Report of The Committee on Cogeneration And Small Power Production Facilities

#### I. INTRODUCTION

Developments in the cogeneration and small power production field in 1984 centered primarily on state actions designed to implement PURPA. This report therefore expands the list of state developments to 19. While no significant federal judicial actions were reported, the FERC issued several important orders and interpretations concerning wheeling and interconnections. Finally, this report introduces a new section entitled "Financial, Accounting, and Tax Developments," which provides, among other items, an in-depth analysis of the "Wallop Amendment" to the Deficit Reduction Act of 1984.\*

#### **II. FERC DEVELOPMENTS**

#### A. Rules

### 1. User Fees

Final action has yet to be taken on the September 1, 1982, proposal of the Federal Energy Regulatory Commission ("FERC" or "the Commission") to establish a schedule of user fees applicable to electric utilities, cogenerators, and small power producers.<sup>1</sup> Both the review of an application for an order to direct the establishment of physical interconnection of facilities under the Federal Power Act ("FPA") and the review of an application for certification of qualifying status as a small power production or cogeneration facility under the Public Utility Regulatory Policies Act ("PURPA")<sup>2</sup> would be covered by this rule. The fee for the former would range from \$6,200 to \$57,400, depending upon whether a hearing was held. The fee for the latter would be \$2,600 in all cases.

### 2. Diesel and Dual-Fuel Cogeneration

The Commission continued to lend full support to its rules regarding the criteria and procedures employed to determine whether a small-power production facility is eligible to qualify for benefits under Section 201 and Section 210 of PURPA.<sup>3</sup> Thus, the Commission recently refused to reconsider those regulations which permit new diesel and dual-fuel cogeneration facilities to obtain qualifying status on a generic basis, despite a challenge by Consolidated Edison Company of

<sup>\*</sup>The Committee wishes to extend its gratitude to Lee M. Goodwin, Esq., for his contribution to the Financial, Accounting and Tax Developments section, and to Robert B. Raven, Esq. for his invaluable assistance in compiling this report.

<sup>&</sup>lt;sup>1</sup>Fees Applicable to Electric Utilities, Cogenerators, and Small Power Producers, 47 Fed. Reg. 39,851 (1982).

<sup>&</sup>lt;sup>2</sup>Public Utility Regulatory Policies Act of 1978, Public L. No. 95-617, 92 Stat. 3117.

<sup>&</sup>lt;sup>3</sup>Order No. 70-E, Small Power Production and Cogeneration, 46 Fed. Reg. 33,025 (1981).

New York, Inc. ("Con Ed") attacking the accuracy of the Final Environmental Impact Statement ("FEIS") issued when the rules were initially promulgated.<sup>4</sup>

The Commission concluded that the FEIS properly addressed the cumulative air quality impact of PURPA-induced diesel and dual-fuel cogeneration, that "[a] full consideration of the environmental consequences of encouraging cogeneration development did not require an analysis of site-specific market penetration of the New York City area."<sup>5</sup> Hence, the FEIS, which established a range of 625 MW to 1,875 MW for potential new diesel and dual-fuel cogeneration development from PURPA by 1995 in all urban areas in the Middle Atlantic Region,<sup>6</sup> was not deemed deficient for lack of proper methodology. The Commission also found that the National Environmental Policy Act ("NEPA") does not require an agency to evaluate economic impacts, such as the effect of cogeneration development on the rates charged to Con Ed's remaining customers, that are not interrelated with the physical environment.<sup>7</sup> Thus, this allegation and Con Ed's contention that the tax effects of cogeneration should have been taken into account in the FEIS failed, as the requisite connection with the physical environment could not be shown.

#### **B.** Interpretations

#### 1. Exemptions From Utility-Type Regulation

One of PURPA's objectives is the encouragement of cogeneration and small power production through the removal of certain regulatory burdens.<sup>8</sup> In response to a request for an interpretation, the Commission has provided some new guidance on the question of which burdens may be eased.<sup>9</sup> Distinguishing regulation which affects the rates, finances or organization of the qualifying facility ("QF") as an electric utility from that which has only an indirect impact on these factors, the Commission concluded that exemption from compliance was appropriate only with regard to the former. Thus, the Michigan statute upon which the inquiry was based — a statute which limited the power of a municipal corporation to make public improvements<sup>10</sup> — was not deemed the "utility type" regulation to which the exemption was intended to apply.

#### 2. Wheeling

The FERC has resolved the issue of whether PURPA modifies the FERC's jurisdiction over the transmission in interstate commerce of electricity generated by QFs. In *Florida Power & Light Company and Florida Public Service Commission*, 29 FERC ¶ 61,140 (1984), the FERC responded to several petitions for declaratory orders filed

<sup>&</sup>lt;sup>4</sup>Order No. 70-F, Small Power Production and Cogeneration Facilities, 49 Fed. Reg. 33,866 (1984). <sup>5</sup>*Id.* at 33,867.

<sup>&</sup>lt;sup>6</sup>Id. at n.10, citing Draft Environmental Impact Statement.

<sup>&</sup>lt;sup>7</sup>Id. at n.14, *citing* Metropolitan Edison Co. v. People Against Nuclear Energy, \_\_\_\_\_ U.S. \_\_\_\_\_, 103 S.Ct. 1556, 1560 (1983).

<sup>&</sup>lt;sup>8</sup>See PURPA § 210(e); 16 U.S.C.A. § 824a-3(e) (Supp. 1983).

<sup>&</sup>lt;sup>9</sup>Ayres, Lewis, Norris & May, Inc., 28 F.E.R.C. ¶ 61,077 (1984).

<sup>&</sup>lt;sup>10</sup>MICH. COMP. LAWS ANN. § 141.104.

by public utilities and other entities located in Florida, including a joint petition filed by Florida Power and Light Company and the Florida Public Service Commission ("FPSC").

In May, 1984, the FPSC issued an order establishing statewide avoided cost rates for firm capacity and energy purchases, and an interim wheeling rate for the transmission of power generated by QFs of one mill per kWh.<sup>11</sup> This rate was not based on cost allocation, but on the policy of seeking to encourage cogeneration. The FPSC stayed the rate pending a determination by the FERC as to whether the FERC had exclusive jurisdiction over the rates for wheeling electricity in interstate commerce.

With respect to the narrow jurisdictional issue, the FERC held that "[n]o provision of the FPA or PURPA makes any distinction for jurisdictional purposes between transmission of conventionally generated energy and transmission of energy produced by qualifying facilities."<sup>12</sup> Therefore, the FERC concluded that the only test of its jurisdiction over the wheeling of QF power was whether the transaction satisfied the interstate commerce criterion established by Section 201(c) of the FPA. The FERC also declined to waive or delegate to the state public utility commissions ("PUCs") its jurisdiction over QF wheeling rates, because the courts have held that the FERC has no discretion under the FPA to reject jurisdiction.<sup>13</sup>

The FERC also indicated that it would be reluctant to approve a utility's wheeling rates for QF power that are less than the utility's other wheeling rates, regardless of whether the lower rates were supported by a state PUC. "[W]e note that any party advocating preferential transmission rates for power generated by qualifying facilities would bear a heavy burden to show that such a preference is not "undue" under Section 205 of the Federal Power Act."<sup>14</sup> On other issues, the FERC declined to discuss whether states have authority to require wheeling. Nor was the FERC willing to discuss whether particular facilities or transactions are in interstate commerce. Such determinations, the FERC concluded, should be made on a case-by-case basis.

No requests for rehearing of the FERC's order were filed. Accordingly, the order is now final and not subject to judicial review.

#### C. Decisions

#### 1. Ownership of Facilities

### a. Partnership Applicants

In Ultrapower 3,<sup>15</sup> the Commission was asked to decide whether a wholly-owned subsidiary of an electric utility company may be a fifty percent partner in a qualifying small power production facility. Section 3(17) of the FPA states that a qualifying facility must be owned "by a person not primarily engaged in the

<sup>&</sup>lt;sup>11</sup>Florida Commission Order No. 13247, Docket No. 830377-U (May 1, 1984).

<sup>&</sup>lt;sup>12</sup>29 F.E.R.C. ¶ 61,140 at 61,292.

 $<sup>^{13}</sup>Id.$ 

<sup>14</sup>Id. at 61,293.

<sup>&</sup>lt;sup>15</sup>27 F.E.R.C. ¶ 61,094 (1984).

generation and sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)."<sup>16</sup>

In the Commission's view, a facility is 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 an electric utility holding company or companies or any combination thereof."<sup>17</sup> The real question faced by the Commission was, therefore, the meaning of the phrase "equity interest" where the holdings of a general partnership are involved.<sup>18</sup> The Commission concluded that, "the entitlement to venture profits, losses, and surplus after return of initial capital contributions, as well as the fact that both partners share equal control of the venture, is dispositive."<sup>19</sup> Since the public utility subsidiary's control of the partnership and entitlement to benefits did not exceed 50 percent, the facility qualified as a small power production facility. The Commission limited its order to the facts of this case.

### b. Change in Ownership

Several orders in 1984 discussed the effect of changes in ownerhship on qualifying status. In *Occidental Geothermal, Inc.*,<sup>20</sup> the Commission held that acquisition of all of Occidental Geothermal's outstanding capital stock by Santa Fe International Corp. would not result in a revocation of the qualifying small power production status of Occidental's geothermal facility. The Commission found that the ownership criteria of Section 292.206(a) and (b) were met because neither Santa Fe nor any parent or subsidiary (including Kuwait Petroleum and the State of Kuwait) was directly or indirectly engaged in the production, transportation or sale of electric energy in the U.S. except solely from qualifying facilities.

In Signal Companies, Inc.,<sup>21</sup> the Director of the Office of Electric Power Regulation (to whom the Commission has delegated the authority to take appropriate actions on uncontested applications for qualifying status) similarly found that qualifying status would not be jeopardized by a change in capacity from 52 megawatts to 55 megawatts or the acquisition of one of the original joint venturers in the project.

#### 2. Interconnection Hearings

On August 9, 1984, Roche Products, Inc. ("Roche") filed a complaint against the Puerto Rico Electric Power Authority ("PREPA") alleging, among other claims, that PREPA had refused to interconnect with, or to purchase from, and sell energy and capacity to QFs. PREPA responded by asking the Commission to hold an interconnection hearing under FPA § 210<sup>22</sup> before certifying any qualified

<sup>19</sup>Id.

<sup>&</sup>lt;sup>16</sup>16 U.S.C.A. § 796(17)(B)(ii) (Supp. 1983).

<sup>&</sup>lt;sup>17</sup>18 C.F.R. § 292.206(b) (1984) (emphasis added).

<sup>&</sup>lt;sup>18</sup>Where a facility is owned by a corporation, the term refers to shares of common stock. Ultrapower 3, 27 F.E.R.C.  $\P$  61,094 at 61,184.

<sup>&</sup>lt;sup>20</sup>29 F.E.R.C. ¶ 61,280 (1984).

<sup>&</sup>lt;sup>21</sup>29 F.E.R.C. § 62,346 (1984).

<sup>2216</sup> U.S.C.A. § 824i (Supp. 1983).

cogeneration or small power production facilities in Puerto Rico. PREPA claimed that because it was the only electric utility on the island of Puerto Rico and had no interconnections outside Puerto Rico, it must provide its own reserves and capacity to meet current and future peak loads. Interconnections to sell to and purchase power from industrial cogenerators and small power producers would, according to PREPA, reduce its revenues and cause an increase in rates to other customers.<sup>23</sup>

The Commission found that Roche's allegations, other than its claim that PREPA refused to interconnect, were matters of application of PREPA's rules and should properly be brought before state judicial forums (the federal district court in the case of Puerto Rico). It then denied PREPA's request that the Commission hold an FPA § 210 interconnection hearing, citing its earlier rule-making in which it determined that electric utilities, on request, must interconnect with, purchase from, and sell electric energy and capacity to QFs.<sup>24</sup> The Commission decision not to hold hearings on such interconnections under FPA § 210 was upheld by the Supreme Court.<sup>25</sup> The Commission also declined to hold in abeyance the certification of qualifying status for any facility pending the possible, future submission of a rule-making by PREPA, finding that holding proceedings in abeyance would thwart the Congressional mandate in PURPA<sup>+</sup> to encourage the development of cogeneration and small power production.<sup>26</sup>

On rehearing,<sup>27</sup> the Commission elaborated on PREPA's allegations of economic injury resulting from interconnections with QFs. The Commission held that, since PREPA was to pay a rate based on avoided costs, ratepayer's rates should not change. If certain costs were not avoided, this should be reflected in the calculation of the avoided cost rate. Regarding PREPA's claim that it would lose revenues if industrial customers built QFs, the Commission noted that utilities often lose customers or have excess capacity. The Commission believed that a concern overriding a utility's possible loss of revenues was its mandate under PURPA § 210 to encourage the development of cogeneration and small power production facilities.

## 3. Other Matters

a. Retail Sales

In PRI Energy Systems, Inc.,<sup>28</sup> the Commission considered PRI's intention to provide cogeneration units to individuals and businesses and to sell the energy produced to those users, while retaining ownership of the cogeneration facilities. An intervenor claimed that this arrangement constituted direct retail sales to end users in contravention of PURPA Section 210(a), which states that the Commission's

<sup>&</sup>lt;sup>23</sup>Roche Products, Inc., 29 F.E.R.C. ¶ 61,098 (1984).

<sup>&</sup>lt;sup>24</sup>Id. at 61,186 n.8, citing Final Rule, Order No. 69, 45 Fed. Reg. 12,214 (Feb. 25, 1980), rehearing granted in part and denied in part, 45 Fed. Reg. 33,958 (May 21, 1980), codified primarily at 18 C.F.R. § 292.303 (1984).

<sup>&</sup>lt;sup>25</sup>American Paper Inst., Inc. v. American Electric Power Service Corp., \_\_\_\_\_ U.S. \_\_\_\_, 103 S. Ct. 1921 (1983).

<sup>&</sup>lt;sup>2</sup><sup>9</sup>29 F.E.R.C. ¶ 61,098 at 61,186.

<sup>&</sup>lt;sup>27</sup>Roche Products, Inc., 29 F.E.R.C. ¶ 61,339 (1984).

<sup>&</sup>lt;sup>28</sup>26 F.E.R.C. ¶ 61,177 (1984).

regulations "may not authorize a qualifying cogeneration facility or small power production facility to make any sale for purposes other than resale."<sup>29</sup>

The Commission found that this language is a limitation on its authority to enact rules requiring electric utilities to offer to purchase power from QFs; it did not refer to the criteria for granting qualifying status to such a facility. Moreover, noting that the language in PURPA § 210(a) does not limit a state's authority to permit retail sales by QFs, the Commission said Congress intended that the question of whether QFs may be permitted to make retail sales should be resolved in state forums as a matter of state law.<sup>30</sup>

### b. Issues To Be Resolved In state Forums

Certain issues to be resolved in state forums have already been mentioned above in the discussion of the *Roche Products* and *PRI Energy Systems* orders. In addition, in *Southern Company Services, Inc.*,<sup>31</sup> the Commission held that the question of whether a purchase of cogenerated power will avoid capacity cost (which would require the rates for such power to be based on avoided costs) should be resolved by the State public service commission.

c. Sequential Use

A cogeneration facility must produce electricity, heat or steam through the "sequential use" of energy.<sup>32</sup> In *Texas Industries, Inc.*,<sup>33</sup> the Commission concluded that this sequential use requirement is satisfied where an extraction turbine is involved because "the rule requires only that the portion of turbine steam flow used for a thermal purpose be previously used for generation, not that all steam providing generation flow to a thermal purpose."<sup>34</sup> The fact that there was additional generation by steam downstream of the extraction point which passed to the condenser without being extracted for a heating purpose was not dispositive.

#### d. Operating And Efficiency Standards

Section 292.205 of the Commission's regulations contains certain operating and efficiency standards regarding the useful thermal energy output of qualifying cogeneration facilities. In John W. Savage,<sup>35</sup> the Commission distinguished a previous case,  $EG\mathcal{CG}G$ ,  $Inc.,^{36}$  and found that the use of thermal energy for aquaculture purposes constituted a useful thermal energy output which could be considered in determining whether the proposal met the operating and efficiency standards of the regulations. The Commission found three important differences

<sup>2916</sup> U.S.C.A. § 824a-3(a)(2) (Supp. 1983).

<sup>&</sup>lt;sup>30</sup>26 F.E.R.C. ¶ 61,177 at 61,434, *citing* Conference Report No. 95-1292, 95th Cong., 2d Sess. 97 (1978).

<sup>&</sup>lt;sup>31</sup>27 F.E.R.C. ¶ 61,444 (1984).

<sup>&</sup>lt;sup>32</sup>18 C.F.R. § 292.202(c) (1984).

<sup>&</sup>lt;sup>33</sup>29 F.E.R.C. ¶ 61,051 (1984).

<sup>&</sup>lt;sup>34</sup>Id. at 61,111, n.4 and accompanying text.

<sup>&</sup>lt;sup>35</sup>28 F.E.R.C. ¶ 61,273 (1984).

<sup>&</sup>lt;sup>36</sup>16 F.E.R.C. ¶ 61,060 (1981).

which distinguished the *Savage* proposal from that in  $EG\mathscr{C}G$ . First, the applicant had provided information indicating the independent attractiveness of his aquaculture venture. The second difference involved the close attention paid to balancing heat demands to the available heat. Finally, the *Savage* facility, unlike that proposed in  $EG\mathscr{C}G$ , was not chiefly a power generation facility, and its size was closely matched to the water heating requirements of the aquaculture application.

## III. FEDERAL LEGISLATION

The major legislative action of the past year relating to cogeneration and small power production was passage of the Wallop Amendment to the Deficit Reduction Act of 1984 (see Section V "Financial, Accounting, and Tax Developments"). Although no other major cogeneration or small power production legislation was enacted, there were several other important developments considered which will likely be addressed by the incoming 99th Congress.

## A. Regional Electricity Planning and Wheeling Legislation

# 1. Regional Planning and Coordination Act of 1984 (H.R. 5766)

This legislation, introduced by Representative Richard Ottinger (D-N.Y.), was designed to implement the recommendations on regional electricity initiatives made by the National Governors Association (NGA) in 1983. NGA had concluded that the electric utility industry is increasingly interrelated and multistate in scope, creating a need for legislation that encourages regional development of electricity demand and supply forecasts, reliability and reserve requirements, wheeling, increased power pooling and interconnections, and electricity import and export agreements. H.R. 5766 included provisions for (1) the regional regulation of electric utilities; (2) the transfer to states of some authority over wholesale power rates currently held by FERC; and (3), the acceleration of review procedures used when ordering electric utilities to wheel power.

The legislation was attacked by the Department of Energy ("DOE"), FERC and electric utility witnesses at hearings in June, 1984. These witnesses maintained that regional regulation would create an additional layer of ratemaking, resource acquisition, and siting requirements, which would only hamper development of electric utility projects. Other electric utility witnesses argued that mandatory wheeling orders would be useless because their regions already maintained a high degree of coordination among electric utilities.

#### 2. The Electric Utility Transmission Reform Act of 1984 (H.R. 5608)

This bill, introduced by Representative Robert Matsui (D-Cal.), represented an attempt to lower electric rates by facilitating the regional distribution of surplus power. Under the proposed legislation, the FERC would be authorized, either on its own motion, or upon separate application by a state agency or utility, to order an electric utility to wheel power or to expand the capacity of a bulk power facility it owns or operates. Authorization would be required if the effect of the wheeling "would be to conserve energy, promote the efficient use of facilities and resources, increase competition in the bulk power market, or is otherwise in the public interest." While this bill was never seriously considered in 1984, it likely will be reintroduced for further consideration this year.

## B. Public Utility Holding Company Act Legislation

In September, 1984, Senator John Heinz (R-Pa.), accompanied by five co-sponsors, introduced legislation to remove impediments under the Public Utility Holding Company Act ("PUHCA") preventing registered gas holding companies from pursuing cogeneration project opportunities (S. 2991). A companion measure (H.R. 4467) was introduced in the House by Representative Doug Walgren (D-Pa.). Under current law, registered gas holding companies are precluded from acquiring or retaining interests in qualifying cogeneration facilities. Under the proposed legislation, the status of these companies would be changed so that acquisition or retention of cogeneration interests would be considered functionally related to gas utility operations and thus permissible under PUHCA.

## C. Other Relevant Developments

There were two other legislative developments of note this past year.

## 1. H.R. 5434

Representative Wes Watkins (D-Okla.) introduced legislation to amend PURPA to provide that small natural gas-fired power production facilities could achieve qualifying facility status under the Act. Although the legislation died this past Congressional session, Representative Watkins intends to reintroduce the bill in 1985.

## 2. H.R. 3660 and S. 1132

This legislation would have established annual charges for the use of government dams based upon a combination of installed capacity and annual generation subject to a ceiling of \$1 per kW of installed capacity plus one-half mill per kWh of energy produced. The bills also provided that the annual charge assessed by the FERC would be the only charge assessed by any government agency for hydropower development at a government dam. Although similar versions of the legislation passed both chambers, House and Senate supporters were unable to reach agreement before the end of the 98th Congress. (See Report of the Committee on Regulation under Part I of the Federal Power Act)

## IV. STATE DEVELOPMENTS

## A. California

## 1. Legislative

On August 21, 1984, the Governor of California signed into law a bill which expressly provides for sales by QFs of electricity generated by those facilities to two consumers for use on the same or immediately adjacent real property without regulation of such sales by the California Public Utilities Commission ("CPUC").<sup>37</sup> On the same date the Governor approved legislation requiring the CPUC to establish rates for natural gas used by cogenerators no higher than the rates for natural gas used in electric utility plants.<sup>38</sup>

#### 2. Environmental Note

In order to promote the development of cogeneration, California law provides that new cogeneration facilities need not offset emissions generated by the facility, and local air pollution control districts must provide an emission growth allowance to mitigate all impact on air quality.<sup>39</sup>

The Environmental Protection Agency ("EPA") has determined these provisions of state law to be inconsistent with the requirements of the Clean Air Act with respect to non-attainment areas. The EPA intends to disapprove the South Coast Air Quality Management District rule which implements Health and Safety Code Sections 41604, 41605 and 42314.

Various bills were introduced last session to respond to EPA's position. None, however, were enacted. California Senate Bill 166, under consideration in the 1985-86 legislative session, preserves the offset exemption for cogeneration facilities and clarifies local air pollution control districts' obligations to provide a growth allowance. The proposed bill clearly fails to respond to EPA's stated concerns with respect to non-attainment areas. The bill may be amended, however, to provide that air pollution control districts in non-attainment areas unable to demonstrate attainment need not provide the exemption. It would seem that a bill, so amended, would comply with all Clean Air Act requirements.

### 3. Suspension of Standard Offer for Large Cogenerators

On October 17, 1984 the CPUC issued Decision 84-10-098 which suspended for projects larger than 50 MW the terms and conditions of Payment Option 3 of Pacific Gas and Electric Company's ("PG&E") Standard Offer #4. On December 5, 1984 the Commission issued Decision 84-12-027 which continued the suspension until development could be evaluated in relation to a QF milestone procedure that was being developed. Payment Option 3, designed for oil or gas fired cogeneration

<sup>&</sup>lt;sup>37</sup>CAL. PUB. UTIL. CODE § 454.4 (Deering Supp. 1985).

<sup>&</sup>lt;sup>38</sup>CAL. PUB. UTIL. CODE § 218 (Deering Supp. 1985).

<sup>39</sup>CAL. HEALTH & SAFETY CODE §§ 41604, 41605 and 42314 (Deering Supp. 1985).

projects, fixed the energy payment formula for 10 years and is based upon PG&E's cost of natural gas or fuel oil and their system incremental energy rate. The incremental energy rate is similar to the system incremental heat rate. The capacity prices are fixed for contract periods up to 30 years.

PG&E and the CPUC Staff became concerned that the PG&E offers were becoming too successful and that the PG&E grid could have difficulty in absorbing the amount of capacity that had signed contracts and were under discussion. The Staff also was concerned that the prices quoted in the Standard Offer were higher than PG&E's true avoided cost due, in part, to the large amount of capacity signed up in the latter part of 1984.

#### 4. Interconnection Priority Procedure

#### a. Interconnection

In mid-1984 it became apparent to PG&E that its transmission system in the northern part of its service territory was in danger of becoming oversubscribed by QFs and it began inserting a provision in its Standard Offers which warned potential QFs that a contribution to help pay for transmission upgrades may be necessary. The CPUC subsequently issued Decision 84-08-031 on August 1, 1984 requiring PG&E to show cause why it should not be held in contempt of the Commission for altering the Standard Offers without prior Commission approval. Following a hearing, the Commission refused to hold PG&E in contempt but endorsed a settlement procedure whereby PG&E, the Commission Staff, and various QFs reached an accord on a "first come-first served" policy for connecting potential QFs. At year-end the Commission was considering the adoption of the settlement procedure.

### b. Milestone Requirements

The CPUC held a hearing *en banc* on November 5, 1984 to receive comments on the suspension of PG&E's Option 3 of Standard Offer #4. At that hearing the Commission directed that performance milestones, measuring a QF's progress toward project completion, should be developed in addition to the Staff's development of an Interconnection Priority Procedure. This would allow the Commission to periodically determine statewide levels of QF power likely to come to fruition.

A committee composed of interested QF developers, representatives of the utilities and the Commission Staff met to develop project milestones that would require developers to demonstrate progress toward project completion. Although project milestones were not adopted by the Commission prior to the end of the year, the committee was considering recommending separate schedules for different technologies which would reflect regulatory critical paths. The committee also considered the imposition of a \$5/kW "earnest money" deposit to reduce the number of developers who sign utility standard offers prior to an adequate assessment of project feasibility.

### 5. Long-Run Avoided Cost Standard Offer No. 4

As far back as its original decision in proceedings instituted by its Order Instituting Rulemaking No. 2,40 the CPUC has recognized the need for a standard offer based upon long-run avoided utilty costs. After the CPUC authorized an interim Standard Offer No. 4 and after a prehearing conference and receipt of comments from parties, it was determined that the evidentiary proceedings to develop Standard Offer No. 4 would be conducted in two phases.<sup>41</sup> The first phase would be to determine what costing methodology is most appropriate for determining a utility's long-run avoided cost, while the second phase was reserved for determining all remaining issues, including pricing mechanisms, data assumptions and contract terms. Recommended approaches ranged from projections of short-run marginal cost to multiple plant proxies (recommending QF choice of the most expensive, load-following utility plant in the state, an oil or gas fired combined cycle plant or a direct fired coal plant) with a number of proposals based upon projections of the utilities' generation resource plans. Although a decision from the CPUC had been anticipated by the end of calendar year 1984, none was forthcoming by January 22, 1985.

## 6. Uniform Standard Offer Language

The CPUC, in its order authorizing the interim Standard Offer No. 4<sup>42</sup> (based on forecasts of the utilities' resource mix and cost), ordered the three major California utilities to confer among themselves and the CPUC Staff to devise uniform contract language. This requirement was extended to the already existing Standard Offer Nos. 1, 2 and 3.<sup>43</sup> The CPUC later ordered workshops for the utilities, CPUC Staff and interested parties to resolve any issues raised by the utilities' efforts, providing that only issues unresolved by the workshops would be the subject of evidentiary proceedings, and that the participants must file a joint stipulation of unresolved issues.<sup>44</sup> Workshops were held in September, 1984 and January, 1985 but final results are not yet available. Preliminary results indicate that few, if any, issues will be left for resolution in evidentiary proceedings.

## B. Florida

#### 1. Judicial Developments

## a. State Rules Under PURPA

The Florida Supreme Court has stayed its mandate in Florida Power & Light Co. v. Florida Public Service Commission, No. 60,671 (Fla. March 17, 1983), discussed in last

<sup>&</sup>lt;sup>40</sup>Decision 82-01-103, issued January 21, 1982.

<sup>&</sup>lt;sup>41</sup>Administrative Law Judge's Ruling, Application 82-04-44 et al., January 6, 1984.

<sup>42</sup> Decision 83-09-054, issued September 7, 1983.

<sup>&</sup>lt;sup>43</sup>Decision 83-10-093, issued October 19, 1983.

<sup>&</sup>lt;sup>44</sup>Memorandum, Application 82-04-44 et al., June 20, 1984.

year's report.<sup>45</sup> The court had reversed the FPSC's order adopting rules under PURPA, on the grounds that: (1) the FPSC erred in not holding a full evidentiary hearing before promulgating the rules; and (2) in any case, the FPSC lacked the statutory authority to promulgate the rules. Subsequently, however, the state legislature delegated authority to the FPSC, and the FPSC promulgated new rules, since challenged by Dade County. Metropolitan Dade County v. FPSC, No. 64,330 (Fla. initial brief filed Jan. 17, 1984). Under the new rules, the FPSC has provided that a utility purchasing power from a QF must make an energy payment equal to 100% of its avoided energy cost, pursuant to American Paper Inst., Inc. v. American Electric Power Service Corp., \_\_\_\_\_ U.S. \_\_\_\_, 103 S. Ct. 1921 (1983), and also must, if it enters into a firm energy and capacity contract, make a capacity payment based on its avoided capacity costs. In specifying the capacity payment the FPSC included a generic risk factor of .8, to account for the risks associated with a utility deferring building new capacity in reliance on QF capacity, so that utilities in effect pay 80% of avoided capacity costs. The County is challenging the FPSC's use of this generic risk factor and the FPSC decision that a QF may not engage in retail sales.

### 2. FPSC Developments

a. Wheeling

The FPSC for the most part concentrated on wheeling issues under PURPA in 1984. As discussed above in Part B.2. of FERC Developments, it was the FPSC's rule imposing a wheeling charge that led to the declaratory order proceeding at FERC in *Florida Power & Light Co. v. Florida Public Service Commission*, Docket Nos. EL84-27-000 *et al.* The FPSC has not yet taken action as a result of the FERC proceeding.

The FPSC also has created a docket on retail wheeling, Docket No. 840399-EU. It is addressing the issue of whether a utility should be required to provide transmission service to wheel electricity from a QF to other facilities owned by that QF. The FPSC has not decided whether to approach the issue generically by adopting a rule on the subject or whether to proceed on a case-by-case basis.

### b. Financing of QFs

The FPSC has proposed rules on utility financing of government-owned small power producing solid waste facilities,<sup>46</sup> which would require that, upon request by a local government, the utility eventually required (under PURPA) to purchase from the facility shall provide advance capacity payments to the local government during the construction of the facility. These payments would be in lieu of firm capacity payments otherwise authorized under the FPSC PURPA rules and would be secured by bond; they would be recovered through the fuel adjustment clause. A final order has not been issued.

<sup>&</sup>lt;sup>45</sup>5 Energy L.J. 161, 163 (1984).

<sup>&</sup>lt;sup>46</sup>Advanced Funding of Governmentally Owned Small Power Production Facilities, Docket No. 840351-EU, 10 Fla. Admin. Weekly 4269 (December 14, 1984).

## C. Hawaii

The Public Utilities Commission ("PUC") is currently in the process of revising its "Standards for Small Power Production and Cogeneration in the State of Hawaii." This is required by Act 243, Session Laws of Hawaii 1983, which amended Section 269-27.2(c) of Hawaii Revised Statutes by deleting the existing guideline for determining the price of non-fossil fuel generated electricity supplied to a public utility by a small power producer or cogenerator.

Proposed amendments to the standards were issued on March 29, 1984.<sup>47</sup> No final order has been issued. Two major changes are proposed. (1) The PUC has proposed a "minimum floor price," which is defined as "that amount equal to the cost of production of the utility's most efficient unit, where the capacity of the unit shall not be less than 10 percent of the system peak for 1983, or, in the event that no unit's capacity is greater than or equal to 10 percent, shall be its largest unit." (2) The PUC is proposing to eliminate the distinction between existing and new capacity under Rates for purchases (§ 6-74-22). The proposed rates for all energy purchases would equal full avoided costs, but not be less than the minimum floor price. Rates for capacity purchases would equal full avoided costs with no floor price.

### D. Indiana

In October, 1984, the Public Service Commission of Indiana ("PSCI") approved new rules implementing PURPA and the Indiana cogeneration statute,<sup>48</sup> (PSCI, Cause No. 37494 (October 5, 1984)). The rules provide complex algorithms for the computation of electric utilities' avoided energy costs and capacity credits, which together make up the utilities' full avoided costs. The capacity credit is based on the cost of the utilities' next avoided or deferrable plant, defined as a new combustion turbine. Avoided energy costs are based on an average of marginal running costs, adjusted for line losses, and for the utilities' most expensive unit (typically a diesel-fired peaking unit). Present total buy-back rates range from 3 cents per kWh to 8 cents per kWh, the maximum rate allowed by the cogeneration statute. The rules simply track PURPA as to standby rates for qualified facilities, providing that they be nondiscriminatory in comparison to other retail customers.

The rules also implement a section of the statute which requires electric utilities to wheel electric capacity at the request of a qualified facility. Nearly all of the investor-owned and rural cooperative utilities in Indiana are appealing the new rules, based in large part on this wheeling requirement. The utilities also allege that the rules conflict with PURPA in requiring capacity payments to be made in advance of the avoidance of capacity. In light of the appeals and other perceived problems with the new rules, a new comprehensive cogeneration statute (House Bill 1838 of 1985) to implement PURPA has been introduced.

<sup>&</sup>lt;sup>47</sup>Decision and Order No. 7888, Docket No. 5069.

<sup>48</sup>IND. CODE ANN. § 8-1-2.4 (Burns 1983).

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# E. Iowa

# 1. Final Rules

On July 27, 1984 the Iowa State Commerce Commission ("ISCC") issued final rules governing the nature of the utility obligation to purchase electricity from solar, wind turbine, waste management, resource recovery, refuse-derived fuel, wood-burning and hydroelectric generating facilities ("AEPs").<sup>49</sup> Significant features of the final rule include the following:

- Establishment of a minimum rate of 6.5¢/kWh for purchases from AEPs. This rate reflects long-term avoided costs, using a recently completed coal-fired facility as a proxy. The Commission views this rate as possibly understating avoided costs in that the cost of any future base-load plant will at least equal the 6.5¢ rate.
- The ISCC adopted the capacity aggregation theory, and found that a sufficiently large and diverse group of AEPs would allow utilities to defer construction. However, the ISCC noted, the necessary number of AEPs would only be constructed if the rate selected recognizes the future benefits of capacity aggregation.
- The ISCC adopted a single statewide rate, citing the following supporting factors: widespread interconnection, joint dispatch facilities, and joint investment in generating capacity.
- The 6.5¢ rate is extended to existing AEPs so as to encourage continued production.
- AEPs are allowed to switch from net sales to simultaneous purchases and sales as often as desired, so long as the AEP pays any costs associated with the change.
- The ISCC rejected a request for mandatory wheeling, and instead made wheeling optional.
- The ISCC rejected a request for intra-utility wheeling, finding instead that transfers of power within a single network can occur in accordance with the net sales option of an AEP.

The investor-owned utilities have filed a petition for judicial review of these rules in the Iowa District Court for Polk County.<sup>50</sup> The ISCC rules went into effect on that date after a stay was denied. The case is presently in the prehearing briefing stage, with the possibility of an evidentiary hearing before the Court in July, 1985.

# F. Kansas

In Kansas City Power & Light Company v. The State Corporation Commission of the State of Kansas, 234 Kan. 1052, 676 P2d 764 (1984), the Kansas Supreme Court held that orders of the Kansas Corporation Commission ("KCC") requiring Kansas City Power & Light Company ("KCPL") to purchase electricity at KCC approved rates exceeding avoided costs violated PURPA. In accordance with that decision, the KCC

<sup>&</sup>lt;sup>49</sup>In re Alternate Energy Production, Order Adopting Rules, Docket No. RMU-83-30.

<sup>&</sup>lt;sup>50</sup>Iowa Power and Light Company v. Iowa State Commerce Commission, Case No. AA-677.

issued an order on October 15, 1984 requiring (1) facilities of less than 100 Kw to file tariffs which state that if capacity costs can be avoided, a capacity payment shall be negotiated between the parties and (2) facilities of more than 100 kW receive a negotiated capacity payment if it can be shown that a utility can avoid capacity costs by purchasing power from the facility.<sup>51</sup>

On November 15, 1984, in Kansas City Power & Light Company v. The State Corporation Commission of the State of Kansas, No. 84,667, KCPL filed an action in the District Court of Linn County, Kansas alleging that PURPA, the FERC regulations implementing PURPA, the Natural Gas Policy Act, the Kansas Parallel Generation Services Act (Kan. Stat. Ann. § 66-1,184 (1980)) and the KCC Order of October 15, 1984 are unconstitutional because they (1) take KCPL's property for the benefit of private parties without just compensation; (2) deprive KCPL of freedom of contract; and (3) deprive KCPL of liberty and of property without due process of law in violation of both the United States and the Kansas Constitutions.

## G. Louisiana

The principal cogeneration activity at the Louisiana Public Service Commission involved efforts by Dow Chemical Company to obtain an interconnection with Gulf States Utilities for the purpose of selling cogenerated electricity. Dow's complaints are being heard in two separate dockets, Nos. 84-1426 and 84-1538. Among the isues being covered by the hearing are Gulf State's need for capacity, the appropriate level of capacity payments, avoided energy costs and whether further payments to cogenerators should be discounted below full avoided costs. No decision has yet been issued in these dockets.

# H. Maine

## 1. Long-Term Rates

On February 10, 1984, the Maine Public Utilities Commission ("MPUC") issued an order establishing certain principles regarding long-term rates for purchases of electricity from cogeneration and small power production facilities by the Maine Public Service Company ("MPS").<sup>52</sup> The MPUC rejected the utility's assertion that no capacity component should be included in its avoided-cost rates notwithstanding the fact that MPUC had earlier determined that MPS has excess capacity.<sup>53</sup> The MPUC stated that, under its regulation, "avoided costs are determined to be the difference between the revenue requirement associated with the utility's current generation expansion plan and the revenue requirement associated with another expansion plan revised to reflect the applicable decrements."<sup>54</sup> The MPUC further

<sup>&</sup>lt;sup>51</sup>In the Matter of a General Investigation to Examine Pricing of Electric Utility Services as Well as Their Load Management and Load Control Programs (Cogeneration and Small Power Production) Docket No. 115,379-U (1984).

<sup>&</sup>lt;sup>52</sup>Re Maine Public Service Co., "Order Establishing Long-Term Rates for Cogeneration and Small Power Production, with Discussion of Method of Calculating Avoided Capacity Costs," Maine Public Utilities Commission 58 P.U.R. 4th 280 (1984).

<sup>&</sup>lt;sup>53</sup>See Re Maine Public Service Co., 49 P.U.R. 4th 417 (1982).

<sup>5458</sup> P.U.R. 4th at 282 (footnote omitted).

stated that the avoided-cost calculation requires the use of an optimal generation expansion plan and therefore MPS was required to exclude the excess capacity from its base case analysis rather than assume that such excess capacity precluded any payment of avoided capacity costs. The MPUC also rejected the utility's contention that existing generating units cannot be used in calculating avoidable capacity costs. The MPUC pointed out that the Maine statute specifically requires a utility to consider the costs of additional *or existing* generating capacity which could be displaced when calculating its avoided-cost rates.

Finally, the MPUC was faced with the question of which MPS unit could most reasonably be viewed as "avoidable." Based on the record before it, the Commission determined that "Seabrook I is avoidable, although not at its full cost and that Seabrook II should be excluded from the base case." After examining the marketability of Seabrook I, the MPUC found that the long-term avoided capacity costs of MPS should be based on the fixed costs of Seabrook I, minus a 20 percent discount.<sup>55</sup> Based on the principles established in its February 10 order, the Commission issued a supplemental order in this docket establishing the particular long-term contract rates available to QFs.<sup>56</sup>

### 2. Revisions to QF Rules

On June 22, 1984, the MPUC issued an order amending its cogeneration and small power production rules which (1) established various technical and economic considerations to be used in determining whether a qualifying facility has demonstrated a capability to deliver electricity to a utility; (2) clarified the distinction between sales of electric energy versus sales of electric energy and capacity; (3) modified the provisions relating to the automatic adjustment of any capacity rate established by the MPUC; and (4) made numerous other minor clarifying changes.<sup>57</sup>

The most significant revisions to the MPUC's regulations were contained in the amendments to Section 4(B).<sup>58</sup> The MPUC identified specific criteria to be taken into account by an electric utility during the negotiation of a long-term contract with a QF. The "criteria" include: (1) ownership of, or an option to acquire, property rights necessary to develop the project; (2) acquisition of necessary governmental authorizations; (3) evidence of sufficient financial capability; (4) presentation of either executed contracts or other evidence demonstrating the long-term availability of a fuel supply; (5) with respect to cogeneration facilities, a description

<sup>&</sup>lt;sup>55</sup>The Commission justified this 20 percent discount as follows:

The 20 per cost discount which we believe to be reasonable is based on our balancing of the likelihood of selling Seabrook I at least the presently estimated full cost, during the later years, with the likelihood of selling Seabrook I at a substantial discount during the early years.

Id. at 285.

<sup>&</sup>lt;sup>56</sup>Re Maine Public Service Company, "Supplemental Order No. 1 and Order on Reopening." Docket Nos. 81-276 et al., Maine Public Utilities Commission (April 4, 1984).

<sup>&</sup>lt;sup>57</sup>Order Amending Rule, Docket No. 84-85 (June 22, 1984) amending 65-407 CMR Chapter 36. See also Policy Statement, Docket No. 84-85 (April 4, 1984) interpreting 65-407 CMR Chapter 36.

<sup>5865-407</sup> CMR § 36.4(B) (July 14, 1982).

of the proposed sale or use of steam; (6) a plan of construction of the facility, including a construction timetable; and, (7) plans or executed agreements for the reliable operation and maintenance of the project for the duration of the contract term.<sup>59</sup>

## I. Massachusetts

Upon petition of the Massachusetts Executive Office of Energy Resources ("EOER"), the Department of Public Utilities ("DPU") in early January 1985 agreed to institute a new rulemaking proceeding on its PURPA Section 210 rules.<sup>60</sup> The EOER's proposed revision provides for the development of "Standard Offers" by each regulated electric utility. DPU-approved Standard Offers would be considered "per se" reasonable and as such not subject to further review. Once a QF requests a contract based on a Standard Offer, the utility must respond within 30 days. If the utility refuses to enter said contract, it must explain why, and the QF then has a right to a hearing.

Each utility's Standard Offer would contain four energy price options, and a schedule of avoided capacity costs, to be updated annually.

Option 1. Full Avoided Energy Costs: all QFs eligible; contract up to 30 years duration.

Option 2. Fixed Escalation: only non oil/gas QFs eligible; payment for first half of contract escalates at rate established in O&M costs; payment for second half of contract at 100% of avoided cost.

Option 3. Partial Levelization: only non-oil/gas QFs eligible; payment for first half of contract is levelized at a rate based upon approved forecast; payment for second half of contract at 85% of avoided cost.

Option 4. Composite Rate: all QFs eligible; rate equal to sum of 1/2 of actual avoided energy rate (at time of delivery) plus 1/2 of "fixed escalation" rate as forecasted.

The EOER's proposal also provides for the DPU to annually review each utility's avoidable capacity costs and to establish a "schedule" of such costs, based upon each company's need for new capacity. To receive payment for capacity, a QF must commit itself to a "target" level of kWh output on peak, and meet or surpass that target.

# J. Michigan

PURPA was implemented in Michigan by the Michigan Public Service Commission's ("MPSC") August, 1982 order in Case No. U-6798. Case U-6798 only specifies an avoided cost rate for facilities of 100 kW or less and directs the utilities to negotiate contracts with larger facilities based upon the 100 kW rate and other appropriate factors. The 100 kW rate is based upon the current cost of a hypothetical coal plant with the capacity portion of the payment reflecting the cost

<sup>&</sup>lt;sup>59</sup>65 407 CMR § 36.(B)(1)(b) (July 28, 1984). It should also be noted that these standards do not apply to qualifying facilities with an installed capacity of 100 kw or less.

<sup>60220</sup> C.M.R. § 8.00 (1981).

of construction of such a plant and the energy payment essentially reflecting operation and maintenance costs and current long term coal contracts of the purcasing utility. Under the 100 kW rate, the capacity payment is prorated according to the relative capacity and availability factors of the qualified facility (as compared to that of the purchasing facility) plus adjustments for the length of term for which capacity will be supplied (full capacity payments typically being reached at approximately thirty years duration).

As implemented by the major utilities in Michigan, the preceding formula has in essence been simplified and modified as follows: Capacity payments are fixed for the life of the contract (with full capacity payments for a contract of at least thirty years duration) and reflect the current cost per kW of a hypothetical coal plant. As of late 1984 typical capacity payments were approximately 3.75 cents per kWh. Energy payments are primarily based upon long-term coal contracts and as of late 1984 typically ranged from approximately 2.5 to 3.0 cents per kWh with projected long-term annual escalation of approximately 8%. Capacity and energy payments are adjusted for on and off peak delivery.

To ensure that the preceding approach complies with the MPSC's directive in Case No. U-6798, several such contracts have been submitted to the MPSC, which has formally approved them on an expedited basis. *In re: Interwest Energy*, Case No. U-7990 (1984); *In re: Viking Energy*, Case No. U-8062 (1984). The MPSC also ruled that all payments under the contracts could be passed through to the ratepayer under Michigan's power supply cost recovery clause and that the applicable contracts are approved as rates and may not be altered without the prior permission of the MPSC.

The MPSC's Order in Case No. U-6798 also made provision for stand-by rates. Most regulated utilities in Michigan at the present time offer (or expect to offer in 1985) stand-by service at rates from 38 to 60 cents times the highest on-peak kilowatt demand per day plus incremental energy charges (*e.g.* 3.2 cents per kWh). Under this rate the charges are computed daily with no ratchet. Some utilities also offer (or expect to offer in 1985) stand-by service on a monthly basis, typically at rates of from \$0.29 to \$2.25 per kW per month. For this charge the user is entitled to obtain power under various retail rate schedules that would otherwise be applicable, with the capacity charge therein removed or substantially reduced.

### K. Minnesota

The Minnesota Public Utilities Commission adopted new Rules Relating to Cogeneration and Small Power Production on October 3, 1984,<sup>61</sup> to implement amendments to Section 216B.164 of the Minnesota Statutes which clarify that it applies to all investor-owned utilities, electric cooperatives, and any municipally-owned electric utility that has not adopted its own rules and which give particular encouragement to small power producers of 40 kW or less. The statute and the implementing rules require that qualifying facilities with capacity less than 40 kW (1) must use the standard form of contract provided by the rule, and (2) may

<sup>&</sup>lt;sup>61</sup>MINN. CODE AGENCY R. § 7835.0100-.9910 (1984).

elect a net energy billing rate, which will equal the utility's applicable retail rate schedule.

QFs with capacity less than 40 kW that do not elect the net energy billing rate may elect either the simultaneous purchase and sell billing rate (available only for QFs under 40 kW) or the time-of-day purchase rates. Time-of-day rates are required for QFs with capacity of 40 kW or more and less than or equal to 100 kW; they are optional for facilities with capacity greater than 100 kW if these facilities provide firm power. Within any category, payment includes a capacity component only if the facility provides firm power. Energy and capacity rates are based upon the purchasing utility's avoided costs filed annually with the MPUC.

Qualifying facilities with capacity greater than 100 kW must negotiate a contract with the utility, and must be entitled to the full avoided capacity and energy costs of the utility, except that a utility may connect a QF of greater than 100 kW under its standard rates.

Pursuant to the statute,<sup>62</sup> the rules provide that for all QFs having capacity of 30 kW or greater, the utility, at the QF's request or with its consent, must provide wheeling or exchange agreements whenever practicable to sell the QF's output to any other Minnesota utility that anticipates or plans generation expansion in the ensuing ten years.<sup>63</sup>

#### L. New Hampshire

On July 5, 1984 the New Hampshire Public Utilities Commission ("NHPUC") issued a comprehensive order<sup>64</sup> setting rates, terms and conditions for the purchase and sale of power under short- and long-term contracts between Public Service Company of New Hampshire ("PSNH") and qualifying cogenerators and small power producers ("SPPs"). The final order adopted the terms of stipulated recommendations worked out during settlement discussions among the parties to the proceeding. Among the innovations are (1) a provision whereby the capacity component for both short and long-term rates will be expressed separately in dollars per kilowatt-year, and (2) a provision for optional time-of-day rates for the energy component, except that time-of-day metering will be required for SPPs with an audited capacity in excess of one MW, and for all SPPs who do not sell all of their output to PSNH. A summary of the rate design follows.

Both short and long-term rates contain an energy component (in cents per kWh) and a capacity component (in dollars per kilowatt-year) based upon PSNH's avoided costs as required by statute. The energy component consists of PSNH's marginal energy costs, multiplied by two factors: (1) the "loss factor" (the annual all-hours average of energy losses that occur in the generation and transmission of electricity, determined to be 1.088) and (2) the "indirect factor" (the combined effects of several potential adders, including adjustments to methodology, inventory costs, working capital costs, and operating and maintenance costs, determined to be 1.08 for this docket).

<sup>62</sup>MINN. STAT. ANN., § 216B.164, Subd. 4(c) (West Supp. 1984).

<sup>&</sup>lt;sup>63</sup>MINN. CODE AGENCY R., § 7835.4100 (1984).

<sup>&</sup>lt;sup>64</sup>Re Small Energy Producers and Cogenerators, DE 83-62, Eighth Supplemental Order No. 17,104, 61 P.U.R. 4th 132 (1984).

The capacity component reflects PSNH's estimated annual avoided cost of generation and transmission capacity per kW, multiplied by a loss adjustment factor that reflects load losses at the time of peak load. The annual capacity payment will be the product of the capacity component, the "NHPUC audit value" for the SPP site, and a "peak-reduction factor." The audit value represents the estimated dependable capacity of the site based on historical data and the characteristics of the plant, and generally will be expressed as a fraction of name-plate rated capacity. The "peak reduction factor" is an adjustment to account for the purchasing utility's actual peakload reduction as a result of purchases from an individual SPP or class of SPPs.65 Measurements will be taken annually during the month of January and the factor eventually will be based on a three-year rolling average. The intent is eventually to group together SPPs with similar characteristics in contributing to peak-load reduction as a way of reducing individual risk. Where there are sufficiently similar facilities to develop class data, the peak reduction factor for all such similar SPPs will be based on class date. A NHPUC objective is to maximize the SPP contribution to peak load, and it is expected that over time the peak reduction factors will rise. Large facilities that wish to avoid the procedure of being grouped by class may contract with PSNH to allow NEPOOL dispatch and NEPOOL capacity credit to PSNH for the specified SPP site.

The short-term energy rate will be redetermined every six months based upon PSNH's marginal energy costs. The short-term capacity component will vary depending upon the length of the SPP commitment and PSNH's need for peaking capacity, but it will not include avoided transmission costs.

The NHPUC incorporated much of the methodology of the interim order in setting long-term rates. Obligations of five to thirty years are permitted. SPPs may select any combination of rates based upon a 30-year schedule of weighted values worked out by the parties, so long as the cumulative net present values, discounted appropriately, do not exceed the values shown in the table. The calculations assume a permanent decrement of 50 MW to peak load and reflect levelized costs for 20 years. The capacity value of commitments less than 20 years will be reduced by 5% for each year that the rate term is less than 20 years. Long-term, front-end loaded rates are subject to a ceiling provision which must be factored into the rate calculation. The buy-out provision of the interim order was modified to apply only to the energy component, and requires the SPP to continue to sell its output to PSNH for the term of the original commitment or the term of the new rate, whichever is greater.

#### M. New Jersey

The New Jersey Board of Public Utilities ("BPU" or "Board") evidenced in three 1984 orders its interest in fostering the development of alternate energy projects, for the benefit of ratepayers and residents of the state.

1. *Resource Recovery Order*, Docket No. 833-236 (February 23, 1984). Pursuant to a legislative mandate that every one of New Jersey's 21 counties must provide for a resource recovery plant, publicly or privately owned, the BPU instituted resource

<sup>&</sup>lt;sup>65</sup>Hydro time-of-day peak reduction factor initially will be .8. See 61 P.U.R. 4th at 140.

recovery generic proceedings that resulted in an order that is intended to (a) guarantee waste flows to the facilities in order that they may obtain financing, and (b) establish the economic parameters within which such facilities will operate. Long-term contracts will include levelized tipping fees and levelized power purchase rates in order to guarantee a project revenue stream that will improve the financial viability of the project and attract investment. The Board recommended that a contract life equal in duration to the period of debt financing, or economic life of the facility should be an option made available by the utility to the resource recovery facility.

2. In the Matter of the Board's Investigation Into the Accident at Three Mile Island Pursuant to the Public Utility Accident Fault Determination Act, Docket No. 836-500 (Stipulation of Settlement of Phase II). The BPU on April 17, 1984 approved a settlement agreement concerning Jersey Central Power & Light Company's ("Jersey Central") share of the costs of TMI-2 cleanup. As part of the settlement, the parties agreed that cogeneration and small power production, including solid waste resource recovery facilities, were mitigating measures that represented an opportunity for substantial cost mitigation of the effects of the TMI-2 accident, and had the potential of benefitting Jersey Central's ratepayers. Jersey Central has been ordered to undertake a program to maximize the use of these technologies throughout the state where such projects can provide energy and capacity at costs to ratepayers which are anticipated to be lower than those of available alternatives.

The parties agreed that Jersey Central's mitigation effort would include the establishment of a separate entity for the purpose of maximizing the development of cost effective technologies. The resulting energy and capacity will be available for purchase and use by Jersey Central or may otherwise offset or replace Jersey Central's requirements. The separate entity may serve as a vehicle to obtain investment capital and make it available to third parties. It may take an ownership interest in cogeneration projects where appropriate, or in shared savings projects. It may provide maintenance support services for cogeneration projects, serve as an area representative or vendor for lines of cogeneration equipment where feasible, negotiate wheeling arrangements with New Jersey utilities, perform feasibility studies, and undertake appropriately related activities.

3. In the Matter of the Consideration for Approval of the Power Purchase Agreement Between Kinsley's Landfill, Inc. and Public Service Electric and Gas Company, Docket No. 846-648. The BPU approved on August 10, 1984 the first power purchase contract to be signed in New Jersey subsequent to BPU issuance of its PURPA guidelines.<sup>66</sup> Because it was the first, the Kinsley/PSE&G contract received particular scrutiny by the Board. Two definitions were of concern, as well as the term of the contract. The Board reiterated the policy stated in its PURPA implementation rules that capacity provided by a QF to a utility has value regardless of whether the utility is capacity deficient. It noted that it had established the Pennsylvania, New Jersey, Maryland Interconnection ("PJM") capacity deficiency value as the appropriate avoided capacity cost value. Therefore, BPU expressed concern over the

<sup>&</sup>lt;sup>66</sup>Decision and Order, Docket No. 8010-687, In the Matter of the Consideration and Determination of Cogeneration and Small Power Production Standards Pursuant to the Public Utility Regulatory Policies Act of 1978, (Oct. 14, 1981).

Kinsley/PSE&G contractual definition of avoided costs, which implies that the rate is available only when the utility is in a capacity deficiency situation.

A second concern arose out of contractual language that implied that the PJM billing rate plus 10% for energy sold by a QF is only applicable when the concerned utility is in a buying mode relative to the power grid.

Clearly, this Board, in its Decision and Orders under Docket No. 8010-687, intended, and does intend, that the avoided cost value of energy sold from a QF to a utility is 110% of the PJM billing rate regardless of whether the utility is a net buyer or seller to the grid. When the utility is a net seller to PJM, the marginal energy which the QF supplies will be sold to PJM at the billing rate; consequently, this price is the full economic value of the energy. Moreover, 110% of the PJM billing rate has been established by this Board as the avoided energy cost in recognition of the various additional benefits which the development of QF power provide, such as reduction of dependence on fossil fuel imports to New Jersey and reduction of produciton costs to New Jersey industry, thus enabling jobs to remain in the state, among others, and therefore is not considered by this Board as a subsidy, but only as fair economic compensation.<sup>67</sup>

The third issue raised by the Board concerned the terms of the agreement, which are of uncertain duration and contain inherently fluctuating monthly energy revenues. While the Kinsley facility may have been financially viable in spite of these terms, the Board was concerned that future projects which may require substantially greater debt financing and equity investment, will not be able to attract investors under terms for power sales similar to those in the Kinsley/PSE&G contract.

The Board used the opportunity to recommend, as it had in the *Resource Recovery Order*, that the parties in future power sales negotiations consider establishment of a levelized price for energy sales, based on long-term projections of avoided energy costs as presently defined by the Board. The Board also recommended again that a contract life equal in duration to the period of debt financing or economic life of the facility should be an option offered by the utility to the QF to improve the financial viability of the project.

## N. New York

## 1. Judicial Developments

Consolidated Edison Company of New York, Inc. v. Public Service Commission of the State of New York, 63 N.Y. 2d 424 (1984). In this October 23, 1984 decision, the New York Court of Appeals modified the judgment of the Appellate Division, Third Department, 98 A.D. 2d 377 (Third Dept. 1983) cited in the 1983 Report of the Committee on Cogeneration and Small Power Production Facilities.<sup>68</sup> The Court of Appeals addressed three issues. First, it reinstated the determination of the New York Public Service Commission ("New York Commission") insofar as it permitted the imposition on utilities of a minimum purchase rate of 6 cents per kWh from facilities that are both Federal and State QFs.

<sup>&</sup>lt;sup>67</sup>Order of Approval in Docket No. 846-648, p. 2. p. 2-3.

<sup>&</sup>lt;sup>68</sup>5 Energy L.J. 161, 165-166 (1984).

Second, the Court held that PURPA does not preempt New York from requiring utilities to purchase electricity from facilities that qualify under Federal and State law at rates higher than the maximum rate that FERC may establish under PURPA. The Court found that there was no direct conflict between the PURPA maximum purchase rate and the higher minimum purchase rate of New York's Public Service law. The Court rejected the argument that the PURPA objective of avoiding consumer-ratepayer subsidies of alternative energy producers precludes higher State rates, finding that the objective of encouraging alternative energy production permits a finding that just and reasonable rates to electric consumers does not mandate the adoption of the lowest possible reasonable rates. *Id.* at 445.

Third, the Court of Appeals held that New York is preempted from requiring utilities to purchase electricity at wholesale in interstate commerce from facilities qualifying only under State law. The Court appears to have left open possible exceptions and/or exemptions from this general rule if evidence is produced at the New York Commission that: (1) a sale is made in intrastate commerce; (2) the sale is exempt from regulation under the Federal Power Act, *i.e.* a sale by a qualified facility owned by a rural electric cooperative, publicly owned corporation or a municipality, or (3) if it can be demonstrated in the case of an interstate wholesale sale that State regulation will have only an incidental effect on interstate commerce while furthering legitimate local public interests.

Con Edison has filed a notice of appeal with the New York Court of Appeals.

### 2. New York Public Service Commission Decisions and Orders

Case Nos. 26574 and 26824, *Consolidated Edison Company of New York, Inc.* In an order issued March 13, 1984, the New York Commission implemented the above cited Appellate Division judgment by requiring that all contracts entered into after December 31, 1983 and during the pendency of the appeal must contain provisions which recognize the possible annulment of the statutory rate. Specifically, the order required contracts entered into with facilities that qualified under State law only to be voided in the event of an adverse decision of the Court of Appeals.

Case No. 28502, Cogeneration Development Corp. In an order issued April 20, 1984, the New York Commission held that district hot water heating systems were exempt from its jurisdiction

Case No. 28872, Intra-Power of New York, Inc. In a decision issued September 12, 1984, in a case of first impression, the New York Commission held that QFs selling steam at retail were exempt from New York Commission regulation over steam rates.

## 3. Legislative Developments

The Legislature adopted Chapter 519 of the Laws of 1984, enacting a new Section 66-g of the New York Public Service Law which provides the New York Commission with authority to require electric corporations to enter into long-term

<sup>&</sup>lt;sup>69</sup>"In the Matter of Determination of Rates for Purchase and Sale of Electricity Between Electric Utilities and Qualifying Cogenerators or Small Power Producers," Docket No. E-100, SUB 41.

contracts to purchase or wheel electricity produced from indigenous natural gas supplies at the well site at a minimum sales price no lower than the utility's avoided cost, and subject to certain other conditions, including that the sales be at just and economically reasonable rates to the electric utility's customers and non-discriminatory to the gas producers. Such sales are exempt from New York Commission jurisdiction except over safety.

It is unknown how the New York Commission would construe Section 66-g if such a facility was a State and federal QF eligible for the State minimum rate under Section 66-c.

#### O. North Carolina

By order dated October 25, 1984, the North Carolina Utilities Commission ("NCUC") issued a final rule incorporating into the Rules and Regulations of the North Carolina Utilities Commission specific procedures and requirements to be observed by cogenerators and small power producers with respect to applications for certificates of public convenience and necessity pursuant to General Statutes of North Carolina Section 62-110.1(a). The statute (at N.C. GEN. STAT. § 62-110.1(g)) exempts from its certification requirements a person who constructs an electric generating facility primarily for his own use and not for the primary purpose of producing electricity, heat or steam for sale. The NCUC ruled in 1984 that a planned 82 MW cogeneration facility that eventually will use all of most of its own power is not exempt from the requirements for certification. The NCUC noted that initially the facility will utilize only about half of its power, and has contracted to sell up to 40 MW to a utility. The expectations of the future were judged to be too uncertain to weigh in considering the scope of the exception. *Re R.J. Reynolds Tobacco Co.*, 61 P.U.R. 4th 323 (1984).

The scope of the rule is limited to persons intending to seek federal or state benefits as cogenerators or small power producers by selling electricity to electric suppliers. Municipalities and counties are included within the meaning of "person." Certification is required before construction of a generating facility can begin. Construction is defined to include not only a new building, structure or generator, but also the renovation or reworking of an existing building, structure or generator to enable it to operate as a generating facility. The rule establishes a two-tier application procedure pursuant to which large projects that desire to qualify for long-term contracts will be required to file detailed information as to their financial and operational reliability. An applicant who desires to enter into a contract for 5 years or more and who will have a projected maximum dependable capacity of 5 MW or more is required to include the following in the application: details concerning the expertise of those persons who will construct and operate the facility; details of utility involvement in the project; a detailed impact assessment from the purchasing utility; applicant's most recent income statement and balance sheet; an economic feasibility study; a statement of actual financing arrangements entered into thus far; and a detailed analysis of energy inputs and outputs, fuel supply, and anticipated kilowatt output, on-peak and off-peak, by months.

After a completed application has been accepted, the NCUC will require the applicant to publish notice of the application once a week for four weeks in a daily

newspaper in the county where the facility is to be located. In addition, the notice and the application must be served upon the utility to which the applicant plans to sell the electricity to be generated. If no complaint is received and no public hearing scheduled, a certificate will be awarded at the end of the notice period.

The certificate will be subject to three conditions: (1) it can be revoked should any other necessary license or permit not be obtained; (2) it should be renewed if construction does not begin within five years after issuance of the certificate; and (3) until construction is completed, the NCUC reserves the right to review, on a case-by-case basis, all plans to transfer or assign a certificate, and any changes in the basic information required of all certificate applicants.

One of the parties to the rulemaking requested an advisory opinion from the General Counsel of the Federal Energy Regulatory Commission ("FERC") as to whether the NCUC is preempted by federal law from requiring the information set forth in Subsection (b)(2) of the proposed rule. The General Counsel of FERC replied that "it would be inappropriate for me to render an opinion on whether the NCUC is proposing a rule which is consistent with the requirements established by the FERC under section 210 of PURPA since the Commission anticipates that these questions will generally be initiated at the State level."<sup>70</sup>

The other item of interest in North Carolina in 1984 was the third biennial proceeding of the NCUC to determine the rates for sale and purchase of electricity between electric utilities and QFs. An order in the proceeding was issued January 22, 1985.<sup>71</sup>

#### P. Ohio

By an order of August 14, 1984 the Public Utilities Commission of Ohio (PUCO) changed its procedures for review of avoided costs paid by utilities to cogenerators and small power producers of 100 kW or less.<sup>72</sup> Whereas prior to issuance of the August 14 order, the PUCO had reviewed each electric utility's avoided cost during the utility's statutorally required semiannual fuel component hearings, subsequent to August 14, 1984, the review process was shifted to formal rate increase proceedings, usually filed on an annual basis.

With respect to its authority to establish avoided costs for QFs with capacity in excess of 100 kW, the PUCO has continued to carry on its calendar a case instituted in May, 1983 involving the rate to be paid by Cincinnati Gas & Electric Company (CG&E) to Energy Conversions of America, Inc. (ENCOA) for electricity to be generated from a 72 MW trash burning plant.<sup>73</sup> An additional issue raised in this

<sup>&</sup>lt;sup>70</sup>Quoted by the NCUC in its Order at p. 2.

<sup>&</sup>lt;sup>71</sup>"In the Matter of Determination of Rates for Purchase and Sale of Electricity Between Electric Utilities and Qualifying Cogenerators or Small Power Producers," Docket No. E-100, SUB 41A.

<sup>&</sup>lt;sup>72</sup>In the Matter of the Promulgation of Rules Pertaining to Cogeneration and Small Power Production in Compliance With the Public Utility Regulatory Policies Act, Case No. 80-836EL-ORD (1984).

<sup>&</sup>lt;sup>73</sup>In the Matter of the Application of the Cincinnati Gas & Electric Company for Approval of a Cost Methodology in the Determination of a Cogeneration and Small Power Production Rate for a Qualifying Facility With a Capacity in Excess of 100 Kilowatts, Case No. 83-741-UNC (Application filed May 17, 1983).

proceeding is whether the utility can recover from its customers amounts paid for power purchased from cogenerators and small power producers. ENCOA had filed a formal initial rate application with the FERC on June 4, 1982 in Docket No. ER82-576-000. By order issued December 23, 1982, the FERC referred the matter to the PUCO.<sup>74</sup> The case has not yet been heard by the PUCO and as of December 31, 1984 all procedural dates had been stayed pending submission of a stipulated agreement between CG&E and ENCOA.

## Q. Puerto Rico

The principal activity in 1984 regarding cogeneration and small power production in Puerto Rico took place before the FERC in a complaint proceeding on the alleged failure of the Puerto Rico Electric Power Authority to interconnect with or to purchase from or sell energy to QFs. The proceeding is described in detail in Part C.2. of FERC Developments.

## P. Texas

The most significant cogeneration development in Texas in 1984 was the adoption by the Texas Public Utility Commission ("TPUC") of amended rules on an emergency basis in July and a permanent basis in November. The amended rules<sup>75</sup> amplify the prior rules, which were virtually identical to the FERC regulations. The most significant requirement is that each utility must file by December 31, 1984 a *standard offer* for the purchase of energy and capacity from a qualifying facility. These filings will be reviewed and approved by the PUC after notice and hearing.

Under Section 23.66(h), standard offers must recite avoided capacity costs based on a committed unit ("CUB") approach keyed to an actual proposed plant or alternative power supply options. The rules prescribe the method for calculating a net present value in dollars per kW per year of the avoidable capacity. Also to be included in the standard offers are anticipated cogeneration capacity requirements by year for the next ten years and terms and conditions for purchase. The method for calculating the cost of avoided capacity was based on the study of avoidable capacity on the Houston Lighting & Power Company system performed by Ernst & Whinney under a contract with the TPUC Staff.

The amended rules state in Section 23.66(d)(i) that a utility need not contract for capacity from qualifying facilities in excess of the utility's needs as reflected in the TPUC approved State Energy Plan. If more capacity is made available than is needed by a utility, priorities are recognized for waste and solid fuel projects. Utilities are permitted to select among projects on the basis of the cost adjusted for quality of firmness.

The amended rules require in Section 23.66(d)(4) that utilities wheel power from a cogenerator to another utility, but the TPUC has indicated that it will study further its right to require wheeling by a utility subject to FERC jurisdiction and the appropriate rates for such wheeling.

<sup>&</sup>lt;sup>74</sup>Energy Conversions of America, Inc., 21 F.E.R.C. ¶ 61,329 (1982).

<sup>&</sup>lt;sup>75</sup>Tex. Admin. Code tit. 16 § 23.66 (1984).

Section 23.66(d)(1) sets a 90-day limit for negotiating contracts for energy or energy and capacity by requiring eventual contracts to be made effective back to the 90th day after requisite notification by the cogenerator. The meaning of this requirement is being litigated in a proceeding initiated by Dow Chemical Company.<sup>76</sup>

Section 23.66(g) requires that a utility base purchases of energy only on avoided cost as determined by an hour by hour pricing model if practicable. Houston Lighting & Power Company is making purchases on this basis, but questions about the operation of the pricing model are being litigated in another Dow initiated proceeding.<sup>77</sup> Another controversial aspect of the PUC rules is a ban in Section 23.31(c) on direct sales by a qualifying facility without a PUC certificate unless the end user is also the sole purchaser of the thermal output of the qualifying facility.

### 2. Malakoff Plant Decertification

On June 15, 1984 the TPUC initiated an investigation into whether the certificate of convenience and necessity granted HL&P's proposed Malakoff lignite electric generating station should be cancelled as unnecessary due to the high level of cogeneration development in HL&P's service territory.<sup>78</sup> A hearing on the merits was scheduled for December 12, 1984. On December 4, 1984, HL&P, Getty Oil Company and the North American Coal Corporation announced that they had signed an amendment to the lignite supply agreement which purportedly will reduce the lignite price by about \$1 billion over the 35-year contract. On December 20, 1984, the TPUC dropped the inquiry into the Malakoff project. Texas cogenerators had maintained before the TPUC that Malakoff should not be built because the amendment contains a price redetermination clause which will negate the base price reduction, and that the facility is unnecessary because of future availability of cogenerated electricity.

#### S. Vermont

On May 6, 1983, the Vermont Public Service Board's ("Board") Rule 4.100, on Small Power Production (hereinafter "the Rule") became legally effective. Under the Rule, QFs (under 80 MW) are authorized to sell electricity only at wholesale. They may also sell their electricity through a central purchasing agency, the Vermont Power Exchange, Inc. ("VPX"), to the interconnecting utility, or to another utility under wheeling provisions. The Board has drafted a model purchase agreement, which would be executed by the QF, VPX, and the purchasing utility.

<sup>&</sup>lt;sup>76</sup>Petition of Dow Chemical Company Against Houston Lighting and Power Company Regarding Payments and Contract for Firm Power Purchases, Docket No. 5874.

<sup>&</sup>lt;sup>77</sup>Petition of Dow Chemical Company for an Order of the Public Utility Commission of Texas Compelling Houston Lighting and Power Company to Comply With the Final Order in Docket No. 4712, Docket No. 5651 (February 16, 1984).

<sup>&</sup>lt;sup>78</sup>Inquiry of the Public Utility Commission of Texas Into Whether the Certificate of Convenience and Necessity Granted Houston Lighting & Power Company's Malakoff Electric Generating Station Should be Cancelled, Docket No. 5755.

Under Section 4.104 of the Rule, the VPX is required to purchase, at full avoided cost, electricity from any QF. The Vermont Department of Public Service has filed, and the Board has approved, rate schedules for the avoided capacity and energy costs of the Vermont composite electric system. Rates are to be reviewed annually. One year, long-term nonfirm, and long-term firm rates are available. Long-term nonfirm rates are available for periods of 5, 10, or 15 years and may be levelized or non-levelized. Long-term firm rates are available for 10, 20 or 30-year periods, and also may be levelized or non-levelized.

Rates were initially approved in the Spring of 1984. Rates for the first 25 MW decrement are set forth in VPX's "Producer's Guide", and current first, second and third decrement levelized rates for firm power are set forth in an August 17, 1984 print-out.

The Board is currently engaged in adjudicatory hearings on the first annual revision of projected avoided costs upon which the purchase power rates are based. *Small Power Production and Cogeneration Rates*, Docket No. 4933. Hearings are scheduled for February 5, 1985.

#### V. FINANCIAL, ACCOUNTING, AND TAX DEVELOPMENTS

There were two major developments in this area during the past year: one with immediate effect, the other with significant future importance. The first was the enactment of the "Wallop Amendment" to the Deficit Reduction Act of 1984. The second was the release of the Treasury Department's report to the President on fundamental tax reform and simplification, which would have a large impact on cogeneration and other small-power facilities if enacted.

# A. The Impact of the Deficit Reduction Act of 1984 and the "Wallop Amendment" on Energy Sales Contracts

The Deficit Reduction Act of 1984,<sup>79</sup> contains a significant provision popularly known as the "Wallop Amendment," which establishes a new rule for distinguishing "service contracts" from "leases" for tax purposes.<sup>80</sup> The tax consequences of all alternative energy and cogeneration projects will be governed in large part by the extent to which these requirements are satisfied.

#### 1. Background

Even before the Deficit Reduction Act, a major area of concern in structuring a small power production or cogeneration facility was whether the contract for the sale of the electrical or thermal output of the project should be treated as a legitimate service contract or as a lease of property for tax purposes. If the energy sale contract is treated as a legitimate service contract for tax purposes, the project owner is treated as being in the business of producing and selling energy, and the owner's receipts form the sale of energy are treated as income from the active

<sup>79</sup>Pub.L. No. 98-369 (1984).

<sup>&</sup>lt;sup>80</sup>The amendment is contained in Section 32(a) of the Act and is codified at 26 U.S.C. § 7701(e).

conduct of a service related business. However, if the energy sale contract is treated as a lease of property for tax purposes, the project owner is treated as if it had leased the energy project to the energy customer, and the owner's receipts are treated as rental income for tax purposes.

#### 2. Energy Sale Contracts for Alternative Energy Projects

The tax treatment of an energy sale contract does not automatically follow the characterization of the contract by the parties involved. On the contrary, the IRS has long taken the position that if a contractual arrangement more closely resembles a lease than an actual service contract in substance, it should be classified as a lease of property for tax purposes regardless of how the contract is characterized by the parties. Prior to the Deficit Reduction Act, service contracts, including contracts for the sale of electrical or thermal energy produced by cogeneration or small power production projects, were classified as service contracts or as leases on the basis of several judicially and administratively established criteria. These criteria included the allocation of operating responsibility for the project and the risk of loss with respect to the project.

The Wallop Amendment replaces the rules of prior law with a detailed list of statutory criteria which an energy sale contract must satisfy in order to qualify as a service contract and avoid classification as a lease for tax purposes. The amendment applies to contracts for the sale of electrical or thermal energy produced by a cogeneration or small power production facility. For purposes of the amendment, a small power production facility is a facility which derives no more than fifty percent of its energy from oil, natural gas, coal or nuclear power.

Under the Wallop Amendment, an energy sale contract will be classified as a service contract if it satisfies four specific statutory requirements. First, the service recipient cannot operate the facility. Accordingly, where the project owner does not want to operate the facility directly, it should arrange for an unrelated third party to operate and maintain the facility, and should not delegate the operation or the maintenance of the project to the energy customer of a party related to the energy customer.

The second requirement is that the service recipient cannot bear any significant financial burden if there is nonperformance under the contract. Accordingly, contracts with minimum payment clauses, such as "hell or high water" power sale contracts, will not qualify as service contracts. However, the mere fact that the energy customer may be required to purchase substitute energy at a higher price if the project fails to operate does not impose a significant financial burden on the energy customer within the meaning of this provision.

The third requirement is that the energy customer cannot receive a significant financial benefit if the operating costs of the facility are less than the standards of performance or operation contemplated in the contract. Under this provision, any increase or decrease in the operation and maintenance expense of the project must be borne by the project owner, and arrangements whereby the power purchaser either pays the entire operation and maintenance cost or shares that cost with the project owner, directly or indirectly, will not be permitted. Accordingly, contracts which pass these costs through to the energy customer, such as "net" power sale contracts, will not qualify under this rule.

The final requirement is that the energy customer cannot have an option or an obligation to purchase all or part of the project at a fixed or determinable price other than fair market value. Under this provision, discount purchase options and fixed price options at any price may not be included in a power sale contract. However, the contract can include an option to purchase the property either at its fair market value, as determined by appraisal at the time of the exercise of the option, or at a value determined pursuant to a formula which is reasonably expected to yield fair market value when the option is exercised.

The new rules added by the Wallop Amendment apply to contracts with tax exempt and governmental entities entered into on or after May 23, 1983, and to other energy sale contracts entered into after November 4, 1983. Contracts entered into prior to those dates will continue to be governed by the rules of prior law.

#### 3. Other Energy Sale Contracts

The Wallop Amendment only applies to contracts for the sale of energy produced by cogeneration and small power production projects. Energy sale contracts which do not qualify under the Wallop Amendment, and other types of service contracts, such as energy management contracts, will be governed by the general rules contained in the Act. Under these general rules, the determination of whether a contract is a service contract or a lease must be made by considering "all of the relevant factors." Six specific factors are set forth in the Act: whether the service recipient controls the property; whether the service provider bears any substantial risk of loss due to nonperformance; whether the service recipient has a significant possessory or economic interest in the property; whether the service recipient has physical possession of the property; whether the service provider concurrently uses the property to provide significant services to more than one customer; and whether the total cost of the contract substantially exceeds the fair rental value of the property.

The first two factors are similar to the criteria considered under current law, and are not difficult for small power production projects to satisfy. However, some of the other factors could present problems for small power production projects which do not qualify under the Wallop Amendment. For example, many components of industrial and commercial energy management systems must be located on the customer's premises, thus giving the energy customer "physical possession" of the equipment. Similarly, many small power production projects are highly capital intensive, and while the cost of the peripheral services associated with such projects may be substantial in absolute terms, those costs often represent a relatively low percentage of the total cost of the output of the project. Because the price for the output of such projects largely reflects the cost of capital to the project developer, it would not differ substantially from the typical return on capital from the rental of a similar item of property.

Alternative energy projects could also have trouble satisfying other criteria set forth in the Act. For example, industrial and commercial energy management systems generally provide their services to a single industrial or commercial user. Vol. 6:2

Thus, contracts for such projects could also fail to satisfy the criterion which is based on the number of customers served by the project. Similarly, in order to obtain financing for a small power production facility, it is often necessary to enter into a long-term contract for the sale of the services provided by the project. However, under the Act, this would violate yet another of the criteria because it would be deemed to give the power purchaser an economic interest in the project.

The more of the criteria set forth in the Act which a contract fails to satisfy, the greater the risk that it will be classified as a lease rather than a service contract. Indeed, statements by Treasury officials have suggested that a contract could be classified as a lease even if it only fails to satisfy one or two of these criteria. Accordingly, the new rules for the classification of contractual arrangements will make it much more difficult for contracts for the sale of the output of small power production projects which do not satisfy the requirements of the Wallop Amendment to qualify as service contracts.

Alternative energy projects could also be adversely affected by another provision in the Act, which would apply the same six criteria set forth above to characterizing other arrangements (such as partnerships) as leases of property for tax purposes. This rule could create particular problems for certain types of contractual arrangements which are becoming prevalent in the alternative energy industry. For example, an increasingly common practice in the small scale hydropower industry is for a private developer to agree to develop a municipal dam to produce power for sale to a third party. The developer agrees to own and operate the project for a period of time less than the full useful life of the project, after which the developer agrees to transfer the project to the municipal entity for no charge. Under the Act, the developer could actually be treated as having leased the project to the municipal entity for the entire period of its useful life. This in turn would cost the developer most of the tax benefits associated with the project. However, because the municipal entity is not the energy customer, the Wallop Amendment would not apply, and its "safe harbor" relief would not be available. Accordingly, project developers should careully scrutinize all of their contractual arrangements, and not just their energy sale contracts, in light of this new Act.

# 4. Treatment of Power Sale Contracts Between Related Parties

The Wallop Amendment was designed to ensure that service providers under legitimate service contracts retain all of the benefits and burdens associated with the property used to provide the service, and to prevent the service provider from shifting those benefits and burdens to the service recipient. However, there was some concern that service providers who were prohibited from shifting these burdens directly to the service recipient would instead shift them to entities related to the service recipient, and unrelated to the service provider, thus frustrating the intent of the Wallop Amendment. Accordingly, the Wallop Amendment does not apply to power contracts under which an entity related to the power purchaser operates the facility, bears a financial burden from non-performance, receives a financial benefit from reduced operating costs, or has an option to purchase the facility at less than fair market value. However, one situation not contemplated when the Wallop Amendment was drafted is that in which the service provider and the service recipient are related to each other. The classification of the contractual relationship between related parties is important because, if the contract for the sale of electricity produced by a facility owned in whole or in part by a company which is related to the electric utility is classified as lease of the facility rather than a legitimate service contract, the facility would be classified as public utility property even though it is a qualifying facility under PURPA. Congress did not intend that related party transactions such as this would automatically fail to qualify under the Wallop Amendment. Unfortunately, given a literal reading, the Wallop Amendment would automatically prevent related parties from entering into legitimate service contracts with each other, since in any such contract an entity related to the power purchaser would operate the facility and share the burdens and benefits associated with the property.

There is no tax abuse or other sound tax policy consideration which would require that related parties not be allowed to enter into legitimate service contracts with each other. Indeed there are sound policy considerations which dictate that related parties should be allowed to enter into legitimate service contracts with each other. Such entities must frequently bid competitively against unrelated entities for the right to develop an energy producing project. A related entity would be placed at a substantial competitive disadvantage if its contractual relationship with the power purchaser could not qualify as a service contract, while unrelated parties developing the identical project would be eligible for service contract classification.

Nevertheless, some staff members of the Joint Committee on Taxation have taken the position that related entities are not eligible for the benefits of the Wallop Amendment when entering into legitimate service contracts with each other. This position is contrary to the intent of the Wallop Amendment, and creates arbitrary discrimination against a public utility's subsidiary or parent when it is doing business in the utility's service territory. Legislative and administrative efforts are now underway to remedy this problem.

The Deficit Reduction Act of 1984 will have a major impact on the structuring of small power production projects in coming years. Nevertheless, by paying careful attention to the new requirements set forth in that Act, the tax benefits associated with small power production and cogeneration projects will continue to be available.

# B. Treasury Tax Reform Recommendations and Their Impact on Cogeneration and Small-Power Production Projects

In December, 1984, the Treasury Department ("Treasury") released its long awaited report to the President on fundamental tax reform and simplification. As expected, the Treasury recommended a "modified flat tax" to replace many existing provisions of the Internal Revenue Code. Under the Treasury proposal, the tax burden on capital intensive industries would increase substantially, affecting cogeneration and alternative energy industries. Among the current provisions which would be eliminated by the Treasury plan are several incentives enacted in recent years specifically to encourage alternative energy development, including the residential energy credit and the alternative fuels production credit. The business energy tax credit, which is the principal tax incentive for alternative energy development, would not be repealed under the Treasury proposal, but it would not be extended beyond its present 1985 expiration date. Current affirmative commitment rules which extend certain credits beyond 1985, such as the three-year extension for hydropower projects, would remain in effect.

In addition to repealing targeted incentives for small power production facility development, the Treasury proposal would make fundamental changes in other incentives for capital investment which are of critical importance to the financing of cogeneration and small power production projects. Under the Treasury proposal, the ten percent investment tax credit would be repealed. The Accelerated Cost Recovery System ("ACRS"), which was the centerpiece of the Administration's 1981 business tax cuts, and which allows project owners to deduct the capital cost of most cogeneration and small power production projects over a five-year period, would be replaced with a "Real Cost Recovery System" ("RCRS"). Under RCRS, the five ACRS categories would be replaced with seven new categories, and depreciation for property in each category would be calculated by applying a constant percentage rate to the unrecovered basis of the property. Most cogeneration and small power production projects would be included in Class 4 or Class 5, and would be assigned depreciation rates of twelve or eight percent, respectively. This is far less generous than the depreciation rates for such projects under ACRS, which average twenty percent. The unrecovered basis would be adjusted each year for inflation, and the remaining basis would be "closed out" (completely written off) once eighty-five percent of the original basis has been recovered. Close-out for projects in Class 4 would occur after seventeen years, and for projects in Class 5, close-out would occur after twenty-five years.

The Treasury proposal would also deny tax-free status to municipal bonds issued to finance private-sector activities. Although recent changes in the tax laws have significantly diminished the utility of industrial development bond (IDB) financing for cogeneration and small power production projects, IDBs remain a popular source of funds for certain types of energy projects, such as waste-to-energy and district heating projects. While the Treasury proposal would deny IDB financing to privately owned energy projects, and to publicly owned energy projects whose output is sold to investor-owned utilities, tax-exempt financing would still be available for strictly public-purpose projects.

The Treasury proposal would also change numerous other aspects of the federal tax law which affect the financing of energy projects. The proposal would repeal the capital gains deduction, which reduces the effective rate of tax on the proceeds of the sale of cogeneration and small power production projects which have appreciated in value. In lieu of the capital gains deduction, the basis of capital assets would be indexed for inflation. Finally, the proposal would only allow a deduction for a portion of interest payments on debt incurred to finance cogeneration and small power production projects. The amount of the interest deduction would vary from year to year based on the rate of inflation for the year.

Members of the cogeneration and alternative energy industries are concerned that the combination of the repeal of the investment tax credit and ACRS, and the failure to extend targeted alternative energy incentives, will have a substantial negative impact on cogeneration and small power production facility development.<sup>81</sup> Of particular concern is the possibility that the relatively low depreciation rates allowed for cogeneration and small power production projects under ACRS would make energy projects less attractive with other types of investment, such as computers, which would be assigned much higher depreciation rates.

The Treasury proposal has been submitted to the President, but it has not yet been embraced as an official administration proposal. While it is impossible to predict the ultimate fate of any tax reform proposal, business interests have already expressed serious objections to the proposed repeal of the investment credit and the scale-back of ACRS deductions.

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<sup>&</sup>lt;sup>81</sup>Because the Treasury proposal would be effective for projects placed in service after 1985, the proposal should not have as dramatic an effect on projects completed in 1985. However, the overall reduction in tax rates would have an impact on 1985 projects by diminishing the value of depreciation deductions to be claimed after 1985.