification. In doing so, the Commission effectively held that the exception of Section 292.206(a) supercedes the requirement of Section 292.206(b) that not more than 50% of the equity interest in the facility be held by an electric utility, since it found it unnecessary to address the question of whether Lawrence Park was an electric utility for purposes of this section.

6. In *Riverbay Corp.*, 25 FERC ¶ 61,316 (1983), the Commission addressed the definition of "electric utility." Here the applicant was a cooperative corporation owning an apartment and commercial complex in New York. As part of its services it purchased power from Consolidated Edison Company and distributed the electricity to its members and commercial tenants; the cost of the electricity was included as a non-itemized element of members' monthly maintenance fees and of some of its commercial tenants' rents. Other commercial tenants had meters apportioning their electricity charges. Riverbay planned to build a cogeneration facility to serve its own load, and applied to the Commission for certification. The Commission thus considered whether Riverbay met the ownership criteria of the statute and Section 292.206(a) of the regulations of not being "primarily engaged in the . . . sale of electric power." The Commission answered this question by referring to its own test set forth in Section 292.206(b), which states that a facility is owned by a person primarily engaged in the sale of electric power "if more than 50 percent of the equity interest in the facility is held by an electric utility." In this case, since Riverbay would be the only owner of the facility, Section 292.206(b) means that Riverbay must not be an electric utility, defined in Federal Power Act Section 3(22), 16 U.S.C. § 796(22), simply as "any person . . . which sells electric energy." Thus the Commission's test results here in a stricter requirement than the statute appears to impose. The Commission found, however, that Riverbay was not making sales of electricity to any of its members or tenants, but was merely allocating operating costs. The Commission therefore held that Riverbay was not an electric utility, and found that its facility would meet the qualification criteria.

7. In *UOP Energy Recovery Corp. of Pinellas*,⁵⁹ the Commission held that the operator of a small power production facility was exempt from FERC jurisdiction

- ⁵⁸*Id.*

⁵⁹25 FERC ¶ 61,318 (1983).

under Section 201(f) of the Federal Power Act, 16 U.S.C. § 824(f). UOP entered into a contract with Pinellas County, Florida to operate a solid waste recovery and electric generating facility owned entirely by the County. Under the contract, UOP would receive a payment for processed waste accepted at the facility and a percentage of the net revenues from the County's sale of electricity. However, UOP would have no authority to make sales on its own nor any control over transmission or sales. The Commission found that UOP would be active as an agent or instrumentality of the County and thus would be exempt from FERC jurisdiction under FPA Section 201(f). The FERC noted that the County was the owner of the facility; UOP was not undertaking any electrical generation or waste disposal activities on its own account; and UOP had no control over the amount of electric energy sold or transmitted or the terms of such transactions, including price, but was acting exclusively on behalf of the County. The Commission also noted that no regulatory purpose would be served by exercising jurisdiction over UOP since the purpose of Part II of the Federal Power Act is the regulation of transmission and sales in interstate commerce, activities which in this case were completely controlled not by UOP but by the County, over which the Commission definitely had no jurisdiction.

8. FERC policy limiting the scope of its Federal Power Act regulation over jurisdictional qualifying small power producers with installed capacity of 30-80 mW continued to evolve in 1983.⁶⁰ That policy had been established initially in *Resources Recovery (Dade County), Inc.* (Docket No. ER82-225-000),⁶¹ in which the FERC waived, for a 76-mW qualifying small power producer, the requirement of filing cost-of-service data requirements⁶² along with its rate schedule filing, and in *Resources Recovery (Dade County), Inc.* (Docket No. ER82-225-003),⁶³ in which the FERC waived applicability of accounting regulations,⁶⁴ reporting regulations,⁶⁵ and annual charges,⁶⁶ and retained minimal statutory filing requirements while waiving applicability of the full filing requirements under regulations governing property dispositions and consolidations,⁶⁷ issuances of securities and assumptions of liability,⁶⁸ and the holding of interlocking positions.⁶⁹

9. In *Resources Recovery (Dade County) Inc. and Resources Recovery (Dade County) Construction Corp.* (Docket No. EC83-20-000), issued November 10, 1983,⁷⁰ the FERC authorized the sale and purchase of jurisdictional facilities by and between "public utility"-qualifying facilities under the Federal Power Act. Compliance with regulatory filing requirements having previously been waived,⁷¹ the joint applicants, in accordance with specific advice from the FERC,⁷² met with FERC staff to

⁶⁰Section 210(e) of PURPA, 16 U.S.C. § 824a-3(e), authorizes exemptions for most PURPA qualifying facilities from regulation under the Federal Power Act, but denies such exemption to qualifying small power production facilities having installed capacity in excess of 30 mW (or 80 mW for a qualifying small power production facility whose primary energy source is geothermal energy).

⁶¹18 FERC ¶ 61,243 (1982).

⁶²18 C.F.R. §§ 35.12 and 35.13.

⁶³20 FERC ¶ 61,138 (1982).

⁶⁴18 C.F.R. Part 101 (the Uniform System of Accounts).

⁶⁵18 C.F.R. Parts 41, 50 and 141.

⁶⁶18 C.F.R. § 36.1.

⁶⁷18 C.F.R. Part 33, which implements Section 203 of the Federal Power Act, 16 U.S.C. § 824b.

⁶⁸18 C.F.R. Part 34, implementing Section 204 of the Federal Power Act, 16 U.S.C. § 824c.

⁶⁹18 C.F.R. Part 45, implementing Section 305(b) of the Federal Power Act, 16 U.S.C. § 825d(b).

⁷⁰25 FERC ¶ 62,191 (1983).

⁷¹See note 8, *supra*, and accompanying text.

⁷²See 20 FERC ¶ 61,138, *supra* at p. 61,305 n. 10, wherein the FERC acknowledged that it had "not yet identified the specific information to be filed" and encouraged applicants "to seek Staff suggestions or comments on its proposed filing."

determine the exact scope of the minimum filing requirements necessary to comply with Section 203 of the Federal Power Act. In approving the applicants' less-burdensome filing and authorizing the transactions, the FERC implicitly accepted the reasoning that the purchase price was immaterial⁷³ where the facilities would not become part of the rate base because avoided costs, rather than cost-of-service of the purchasing utility, was the ratemaking standard.

10. Other orders issued by the FERC in 1983 include: *University of San Francisco*⁷⁴ (in which the FERC formally outlined the relationship between the regulatory benefits provided by PURPA and other, non-PURPA related requirements, such as local, state and Federal zoning, construction, and environmental laws); *George W. Yeagle*⁷⁵ (in which the FERC interpreted the "sequential use" requirements for cogeneration facilities in light of its operating and efficiency standards for such facilities), and; *Massachusetts Refusetech, Inc.*⁷⁶ (in which the FERC reiterated its earlier interpretation that the "power production capacity" of a small power production facility will be calculated based on its "maximum net capacity" and not the facility's average net capacity).⁷⁷

11. In *Middle South Services, Inc., et al. v. Middle South Utilities, Inc.*, 24 FERC ¶ 63,119 (1983), an initial decision was issued providing that Middle South Utilities should pay for the capacity value of purchases from cogeneration or small-power producers unless it can demonstrate to the Commission why no capacity payment is appropriate. The decision arose in a dispute between Middle South and the States of Arkansas and Louisiana over whether a pool's guidelines for the purchase of cogenerated power set out in a proposed tariff filed with the FERC undermined the intent in Section 210 of PURPA of encouraging the development of cogeneration and small-power production facilities.

Previously, Middle South had refused to recognize the capacity-value of any purchase from a qualifying facility, thereby barring any such purchase from triggering a change in the equalization payments among the member utilities. Under the proposed agreement, however, the Operating Committee of Middle South would determine whether it should pay a capacity charge to qualifying facilities — if in the eyes of the Operating Committee the purchase would permit the system either to postpone construction, to construct a smaller, less expensive generating unit, or to reduce its firm power purchases from outside sources. Additional weight was placed on whether the qualifying facility would be under the control of Middle South's central dispatcher. Louisiana and Arkansas argued that the determination of whether for planning purposes the purchase from a qualifying facility has capacity-value should be made by state regulators.

The Presiding Administrative Law Judge found Middle South's position that it has no need for capacity until the early 1990's was a "somewhat subtle way of saying that for years to come it will not agree to pay a capacity component to a qualifying facility . . . and that it will likely contest before a State regulatory agency any efforts" by a qualifying facility to receive such payments. The Presiding Judge concluded that there is no rational basis for Middle South's position, noting that Middle South showed that it had a "so-called displacement program underway to add new

⁷³ However, the FERC did require applicant certification that the facilities were valued in excess of \$50,000, and thereby constituted jurisdictional facilities under the terms of Section 203 of the Federal Power Act.

⁷⁴ 23 FERC ¶ 61,409 (1983) (Docket No. QF83-102-000).

⁷⁵ 25 FERC ¶ 61,226 (1983) (Docket No. QF83-203-000).

⁷⁶ 25 FERC ¶ 61,406 (1983) (Docket No. QF83-373-000).

⁷⁷ See also *Occidental Geothermal, Inc.*, 17 FERC ¶ 61,231 (1981) (Docket No. QF81-7-000).

generating capacity which will utilize nuclear fuel or coal — thereby allowing the system to retire or otherwise make less use of its existing oil- and natural gas-fired generating plants. . . .” The Presiding Administrative Law Judge concluded that the most equitable way for the Commission to proceed would be establishing a presumption that “every proposed Section 210 purchase would be presumed to have capacity-value; the burden to rebut the presumption would lie with Middle South.” Middle South would then have the opportunity to show that it needs no more capacity and why the power available from a qualifying facility would not help it meet its goal of displacing existing oil- and gas-fired units. Additionally, the Presiding Judge noted that for various reasons the system may have a continuing need for additional capacity and that a “qualifying facility, whatever its size, can contribute toward that need.”

While FERC's decision is unique due to the multi-state nature of the Middle South System, and most determinations on avoided-cost payments made to qualifying facilities are made by the States, the decision could have significant impact for those States struggling with the question of establishing capacity-value of purchases from cogenerators and small-power producers.

12. In *Vermont Elec. Coop., Inc. v. Vermont Department of Public Service* (September 23, 1983) the Vermont Electric Cooperative, Inc. (VEC), a non-profit rural electric cooperative, filed a complaint and petition for declaratory order with the FERC against the Vermont Department of Public Service and the Public Service Board.⁷⁸ The petition stems from the state's most recent rulemaking implementing Section 210 of PURPA. That rulemaking, discussed in Section IV. K, *supra*, of this report, provides in part, that avoided cost be calculated based upon the avoided cost of the “Vermont composite electric utility systems” which include the combined generation, transmission, and distribution resources and combined retail load requirements of the state's retail electric utilities.⁷⁹ In addition, the rulemaking creates a purchasing agent for the Vermont retail electric utilities to purchase power from any qualifying facility with a capacity greater than 50 kW. The power purchased by the agent is then distributed to the state's retail electric utilities based upon their pro-rata share of total state retail kilowatt-hour sales.⁸⁰

VEC's complaint states that an avoided cost method based upon a statewide composite avoided cost violates the PURPA requirement that rates be based upon the purchasing utility's avoided cost and, contrary to PURPA, requires VEC to purchase at a rate in excess of its avoided cost.⁸¹ VEC also claims that the purchasing agent, the Department of Public Service, is not a qualifying facility and hence VEC is not required to buy from it under PURPA.

The FERC, without further elaboration, issued a notice of intent not to act in the matter and terminated the docket.⁸² The FERC's action in this matter may signal a policy of deferral to the state forum for resolution of PURPA disputes.⁸³

13. In *PRI Energy Systems, Inc.*, 26 FERC ¶ 61,177 (1984), the FERC found that a cogeneration facility may not be denied qualifying status on the ground that it intends to engage only in retail sales of electricity. The decision follows the reasoning

⁷⁸ Docket No. EL83-32. See 48 Fed. Reg. 46,616 (October 13, 1983) for public notice of the petition.

⁷⁹ Public Service Board Rule 4.103(A)(11) and Rule 4.104(A).

⁸⁰ *Id.*, Rule 4.103(A)(8) and Rule 4.104(A).

⁸¹ See *Appeal of Granite State Electric Company*, 121 N.H. 787, 435 A.2d 119 (1981), holding that avoided cost rates cannot be based upon the avoided costs of another utility.

⁸² 25 FERC ¶ 61,273 (1983).

⁸³ See, e.g., *Energy Conversions of America Inc.*, 21 FERC ¶ 61,329 (1982), involving FERC's decision not to set a rate for a qualifying facility in the 30-80 MW range. In the course of the FERC proceeding a hearing had been docketed before the state commission.

of an interpretation issued April 13, 1983 by the Office of General Counsel. (*See*, Section II. B. 2, *supra*.)

PRI proposed to develop a topping-cycle facility fueled by synthetic gas, producing thermal energy to be used in food processing and preparation, with a capacity of 60 kW. The applicant sought qualifying status for the first of several individual cogeneration units that PRI intends to market to individuals and business concerns that are able to use heat and power produced. PRI will retain ownership of the facilities and sell the energy produced to the user.

Hawaiian Electric Company, Inc. ("HECO") requested that PRI's application for qualifying-status be denied on the ground that PRI intends to engage only in direct retail sales of electricity to end users, in violation of Sections 201 and 210 of PURPA and regulations thereunder. In addition, HECO maintained that granting qualifying status might result in its loss of industrial load to the detriment of HECO's remaining customers.

The FERC found that a cogeneration facility is qualifying under Section 201 if it meets the operating and efficiency standards of the FERC regulations at 18 C.F.R. §§ 292.205(a) and (b), and the ownership criteria at 18 C.F.R. § 292.206. "None of these criteria involve a consideration of the type of purchaser to whom the sale may be made by the cogeneration facility." Slip op. at 3.

Section 210(a) of PURPA, upon which HECO relied in opposing the application, states that the Commission's regulations "may not authorize a qualifying cogeneration or small power production facility to make any sale for purposes other than resale." Based upon the legislative history of Section 210(a), and the language of the statute, FERC concluded that "[t]his language shows that Congress was simply limiting the authority of the Commission with respect to the types of sales qualifying facilities could make rather than limiting the facilities entitled to qualifying status." *Id.* Moreover, the language does not limit a State's authority to permit retail sales by qualifying facilities.

Regarding HECO's argument that PRI was attempting to gain the benefit of exemptions authorized by Section 210(e) of PURPA, FERC noted that the exemptions are not limited to facilities making sales for resale. Those cogeneration facilities meeting the criteria for qualifying status are eligible for the exemptions. 18 C.F.R. § 292.601(a).

HECO also argued that granting qualifying status to PRI would harm HECO's existing customers. FERC found that "[w]hile such concerns may have merit, the concerns are irrelevant to the qualifying status of PRI's facility. Inasmuch as Congress intended that questions concerning retail sales be resolved pursuant to State law, such concerns are more appropriately raised in State forums." *Id.* at 4.

D. Important pending issues

1. *Ultrapower 3*, Docket No. QF84-121-000, presents the issue whether a utility subsidiary may be a 50 percent partner in a qualifying facility owner. *Ultrapower 3* is a general partnership organized under the laws of the State of California. It intends to construct a small power production facility, with a capacity of approximately 11 megawatts, that will use wood waste as its primary energy source. It will sell its electric output to Pacific Gas and Electric Company.

The general partners of *Ultrapower 3* are *Ultrapower 3, Inc.*, a subsidiary of a non-utility company, and *Rincon Investing Company (Rincon)*, a wholly owned subsidiary of *Tucson Electric Power Company*, an electric utility.

The ownership criteria governing qualifying small power production facilities appear in Section 3(17)(C) of the Federal Power Act. That section provides that, to obtain qualifying status, a small power production facility must be owned

by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

The regulations implementing this statutory provision appear in Section 292.206 of the Commission's regulations. In relevant part these regulations provide that a small power production facility is considered to be owned by a person primarily engaged in the generation or sale of electric power

if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by a electric utility holding company, or companies or any combination thereof. 18 C.F.R. § 29 2.206(b).

In its application *Ultrapower 3* notes that the Commission's regulations do not define the term "equity interest". In the case of a corporation the rules indicate that the term refers to shares of common stock. However, in the case of a general partnership the test for ownership interests is not apparent; the applicant contends that the determination of whether the proposed arrangement satisfies the limitation on utility involvement should be based on applicable state law governing the interest of a partner in the partnership.

Under California law, which has adopted the Uniform Partnership Act, a partner's interest in the partnership is defined as the partner's share of the profits and surplus. The applicant cites provisions in the partnership agreement between *Ultrapower 3, Inc.* and *Rincon* which allocate profits on a 50-50 basis to the partners, and which provide that upon dissolution, partnership surplus will be distributed on a 50-50 basis. Based on these provisions in the partnership agreement the applicant contends that the arrangement satisfies the applicable test for utility participation in a qualifying facility.

2. In *Abbott Energy, Inc.*, Docket No. QF83-440-000, the FERC is presented with the question whether transfers of power between corporate affiliates are "sales", rendering the supplier an "electric utility" within the meaning of Section 3(22) of the Federal Power Act.

Abbott Laboratories' energy subsidiary, *Abbott Energy, Inc.*, has built a cogeneration facility to serve the *Abbott Labs'* complex at *Barceloneta, Puerto Rico*. The cogeneration project would generally provide power only to the other facilities in the complex, which include *Abbott Chemicals, Inc.*, *Abbott Pharmaceuticals, Inc.*, and *Abbott Hospitals, Inc.* The cogeneration facility cost \$35 million.

When the facility was being planned, *Abbott Labs* and the *Puerto Rico Electric Power Authority ("PREPA")* conducted negotiations concerning the qualification of the facility under Section 210 of *PURPA*, and its consequent entitlement to favorable back-up purchased power rates which *PREPA* had developed. *PREPA* asserted that a prerequisite for that favorable back-up rate was certification by the FERC of the facility's status as a qualifying facility. Accordingly, *Abbott Energy, Inc.* filed a request for FERC certification under 18 C.F.R. § 292.207(b)(1). On November 2, 1983, *Abbott Energy* furnished additional information to complete the application.

On January 9, 1984, *PREPA* filed an opposition to the designation of *Abbott Energy, Inc.*'s facility as a qualifying facility.⁸⁴ The basis for *PREPA*'s opposition is that *Abbott Energy*, the owner of the facility, is an "electric utility" within the meaning of Section 3(22) of the Federal Power Act. As such, it is not eligible for qualifying facility status, under 18 C.F.R. § 292.206(b). *PREPA* argued that *Abbott*

⁸⁴ *PREPA* also protested and requested that the case be held in abeyance pending an evidentiary hearing or petition for rulemaking to address other issues raised. See text accompanying notes 85-86, *infra*.

Energy, Inc. was a "seller" of electricity to its corporate affiliates and was therefore an "electric utility." Further, PREPA asserted that Abbott Energy, Inc. did not "sell" its energy *solely* from self-generated power, because it sought to purchase back-up power from PREPA for "resale" to the Abbott affiliates. Therefore, PREPA argued, Abbott Energy, Inc. does not meet the exception to the ownership requirement in 18 C.F.R. § 292.206(a).⁸⁵

On January 23, 1984, Abbott Energy, Inc. filed a response to PREPA's challenge, contending that Abbott Energy's internal transfers to its corporate affiliates were not to be considered "sales", and therefore Abbott Energy is not an "electric utility" under the Federal Power Act and FERC regulations. Moreover, Abbott Energy asserted that, taken together with its affiliates under the Abbott Laboratories umbrella, Abbott was clearly not "primarily engaged" in generation or sale of electric power.

Aside from the narrow issue directly involved in this qualifying facility docket, PREPA has raised a larger issue relating to cogeneration. PREPA asserts that industrial cogeneration, by removing significant demand from its rate base, will increase electric power costs to its remaining customers, a cost which the cogenerators should bear in PREPA's view. PREPA estimates that anticipated cogeneration during 1984-1985 will require rate increases in excess of 8 percent.⁸⁶

3. In *Public Service Co. of New Mexico*, Opinion No. 203,⁸⁷ the Commission approved an experimental rate package intended to facilitate the creation of a competitive market in exchanges of block and economy energy between six consenting utilities.⁸⁸ Under the terms of the regulatory "treatments" approved by the Commission, the six participating utilities are granted substantial freedom to negotiate the prices at which they will make economy and block energy transactions. In addition, each participant is given the opportunity to retain a portion of any profits realized in the transactions and each is permitted to "flow through" all costs incurred in purchases in the experimental market. For their part, the participants have voluntarily undertaken to provide wheeling services for each other to the extent necessary to permit trades in the energy commodities. The temporary experiment, of two-years' duration, will be extensively monitored by the participating utilities and by a contractor retained by the Commission for this purpose.

None of the participants in the Opinion No. 203 experiment is a cogenerator or small power producer. The Commission offers four reasons why no such facilities are included in the two-year experimental rate program.⁸⁹

The first of these reasons is the absence of any significant development of qualifying facilities⁹⁰ in the area covered by the proposed experiment. Of the few

⁸⁵ Section 292.206(a) provides:

A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power *solely* from cogeneration facilities or small power production facilities) (emphasis added).

⁸⁶ Protest and Position Statement; Request for Evidentiary Hearing; Alternative Petition for Rulemaking, Docket No. QF83-440-000 (filed January 9, 1984) at 11.

⁸⁷ 25 FERC ¶ 61,469 (1983).

⁸⁸ The four investor-owned utility participants are Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico and Southwestern Public Service Company. 25 FERC ¶ 61,469 at pp. 62,029 and 62,062. The two publicly-owned utilities are the City of Farmington and Salt River Project Agricultural Improvement and Power District. *Id.* at n.2.

⁸⁹ The Commission's explanation, entitled "The Absence of Cogenerators and Small Power Producers From the Proposed Experiment," is set forth in an Appendix to Opinion No. 203. See 25 FERC ¶ 61,469 at p. 62,070.

⁹⁰ See Federal Power Act, as amended, Sections 3(17), (18), 16 U.S.C. § 796(17), (18) (Supp. V 1981).

qualifying facilities located in the experimental region, all are small wind facilities; of the few existing ("pre-PURPA")⁹¹ cogeneration facilities none were deemed by the Commission likely to become qualifying facilities.⁹² The Commission also found little potential for cogeneration development in the experimental area. It found that virtually all of the potential applications for cogeneration or small power production in the covered area are quite small (*i.e.*, less than 5 megawatts).

The Commission went on to find that, even if there were qualifying facilities in the area, they would be unlikely to participate in the bulk power market. It noted that the long-term contracts favored by many cogeneration facilities would not be consistent with short-term sales into a flexible experimental market. Added to this legal impediment, according to the Commission, are the economic and technical problems that would be faced by any qualifying facilities interested in participating in a bulk power market. The Commission observed that qualifying facilities are generally unable to provide reliability by maintaining spinning reserves,⁹³ as required under the terms of the experimental rate program. The Commission also noted that qualifying facilities would be unable to adjust efficiently for the inadvertent energy flows⁹⁴ that would be encountered at the interconnection points required for the experiment.

For these reasons, the Commission concluded that the absence of any qualifying facility participation in its bulk power experimental market program is "unrelated to the experimental design."⁹⁵ It did, however, leave the door open for approval of qualifying facility participation in subsequent experimental programs where the exclusion of a particular generating technology would hinder the achievement of the Commission's goal of encouraging a competitive market in bulk energy transactions.

III. FEDERAL LEGISLATION

Bills to amend PURPA were not renewed during the First Session of the 98th Congress. However, other relevant legislative developments are noted below.

A. Gas holding company investment in cogeneration facilities

H.R. 4467, introduced by Congressmen Walgren and Broyhill on November 18, 1983, would enable a company registered under the Public Utility Holding

⁹¹ "Pre-PURPA" facilities, as the Commission uses the term are cogeneration facilities constructed prior to enactment of the Public Utility Regulatory Policies Act of 1978, Pub. L. 95-617, 92 Stat. 3117 (November 9, 1978), codified at 16 U.S.C. §§ 2601 *et seq.*, 16 U.S.C. §§ 796 (17), (18), 824a-3, 824i, 824k (Supp. V 1981).

⁹² The existing facilities are unlikely to become qualifying facilities, according to the Commission, because they either lack the thermal energy recovery or sequential processes required under the Commission's regulations, *see* 18 C.F.R., Part 292, Subpart B (1983), or have little excess capacity to utilize for transactions in electrical energy. 25 FERC ¶ 61,469 at p. 62,071.

⁹³ The term "spinning reserves" refers to reserve capacity in operation and capable of taking load at any time. *See id.* at p. 62,073, n.9. The Commission found that, although a qualifying facility could arrange with a contiguous utility to provide the required spinning reserves, such transactions are likely to be uneconomic and therefore a disincentive to qualifying facility participation in the experimental market. *Id.* at p. 62,072.

⁹⁴ The term "inadvertent energy flow" refers to the discrepancy between the amount of electrical energy scheduled to flow across an interconnection point and the energy flow actually achieved. *Id.* at p. 62,073 n. 10. The Commission observed that the new methods available to cogeneration facilities for adjusting for inadvertent flows exact large efficiency penalties, and that arrangements with contiguous utilities for performance of the required adjustments, like arrangements for provision of spinning reserves, are likely to be too costly to render participation in the experimental program economically viable. *Id.* at p. 62,072.

⁹⁵ *Id.* at p. 62,072.

Company Act of 1935 ("PUHCA") solely by reason of direct or indirect ownership of voting securities of one or more gas utility companies or a subsidiary company of such registered company to invest in or acquire any interest in any qualifying cogeneration facility as defined in PURPA to the same extent as if the registered company were not required to be so registered. If enacted, the proposed bill would encourage cogeneration development by the three principal distributors of natural gas in the highly industrial Ohio Valley region (Columbia Gas, Consolidated Natural Gas, and National Fuel Gas) notwithstanding the "functional relationship" test of the PUHCA. The bill does not cover investment in small power production facilities. Hearings have not been scheduled.

B. Government dams

Two bills, introduced in 1983 to amend Section 10(e) of the Federal Power Act, would limit annual charges at government dams for hydropower generators, including qualifying facilities. S. 1132, co-sponsored by Senators McClure, Murkowski and the late Senator Jackson, would set a ceiling on the annual charge to be assessed by the FERC for use of government dams to generate hydropower of up to \$1 per Kw of installed capacity plus one-half mill per Kwh of energy produced. In addition, the bill provides that the annual charge assessed by the FERC shall be the only charge assessed by any agency for hydropower development at a government dam, thereby eliminating the continuing controversy surrounding the issue of the Bureau of Reclamation's authority to assess a separate "falling water" or "power privilege" charge for the use of a Reclamation dam. The bill was referred to the Committee on Energy and Natural Resources and a hearing was held before the full committee on July 25, 1983. On February 28, 1984, that Committee reported out an amended version of the bill. The legislation passed the Senate on March 30, 1984.

A companion bill to S. 1132 was introduced in the House by Democratic Whip Foley and cosponsored by Representatives Swift, Fazio, Morrison, Boxer, Coelho, R. Smith, D. Smith, Craig, Chappie, Pashayan, Mineta, Moorhead and Richardson. H.R. 3660 is similar to S. 1132 and contains an additional provision designed to alleviate the problem created by provisions contained in repayment contracts between the Department of the Interior and three irrigation districts in Washington State. The bill has been referred to the Energy and Commerce Committee's Subcommittee on Energy Conservation and Power. A hearing on the bill is expected in the Spring of 1984.

C. Lease-back tax benefits

General tax legislation reported out by the House Ways and Means Committee (H.R. 4170) and the Senate Finance Committee (S. 2062) last year may further restrict enjoyment of tax benefits in many lease-back situations that involve governmental and other non-taxpaying entities. These bills propose new rules under which tax-exempt entities would generally be unable to "sell" or "convey" their tax benefits (which are of no use to them) to taxpaying entities. The House Bill contains what is in effect an exemption for solid waste disposal plants. The Senate Bill contains a similar but more qualified exemption for solid waste disposal plants and cogeneration facilities. Both bills offer a grandfather exemption for plants put into service or contractually committed by May 23, 1983. The Senate Bill also includes a specific list of projects excluded from the reach of the bill. These bills have a good chance of enactment. If not enacted during the 98th Congress, these measure (or closely similar ones) are expected to be reintroduced next year.

D. *Municipal Preference*

On November 16, 1983, one of the last days of the 1st Session of the 98th Congress, Congressman Richard Shelby (D-Ala.) introduced legislation designed to eliminate the applicability of municipal preference in relicensing proceedings. H.R. 4402, titled "Electric Consumers Protection Act of 1983," is co-sponsored by 44 members of both parties. The bill was referred to the House Energy and Commerce Committee's Subcommittee on Energy Conservation and Power, where hearings were scheduled for May 17, 1984 by Subcommittee Chairman Richard Ottinger (D-N.Y.).

The legislation is designed to reverse the effect of the FERC's declaratory order issued in the *City of Bountiful* case, 11 FERC ¶ 61,337 (1980), affirmed in 1982 by the U.S. Court of Appeals for the 11th Circuit, *Alabama Power Co. v. FERC*, 685 F.2d 1311, *cert. denied*, 103 S. Ct. 3573 (1983). The FERC therein declared that the municipal preference provision of Section 7(a) of the Federal Power Act shall apply in all relicensing proceedings under Section 15 of the FPA, including those involving the original licensee. Subsequent to the Supreme Court's denial of certiorari, the FERC in a separate proceeding voted to overturn the *Bountiful* rule, holding instead that the municipal preference does not apply, as a matter of law and policy, against the original licensee in a relicensing proceeding. *Pacific Power and Light Co.*, 25 FERC ¶ 61,052 (1983), *rehearing denied*, 25 FERC ¶ 61,290 (referred to as the "Merwin Dam" case).

The sponsors of H.R.4402 believe that the FERC's latter decision in the Merwin Dam case is the proper one and Congressional affirmation of it is necessary for the protection of consumers. The bill amends Section 7(a) of the FPA by clearly providing that the municipal preference applies only in "original" licensing proceedings, and deleting the reference in Section 7(a) to relicensing proceedings under Section 15 of the FPA. In conjunction therewith, the bill amends Section 15 of the FPA by providing that the Commission shall issue a new license to an *existing* licensee, *unless* the project does not meet the public interest standards of Section 10(a) of the FPA. If the existing licensee's proposal does not meet such standards, then the Commission may issue the license to a different licensee. Finally, the bill provides that, in those cases where a different licensee is awarded the project, it shall pay the existing licensee "just compensation in an amount that the Commission shall determine in accordance with due process of law," in lieu of the "net investment" method currently applicable.

IV. STATE DEVELOPMENTS

A. *California*

The California Public Utilities Commission (CPUC) continued its activities in implementing the precedent-setting OIR-2.⁹⁶ In that order, the CPUC established guidelines for utility purchases of electricity from qualifying facilities and ordered utilities to file five standard price offers — as-available offer, firm capacity offer, less-than-100 Kw offer, five-year forecast offer, and long-term resource plan-based offer — which would be available as *pro forma* contracts for interested qualifying facilities.

⁹⁶ Rulemaking on the Commission's Own Motion to Establish Standards Governing the Prices, Terms, and Conditions of Electric Utility Purchases of Electric Power from Cogeneration and Small Power Production Facilities, Decision 82-01-103, issued January 21, 1982.

One of the first actions implementing OIR-2 in 1983 was the CPUC's review of compliance filings made by Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company. Specifically, these utilities had filed standard offers reflecting the as-available, firm capacity, and less-than-100 Kw alternatives. In its order, the CPUC focused on rate issues, and deferred consideration of such issues as interconnection, filing requirements, insurance, and miscellaneous contract provisions.⁹⁷ Among other things, the order required modification of the standard offeres to include provisions governing (1) a choice of payment options based on availability of a qualifying facility's energy output; (2) restrictions on the ability of a utility dispatcher to require decreases in a qualifying facility's output; (3) payment rights for qualifying facility performance in excess of utility capacity factors; and, (4) reductions in capacity credits due to failure to meet performance standards. In addition, the CPUC required capacity credits to be based on 100% of the capital costs of combustion turbines, with energy prices to be based on average year incremental heat rates and variable operating and maintenance costs. Finally, the CPUC addressed the issue of termination by establishing notice requirements and a schedule of capacity payment refunds.

In May 1983, the CPUC established procedures to help resolve methodological disputes pertaining to the standard offer based on long run avoided costs. The CPUC was concerned that neither the evidentiary hearing process, nor the notice and comment rulemaking route, would provide for quick resolution of such issues as avoided cost methodology, performance requirements, and termination penalties.⁹⁸ For that reason, the CPUC proposed a series of "negotiating conferences" to give parties an "opportunity to work together toward a methodology for an interim long-term standard offer[s]."⁹⁹

In its subsequent Interim Opinion, the CPUC approved payment options developed at the negotiating conferences.¹⁰⁰ Specifically, three payment options were made available under Standard Offer No. 4. Option 1 provides a 10-year fixed payment stream using a ramped-up forecast. Under Option 2, a payment stream is fixed for 10 years and levelized. Finally, Option 3 provides for forecasted incremental energy rate payments. Capacity payments will be the same regardless of option selected. In its Order, the CPUC addressed qualifying facility concerns that "regulatory authority" clauses could provide a basis for contract changes based on prospective regulatory developments.¹⁰¹ The CPUC ordered deletion of such clauses in Standard Offer No. 4, but held that in return qualifying facilities could not switch to other more-favorable versions of Standard Offer No. 4 subsequently promulgated until expiration of the contracts.¹⁰²

B. Florida¹⁰³

1. *New PURPA rules.* The Florida Public Service Commission ("FPSC" or "Commission") replaced its 1981 cogeneration rules (Order No. 12443, September 2,

⁹⁷ Decision 82-12-120, issued December 30, 1982. These issues were subsequently addressed in Decision 83-10-093, issued October 19, 1983.

⁹⁸ *Interim Opinion on Procedural Guidelines*, Decision 83-05-038, slip op. at 7, issued May 4, 1983.

⁹⁹ *Id.*

¹⁰⁰ Decision 83-09-054, issued September 7, 1983.

¹⁰¹ *Interim Opinion*, *supra* n.98, slip op. at 39.

¹⁰² The CPUC Staff has proposed further proceedings to develop a final version of Standard Offer No. 4. *Commission Staff Statement of Issues*, Application 82-04-44, filed December 21, 1983.

¹⁰³ For a related judicial development, see discussion of *Florida P&L Co. v. Florida PSC*, Part I.B., *supra*.

1983, explained by Order No. 12634, October 27, 1983, appeal pending *sub nom. Metropolitan Dade County v. FPSC*, No. 64,330, Sup. Ct. Fla.).

a. *Buy-sell option.* The 1983 rules allow qualifying facilities to elect netting or simultaneous buy-sell and to change the election no more frequently than once a year. However, the FPSC announced that it will seek a FERC waiver so that buy-sell may be prohibited in Florida.

b. *As-available energy.* The rules codify a formula for determining avoided energy costs for as-available energy sales. The formula is intended to allocate to utilities and their ratepayers savings realized by Florida Broker transactions in qualifying facility power and to allocate to qualifying facilities supplying a given utility, as a group, the additional energy cost savings realized by that utility.

c. *Firm power and energy.* The rules contemplate both negotiated contracts and a standard-offer contract for sales of firm power and energy to each regulated utility in the State. Such firm power contracts would include a capacity payment, unlike purchases of as-available energy. The rules specify a one-year deferral value formula to determine avoided capacity costs, which will be used both in testing prudence of a negotiated contract and to define terms of a standard-offer contract. The avoided costs are to be those of a statewide avoided unit, of one of the four investor-owned utilities, rather than a different unit for each utility. A unit is to be selected in an annual implementation hearing, together with its anticipated in-service date and estimated costs. Contracts signed thereafter (until the next annual implementation hearing) are evaluated for prudence by reference to that unit, with qualifying facilities given the option to be bound by the estimated costs of that unit either as originally estimated by the FPSC or as reestimated at each year's implementation hearing. Beginning with the anticipated in-service date of the statewide avoided unit, if the qualifying facility maintains at least a 70% capacity factor the standard offer contracts will provide capacity payments combined with energy payments based on costs of the fuel planned to be used in that statewide unit. Standard-offer capacity payments are set 20% below the formula-determined avoided costs to reflect the risk of qualifying facility supplied power. Prior to the anticipated in-service date, the purchasing utility will pay its own avoided energy costs. The rules require that a standard-offer contract be signed at least two years before the anticipated in-service date and continue for at least ten years beyond that date. The rules include a formula setting early capacity payments, beginning up to seven years in advance of the in-service date at the qualifying facility's option if the qualifying facility assures repayment in case of abandonment by posting a surety bond or equivalent.

d. *Resale and wheeling among utilities.* The rule encourages, but does not require, utilities to resell power to the utility planning the statewide avoided unit, presumable under FERC rate schedules. The rules also require utilities to wheel qualifying facility power, at the qualifying facility's option. The FPSC held that retail sales by qualifying facilities are forbidden in Florida but reserved for case-by-case consideration requests for wheeling to consumers under common ownership with a qualifying facility. The FPSC also allowed utilities to charge qualifying facilities a customer deposit based on the excess, if any, of the qualifying facility's purchases above sales.

e. *Cost recovery and contract review.* The new rules assure utilities of recovery of the following payments to qualifying facilities via the Fuel and Purchased Power Cost Recovery Clause:

(1) All payments for as-available energy pursuant to the utility's purchase tariff;

(2) Payments for as-available energy pursuant to a separately negotiated contract "if the payments are in the best interest of the utility's ratepayers;"

(3) Firm energy and capacity payments pursuant to a utility's standard offer; and

(4) Firm energy and capacity payments pursuant to a separately negotiated contract "if the contract is found to be prudent" in accordance with the rules.

All contracts must be filed with the FPSC. It appears optional with the utility whether to seek advance FPSC approval of a contract or to await fuel clause proceedings. Since passage of PURPA, the FPSC has approved two contracts between qualifying facilities and a utility, in both cases before adoption of the present rules.

2. *Implementation hearing.* The first annual implementation hearings, begun in January 1984, are considering numerous interpretation issues of first impression in addition to selection of the first "statewide avoided unit".

3. *Appeal.* The pending appeal by Dade County to the Florida Supreme Court, cited *supra*, challenges the 20% reduction of the standard offer capacity payment and contends that retail sales by qualifying facilities are not prohibited by Florida law.

C. Hawaii

The Hawaii Public Utilities Commission ("PUC") considered the relation of its PURPA regulations to the FERC regulations in *Re Wind Power Pacific Investors-III*, 54 P.U.R. 4th 75 (1983). An electric utility protested an application for certification in part on the ground that under the Hawaii rules, a person and not a facility qualifies and there can only be one such applicant, not two as there were in this case. The PUC found that its rules were closely patterned after the FERC rules and that where the FERC had interpreted its rules the PUC would follow that interpretation whenever consistent with state policy. The FERC had stated that under its rules, a facility qualifies and that the benefits of qualification accrue to the owners and operators; consequently, the PUC held that the utility's argument that a facility must be owned by one person was inapplicable. In addition, the PUC upheld, as meeting the requirement of selling energy directly to an electric utility, an arrangement whereby the owner and constructor of the facility sold all its output to the operator, which used some and sold the excess to the electric utility. The PUC found that this was essentially a financing arrangement, and that the operator was in fact selling its energy directly to the electric utility.

D. Iowa

In 1983, both the Iowa General Assembly and the Iowa State Commerce Commission (Iowa Commission) considered proposals designed to encourage the development of facilities using solar, wind, waste, wood or hydroelectric energy sources.

By enacting Senate File 380, the 70th Iowa General Assembly established a state policy "to encourage the development of alternate energy production facilities and small hydro facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient use."¹⁰⁴ To achieve this statutory policy, the Iowa Commission was directed to "require electric utilities to enter into long-term contracts to . . . purchase or wheel electricity . . . [and to] provide for the availability of supplemental or backup power. . . ."¹⁰⁵

¹⁰⁴S.F. 380, § 2 (to be codified in Iowa Code § 476.34).

¹⁰⁵S.F. 380, § 4 (to be codified in Iowa Code § 476.36(1)).

The key features of Senate File 380 are the provisions pertaining to the calculation of rates for purchase of generated power. A basic criteria guides all rate-setting proceedings: "[t]he rates shall be established at levels sufficient to stimulate the development of alternate energy production and small hydro facilities in Iowa and to encourage the continuation of existing capacity from those facilities."¹⁰⁶ The statute also specifies certain factors to be considered in setting rates — estimated capital cost of next generating plant to be placed in service, term of the contract, levelized annual carrying charges, and annual energy costs — and provides that other factors may be considered (including lower rates for existing facilities).¹⁰⁷

Two other features of S.F. 380 are of note. First, the issue of excess capacity has been removed as a possible problem area in contract negotiations: capacity purchased from an alternate energy or small hydro facility is not to be included in calculation of a utility's excess generating capacity for ratemaking purposes.¹⁰⁸ Equally significant, the statute places an eight cent per kwt *ceiling* on rates that can be paid to new facilities (this ceiling expires as of July 1, 1986).¹⁰⁹

On October 21, 1983, the Iowa Commission initiated a rulemaking implementing Senate File 380. The proposed rules envision a procedure under which, in the absence of a negotiated rate, either party may apply for a Commission determination of a rate.¹¹⁰ There is a rebuttable presumption that such rate is valid for similar facilities for a two-year period.¹¹¹ The proposed rules also add the following to the list of factors to be considered in setting a rate: time of day, dispatchability, reliability, scheduled outages, system emergencies, and retail rates.¹¹²

Comments on the proposed rules were filed on December 8, 1983, and a public hearing was held on December 13, 1983. The major topics analyzed included (1) elimination of the new/old facility distinction, (2) intra-utility wheeling, (3) wheeling rates, (4) contested proceeding requirements, (5) rate floors over the length of the contract (based on the avoided cost of the next unit to be placed in service in the state), (6) mandatory capacity credits and escalator clauses, (7) statewide rates, and (8) ratemaking factors.

The Iowa Commission has voted in principle to issue a new set of proposed rules which provide, among other things, for a statewide rate floor of 6.5 cents per kwh.¹¹³ Comments on the proposed rules are due March 20, with final rules expected to be made effective by June 1984.

E. *Maine*¹¹⁴

On January 9, 1984, the Maine Public Utilities Commission ("MPUC") issued a Decision and Order establishing standard long-term cogeneration and small power production rates for Maine's largest investor-owned utility, Central Maine Power

¹⁰⁶ S.F. 380, § 4 (to be codified in Iowa Code § 476.36(2)).

¹⁰⁷ S.F. 380, § 4 (to be codified in Iowa Code §§ 476.36(3), (4)).

¹⁰⁸ S.F. 380, § 6 (to be codified in Iowa Code § 476.38).

¹⁰⁹ S.F. 380, § 7.

¹¹⁰ Iowa Admin. Code § 250-15.9 (proposed).

¹¹¹ *Id.*

¹¹² Iowa Admin. Code § 250-15.9(2) (proposed).

¹¹³ Des Moines Register, January 19, 1984, at 5, col. 1.

¹¹⁴ See also the discussion of *Central Maine Power Co. v. Public Utilities Commission*, 345 A.2d 34 (Me. 1983), in the section on judicial developments.

Company ("CMP").¹¹⁵ That proceeding, begun in July 1981,¹¹⁶ established leveled avoided cost rates for CMP purchases of energy and capacity from qualifying facilities, under contracts commencing in 1983, as follows: (1) 5.67¢ per kWh for a five-year contract, (2) 8.24¢ per kWh for a ten-year contract, and (3) 9.40¢ for a fifteen-year contract.¹¹⁷ Under Maine regulations¹¹⁸ implementing PURPA and the Maine Small Power Production Facilities Act of 1979, as amended,¹¹⁹ Those rates apply to qualifying facilities with an installed capacity of 1,000 kW or less, although the MPUC stated that its conclusions are intended to "provide guidance for all negotiations between CMP and qualifying cogenerators and small power producers, even when the facilities involved are too large to take advantage of the standard rates directly."¹²⁰ The rates are based upon CMP's total revenue requirements, as derived from a comparison of CMP's current generation expansion plan ("base plan") with a variation of that plan reflecting a 50 mW load reduction ("50 mW decrement plan"),¹²¹ and are subject to annual adjustment under Maine regulations.¹²²

Earlier, in *Scott Paper Company*,¹²³ the MPUC granted approval to a fifteen-year contract for CMP purchases from Scott's Somerset mill in Skowhega, Maine, at a base rate of 5.6 cents per kWh, to be "increased or decreased by an adjustment factor which reflects each increase or decrease in the retail rate [i.e., either fuel cost adjustment or applicable base rate] paid by Scott to CMP at its Somerset facility, over the term of the contract."¹²⁴

In *Central Maine Power Company* (Docket Nos. 83-247 and 83-248),¹²⁵ the MPUC granted CMP's request for an increase in its fuel cost adjustment rate, prompted primarily by CMP projections of higher oil prices and a higher load forecast. The correlative increase in CMP's standard short-term avoided cost rates resulted in an average avoided cost rate (for the 1-50 mW all-hours decrement) of 4.93¢ per kWh for the period from November 1, 1983, through October 31, 1984. Earlier in the year, the MPUC had reduced fuel cost adjustment rates and correlative short-term avoided cost rates for CMP.¹²⁶

F. Montana

In a follow-up proceeding to its initial PURPA Section 210 implementation, the Montana Public Service Commission issued Order No. 5017 reaffirming its commitment to long term rates for the purchase of qualifying facility power.¹²⁷ The Commission determined that avoided energy costs include fuel, operation and maintenance, inventory and working capital. Energy costs are calculated based upon the energy cost of the next baseload facility planned by the utility. Capacity

¹¹⁵*Central Maine Power Company and Scott Paper Company*, "Decision and Order," Docket No. 82-174, Maine Public Utilities Commission (January 9, 1984).

¹¹⁶Notice of Investigation and Hearing, issued July 27, 1981, Docket No. 81-155; later consolidated with Docket Nos. 82-89 and 82-166, and reassigned final Docket No. 82-174.

¹¹⁷Decision and Order at p. 62.

¹¹⁸65-407 C.M.R. 36.4(C)(3)(b).

¹¹⁹35 M.R.S.A. §§ 2321 *et seq.*

¹²⁰Decision and Order at p. 3.

¹²¹Decision and Order at pp. 8-9.

¹²²65-407 C.M.R. 36.3(C)(4) and 36.4(C)(3)(b).

¹²³Docket No. 83-8, 53 P.U.R. 4th 169 (April 29, 1983).

¹²⁴*Id.* at 173.

¹²⁵"Order Authorizing and Establishing Rates," issued October 31, 1983.

¹²⁶*Re Central Maine Power Co.*, Docket Nos. 82-52, 83-82, 52 P.U.R. 4th 349 (1983).

¹²⁷*In the Matter of the Commission's Investigation into and Refinement of Electric Avoided Costs Based Rates for Public Utility Purchases From Qualifying Cogenerators and Small Power Producers*, Docket No. 83.1.2 (November 10, 1983).

costs are calculated based upon the capacity cost of a hypothetical combustion turbine.

The order requires the state's utilities to offer three forms of a long term rate: levelized, non-levelized and escalating over the term. The escalating rate permits the capital component to be levelized while the energy component escalates.

G. *New Hampshire*

The 1983 legislature made significant amendments to the state mini-PURPA known as the Limited Electrical Energy Producers Act (LEEPA). These amendments generally track the definitions and standards used in Section 210 of PURPA but also contain an explicit directive with respect to long term rates.¹²⁸ Under the amended LEEPA, the state public utilities commission is required to set utility purchase rates for qualifying facility generated power on the basis of the avoided cost standard. The standard of the prior law required only that rates be set from time to time. The definition of a qualifying facility is the same as that used in PURPA with two exceptions. First, qualifying small power producers may not exceed 20 megawatts of capacity. Second, the amended Act retains the "limited producers" definition. A limited producer is a qualifying facility whose capacity does not exceed 5 megawatts. Limited producers are entitled to all benefits of LEEPA and also are the only class entitled to make retail sales and entitled to request wheeling to the retail user.¹²⁹

LEEPA also provides the Commission with discretionary authority to establish long term rates calculated at the time of delivery or calculated for a specified term at the time the qualifying facility agrees to be obligated to deliver for the specified term.

The New Hampshire Commission had its first opportunity to examine its newly-granted jurisdiction under LEEPA in a case involving the state's largest electric utility, Public Service Company of New Hampshire (PSNH).¹³⁰ In that docket, the Commission exercised its discretionary authority under LEEPA and established interim long term rates for the sale of power to PSNH. The Commission's orders in that docket established three innovative long term ratemaking concepts. First, the Commission established 10, 15 and 20 year rates by calculating a present worth of the utility's avoided cost over the appropriate term. Under this method any rate design is permitted provided that the present worth of the rate does not exceed the present worth determined by the Commission to represent PSNH's avoided costs over the period and provided that the initial price in 1984 does not exceed 9¢ per kwh. This cap is designed to limit the amount of the "front-ended" rate. The level of the initial price is permitted to escalate at 6.7% a year after 1984, but the total rate must adhere to the appropriate present worth.

The second area of innovative ratemaking involves the adders to the base fuel costs which were used to determine the avoided energy cost. The Commission ruled that avoided variable operation and maintenance expenses, avoided inventory expenses and avoided cash working capital were components of avoided energy costs. Inventory expenses were included to reflect the fact that qualifying facility purchasers would reduce the amount of oil consumed and hence the amount required to be kept in inventory. The cash working capital adder was included because the company avoids the normal billing lag in customer receipts over

¹²⁸ N.H. Rev. Stat. Ann. § 362-A (Supp. 1983).

¹²⁹ *Id.*, § 362-A:2(a).

¹³⁰ Rates for Small Power Producers and Cogenerators, Docket No. DE 83-63.

expenses when power is delivered by a qualifying facility. Hence, less working capital is needed by the utility.

The third concept is referred to as the "buyout provision". Under this provision any qualifying facility can buy out of its "front-ended" rate by paying the utility the difference between the rate received and the utility's actual avoided costs plus interest at the utility's cost of capital.

H. New Jersey

1. *Legislation.* The State's utility franchise tax law (N.J.S.A. 54:308-50 et seq.) was amended to entitle qualifying facilities to a credit of the tax on purchases from utilities up to the extent of their sales to utilities. (Assembly Bill A-770, enacted in March of 1983.) Even prior to the amendment, the 13 percent utility franchise tax on utility sales to their customers did not apply to sales by qualifying facilities to utilities. However, all qualifying facility purchases from utilities (whether on a netting or a simultaneous buy-sell basis) were subject to the tax. The amendment provides for credit against or rebate of that tax, up to a maximum credit equal to 13 percent of the price of power purchased by a qualifying facility applied to a quantity purchased no larger than the quantity sold by the qualifying facility. As a result of the amendment, utility franchise tax considerations will not affect the qualifying facility's election between simultaneous buy-sell and netting. The new law gives the New Jersey Board of Public Utilities ("BPU") responsibility to issue implementing regulations.

2. *Administrative developments.* On October 14, 1983, the BPU amended its original Order in Docket No. 80-10-687 (issued October 14, 1981) regarding avoided cost rates for cogenerators and small power producers. The new order removes the ceiling of one megawatt established in the original order as a criterion for receipt of the avoided cost rates authorized by the Board. Those rates continue to be the PJM pool billing rate plus ten percent. The capacity credit continues to vary with the utility affected, and ranges from approximately \$30-45 per kilowatt per year. The 1981 order also called for a second phase designed to address the subject of tariffs and standards for wheeling. The 1981 order stated "that the transmission of electricity, or wheeling, can further lead both to the efficient use of electricity and the encouragement of cogeneration and small power production." Since the three major utilities submitted written testimony in February 1982, Phase II has remained an open docket, and no action has been taken.

I. Puerto Rico

In January 1983, the Puerto Rico Electric Power Authority ("PREPA") issued rules implementing PURPA Section 210. PREPA is an unregulated electric utility.

The PREPA rules include provisions for energy and capacity payments to qualifying facilities. The rates are set annually by PREPA, based on projected avoided costs using a 100-megawatt decrement. The energy rate for the period July 1983-June 1984 is 5.1¢ per kWh, and the capacity rate is 40¢ per kW/month.

PREPA has imposed certain conditions on purchase of power from cogenerators and small power producers. First, electric power produced by a qualifying facility is not to be transferred to "another person or entity" except for subsidiary companies located on the same premises. Second, capacity payments are predicated on a minimum two-year contract, and achievement of 70 percent or

¹³¹ See also the FERC pending issues section, describing a PREPA challenge to qualifying facility status for an industrial cogenerator.

better availability by the qualifying facility. For each kWh below the amount necessary to achieve 70 percent availability, 0.1¢ is deducted from the capacity payment. Third, energy and capacity payments are subject to true-up based on a PREPA production cost study.

J. Texas

1. *Legislation.* During the 1983 session, the Texas Legislature amended the Public Utility Regulatory Act to require the Texas Public Utility Commission ("TPUC" or "Commission") to make and enforce rules to encourage the economical production of energy by qualifying facilities (S.B. No. 232). The Texas Legislature does not meet in 1984.

2. *Administrative developments, energy costs.* In *Energy Costs GENSOM-AC* (TPUC Docket No. 4712) the Commission specified the manner in which avoided energy costs are to be determined. The computer program identified as GENSOM-AC was adopted by the Commission as the methodology to be used to determine avoided energy costs within the Houston Lighting & Power Company ("HL&P") service area. In its Final Order, the Commission incorporated the terms of a stipulation which had been agreed upon by the parties and which included the GENSOM-AC methodology. With GENSOM-AC, calculations are made both with and without cogeneration to determine avoided energy costs. The parties in Docket No. 4712 stipulated that payment of avoided energy cost by HL&P shall be equal to 99% of the sum of avoided fuel costs as calculated by GENSOM-AC plus appropriate adjustments for line losses, variable operations and maintenance expense and other adjustments approved by the Commission. HL&P, in its bidding proposal, discussed below, is also offering a 99% avoided energy cost payment.

At this time, cogenerators have not succeeded in negotiating a payment by HL&P exceeding this 99% avoided energy cost level. In support of the 99% payment, Commission Staff argue that HL&P ratepayers will support cogeneration if it has a favorable impact on their bills and, because avoided costs are estimated, it is advisable to have a cushion to protect against an overestimation. Although tariffs must reflect full avoided costs unless a waiver has been granted by the FERC, Texas utilities are free to negotiate contracts with rates less than full avoided costs.

3. *Capacity costs.* As required by the final Order in Docket No. 4712, a study is currently being conducted to determine the avoided capacity costs to be paid by HL&P through 1995. A preliminary report has been issued and a final report is scheduled to be completed in March 1984.

4. *HL&P's bidding proposal.* HL&P has proposed, through a December 13, 1983 letter to existing or potential cogenerators within its service area, a bidding procedure through which HL&P will purchase 600 MW of electric generation capacity through 1995. Under this proposal, HL&P would contract with cogenerators who offer to sell cogenerated electricity at the lowest prices below HL&P's offered capacity payments. Bids were to be received on or before January 31, 1984.

HL&P's bidding proposal has been challenged by the Texas Industrial Energy Consumers, Northern Natural Resources Company and Diamond Shamrock Chemicals Company (TPUC Docket No. 5543). Protestors are asking the Commission to restrain HL&P from proceeding with the bidding proposal and that the Commission declare the proposal illegal. A Prehearing Conference was held in Docket No. 5543 and the Examiner issued a Temporary Restraining Order. This Order was affirmed on appeal by HL&P to the Commission. At a second Prehearing Conference held on February 15, 1984, the parties agreed to suspend the discovery

schedule and attempt to negotiate the capacity credit issue. The Commission's General Counsel will preside over and guide the discussions and negotiations among the parties and other interested persons.

The protestors allege that HL&P will not be purchasing all cogenerated electricity at full avoided costs because HL&P is (1) limiting the amount of capacity it will purchase and (2) requiring cogenerators to bid against one another for capacity payments rather than paying full avoided costs.

Challengers to HL&P's proposal also argue that it violates TPUC Regulation 052.02.05.058(h)(1) which requires purchases from qualifying facilities to be based on avoided costs of energy and capacity. The challengers also allege that HL&P's proposal violates the Final Order in Docket No. 4712 which requires the parties and TPUC staff to cooperate in the aforementioned study to determine HL&P's avoided capacity costs. Finally, the challengers allege HL&P's proposal violates the newly enacted Section 16(g) of the Public Utility Regulatory Act which requires the Commission to make and enforce rules encouraging cogeneration. The protestors submit that HL&P's proposal discourages cogeneration.

K. Vermont

The Vermont Public Service Board has promulgated a new rulemaking implementing PURPA Section 210.¹³² Unique features of the rulemaking include the use of an avoided cost rate based upon the composite avoided cost of the Vermont electric utility system and the use of a state wide purchasing agent to purchase qualifying facility power on behalf of the state's electric utilities. The utilities are required to purchase the power from the agent based upon their pro-rata share of total state retail kilowatt-hour sales.

The rulemaking provides for the calculation of rates for short term sales, long term non-firm sales over a 5, 10 or 15 year period and long-term firm sales over a 10, 20 or 30 year period. All rates are seasonally and time-of-day differentiated. Long term rates are determined on a levelized present worth basis and a non-levelized basis. Long term levelized firm rate eligibility requires that the qualifying facility establish a reserve fund to cover anticipated capital replacements and maintenance requirements over the term of the rate.

At the time of this writing proposed rates have been calculated by the Department of Public Service and the Public Service Board. The Commission has yet to rule on the rate proposals.

L. Washington

On November 9, 1983 the Washington Utilities and Transportation Commission (WUTC) rejected a tariff filing by Washington Water Power Company which proposed rate increases with an annual revenue effect of approximately \$6,069,000 to compensate the company for annual expenses associated with the purchase of power from Potlatch Corporation's cogeneration facility. In reaching the ultimate determination that the proposed rates and charges were not fair, just, and reasonable, the WUTC determined that the proposed purchase agreement was not based on the proper methodology to calculate the avoided costs as defined by PURPA and State law and regulations (which were essentially similar to the Federal regulations implementing PURPA). Washington Water Power based its calculations of avoided costs using projected costs for a coal-fired plant although it admitted at

¹³² Public Service Board Rule No. 4.100 *et. seq.*

hearing that the plant was not specifically the resource the company anticipated it would avoid constructing. The total of the contract capacity rate and energy rate under the agreement was approximately 6.3¢ per kilowatt hour.

Company studies indicated that an additional resource which could be avoided would not be necessary until the 1989-90 operating year even without including the Potlatch unit in the resource base. If Potlatch was included in the resource base, the additional resource would be delayed for two more years. Therefore, considering the current and projected future energy surplus, the WUTC felt that "there are no capacity costs to be avoided under the terms of the FERC regulations and the WUTC's rules, which define "avoided costs" as "incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, the utility would generate itself or purchase from another source." The WUTC did note that, on the other hand, there are some energy costs which may be avoided and are appropriate in the period of surplus and to the extent that a cogeneration facility can deliver firm energy, the appropriate rate at the present time in the region is the rate for firm energy purchased from the Bonneville Power Administration. In reaching its decision, the WUTC reaffirmed its adoption of the goal of encouraging cogeneration but explained that that goal did not require that a utility pay for capacity which is not needed to meet its total system load.

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