

## Report of The Committee on Cogeneration and Small Power Production Facilities

In 1985, developments concerning the cogeneration and small power production at the state level were significant. Therefore, this report has been expanded to include twenty-three states. The section on Financial, Accounting and Tax Developments has been deleted with the understanding that the report of the Committee on Tax Developments will cover issues relevant to cogeneration and small power production.

### I. FEDERAL JUDICIAL DEVELOPMENTS

#### A. *Consolidated Edison Co. v. Public Service Commission.*

The most significant federal judicial development of 1985 affecting cogeneration and small power production was the United States Supreme Court's decision in *Consolidated Edison Company of New York*,<sup>1</sup> not to decide whether a statutorily-imposed floor rate for utility purchases from qualifying facilities is in conflict with, and pre-empted by, the Public Utility Regulatory Policies Act of 1978 (PURPA).<sup>2</sup> On March 25, 1985, the Supreme Court dismissed an appeal by Consolidated Edison Company of New York, Inc. (ConEd) from a decision of the Court of Appeals of New York<sup>3</sup> upholding the constitutionality of New York Public Service Law Section 66(c),<sup>4</sup> which sets a statutory minimum rate of six cents per kilowatt hour for utility purchases from qualifying facilities (QF's).<sup>5</sup>

Under Section 210 of PURPA,<sup>6</sup> the Federal Energy Regulatory Commission (the FERC) was required to prescribe rules that would foster development of qualifying cogeneration and small power production facilities. Among other things, PURPA directed the FERC to establish rates for purchases by electric utilities that are (i) just and reasonable to the electric consumers of the utility; (ii) in the public interest, and (iii) not discriminatory against QF's. According to the regulations promulgated by the FERC, a purchasing utility is not obligated to pay a rate for electricity that exceeds its "avoided cost."<sup>7</sup>

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1. 105 S. Ct. 131 (1985).

2. 16 U.S.C. § 824(a)-(3) (1982).

3. *Consolidated Edison Co. v. Public Serv. Comm'n*, 63 N.Y.2d 424, 472 N.E.2d 1981, 483 N.Y.S.2d 153 (1984), *cert. dismissed*, 105 S. Ct. 1831 (1985).

4. N.Y. PUB. SERV. LAW § 66(c) (McKinney Supp. 1986).

5. Section 2 of the New York Public Service Law provides a slightly more expansive definition of qualifying facility than that provided in the regulations promulgated under PURPA [hereinafter the PURPA Regulations]. Compare N.Y. PUB. SERV. LAW § 2 (McKinney Supp. 1986) with 18 C.F.R. §§ 292.202(c), 292.203-.206 (1985).

6. 16 U.S.C. § 824(a)(3)(a) (1982).

7. The PURPA Regulations state that, "Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a)(2) (1985). A utility's "avoided cost" is the amount that it would have cost the utility to generate or purchase the electricity and capacity from a source other than the qualifying facility. See 18 C.F.R. § 292.101(b)(6) (1985).

In 1980, the New York assembly passed Section 66-c of the Public Service Law "to encourage the development of alternate energy production facilities, cogeneration facilities and small hydro facilities in order to conserve . . . finite and expensive energy resources and to provide for their most efficient utilization."<sup>8</sup> Section 66-c provides that the minimum price for electricity that an electric utility purchases from the alternate energy facilities must be six cents per kilowatt hour, subject to periodic revision by the New York Public Service Commission (the Commission) to reflect increases in the cost of utility-generated electricity.

The Commission issued an order requiring ConEd and the other New York State electric utilities to pay QF's the greater of their avoided costs or the six cent statutory minimum rate. ConEd appealed from the Commission's order, assenting that the New York statute was in direct conflict with PURPA because it would force ConEd to pay a rate for electricity that exceeded the federally-mandated avoided cost rate. The Appellate Division of the New York supreme court held that the six cent floor rate was invalid to the extent it exceeded ConEd's avoided costs,<sup>9</sup> on the theory that Section 66-c was preempted by PURPA which vested the FERC with exclusive jurisdiction to determine the rates electric utilities are required to pay for power purchased from qualifying cogenerators and small power producers.

In 1984, the New York Court of Appeals reversed the supreme court of New York.<sup>10</sup> The court concluded that avoided cost defined by PURPA and the Regulations thereunder is the maximum rate that may be imposed by the FERC. However, the court relied on the preamble to the FERC's regulations implementing the PURPA which notes that states are permitted to enact laws or regulations providing for rates which would result in even greater encouragement of cogeneration and small power production to support its conclusion that Section 66-c and PURPA are complementary rather than conflicting.

On March 25, 1985, the United States Supreme Court voted six to two to dismiss ConEd's appeal from the New York Court of Appeals decision "for want of a substantial federal question."<sup>11</sup> Justices White and Blackmun filed a dissenting opinion in which they criticized the majority for failing to exercise the Court's mandatory jurisdiction over what they considered a substantial federal question that "is both open to debate and important."<sup>12</sup> The dissenting opinion noted that the outcome reached by the New York Court of Appeals was in direct conflict with that reached by the highest court in the State of Kansas.<sup>13</sup>

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8. N.Y. PUB. SERV. LAW 66(c) (McKinney Supp. 1986).

9. 98 A.D.2d at 383, 471 N.Y.S.2d at 689.

10. Consolidated Edison Co. v. Public Serv. Comm'n, 63 N.Y.2d 424, 472 N.E.2d 981 (1984).

11. Consolidated Edison Co. v. Public Serv. Comm'n, 105 S. Ct. 1831 (1985).

12. *Id.* at 1833.

13. *Id.* at 1832; *see* Kansas City Power & Light Co. v. Corp. Comm'n, 234 Kan. 1052, 676 P.2d 764 (1984), in which the Supreme Court of Kansas held that an order by the Kansas Corporation Commission setting rates for cogeneration sales to utilities, that were not based upon avoided costs, was invalid because it violated PURPA and the PURPA Regulations. The court concluded that, "federal law has preempted the field in the area of cogeneration, and that the KCC [Kansas Corporation Commission], a state regulatory authority, cannot require KCPL [Kansas City Power & Light] to purchase electricity from cogenerators at a rate greater than the federal regulated rate based on avoided cost." 234 Kan. at 1057, 676 P.2d at 767-68.

*B. City of Chanute v. Kansas Gas & Electric Co.*

In *City of Chanute*,<sup>14</sup> the Tenth Circuit Court of Appeals held that two municipalities were entitled to a preliminary injunction requiring the local electric utility to wheel power from the generation facilities of suppliers within the Southwestern Power Administration, with whom each municipality had contracted to receive certain allotments of power. This action was instituted by the municipalities on the theory that the utilities' refusal to wheel violated antitrust laws.

The defendant electric utility argued that the municipalities were not entitled to the requested equitable relief because PURPA had provided them with an adequate remedy at law by authorizing the FERC to order wheeling in certain circumstances. The court found that the municipalities did not have an adequate remedy at law. The court further held that the drafters of PURPA had intended to preserve the jurisdiction of the federal and state courts in actions under antitrust laws, whether or not the parties to such actions could have sought remedies under PURPA.<sup>15</sup>

## II. FERC DEVELOPMENTS

### A. Rulemaking

#### 1. User Fees

On September 30, 1985, the FERC issued a final rule effective November 4, 1985, which established a schedule of user fees applicable to electric utilities, cogenerators, and small power producers.<sup>16</sup> The rule adds a new Subpart E to 18 C.F.R. Part 381, and in new Section 381.505, establishes a fee of \$1,800 for a routine application for Commission certification as a QF. If an application presents a complex issue requiring an extraordinary amount of Commission time and effort to process, an applicant may be billed for a greater amount,<sup>17</sup> and in the event that an applicant is unable to pay the fee because of "severe economic hardship," a waiver may be requested.<sup>18</sup>

On November 25, 1985, the Commission acting on requests for rehearing filed by nine petitioners, granted rehearing solely for the purpose of further consideration.<sup>19</sup> The Commission did not stay the effect of the rule, and has yet to decide the rehearing requests on their merits.

#### 2. Electric Notice of Inquiry

In May and June of 1985, the Commission issued a two-phase Notice of Inquiry (NOI) designed to assist the Commission in evaluating whether its policies promote or hinder efficiency in electric markets, and to determine how the

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14. 754 F.2d 310 (10th Cir. 1985).

15. *Id.* at 312.

16. Fees Applicable to Electric Utilities, Cogenerators, and Small Power Producers, 50 Fed. Reg. 40,347 (1985) (to be codified in 18 C.F.R. pts. 32-36, 45, 101, 292, 375, and 381).

17. 18 C.F.R. § 381.107 (1985).

18. *Id.* § 381.106.

19. 50 Fed. Reg. 49,924 (1985).

Commission's policies could be changed, if necessary, to promote greater efficiency in the electric utility industry.<sup>20</sup> Cogenerators' and small power producers' needs for increased wheeling opportunities were addressed in Phase I of the NOI. Several commentors to Phase I noted that greater wheeling opportunities will allow cogenerators and small power producers to wheel power to purchasers other than local utilities, for new markets thereby, allowing them to receive higher rates for their power.

## B. Decisions

### 1. Utility Ownership of Qualifying Facilities

The Commission rejected a request for an interpretation of its regulations which would have permitted greater utility involvement in ownership of QF's. Section 201 of PURPA limits QF status to cogeneration and small power production facilities "owned by a person not primarily engaged in the generation or sale of electric power."<sup>21</sup> Section 292.206 of the Commission's regulations equates "ownership" with "equity interest," limiting qualifying status to facilities in which "[no] more than 50 percent of the equity interest in the facility is held by an electric utility or utilities . . . ."<sup>22</sup> In *KP Diversified Investors, Inc.*<sup>23</sup> the Commission refused to interpret Section 292.206 to grant qualifying status to a facility in which utilities would own more than fifty percent of the equity as limited partners, but would have no voice in its management.<sup>24</sup> The Commission found that "reliance on the element of control to the exclusion of capital contributions and the distribution of profits is improper."<sup>25</sup>

### 2. Waiver of Utility Purchase and Sale Obligations

In *Oglethorpe Power Corp.*,<sup>26</sup> the Commission: (1) concluded that it has the implicit authority under Section 210 to grant a waiver of the utility's purchase obligation where strict compliance would not advance the purpose of encouraging cogeneration and small power production; (2) waived the purchase requirement as to members of a Georgia electric cooperative, Oglethorpe Power Corporation (Oglethorpe), which acted as the generation and transmission agent for the member retail cooperatives; and (3) determined that Oglethorpe failed to meet its burden in applying for a waiver of the sale obligation under

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20. Regulation of Electricity Sales-for-Resale and Transmission Service (Phase I), 50 Fed. Reg. 23,445 (1985); Regulation of Electricity Sales-for-Resale and Transmission Service (Phase II), 50 Fed. Reg. 27,604 (1985).

21. 16 U.S.C. § 796(17)(c)(ii) (1982).

22. 18 C.F.R. § 292.206(b) (1985).

23. 32 F.E.R.C. ¶ 61,013 (1985).

24. The ownership structure offered for approval consisted of a two-tiered limited partnership program in which electric utilities would participate as limited partners in an Investment Partnership which would be managed by non-utility program managers who would have exclusive power to select projects for investment. The Investment Partnership would itself be a limited partner in the Operating Partnership in which it would have no management responsibilities. *Id.* at 2-10 (petition of KP Diversified Investors, Inc. For a Declaratory Order).

25. 32 F.E.R.C. at 61,050.

26. 32 F.E.R.C. ¶ 61,103 (1985).

18 C.F.R. Section 292.305(b)(2).

In holding, for the first time, that it has the authority to waive buyback requirements, the Commission noted that existing regulatory provisions for waiver<sup>27</sup> permitted waivers "only with respect to individual utilities based on a showing by the applicant that designated standards have been met."<sup>28</sup> The Commission concluded that Section 210 gives it implicit discretion to waive purchase and sale requirements "where strict compliance would serve no purpose."<sup>29</sup>

The Commission granted the waiver because Oglethorpe was "ready and willing to stand in the shoes" of its members, and the waiver "will not frustrate Congress' intent, because no QF will be deprived of a market for its power and each will receive a rate established as sufficient to encourage QFs."<sup>30</sup> Because Oglethorpe's rates were based on its full avoided cost, they were "on their face, in compliance with the regulations [and thus were] sufficient to encourage QFs,"<sup>31</sup> although Oglethorpe's rates might sometimes be lower than its members' avoided costs.

The Commission denied Oglethorpe's request for a waiver of its obligation to sell power to QF's. The Commission noted that the regulation regarding waiver of the sale requirement<sup>32</sup> is subject to a higher standard than that governing the waiver of the purchase requirement. Waiver of the sale obligation would be granted only if the utility-seller could show that its "ability to serve its customers will be impaired or that it will otherwise suffer an undue burden if required to sell power to QFs."<sup>33</sup> Oglethorpe failed to make the requisite showing.

### 3. Backup Power

The FERC's decision in *Alcon (Puerto Rico) Inc.*<sup>34</sup> raised questions concerning the right to backup power of a manufacturing plant which consumed power produced by a cogeneration facility leased from an unrelated third party. The owners of the cogeneration facility and the manufacturing plant argued that the lease arrangement was selected solely to facilitate financing of the cogeneration project.

Relying on language in its regulations which requires a utility to sell backup power to the owner and operator of a QF, and on its finding that the owner of the manufacturing plant would neither own nor operate the cogeneration facility, the FERC held that only the owner of the cogeneration facility was entitled to backup power.<sup>35</sup> The Commission also noted that if the cogenerator resold purchased backup power to the manufacturing plant, the cogenerator would become an "electric utility" under Section 3(22) of the Federal

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27. 18 C.F.R. §§ 292.305(b)(2), 292.403(b) (1985).

28. 32 F.E.R.C. at 61,284.

29. *Id.*

30. *Id.* at 61,285.

31. *Id.*

32. 18 C.F.R. § 292.403(b) (1985).

33. 32 F.E.R.C. at 61,284.

34. 32 F.E.R.C. ¶ 61,247 (1984).

35. *Id.* at 61,579.

Power Act (FPA).<sup>36</sup> In that event, the cogeneration facility would cease to be a QF.<sup>37</sup>

Commissioner Stalon filed a vigorous and lengthy dissent to the Commission's order on the backup power issue.<sup>38</sup> On October 17, 1985, the Commission issued an order granting rehearing for the limited purpose of further consideration.<sup>39</sup>

#### 4. Qualifying Facility Definition

In a declaratory order issued in *Kern River Cogeneration Co.*,<sup>40</sup> the Commission concluded that interconnection equipment,<sup>41</sup> owned by a cogenerator to transmit backup power to the consumer of its cogenerated power was a part of the cogeneration facility. It reached that conclusion in spite of the fact that under the Federal Power Act,<sup>42</sup> interconnection equipment was traditionally treated as a transmission rather than a generating facility. By including the interconnection equipment as part of the generating facility, that equipment became part of the qualifying facility under PURPA and was therefore exempted from regulation under the Federal Power Act.

#### 5. Operating and Efficiency Standards

In *Electrodyne Research Corp.*,<sup>43</sup> the Commission clarified its application of the useful thermal output requirement for cogeneration facilities.<sup>44</sup> Electrodyne Research Corporation (Electrodyne) appealed the QF certification of its cogeneration facility because the Office Director's order<sup>45</sup> had not included the drying of anthracite culm<sup>46</sup> for Electrodyne's affiliates as part of the facility's useful thermal output. In the alternative, Electrodyne requested that a previously withdrawn application for certification as a small power producer be reinstated and granted.

In denying Electrodyne's appeal, the Commission held that in order for a thermal output to be "useful," it must have an independent business purpose with some independent economic justification.<sup>47</sup> Where the output is used for "a common industrial or commercial thermal application, it would be regarded

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36. See 16 U.S.C. § 796(22) (1982).

37. 32 F.E.R.C. at 61,579.

38. *Id.* at 61,581-88.

39. Order Granting Rehearing for Purpose of Further Consideration and Deferring Consideration of Motions to Intervene, Alcon (Puerto Rico), Inc., Docket Nos. QF84-147-001,-008.

40. 31 FERC ¶ 61,183 (1985).

41. The switchyard was designed to direct the flow of standby power between a utility and the end user of electricity, to synchronize power flows with the utility's system, and to provide protection for the parties' facilities.

42. 16 U.S.C. § 826 (1982).

43. 32 FERC ¶ 61,102 (1985).

44. See 18 C.F.R. § 292.205(a)(1) (1985).

45. Electrodyne Research Corp., 29 FERC ¶ 62,258 (1984).

46. Anthracite culm is a refuse material consisting of discarded anthracite coal mixed with rock and other noncombustible materials.

47. See John W. Savage, 28 FERC ¶ 61,273 (1984); E.G. & G., Inc., 16 FERC ¶ 61,060 (1981).

as useful, even where its user is affiliated with the cogenerator.<sup>48</sup> Where the proposed thermal output application consists of new technology not yet found to be economical, the analysis varies depending on whether the thermal output would be used by an affiliate.<sup>49</sup> The FERC stated that “[w]here the usefulness of the thermal application has not been established by common practice, and an affiliated use of the cogenerator’s own use is involved, the Commission will require the applicant to provide evidence that the output would be economically justified in an independent business setting.”<sup>50</sup>

## 6. Small Power Production Developments

### *a. Minor uses of fossil fuels*

In *LUZ Solar Partners Ltd.*,<sup>51</sup> LUZ Solar Partners sought QF certification of a small power production facility which would use solar energy as the primary energy source to heat oil that would in turn be used in a heat exchanger to produce steam. Fossil fuels also were proposed to be used in a gas-fired auxiliary steam boiler. The Commission held that oil and natural gas may be used in a small power production facility for purposes not specified in Section 3(17)(B) of the FPA, which excludes from the definition of “primary energy source” the following:

- (i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and
- (ii) the minimum amounts of fuel required to alleviate or prevent —
  - (I) unanticipated equipment outages, and
  - (II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages;<sup>52</sup>

The commission found that the use of oil and natural gas for purposes outside those specified in Section 3(17)(B) is permitted because (1) the statutory language does not expressly state that the enumerated uses constitute an exclusive list of permissible fossil fuel uses; (2) the legislative history of Section 3(17)(B) and, in particular, the conference report which added “for other minor uses” to the list set out in Section 3(17)(B); and (3) the broader purposes of Sections 201 and 210 of PURPA to encourage the development of cogeneration and small power production facilities.<sup>53</sup> The Commission also found that its regulations did not bar consideration of a minor use not specified in the statute.<sup>54</sup>

### *b. “Waste” as a primary energy source*

In *Turbo Gas and Electric, Ltd.*,<sup>55</sup> the Commission certified two proposed

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48. 32 FERC at 61,278.

49. *Id.*

50. *Id.*

51. 30 FERC ¶ 61,122 (1985).

52. 16 U.S.C. § 796(17)(B) (1982).

53. 30 FERC at 61,225-26.

54. *Id.* at 61,226.

55. 30 FERC ¶ 61,123 (1985).

facilities which would utilize turbo-expanders<sup>56</sup> in small power production facilities and denied QF certification to a facility which would utilize a turbo-expander in a cogeneration configuration. With regard to the proposed cogeneration configuration, the Commission found that using the thermal output of an internal combustion engine to preheat the gas entering the turbo-expander<sup>57</sup> was required only by virtue of the use of the turbo-expander, and that in reality the turbo-expander and the internal combustion engine were a single integrated system properly treated as a variation of a combined cycle facility. Because the only output of the combined cycle facility was electric power, it did not have a useful thermal output and, thus, did not satisfy the definition of a cogeneration facility under the Commission's regulations.<sup>58</sup>

With regard to the small power production facility application of the turbo-expander, the Commission found that the energy resulting from the expansion of natural gas, condenser discharge water, blowdown steam, stack gas, and hot air from an industrial facility qualified as "waste" under Section 3(17)(A)(i) of the FPA<sup>59</sup> and the Commission's regulations.<sup>60</sup> The Commission stated that in order to be "waste," a fuel must (1) be a byproduct and (2) have little or no commercial value.<sup>61</sup> The heat recovered as steam from the internal combustion engine did not qualify as "waste" because it was not a byproduct.<sup>62</sup>

In *Turbine Tech, Inc.*,<sup>63</sup> the Commission denied certification as a qualifying small power production facility to a facility designed to generate electricity using the "waste inertial energy" resulting from an imbalance between the up-stroke and downstroke energy requirements in oil well pump jack operations. The Commission found that (1) the proposed primary energy source was the result of an induced inefficiency and, therefore, was not "waste" because it was not an unavoidable byproduct, and (2) the "inertial energy" had not been shown to be the primary energy source for the project since it appeared that power would be drawn directly from the oil well's power source.

In *Electrodyn Research Corp.*,<sup>64</sup> discussed above in reference to the useful thermal output requirement for qualifying cogeneration facilities, the Commission granted Electrodyn's application for certification as a qualifying small power production facility, and in the process, made a generic determination that existing anthracite culm<sup>65</sup> constitutes "waste"<sup>66</sup> and is eligible as fuel for qualifying small power production facilities. In so doing, the Commission departed from its general rule that a commercial value determination must be

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56. A turbo-expander consists of a turbine generator set driven by the energy resulting from the expansion of natural gas when its pressure is reduced as it moves from a transportation pipeline to a local distribution system.

57. Because the expansion of gas in the turbo-expander lowers its temperature below that suitable for use in a local distribution system, gas must be preheated before it enters the turbo-expander.

58. 18 C.F.R. § 292.202(c) (1985).

59. See 16 U.S.C. § 796(17)(A)(i) (1982).

60. See 18 C.F.R. § 292.204(b)(1)(i) (1985).

61. See *American Lignite Products*, 25 FERC ¶ 61,054 (1983).

62. 30 FERC at 61,231.

63. 31 FERC ¶ 61,184 (1985).

64. 32 FERC ¶ 61,102 (1985).

65. See *supra* note 45.

66. 32 FERC at 61,280.



case specific<sup>67</sup> in order to encourage use of anthracite culm fuel, thereby alleviating environmental problems.<sup>68</sup> The generic classification excludes anthracite culm resulting from mining operations that occurred after the *Electrodyne* order<sup>69</sup> and anthracite silt.<sup>70</sup>

## 7. Enforcement

The FERC declined to initiate an enforcement action against the Oklahoma Corporation Commission in *Applied Energy Services, Inc. v. Oklahoma Corp. Commission*.<sup>71</sup> Applied Energy Services had filed a petition under Section 210(h) of PURPA<sup>72</sup> which authorizes the Commission to bring enforcement actions against state regulatory agencies that do not comply with the Commission's requirements for state implementation of its rules under Section 210(f) of PURPA.<sup>73</sup> At issue was a decision by the Oklahoma Corporation Commission (OCC) rejecting the complainant's challenge to an OCC rule under which it can reopen contracts between an electric utility and a qualifying facility.<sup>74</sup> The complainant argued that the rule was inconsistent with FERC regulations permitting the utility and qualifying facilities to enter into long-term contracts in which the qualifying facility is given the choice of receiving a price equal either to the utility's avoided costs at the time of delivery, or as determined by the contract.<sup>75</sup> The Commission majority, in a two-paragraph notice, announced its intention not to initiate an enforcement action.

Commissioner Stalon dissented from the Commission's decision to take no action. Although he agreed that no enforcement action was necessary, he concluded that the Oklahoma rule was inconsistent with Section 210 regulations.<sup>76</sup>

## C. Other Developments

On September 30, 1985, the Commission awarded a contract to conduct a "Study of the Implementation of PURPA - Cogeneration and Small Power Production (Survey of Decentralized Electricity Generation Development)." The survey, which is expected to be completed by late summer in 1986, will seek to assess the effectiveness of the Commission's rules in encouraging the development of cogeneration and small power production. The survey will encompass all projects that have filed for certification as QFs, all state regulatory agencies concerned with QFs, and all major electric utilities. Data will be collected on project status, interactions between QFs and utilities, and the effectiveness of Commission procedures. No data will be collected on rates for elec-

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67. See *Kenvil Energy Corp.*, 23 FERC ¶ 61,139 at 61,303 (1983).

68. *Id.*

69. *Id.*

70. *Id.* at 61,281. Anthracite silt is composed of the coal fines and ash materials found in the process water used in the coal washing process.

71. 31 FERC ¶ 61,313 (1985).

72. 16 U.S.C. § 824(a)(3)(h) (1982).

73. 16 U.S.C. § 828(a)(3)(f) (1982).

74. Order No. 274115, Cause 27759 (Okla. Corp. Comm'n 1985).

75. See 18 C.F.R. § 292.304 (1985).

76. 31 FERC at 61,711-12.

tricity sales. The survey will be conducted by the management consulting firm of Hagler, Bailly & Co., working with the publication, *Cogeneration and Small Power Monthly*, and Softhink, Inc., at a cost of \$119,731.

### III. STATE DEVELOPMENTS

#### A. California

##### 1. Legislative

SB 166 establishes preferential treatment for cogeneration projects' air quality permit applications. It prohibits an air quality district from requiring emissions offsets under its permit system for cogeneration technology projects or qualifying facilities. A statewide mandate is imposed for creation of growth allowances for cogeneration and resource recovery projects. The legislation requires that air quality districts reduce the offset requirement for cogeneration technology projects or QF's by the amount of utility air quality displacement credits. If a QF project meets the criteria, it is entitled to at least ninety percent of the available utility displacement credits.

Regarding geothermal, AB 899 allows the State Lands Commission a ten percent royalty on direct heat usage leases, and AB 1666 requires geothermal project developers to identify adequate amounts of steam for their projects before they are certified.

Finally, AB 475 requires that utilities verify all computer models used in California Public Utilities Commission (PUC) proceedings and provide the PUC with access to all computer models used in connection with PUC proceedings.

##### 2. California Energy Commission

In its Electricity Report V, the California Energy Commission (CEC) created a new need assessment test to evaluate thermal projects greater than 50 MW under its statutory authority.<sup>77</sup> Departing from the simplistic "first-in, first-out" siting approach it had been using, CEC established a four-part test for use in all siting cases, including those already pending before it.<sup>78</sup> These factors are:

1. Reserved need—Based on technologies which balance several factors, including supporting a sound economy, environmental protection, health and safety and conservation of resources, CEC identifies not only the amount, but the type of resource it prefers for California utilities over the 12-year planning horizon.
2. Proposed facility will not exceed unfilled "reserved need" for that resource.
- 3a. For QFs, power produced will be sold at or below avoided cost determined by the ratemaking authority.
- 3b. For utility projects, power produced is the lesser of threshold cost or utility avoided cost.
- 4a. Power delivered matches load conditions of the area it serves.
- 4b. Facility provides overall benefits based on balancing statutory criteria of CEC mandate: need, environment, and conservation of natural resources.

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77. CAL. PUB. RES. CODE §§ 25000-25968 (West 1984).

78. *Affordable Electricity in an Uncertain World*, 1985 Cal. Elec. Rep. 89-90 (May).

These criteria now serve as the basis for evaluating all QF projects before the CEC. As of January 1, 1986, only one of the 22 QF projects before the CEC received its siting certification (the Gilroy cogeneration project).

To better identify the actual utility need over the 12-year planning horizon, CEC is beginning a process to establish which proposed QF projects under 50 MW are "likely to be available" (LTBA). The first hearings were held in December, 1985 with results expected in mid-1986. This effort represents a comprehensive attempt to develop a statistically valid predictor of QF success rates.

### 3. California Public Utilities Commission (PUC)

#### *a. Suspension of interim long-run standard offer no. 4*

Following actions taken during 1984 which partially suspended interim long-run Standard Offer No. 4 for cogenerators larger than 50 MW, the PUC continued to examine whether continuing an interim long-run standard offer made sense. Numerous QFs had signed the offer after the partial suspension. Further, fuel prices and resource plans had changed since the offer was adopted, and significant delays had occurred in approving a pricing methodology for the final long-run standard offer.

The PUC completely suspended interim long-run Standard Offer No. 4 in April 1985.<sup>79</sup> This suspension will remain in effect until completion of the final long-run standard offer proceeding.<sup>80</sup>

#### *b. Development of long-run standard offer*

The PUC adopted staff's proposed simplified generation resource plan methodology for determining long-run avoided costs.<sup>81</sup> The methodology first identifies the most cost-effective way that the utility would generate power to meet its system requirements in the absence of QFs. Then, two price offers would be made available to the QF. First, if the utility were able to defer or cancel some future plants because of QF power, the QF price would be based on the capital and operating costs of those avoided plants. In the alternative, if the QFs do not displace any future utility resources, the QF price would be based on the properly calculated short-run marginal cost of the utility. In this case, the price would be determined by running the total system cost twice—once with the expected QFs and once without those QFs. The differential cost between these two scenarios would be divided by the number of expected QFs to determine the utility's short-run marginal cost.

Phase II of this proceeding will produce a final long-run offer complete with contract terms and payment options which implement the adopted costing methodology. Compliance filings with actual standard offer prices and terms following evidentiary hearings are expected in July 1986, with a final Commission decision by October 1986. Key issues for this proceeding include: dispatch-

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79. CPUC D.85-04-075 (Apr. 17, 1985).

80. Cal. Pub. Util. Comm'n [hereinafter CPUC] D.85-07-021 (July 10, 1985).

81. CPUC D.85-07-022 (July 10, 1985).

ability of QFs, fixed payment period in the absence of a displaced unit, input assumption sources, and technology specific considerations.<sup>82</sup>

*c. Transmission line constraints and cost allocation policies*

California Utilities had attempted to charge QFs for transmission system upgrades which allegedly would not be built except to allow QF additions to the system. Following an investigation, the PUC found that utilities could require QFs to pay only for transmission facilities which do not benefit the system and are only beneficial to QFs.<sup>83</sup>

Informal guidelines were suggested to divide cost responsibility between utilities and QFs when there were no demonstrable system benefits, and a cost cap of \$150/kw was used as basis for allocating costs to the QF. All parties recognized that QFs would rarely pay for transmission system costs in addition to other interconnection charges.

*d. Out of state deliveries*

Another issue addressed by the PUC was whether QFs delivering power to California from outside utility service areas were entitled to standard offers and the same avoided costs as QFs within service areas. One party claimed that it was entitled to deliver power to California under interim long run standard offer provisions over the Pacific Intertie. Since the Intertie delivers large amounts of economy energy to California from the Pacific Northwest, Staff, utilities, and several other parties expressed concern about potential adverse economic affects on California ratepayers which would violate PURPA's mandate to keep ratepayers indifferent. In response, the PUC instituted an investigation.<sup>84</sup> Hearings should commence some time in early 1986, and preliminary filings show that the utilities and staff support differential avoided cost and negotiated contracts for QFs that potentially displace economy energy.

*e. QF milestone procedure*

In January, 1985, the PUC adopted an Interconnection Priority Procedure for use in areas with transmission constraints.<sup>85</sup> The elements of this procedure are as follows: 1) \$5/kw fee which was refundable at the time the QF went on line or applied to the special facilities (interconnection) charges; 2) obtaining a critical path permit (defined by technology); and 3) filing a comprehensive project questionnaire before signing a standard offer.

This procedure was revised later in 1985 based on actual working practice, but its elements have remained essentially the same. It was renamed the QF Milestone Procedure in August, 1985,<sup>86</sup> and the intent is to use this as a QF tracking device to determine how many QFs with signed interim Standard

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82. A.82-04-44, *et seq.*

83. CPUC D.85-09-058 (Sept. 18, 1985).

84. CPUC D.85-11-008 (Nov. 11, 1985).

85. CPUC D.85-01-038 (Jan. 16, 1985).

86. CPUC D.85-08-045 (Aug. 21, 1985).

Offers No. 4 actually come on line.

### B. Connecticut

In December, 1985, the Connecticut Department of Public Utility Control (DPUC) issued a decision in its generic investigation into cogeneration and small power production in Docket No. 85-04-16. The investigation had been initiated by the DPUC on April 30, 1985. In addition, the Connecticut General Assembly enacted Public Act 85-534,<sup>87</sup> which, *inter alia*, directed the DPUC to conduct a study of cogeneration and small power production, and of the appropriateness of permitting the state's electric and gas utilities to own QF's. Prior to 1985, the Connecticut statute prohibited electric and gas utilities from having ownership interests in QF's. However, with the enactment of Public Act 85-534, the Connecticut General Assembly authorized electric and gas utilities to own QFs of 300 kilowatts or less on an interim basis, subject to certain conditions.<sup>88</sup> The General Assembly further directed the DPUC to investigate and report on electric and gas utility ownership of QFs.<sup>89</sup>

#### 1. *Generic Investigation and Decision, 85-04-16*

In its decision in *Generic Investigation and Decision*, Docket No. 85-04-16, the DPUC noted that despite Connecticut's strong statutory endorsement of cogeneration and small power production, the state lagged far behind the other New England states in QF-generated power. The DPUC stated that it was aware of only one currently operational QF in the state with a DPUC-approved long-term contract and of a few resource recovery facilities with DPUC-approved contracts that would become operational in the next few years. Therefore, the DPUC took steps to encourage in-state QF development.

The DPUC devised standard long-term contracts for the state's two investor-owned utilities — Connecticut Light and Power Company and United Illuminating Company. Under these contracts, QFs have the option of 10-, 20-, or 30-year contract terms and the option of current, projected, or levelized energy payments and projected or levelized capacity payments.

In developing payment options for electricity contracts between utilities and QFs, the DPUC restricted the options available to fossil fuel fired QFs. As a precondition to the sale of long-term capacity to a utility, natural gas or oil-fired QFs that expect to provide firm capacity and receive capacity payments must have dual fuel capability. Long-term power contracts for QFs located outside Connecticut will be subject to the same conditions applicable to fossil-fueled QFs, and higher levels of security may be required for out-of-state QFs that desire levelized capacity payments.

Under the standard contracts, QFs must post security as a condition of receiving front loaded payments from a utility. Resource recovery projects and renewable resource fueled QFs normally will be required to post security in the amount of ten percent of the avoided cost payments to be received by the QF.

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87. 1985 Conn. Legis. Serv. 235 (West).

88. *Id.* at 236.

89. *Id.*

All other QFs will be required to post twenty percent of the avoided cost payments. These security guidelines may vary based on project risk, project backing, alternative security arrangements such as liens or performance guarantees, and other factors. Also, QFs are required to maintain a prudent amount of comprehensive liability insurance.

For determining avoided capacity costs, the DPUC adopted a proxy plant method using the cost of plant that would have been built but for the QF contract. Prior to the in-service date of the proxy plant, a differential revenue requirements methodology will be used to calculate avoided fuel, operations, and maintenance costs. Avoided energy costs were set at the cost of the most expensive, least efficient, last dispatched generating units on a utility's system, rather than at average on-peak and off-peak costs. Avoided transmission and distribution investment and line losses are also a component of the avoided cost calculation.

The DPUC also established criteria for setting the rates at which utilities will supply back-up power, supplementary power, and maintenance power to QF's.

In response to the General Assembly's directive in Public Act 85-534 that the DPUC investigate electric and gas utility ownership of QFs, the DPUC recommended: (1) that the General Assembly remove the prohibition on electric utility ownership of QF's to the extent permitted by PURPA, i.e., by fifty percent; (2) that the General Assembly remove the absolute bar on gas utility ownership of QFs to permit fifty percent ownership, provided that gas utility-owned QFs have dual fuel capability and that such QFs purchase gas under a DPUC-approved tariff or carriage rate; and (3) that combined gas and electric utilities be permitted to own QFs only under conditions more restrictive than those applicable to other types of utilities.

### C. Florida

#### 1. Florida Public Service Commission Developments

##### a. *"Self-service wheeling"*

In the Florida Public Service Commission's (FPSC's) proceeding on "self-service wheeling" (i.e., transmission service from a QF to other facilities owned by the QF's owner), Docket No. 840399-EU, an "Order Proposing Rules" (Order No. 14143) was issued on March 5, 1985. Proposed Rule 25-17.882 stated that self-service wheeling is permissible only when the owner and/or operator of the QF or the transmitting utility "demonstrates that the provision of this service will not result in any adverse economic impact on the utility's general body of ratepayers." All "retail sales" of energy or capacity by a QF to an entity which is not a public utility would be prohibited by proposed Rule 25-17.883.

Proposed Rule, 25-17.88, generically addressed wheeling of as-available energy or firm energy and capacity from a QF to a public utility. Statutorily defined "public utilities" would be ordered to provide such wheeling in both interstate commerce (with the charges, terms and conditions therefor to be established by the FERC) and intrastate commerce (with regulatory scrutiny of

the FPSC). Municipal systems and rural electric cooperatives (RECs) would similarly be required to wheel upon charges, terms, and conditions specified by the FPSC. Any utility could refuse to provide transmission service "if the provision of such service would adversely affect the adequacy, reliability, or cost of providing electric service to the utility's retail ratepayers."

Following the submittal of testimony by interested parties and hearings thereon, the FPSC Staff's recommendations were released on June 28, 1985. The staff advocated that (i) each investor-owned municipal and REC utility be required to provide transmission service from QFs to other electric utilities, (ii) the FERC should determine, in the first instance, whether a particular wheeling transaction would occur in interstate or intrastate commerce,<sup>90</sup> (iii) the owner and/or operator of the QF would, in every instance, be responsible for the costs of transmission service, (iv) utilities should deny, curtail, or discontinue transmission service if its provision would adversely affect the utility's general body of retail or wholesale customers, (v) Rule 25-17.882 (on "self-service wheeling") be amended by removing the language on "adverse economic impact" and replacing it with a required showing of likelihood of lower cost electric service to the utility's retail and wholesale customers without adversely affecting adequacy or reliability of service to all customers, (vi) the FPSC not adopt Rule 25-17.883, but rather seek legislation to permit retail sales by unregulated entities pursuant to terms and conditions established by the FPSC,<sup>91</sup> (vii) an appropriate rate for (intrastate) "self-service wheeling" should be determined in a separate proceeding, and (viii) the establishment of a separate generic docket to develop appropriate standby and backup rates for each utility.<sup>92</sup>

On July 12, 1985, utilities and other intervenors filed responses to the FPSC Staff's recommendations. The FPSC adopted the Staff's recommendations with minor modifications in Order No. 15053 issued on September 27, 1985, and ordered all electric utilities to file tariffs by January 2, 1986, specifying (at a minimum) the availability of, and charges, terms, and other conditions for, both interstate and intrastate transmission service of QF output. As of early January, approximately one-half of the affected utilities had tendered tariff filings. On January 21, 1986, at the behest of its Staff,<sup>93</sup> the FPSC extended the tariff filing date to February 14, 1986, ostensibly to aid utilities (principally municipalities and RECs) having difficulty developing their tariffs.

### *b. Implementation of cogeneration rules*

In Order No. 14339 issued on May 2, 1985, in Docket No. 830377-EU, the FPSC established an "interim nonfirm wheeling rate" of one mill per kWh

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90. This would comport with the FERC's finding in Dockets Nos. EL84-27-000 et al., reported at 29 FERC 61, 140 (1984).

91. Such terms and conditions would include a commitment by the unregulated supplier to serve a designated load for a specified period, and the suspension of the regulated utility's obligation to serve such designated load for the same time period.

92. In this regard, Docket No. 850673-EU was opened by the FPSC in December 1985.

93. The Staff issued a memorandum on December 26, 1985, describing its expectations of the tariffs' contents and form.

to apply only to transmission service which (a) occurs in intrastate commerce and (b) involves wheeling QF power from one utility to another ("self-service wheeling" was excluded). All Florida electric utilities were required to file appropriate amendments to their cogeneration tariffs by June 2, 1985.<sup>94</sup>

### *c. Annual Planning Hearing*

In January 1985, the FPSC opened Docket No. 850004-EU to receive, on an annual basis, information concerning the anticipated future need for additional electric generating capacity in Florida. The FPSC was hopeful of adopting a twenty-year optimal statewide generation expansion plan which could be used in a variety of ways, including setting prices for QF-generated energy and capacity.<sup>95</sup>

In July 1985, each individual electric utility in Florida was ordered to submit a twenty-year optimal generation expansion plan for the state as a whole and for peninsular Florida; however, the FPSC's Order (No. 14524) permitted a joint response by the electric utility industry. The Florida Electric Coordinating Group (FCG) developed a statewide plan on behalf of the individual utilities and, on October 14, 1985, submitted it to the FPSC. On November 7, 1985, the FPSC Staff, some utilities, and certain intervenors filed direct testimony. The FPSC Staff witnesses criticized the FCG study as inadequate for planning purposes, and proposed financial penalties for the investor-owned utilities (IOUs) due to the failure of the IOUs to engage in meaningful joint statewide planning.

The FPSC postponed hearings on the statewide plan to an as-of-yet-unspecified date, and through its Staff, sought and obtained a Stipulation from the IOUs containing "a commitment to do better . . . ." The Stipulation included a January 31, 1986, deadline for the IOUs' submittal of a plan for developing twenty-year optimal statewide generation expansion planning studies for the FPSC's comment and/or approval, and indicated that the current "standard offer" prices for QF energy and capacity would continue to be effective until further order of the FPSC.

### *d. Financing of government-owned QFs*

On July 22, 1985 (following hearings in January and April), the FPSC issued Order No. 14596 in Docket No. 840351-EU, whereby it adopted Rule 25-17.89 relating to advance funding of government-owned solid waste facilities. Under subsection (3)(a) of this statute, a local government may petition the FPSC

to require an electric utility to enter into a contract with the local government to provide advanced funding to such government for the construction of the electrical component<sup>96</sup> of a solid waste facility.

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94. In the opinion of some, the one mill per kWh rate was ultimately superseded by the FPSC's later dictates in Order No. 15053, discussed above.

95. The FPSC had previously established, in the Spring of 1984, QF pricing mechanisms based upon a hypothetical "statewide avoided generating unit" with an anticipated in-service date of April 1, 1992.

96. "Electrical component" is statutorily defined as "the turbine, generator, and associated transmis-



A utility may not, however, be required by the FPSC to pay the local government any advance funding which is not collected from the utility's ratepayers.

FPSC Rule 25-17.89(2) specifies that any such advance capacity payments shall be in lieu of firm capacity payments otherwise authorized pursuant to FPSC Rule 25-17.83 (which prescribes terms and conditions for firm energy and capacity payments), and must be secured by a surety bond or equivalent assurance which guarantees repayment to the utility if the local government is unable to meet the terms of the contract.

#### D. Georgia

##### 1. Judicial Developments

Still pending before a United States District Court is the first antitrust suit filed on behalf of a cogeneration facility against an electric utility, *Greensboro Lumber Co. v. Georgia Power & Light*, Docket No. C84-2022A, (filed October 5, 1984 in the Northern District of Georgia). Georgia's largest rural electric cooperative, Oglethorpe Power Company, is charged with preventing Greensboro from gaining a fair price for its cogenerated power through various organizational structures, joint ownership of generation facilities, and operation of related transmission facilities.

Oglethorpe, which is a generation and transmission cooperative with thirty-nine system members, is charged with paying too little for cogenerated power, thereby discouraging industries from taking advantage of cogeneration opportunities provided under federal law. The lawsuit also complains that the state investor-owned utilities, as well as Oglethorpe and the Municipal Electric Authority of Georgia, have conspired to prevent Greensboro from access to transmission lines and related equipment to wheel electricity to another plant facility.

##### 2. Administrative Developments

On August 6, 1985, the Attorney General for the State of Georgia issued an official opinion letter on the legality of retail electric sales by cogeneration facilities within the state. According to the letter, written in response to a Public Service Commission request, cogeneration facilities may not make retail sales of electricity in Georgia, except to electric suppliers, without becoming subject to the Commission's jurisdiction.

The Attorney General relied on the Georgia Cogeneration Act of 1979<sup>97</sup> which states that cogeneration facilities may operate without being subject to the Commission's jurisdiction or regulation, provided that the cogenerator itself uses all the useful energy produced or sells the excess to no party other than an electric supplier.<sup>98</sup> The Attorney General also relied on the Georgia Territorial

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sion facilities of a solid waste facility." FLA. STAT. § 377.709 (2)(d) (1985).

97. GA. CODE ANN. §§ 46-3-50 to -53 (1982).

98. In order to operate as a cogeneration facility without being subject to the Commission's regulation or jurisdiction, it is also required that the facility's power production capacity must be 30 megawatts or less. GA. CODE ANN. § 46-3-53 (1982).

Electric Service Act<sup>99</sup> which established, with certain exceptions, geographical areas in the state in which electric suppliers have the exclusive right to provide retail service.<sup>100</sup>

### *E. Hawaii*

On March 18, 1985, the Hawaii Public Utilities Commission (HPUC) adopted a new methodology for avoided costs for QFs under 100 kw.<sup>101</sup> It changed avoided cost calculations from a comparison of production simulation models with and without QFs to a proxy unit methodology for off and on peak, resulting in higher payments for QFs.

On May 2, 1985, the HPUC revised its rules for QFs greater than 100 kw.<sup>102</sup> It applied the same methodology and established a floor price for the term of the contract which equals the avoided cost when the contract become effective. No standard offer was established. Each contract's payment structure is reviewed for inclusion in the purchasing utility's fuel costs.

### *F. Indiana*

In October, 1984, the Public Service Commission of Indiana (PSCI) approved new rules implementing PURPA and the Indiana cogeneration statute (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 three cents per kWh to eight 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.) The Indiana Court of Appeals heard oral argument on December 18, 1985, on a request for an injunction to halt enforcement of the rules. No decision had been issued as of January 31, 1986.

The rates and tariffs filed by several nongenerating utilities to implement the new rules have been approved. On June 5, 1985, the five large investor-owned Indiana electric utilities filed rates and tariffs to implement the new

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99. GA. CODE ANN. §§ 46-3-1 to -53 (1982).

100. *Id.* §§ 46-3-2 to -10.

101. Hawaii PUC Docket 4569.

102. Hawaii Admin. Rules Chapter 6-74.

rules. These rates and tariffs have been questioned by the Commission as patently not complying with the Commission's rules.

### G. *Kansas*

In *Kansas City Power & Light Co. v. The Corp. Commission*, No. 84-C-67, the District Court of Linn County, Kansas issued a Memorandum Decision on May 31, 1985, affirming the October 5, 1984, Order of the Kansas Corporation Commission (KCC) adopting regulations implementing PURPA. Kansas City Power & Light Company (KCP&L) brought the above-referenced action contending that PURPA, FERC regulations implementing PURPA, KAN. STAT. ANN. 66-110-111, 1,184 and 1,185 and the October 5, 1984, Order of the KCC are unconstitutional because they take KCP&L's property without just compensation, deprive KCP&L of the freedom of contract, and deprive KCP&L of liberty and of property without due process of law. The District Court disagreed and stated that due to the national interest in conserving energy and the fact that public utilities are subject to regulation under the police power of the federal and state governments, the statutes, acts, regulations, and orders involved in this case are reasonably related to federal and state energy objectives and are not unconstitutional. The Kansas Supreme Court granted the parties' petition requesting that the it agree to hear this case, thus bypassing the Kansas Court of Appeals. The Kansas Supreme Court was subject to hear oral argument of this case January 14, 1986. Should the Court find PURPA and/or the FERC regulations implementing PURPA unconstitutional, the KCC has indicated that it will appeal such decision to the U.S. Supreme Court.

### H. *Massachusetts*

#### 1. Regulatory Developments

On September 12, 1985, the Massachusetts Department of Public Utilities (DPU) issued an Interim Order in Docket No. 84-276, the ongoing review of the Commonwealth's regulations under PURPA. The Interim Order followed three days of hearings in April 1985, initiated by the Petition of the Massachusetts Executive Office of Energy Resources (EOER). EOER argued that state PURPA regulations promulgated in 1981 to not provide sufficient encouragement to QF's.

While declining presently to adopt the specific rate options proposed by EOER, the DPU in its Interim Order endorsed two of the most significant policy positions advocated by the EOER. First, the DPU found that standard offer, long-term fixed price contracts are necessary to encourage QF development. The DPU stated that the absence of such contracts created a non-price barrier to cost-effective generation and threatened the maximization of the Department's goal of achieving optimization of the electric supply industry. Since 1981, the avoided cost rates available from the DPU have been short-run only, changing every three months.

Second, the DPU found that long-term fixed price contracts must reflect, as accurately as possible, what it called "the market clearing price" for the power purchased. Although it did not prescribe a price-setting methodology, the

DPU stated that capacity value was a necessary component of the long-term market clearing price.

Additional hearings were held in October 1985, on how best to implement the policies set out by the Department in its Interim Order. Remaining issues include whether to use an auction approach for setting long-term values for energy and capacity, who should bear the risk of long-term fossil fuel price uncertainty faced by potential oil and gas fired cogenerators, and what forms of financing guarantees, if any, are needed to secure the front-loaded portion of levelized payment contracts. A Proposed Rule was due out at the end of January 1986, with a Final Rule expected in the spring.

## 2. Legislative Developments

On October 8, 1985, Governor Michael S. Dukakis signed into law "An Act Providing Financing Incentives for Cogeneration, Small Power Production Facilities and Industrial Energy Conservation" (Ch. 370 of the Acts of 1985). The new law adds cogeneration and small power production projects proposed for commercial and industrial sites to the pool of applicants eligible to apply to the Massachusetts Industrial Finance Agency for tax exempt bond financing. In addition, the law empowers municipalities to accept and use for the first time state and federal grants and loans for cogeneration and small power production facilities.

### *I. Michigan*

On December 30, 1985, Monroco Partners filed a complaint with the Michigan Public Service Commission (MPSC) against Detroit Edison (Case No. U-8387) requesting that the MPSC find the avoided cost contract proposed by Monroco (and agreed to by MPSC Staff) to be reasonable and direct Detroit Edison to sign the contract. The MPSC immediately issued an order requiring Detroit Edison to either sign the contract or specify why it should not sign the contract, and commented on Detroit Edison's apparent refusal to negotiate in good faith. The order also shifted the burden to Detroit Edison to go forward with the presentation of evidence in the matter.

Mediation efforts by MPSC Staff (Staff) in 1985 in connection with the avoided cost power purchase contract which is the subject of Case No. U-8387 caused Staff to examine (1) the details of how the energy and capacity rates should be computed for larger QF's; and (2) power purchase contract terms that are acceptable for cogeneration facilities financed on a project finance or nonrecourse basis. Due to active Staff involvement in Case No. U-8387, the rate computation methodologies and contract terms therein may serve as a model for other Michigan projects.

Under the Case No. U-8387 methodology, capacity payments for Detroit Edison are equivalent to a current average levelized rate of approximately 3.81 cents/kWh, with the actual rate being slightly lower than this until the date Detroit Edison needs additional capacity (1991) and higher thereafter. Under the same methodology, energy payments are based on the average running cost of all base load fossil plants in the Michigan Pool and would currently be approximately 2.7 cents/kWh and are expected to escalate at approximately

five percent per year.

In 1984, Consumers Power Company (Consumers) stopped construction on its Midland Nuclear facility after investing over \$4 billion in the facility. As a result, the financeability of cogeneration projects in Consumers' service territory was impaired because cogeneration lenders questioned Consumers' ability to make avoided cost payments. However, in July 1985, the MPSC authorized an increase in Consumers' rates of approximately \$99 million, an amount determined by the MPSC as necessary to assure the financial health of Consumers. Although appeals of the rate increase are pending, opponents of the rate increase were denied preliminary injunctive relief. Thus, it appears that Consumers has achieved the financial stability necessary to assure lenders that it can meet its contractual obligations to cogenerators.

Regulated utilities in Michigan offer standby service at rates from thirty-eight to sixty cents, based on the highest peak kilowatt demand per day plus incremental energy charges (e.g., 3.2 cents per kWh). The charges are computed daily with no ratchet. Some utilities also offer standby service on a monthly basis, typically at rates of approximately \$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. However, some utilities have refused to make standby service available to third-party financed facilities due to the *Alcon* decision.

#### *J. New Hampshire*

1. On September 5, 1985, the New Hampshire Public Utilities Commission (NHPUC) issued an order<sup>103</sup> updating short- and long-term avoided cost rates for power purchases from qualifying cogeneration and small power producers (SPPs) by the Public Service Company of New Hampshire (PSNH). The order was the first annual update of such rates required by the NHPUC's July 6, 1984 order,<sup>104</sup> which also established the methodology used in calculating the rates. The order was prompted by a petition by PSNH which submitted new data and requested that the NHPUC update short-term capacity component rates, long-term avoided energy costs and corresponding levelized rates, and long-term avoided capacity costs and corresponding levelized rates.

The major issue upon which the NHPUC focused in the order was the discount rate to be employed in calculating the avoided cost rates. PSNH proposed using higher discount rates in the calculation of short- and long-term avoided cost rates, relying on the NHPUC's recent determination of the PSNH long-term weighted cost of capital. The NHPUC refused to increase the discount rates, concluding that to do so would represent a change in the methodology of calculating avoided cost rates. The NHPUC made it clear that a change in rate calculation methodology will not be considered in an update proceeding, but must be reviewed in an independent proceeding at the request of a party or

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103. Re Small Power Producers and Cogenerators, DE 85-215, Order No. 17,838, 69 PUB. UTIL. REP. 4th (PUR) 365 (1985).

104. Re Small Power Producers and Cogenerators, DE 83-62, Eight Supplemental Order No. 17,104, 61 PUB. UTIL. REP. 4th (PUR) 132 (1984).

upon the NHPUC's own initiative.

After rejecting use of a higher discount rate, the NHPUC approved updating the short-term avoid capacity cost rates and long-term avoided energy costs and resulting levelized rates.<sup>106</sup> The updated rates apply to all contracts entered into on or after June 21, 1985.

2. In an order issued December 6, 1985,<sup>108</sup> the NHPUC upheld its authority to grant a zoning exemption to an SPP on the basis that the SPP is a "public utility" for which such grants are specifically authorized.<sup>107</sup> The NHPUC found that the Limited Electrical Energy Producers Act (LEEPA),<sup>108</sup> which applies to SPPs, does not exempt SPPs from public utility status. The NHPUC based its finding on a 1983 amendment to the LEEPA which eliminated a specific provision exempting SPPs from regulation as public utilities, and replaced it with language that exempts SPPs only from "rules and statutes related to electric utility rates or relative to the financial or organizational regulation of electric utilities."<sup>109</sup> Without such an exemption, "all producers of electric energy are public utilities" within the broad statutory definition, the order concludes, including the SPP applicant for the exemption and other SPPs.

## *O. New Jersey*

### 1. Regulatory Developments

The New Jersey Department of Energy issued its final Energy Master Plan in December of 1985. The Energy Master Plan calls for capacity payments based on a hypothetical 600 megawatt coal plant and energy payments based on oil or gas-fired generation until 1992, the on-line date of hypothetical coal plant. At that time, energy payments would be based on coal generation. The recommendations of the Department of Energy in the Energy Master Plan are binding on the Board of Public Utilities, which actually determines the avoided cost rates.

The Energy Master Plan also addressed backup power, wheeling, permitting, and a grievance procedure for charges of bad faith bargaining.

### 2. Legislative Developments

Legislation was enacted or under consideration in New Jersey to provide additional incentives for cogeneration development. Tax exemptions from state sales and use taxes were enacted in August 1985 for cogeneration equipment and structural facilities. (S-2529, P.L. 1985, C.266). Another bill was enacted in November 1985 which would exempt the sale of natural gas to cogeneration facilities from state Gross Receipts and Franchise Taxes (approximately 13.5%) within New Jersey (S-2531, P.L. 1985, C. 359).

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105. The NHPUC determined that, absent a change in the applicable discount rate, the long-term avoided capacity cost and corresponding levelized rate would remain the same.

106. *Re Bridgeport Steam Power Co.*, DE 85-26, — PUB. UTIL. REP. 4th (PUR) (1985).

107. N.H. REV. STAT. ANN. § 674:30 (1983 Supp.).

108. *Id.* § 362-A.

109. *Id.* 85-26 at 4; N.H. REV. STAT. ANN. 362-A:2 (1983 Supp.).

Other legislation pending in the Assembly Revenue, Finance and Appropriations Committee would provide supplemental budgetary appropriations of \$500,000 to fund industrial cogeneration and coal conversion studies for matching grants which would not exceed fifty percent of the total study price or \$10,000 (A-2717). Finally, legislation was also under review to exempt all cogeneration facilities from property taxes for a five-year period within the state (A-2773).

#### *K. New Mexico*

##### *1. Administrative Developments*

###### *a. Proposed rule on avoided cost calculation*

In late December 1985, the New Mexico Energy and Minerals Department filed with the State Public Service Commission a proposed rule implementing the FERC regulations<sup>110</sup> promulgated pursuant to Section 201 and 210 of PURPA.<sup>111</sup> The proposed rule, which would be the Second Revision to the Commission's First Revised General Order No. 37,<sup>112</sup> provides standard methodologies for calculating long- and short-run avoided cost rates for purchases of energy and capacity by utilities from qualifying facilities. In addition, the proposed rule directs all utilities to make available to qualifying facilities a uniform standard contract for the utilities' purchase of electricity.

Under the proposed rule, short-run avoided energy costs are to be based on current marginal energy costs for the most recent three-month period, or, for future years, upon the transactions methodology established in the particular proceeding. Utilities' current shortage costs are to form the basis of the short-run avoided capacity cost calculation.

Long-run avoided costs are to be calculated using a proxy unit method. Because planned additions to a utility's existing resource base entail costs which are considered avoidable, the long-run avoided cost proxy is set to equal the total cost associated with a utility's next planned resource addition. For avoidable baseload additions, long-run avoided energy costs are to include both variable operating costs and capitalized energy costs.<sup>113</sup> For avoidable peaking (or demand-driven) additions, long-run avoided energy costs are to be based on short-run marginal energy costs. Long-run avoided capacity costs for both baseload and peaking additions are to be based on the total fixed costs of a combustion turbine.

In addition to addressing the calculation of avoided cost-based rates for purchases from qualifying facilities, the proposed rule also covers rates for sales to qualifying facilities; electric utility reporting requirements; system emergen-

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110. 18 C.F.R. pt. 292 (19\_\_\_).

111. 16 U.S.C. §§ 824, 824(i) (1982).

112. The New Mexico Public Service Commission's First Revised General Order No. 37 became effective December 10, 1982, and is currently in force.

113. Under the proposed rule, variable operating costs are to be based on average operating costs at existing baseload plans escalated at the expected inflation rate plus one percent. Capitalized energy costs are to be based on the total fixed costs associated with the avoidable proxy unit net of reliability-related capital expenditures.

cies; safety requirements and interconnection costs; and wheeling of power.

A significant objective of the proposed Second Revised General Order No. 37 is the adoption of an avoided cost methodology which will allow qualifying facilities to verify utilities' avoided cost rates. Under the proposed rule, qualifying facilities would have the option of signing the standard contract or negotiating a contract with the utility using the standard contract as guidance.

#### *L. New York*

##### *1. Judicial Developments*

*Consolidated Edison Co. v. Public Service Commission.*<sup>114</sup>

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

Case 28793, *Niagra Mohawk Power Corporation - Long-Run Avoided Costs*. On August 26, 1985, the PSC issued an order granting in part Niagara Mohawk's petition to recalculate its long-run avoided cost rates to on-site generators. The order authorized recalculation of long-run avoided cost estimates which had been arrived at by use of a settlement process instituted by the Commission on April 12, 1984 and approved by the PSC on October 12, 1984. The PSC suspended Niagara Mohawk's obligation to make payments under the long-term settlement rates pending recalculation of the long-run settlement numbers with one exception. The PSC required Niagara Mohawk to make its existing long-term settlement rates for fifteen years available to hydroelectric facilities of up to 20 megawatts for sales commencing in 1985 and 1986. On November 12, 1985, the PSC extended the availability of the existing long-run avoided cost estimates to hydroelectric facilities commencing sales not later than December 31, 1987. The PSC also clarified that the settlement estimates to be received will start with the year in which the facility commences commercial operation and will end with the year 2000. Finally, the August 26 Order provided that Niagara Mohawk's future long-run avoided costs would be calculated together with those of other major electric utilities in Case 28962.

Case 28962, *Electric Utilities—Long-Run Avoided Costs*. By Order issued November 28, 1984, the PSC instituted a proceeding to determine long-run avoided costs for the remaining six major electric utilities within the state similar to the proceeding instituted for Niagara Mohawk in Case 28793. In a ruling issued April 2, 1985, Presiding Judges Boschwitz and Moynihan recommended that the PSC adopt Staff's estimates of avoided cost if the parties failed to reach a settlement by June 28, 1985. Subsequently, with the parties having failed to reach such settlement, the Staff filed its report setting forth Staff's estimates of each utility's long-run avoided costs (Case 28962 "Long-Run Avoided Costs - Methodology and Estimates" filed August 26, 1985 and revised September 10, 1985). Staff's report also includes calculations of long-run avoided costs for Niagara Mohawk consistent with the PSC's August 26, 1985 order.

Case 28689, *Shawmut Engineering Company*. The PSC issued an order at

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114. See *supra* note 3.



its session of April 3, 1985, directing Niagara Mohawk to enter into a long-term contract with Shawmut Engineering Company for purchase of the electrical output of Shawmut's Erie, Pennsylvania, 13 megawatt solid waste recovery and small power production facility at the rates previously approved by the Commission in Case 28793. The PSC required that the out-of-state on-site generator obtain a statement from all necessary utilities of willingness to wheel its energy to Niagara Mohawk.

Case 29006, *Bethlehem Steel Corp.* In a declaratory ruling issued on June 7, 1985, the New York PSC held that Bethlehem's renovation of its thirty year old coke oven gas cogeneration facility did not amount to "substantial redevelopment."<sup>115</sup> Accordingly, the facility was ineligible for the statewide minimum purchase rate of six cents per kWh since it does not provide new capacity under state law. The PSC found, however, that Bethlehem demonstrated a need for purchase rates based on full avoided costs "to remain viable or to increase its output" and held that Bethlehem was entitled to full-avoided cost-based rates when frequency changer capability is available, for such electricity delivered to Niagara Mohawk Power Corporation, adjusted downward for losses incurred in converting such electricity from 25 Hz to 60 Hz, so long as its facility burns coke over gas as its exclusive<sup>116</sup> energy source. Finally, the New York Commission held that Bethlehem was entitled to a long-term contract with terms and conditions (including the full avoided cost-based rates on the 25 Hz system applicable when frequency changer capability is not available) negotiated between it and the utility.

Case 29157, *Montenay International Corp.* In a declaratory ruling issued at its September 5, 1985 session, the New York Commission declared that Montenay, as owner and operator of a proposed cogeneration facility supplying electricity and/or steam to users located at or near the project site is neither an "electric" or "steam" corporation (as defined in Section 2(13) and (22) of the N.Y. Public Service Law) and is not a utility subject to the PSC's jurisdiction.

### 3. Legislative Developments

The New York Assembly has passed legislation (A.3779, S.4057) granting the Public Service Commission authority to order electric utilities to enter into long-term contracts with cogenerators at rates consistent with long-run avoided costs. The Bill is expected to face opposition by the New York Senate, electric utilities and the New York Public Service Commission.

#### *N. North Carolina*

The North Carolina Utility Commission (NCUC) issued an order on January 22, 1985 in its third biennial proceeding to determine the rates for sale

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115. The Commission applied factors regarding "substantial redevelopment" as set forth in Case 28172, *Potsdam Paper Corp.*, declaratory ruling (May 19, 1982).

116. At its July 24, 1985 session, the New York Commission in light of the large variability of coke oven gas (the primary fuel) supply, clarified its declaratory ruling to allow natural gas as a supplementary fuel to comprise up to 25 % of the annual BTU heat input of the facility.

and purchase of electricity between electric utilities and QFs.<sup>117</sup> Chief among the issues addressed in the proceeding was the risk to utility ratepayers of long-term levelized rates.<sup>118</sup> The NCUC noted that although such rates are important to the financing of QFs because they assure a constant income flow, they involve a risk to ratepayers because they "require greater overpayments during the early part of the contract period and they are necessarily more difficult to forecast accurately."<sup>119</sup> In addressing this issue, the NCUC chose to limit the availability of five, ten and fifteen-year levelized rates to hydroelectric facilities and those QFs with generating capacities of five megawatts or less.<sup>120</sup> In the case of small QF's, stated the Commission, a default on a long-term contract posed little risk to utilities. Furthermore, the Commission stated its belief that offering the long-term contract as standard options would encourage their development and offset their lack of skills and resources in negotiating contracts with utilities.<sup>121</sup>

The NCUC also addressed concerns regarding lost capacity resulting from a QF choosing to wheel at the end of the term, leaving a utility without the capacity to serve its customers, on which it had relied. The NCUC responded to this issue by requiring QFs that enter into ten or fifteen-year contracts at levelized rates to accept the condition that the contract be renewable for subsequent terms at the utility's option on substantially the same terms and at a rate either set by arbitration or "mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rate and other factors."<sup>122</sup>

QFs with generating capacities greater than five megawatts and smaller QFs not choosing the levelized contract may contract at the variable rates set by the Commission or at rates and terms negotiated with the utility.<sup>123</sup>

The Commission refused to require the posting of a surety bond by QFs with long-term contracts at levelized rates, on the ground that the risk of de-

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117. *Re: Rates for Sale and Purchase of Electricity Between Electric Utilities and Qualifying Facilities (Biennial Determination)*, 64 PUR 4th 369 (N.C. 1985).

118. Such rates are permitted under 18 C.F.R. § 292.304 (d)(2) (1985), which permits a QF to choose:

to provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall . . . be based on either: (i) the avoided costs calculated at the time of delivery; or (ii) the avoided costs calculated at the time the obligation is incurred.

In the sectional analysis accompanying Section 202.304(d), the FERC stated:

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

45 Fed. Reg. 12214, 12224 (Feb. 25, 1980) (quoted by the NCUC at 64 PUR 4th at 378-79).

119. *Id.* at 381.

120. *Id.* at 377.

121. *Id.* at 380.

122. *Id.* at 381.

123. *Id.*

fault posed by the smaller QFs did not warrant such a guaranty.<sup>124</sup> Finally, the Commission refused to set wheeling rates for North Carolina utilities, deferring to the FERC's declaration of exclusive jurisdiction over utilities connected to interstate transmission facilities.<sup>125</sup>

### *O. Oklahoma*

#### 1. THE REQUIREMENT FOR INCLUSION OF "GOVERNMENT REVISION" CLAUSE IN POWER PURCHASE CONTRACT

On October 26, 1984 the Corporation Commission of the State of Oklahoma (OCC) issued general rules and regulations governing the relationship between cogeneration and small power production facilities and electric utilities. On December 18, 1984, Applied Energy Services, Inc. (AES) filed a Motion to Intervene for the limited purpose of addressing Rule 58(H) of the general rules and regulations governing the operations of electric utilities. The AES motion requested the OCC to delete Rule 58(H) from its rules. This provision states:

The utility shall include in each contract with a cogenerator or small power producer the provision, and put the cogenerator and small power producer on actual notice, that the Commission may, after proper notice and hearing, change the terms that otherwise finalize experimental purchase tariffs and special contracts.

AES contended that under this rule a cogenerator or small power producer would lack assurance that the price for its electric sales to an Oklahoma utility would be honored for the life of the contract. It also asserted that Rule 58(H) violated the FERC rules implementing section 210 of PURPA. AES specifically cited 18 C.F.R. Sections 292.303 and 304.<sup>126</sup>

Oklahoma Gas & Electric Company ("OG&E") opposed the AES motion, arguing that Rule 58(H) was a proper exercise of the OCC's jurisdiction to ensure that the general body of ratepayers do not subsidize a QF now or at any time during the life of the contract period. OG&E also argued that Section 292.304(b)(5) of the FERC rules must be read so as to prohibit the payment of purchase rates that exceed avoided cost at any time during the contract term.

The OCC rejected the AES argument, finding that the OG&E position "is the more reasonable."<sup>127</sup> It based its finding on the conclusion that "this Commission retains the authority to ensure that rates set in a contract between a [*sic*] electric utility and a QF do not exceed the avoided cost of the electric utility."<sup>128</sup> AES subsequently filed a Complaint Seeking Enforcement under

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124. *Id.* at 381-83.

125. *Id.* at 378, 391. The decision deferred to by the NCUC was Florida Power & Light Co., 29 FERC ¶ 61,140 (1984).

126. Section 292.303 requires that utilities shall purchase, in accordance with Section 292.304, any energy and capacity made available from a qualifying facility. Section 292.304(d) provides a qualifying facility the option to sell either on an "as available" basis or "pursuant to a legally enforceable obligation." Qualifying facilities are also provided the option to have the rate "calculated at the time of delivery" or, in the case of the sale of energy or capacity pursuant to a legally enforceable obligation over a specified term, at a rate calculated at the time the obligation is incurred. § 292.304(d)(2)(i).

127. Order No. 274115, Cause No. 27759 (Mar. 5, 1985) (Eagleton, Vice Chairman, concurring in part, dissenting in part).

128. *Id.*, *mimeo* at 5.

section 210(h)(2)(A) of PURPA with the FERC, in which it reiterated its contention that the FERC rules preclude the OCC from changing the price for an established purchase power contract after it has given its initial approval of that contract.

AES argued that the clear intent of the federal rules is to prevent the state commission from reentering the contract later to redefine avoided costs or change the already approved contractual price terms, and that the OCC rule conflicts with and is preempted by the federal rules. On June 3, 1985 the FERC issued a notice that it did not intend to initiate an enforcement action in response to the AES complaint.<sup>129</sup> No explanation for its failure to initiate an enforcement action was given. Commissioner Stalon filed a vigorous dissent in which he agreed with AES that Rule 58(H) "is inconsistent with this Commission's Section 210 regulations," and stated that he believed that the FERC should issue a declaratory order to that effect. He did not, however, recommend that enforcement action be initiated against the OCC.<sup>130</sup>

### *B. Application of Smith Cogeneration, Inc. For Approval of Power Sales Agreement*

In response to a request by Smith Cogeneration, Inc. (SCI) the OCC conducted a hearing and issued orders mediating and resolving the terms and conditions of a proposed power sale agreement between SCI and Oklahoma Gas and Electric Company (OG&E).<sup>131</sup> The following issues were addressed in the proceeding:

#### 1. Rule 58(H) Exemption

The OCC granting SCI's request for a waiver of Rule 58(H), on the theory that such waiver was necessary to enable SCI to obtain adequate project financing.

#### 2. Levelized Capacity Payments

Through the use of "levelized" capacity payments, SCI proposed to borrow a portion of the capacity payments in the period 1993 through 1997 and that it be paid these additional monies from 1988 through 1992. To protect the ratepayers SCI offered to provide a performance bond or insurance to guarantee repayment of principal and interest. The OCC accepted SCI's proposal, and distinguished levelized payments from inclusion of CWIP in rate base, since the SCI facility will be used and useful to the ratepayers before the ratepayers begin paying for capacity from the plant.

#### 3. Proposed Discounts of Capacity Payments

The OCC rejected OG&E's proposal to deduct twelve percent from the capacity payments because the SCI project would provide non-dispatchable en-

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129. Docket No. EL85-25-00, *Applied Energy Servs., Inc. v. Oklahoma Corp. Comm'n.*

130. *Id.* (dissenting statement).

131. Cause No. 29727, Order No. 287326 issued October 21, 1985.

ergy. The first six percent OG&E proposed to deduct was based on a Black & Veatch report addressing the limits in which the OG&E system can accept cogenerated power without incurring increased operational costs. The second proposed six percent discount was based on assertions that acceptance of cogenerated power would reduce the useful life of OG&E generating facilities. The OCC rejected both proposed discounts; the first on the basis that the OG&E system can accept the power from the SCI project without incurring increased costs, and the second on the basis that there was no empirical validation of the assertion of decreased useful life of OG&E's generating facilities.

#### 4. Energy Payments

OG&E argued that the appropriate avoided energy payment for a non-dispatchable cogeneration facility is the energy cost of its lowest cost baseload facility. SCI contended that this rate was inconsistent with the PURPA definition of avoided costs and that, in response to the availability of energy from a non-dispatchable facility, OG&E would reduce the output of its *highest* cost, rather than its lowest cost facility.

The OCC concluded that for the on-peak hours during 1988 through 1992, avoided cost payments should be based on the OG&E avoided gas costs. For all other hours these payments should be based on system average fuel costs, excluding the value of gas used in the on-peak calculation. For the period of 1993 through 2002, SCI is to be paid the avoided system average fuel cost for all hours of operation.

On October 30, 1985, OG&E filed a Motion to Reconsider with the OCC, in which it objected to several aspects of the OCC's order. The issues raised by OG&E in its motion to reconsider were resolved through Commission approved settlement between the parties.<sup>132</sup> The parties agreed to an adjustment to the energy payment portion of the rate, for the years 1993 through 2002. For generation up to a sixty-five percent capacity factor, payments are based on coal; payment for additional generation is based on average system fuel cost.

#### P. Pennsylvania

The terms and conditions under which regulated electric utilities are required to make purchases from qualifying facilities continue to be governed by 52 Pa. Code § 57.31 *et seq.*<sup>133</sup> During 1985, the Pennsylvania Public Utility Commission (PUC) reviewed and approved the terms of several agreements between electric utilities and qualifying facilities and granted rate recognition to the purchased power costs arising from those agreements. Only those decisions of special interest are summarized herein.

1. *West Penn/AES*.<sup>134</sup> After reaching an impasse in negotiations, AES Beaver Valley, Inc. (AES) filed a formal complaint with the PPUC request-

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132. Order on Reconsideration, Cause No. 29727, Order No. 288655, issued November 15, 1985.

133. The regulations were first published by the Pennsylvania Public Utility Commission in the Pennsylvania Bulletin, Vol. 12, No. 50, Saturday, December 11, 1982 (Docket L-810060).

134. AES Beaver Valley, Inc. v. West Penn Power Co., Docket No. C-844022, Long-form Opinion (Mar. 13, 1985).

ing that West Penn Power Company (West Penn) be ordered to enter into a power purchase agreement. The consequent settlement negotiations between AES and West Penn resulted in a settlement agreement subject to the condition precedent of a PUC order assuring West Penn of a full and timely pass-through to its ratepayers of all purchased power costs associated with the agreement.

The PPUC adopted an Order Nisi, granting the requested rate recognition, in a public meeting on September 28, 1984. The Order Nisi was entered on October 2, 1984 and published in the Pennsylvania Bulletin on October 27, 1984. In its order, the PUC rejected an intervenor's contention that West Penn's ratepayers should not be required to pay leveled capacity payments in advance of the date when West Penn planned to add additional generating capacity. It should be noted that the payments agreed to by AES and West Penn fall below West Penn's full avoided costs. For that reason, the PPUC found the leveled rates to be to the advantage of West Penn's ratepayers.

The PUC also reaffirmed that the Energy Cost Rate is the appropriate mechanism for recovery of payments made to a qualifying facility since it allows for a proper matching of payments with cost recovery from ratepayers.

2. Other. As part of the PPUC's investigation into the continuation of Philadelphia Electric Company's Limerick-2 nuclear facility, industrial intervenors unsuccessfully attempted to have Philadelphia Electric cancel Limerick-2 and base its avoided costs on the costs of that unit.<sup>135</sup> The Administrative Law Judge found that the proposal was inappropriate because it would use a PURPA-mandated full avoided-cost rate thereby setting aside least-costing pricing goals.

### *Q. Texas*

#### 1. Standard Avoided Cost Filings

The most important development in cogeneration regulation before the Texas Public Utility Commission (TPUC) in 1985 was the consideration of standard avoided cost filings by the major public utilities. The TPUC rules, 16 TAC § 23.66(g), require that each generating utility file a comprehensive calculation of avoided cost of capacity and energy related to an identified avoidable unit by December 31, 1984. A ten year forecast of anticipated purchases of firm capacity from cogenerators and a standard set of terms and conditions for purchase were required elements of the filings.<sup>136</sup> Testimony of the utilities, TPUC Staff and intervenors was filed on varying procedural schedules throughout 1985. By December 1, virtually all of the cases were settled by stipulations incorporating agreed avoided cost calculations, terms and conditions, and projected purchases. The public records of these proceedings provide

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135. See Limerick-2 Nuclear Generating Station Investigation, Docket No. I-840381, Recommended Decision (July 16, 1985).

136. The filings include Texas-New Mexico Power Company, Docket No. 6062; Southwestern Public Service Company, Docket No. 6063; Houston Lighting & Power Company, Docket No. 6064; Texas Utilities Electric Company, Docket No. 6065; Southwestern Electric Power Company, Docket No. 6069; West Texas Utilities Company, Docket No. 6070; Gulf States Utilities Company, Docket No. 6071; and Central Power and Light Company, Docket No. 6105.

a valuable source of information for prospective cogenerators in Texas.

## 2. Wheeling

On September 30, 1985, the TPUC adopted a mandatory wheeling rule, 16 TAC § 23.66(d)(4), requiring utilities to provide transmission system access to all qualifying facilities wishing to transport electricity to other utilities in Texas. The TPUC rule distinguishes between the intrastate utilities whose transmission is subject to TPUC control and those utilities operating in interstate commerce who are regulated by the FERC. Rates, terms and conditions for wheeling by intrastate utilities will be governed by the provisions of the rule.

## 3. Standby and Backup Rates

On October 16, 1985, the TPUC upheld an Examiner's Report in *Central Power and Light Company*, Docket No. 6281, which found the existing tariff for standby and maintenance service for customers with generating capacity to be unreasonable. Central Power and Light Company was ordered to file revised tariffs reflecting specified standards in the opinion. Interruptible standby service will be available at hourly incremental costs plus 10% with a standby service charge of 15% of average allocated cost of system transmission facilities. Backup power in excess of contract maximum for firm power will be billed at the full firm monthly rate. Various terms and conditions have been modified to make standby and maintenance service rates more acceptable to customers with generating capacity.

## 4. Notice of Intent Proceedings

The TPUC must approve a notice of intent for a utility prior to the filing of an application for a certificate of convenience and necessity to construct an electric generating station. In *Southwestern Public Service*, Docket No. 6055, the TPUC turned down a notice of intent for a proposed coal plant on the grounds the utility had failed to demonstrate adequate consideration of purchased power alternatives, including power available from perspective cogenerators and small power producers. A similar challenge is currently pending in *Texas-New Mexico Power Company*, Docket No. 6397. Prospective cogenerators have been using the notice of intent proceedings as a forum for airing complaints about nonreceptiveness of utilities to cogeneration as an alternative to the construction of new generating units.

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Michael J. Zimmer, *Vice-Chairman*

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