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I. Introduction

The energy crises of the 1970's fueled numerous congressional hearings and debates as legislators searched frantically for politically acceptable ways to increase the United States' energy efficiency and to reduce its dependency on imported oil. Among the many solutions offered by various commissioned studies and expert witnesses was one to revive an old technology: cogeneration. Cogeneration involves the simultaneous production of electricity and some other form of useful energy.[1] Whereas central station generation of electricity is only about thirty-three percent efficient, combined generation of electricity with industrial process steam or heat can be sixty to eighty percent efficient.[2] Thus, Congress was informed that, with

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1. More exactly, the term cogeneration refers to the combined production of any two forms of useful energy from the sequential use of energy from a single fuel source. Thus, it can refer to the combined production of mechanical and thermal energy, for example. In general parlance, and throughout the energy legislation discussed here, however, the term more narrowly refers to the combined production of electricity and useful thermal energy. Even within this more narrow definition, there are still a variety of forms of cogeneration. Electricity may be produced from the exhaust heat or steam of an industrial process in a "bottoming cycle" system. Or, reversing the sequence, waste heat from electrical generation may be used for space heating or process needs in a "topping cycle" system. Systems may range in size from small "package" units designed to supply the heating and power needs of a single building to large custom-built units designed to produce millions of pounds of steam per hour for process needs and power production. While the size of the system is not material to the discussion here, ownership is. Since most of the recent legislative effort to encourage cogeneration has focused on the *private* production of electricity and some other form of thermal energy, the term "cogeneration" will be used in this more restricted sense throughout this article unless otherwise specified.

2. The inherent inefficiency of central station generation, limited by the laws of thermodynamics to around 33% efficiency, has been stressed repeatedly in congressional reports. *See* S. REP. NO. 442, 95th Cong., 2d Sess., *reprinted in* 1978 U.S. CODE CONG. & AD. NEWS 21 [hereinafter cited as S. REP. NO. 442]; GAO report, *Industrial Cogeneration—What It Is, How It Works, Its Potential,* April 29, 1980 EMD-80-7, at 1. A variety of figures on the efficiency of cogeneration have been bandied about. *See* T. Casten & H. Ross, *Cogeneration and Its Regulations,* 108 PUBLIC UTILITIES FORTNIGHTLY 18-21 [hereinafter cited as Casten & Ross]; F.

industrial use of cogeneration, fuel efficiencies could be obtained which theoretically could reduce the *total* energy consumption of the United States by fifteen percent by 1985.[3]

Moreover, since the technology for cogeneration was developed in the nineteenth century, cogeneration appeared to be a ready remedy for the nation's energy ills. Lengthy research and development programs were not needed, and cogeneration already was economically competitive if institutional barriers to its development were removed.[4] Spurred by this testimony, Congress enacted a series of provisions to encourage the redevelopment of cogeneration.

This article examines these provisions and evaluates their effectiveness. Since much of the recent legislation merely attempts to remove barriers previously created by legislation and regulation, however, the causes of the earlier demise of cogeneration first are traced. Thus, this article chronicles how the law has interacted with a technology first to curtail the technology's development and then to reverse the process. Finally, the article evaluates the effectiveness of the current legal revitalization effort.

II. The Demise of Cogeneration

At the turn of the century, over fifty percent of the electricity consumed in this country was cogenerated.[5] Electricity was primarily produced by reciprocating engines, which exhausted steam as a waste by-product. Many industries found it cost-effective to install these engines to supply steam for space heating or process needs as well as for electricity. Any surplus electricity was sold to other concerns nearby—usually in the same block, giving rise to the term "block plant." Electric utilities, which had to use engines of similar size and type, found it difficult to compete with these industrial concerns unless they also could recoup some of the cost of the plant from the sale of the waste steam. Thus, Consolidated Edison, which opened the first central station generating plant in 1882 in New York City, purchased the New York Steam Company and entered the district heating business the same year.[6]

Cross, *Cogeneration: Its Potential and Incentives for Development,* 3 HARV. ENV'TAL L. REV. 236 (1979) [hereinafter cited as Cross].

3. Even with more realistic projections of its application, expert testimony at the National Energy Act Hearings still indicated that cogeneration could reduce current *electrical* consumption anywhere from 10 to 75 percent. Cross, *supra* note 2, at 238 (citing *National Energy Act, Part 3, Vol. I: Hearings on HR 6660 and 6831 Before the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce,* H.R. REP. NOS. 6660, 6831, 95th Cong., 1st Sess. 335, 341 (1977)).

4. S. REP. No. 442, *supra* note 2, at 21, 33.

5. Because of the paucity of data, figures on the extent of cogeneration are rough estimates. The above figure is an estimate of the Edison Electric Institute, Wall St. J., Feb. 29, 1981, at 31.

6. R. MEADOR, COGENERATION AND DISTRICT HEATING 34 (1981).

By 1902, 3600 private and public electric generating systems operated in the United States. The typical electric plant had a generating capacity of 200 to 300 kilowatts and served a distribution area of less than one square mile.[7] Only one state regulated electricity sales,[8] and municipalities generally permitted, if not actually encouraged, competition. In 1887, for example, New York City gave franchises to six companies, while Denver permitted anyone to start an electric company as long as public thoroughfares were not obstructed.[9] Industries competed forcefully with utilities in supplying electricity to small neighborhood blocks.

A. The Growth of Economies of Scale

In 1903 a major technological advance occurred, the development of the turbogenerator. These new units could send steam through a turbine to produce mechanical energy that then was converted into electricity by a directly connected generator. This development produced huge economies in electric power generation, but also reduced the quality of the steam emerging as a waste product. Furthermore, the change in technology permitted a shift from direct current to alternating current, which greatly increased the distance utilities economically could transmit and distribute electricity. Thus, district heating became less economical from the utilities' viewpoint, while large scale central generation became more economical.[10]

By 1910, the new technology had become the norm for the industry. To realize the economies available with new plants, utility companies sought rapid increases in their load requirements.[11] Since industries were the only large users of electricity at this time, utilities naturally tried to find ways to induce large industrial users to purchase electricity instead of generating it themselves.

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7. J. Johnson, *Government Ownership of Electric Utilities*, *in* 10 THE REFERENCE SHELF No. 9, at 102 [hereinafter cited as Johnson]. Bauer notes that in 1900 the maximum size of a generating unit was 3500 kw. Such a unit occupied a floor space of 35 by 70 feet, with a height of 75 feet. Thus, massing a number of these units involved high building costs, as well as high equipment costs. J. BAUER, THE ELECTRIC POWER INDUSTRY 19 (1939) [hereinafter cited as BAUER].

8. Massachusetts initiated regulation of electricity sales and service in 1887. W. JONES, REGULATED INDUSTRIES 67 (1967) [hereinafter cited as JONES].

9. Johnson, *supra* note 7, at 54.

10. Industrial cogeneration, however, did not immediatley become uneconomic. Writing in 1918, the Missouri Public Service Commission noted:

> It is well-known among utility operators that the large isolated plant generating electricity and producing steam for heating is the most serious competitor of the central station generating electricity only. As the combined service can be rendered at a smaller investment and operating cost than if the two classes of service are supplied from separate plants, it is very difficult for the central station to supply such consumers with electricity at a price sufficiently attractive to persuade the owner to shut down his electric plant, use the central station's energy, and operate his private plant to supply the heating only.

In re Union Electric Light and Power Co., 1918E Pub. Util. Rep. (PUR) 490, 512.

11. The economies of scale and resultant decrease in marginal costs (expenses for addi-

In 1912, for example, about 500 privately owned generating plants operated in Boston Edison's service area. Some were industrial concerns; others were property owners who furnished power and heat to tenants. To induce these private generators to stop generating electricity, Boston Edison offered to let them buy power at wholesale rates and to resell to any tenants or current customers at retail rates.[12] Thus, the practice of sub-metering was born.

Conversely, Union Electric (U-E) offered attractive long-term, fixed-price contracts for steam and electricity service to about forty self-generators in the St. Louis area. In return, U-E obtained leases to the self-generators' in-house plants. U-E closed down some of these plants entirely, but retained the more profitable ones and even connected adjacent customers to them. During the heating season, U-E provided electricity and heat to these businesses by operating the leased cogenerating plants. In the summer, however, U-E shut down these plants and provided electricity from its central generating station. The utility thus could choose the most economical mix between local and central station power generation.[13]

Virtually all utilities offered preferential rates to industrial customers. These rates often were set well below the utilities' embedded costs;[14] the utilities reasoned that if they encouraged more electricity consumption, they could build more of the new and cheaper plants. In this manner, average costs per kilowatt-hour would fall more rapidly and thereby would lead to more rapid growth of the electric utility industry. As a result of this utility policy, it became economically unattractive for many industrial firms to operate old cogeneration plants when these below-cost rates for utility-supplied power

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tional unit of electricity generated) that utilities wished to exploit can be seen in the following table:

Year	Max. Size Of Unit	Prime Mover Cost ($/kw)	O & M Cost (¢/kwh)	Efficiency (Btu/kwh)
1900	3,500	40	.20=.020	26,000
1910	10,000	20	.008	20,000
1930	90,000	12	.004	10,000

(Monetary figures appear to be expressed in current year dollars). BAUER, *supra* note 7, at 18-23.

12. *In re* Boston Edison Company, 98 Pub. Util. Rep. (NS) 427 (1953); Boston Real Estate Bd. v. Massachusetts Dep't of Public Utilities, 15 Pub. Util. Rep. 3d (PUR) 47 (1956).

13. Additionally, U-E encouraged another 46 businesses in downtown St. Louis to give up cogeneration by providing electricity and space heating from its efficient "modern" district heating plant on Tenth Street. *In re* Union Electric Light & Power Co., 1918E Pub. Util. Rep. (PUR) 490. State *ex rel.* Washington University v. Public Service Comm'n, 1926 A. Pub. Util. Rep. (PUR) 764.

14. Embedded costs are frequently equated with the average costs of utility. They include not only the variable costs of fuel, operation and maintenance, but also the capital costs already incurred for plant, transmission and distribution. These capital costs must be recovered in the rates to produce the return required by investors, but utilities typically have been free in the past to recover these costs from whichever customers they desired. Thus, residential customers in the time period discussed here tended to pay very high rates compared to large industrial customers.

were available.[15]

B. State Regulation

Noting the changes occurring in the electrical industry, state governments began to control electrical corporations through the states' public service laws to avert the "ruinous competition" of a newly perceived natural monopoly.[16] By 1915, fifteen of the twenty most populous states had brought some aspect of private power production under public service commission control.[17]

Although the definitions of "electrical corporation" employed by these states generally were quite similar,[18] the state did not agree as to when a private generator of power became an electrical corporation subject to public utility regulation. Some states placed a gloss on the definition that included a requirement for the electrical business to be deemed "affected with a public interest" before it would

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15. Sometimes these rates were even below the incremental costs (the fuel and variable operation and maintenance costs) of the power supplied. For further discussion of this phenomenon, see BAUER, *supra* note 7, at 84.

16. In economic theory, industries with continually declining marginal cost curves are "natural monopolies." Because of high fixed costs, the larger the firm, the lower its per unit costs. Thus, there is a tendency for the firm that grows most rapidly to put its competitors out of business. Averting the waste of societal resources involved in such destructive or "ruinous" competition has been one of the major factors motivating public regulation of a number of industries. (The railroad industry has probably been the most notable example of regulation based on this premise.)

Massachusetts appears to have had a regulatory policy based on the theory of the natural monopoly of the electrical industry as early as 1912: "The established policy of the Commonwealth (is) said to be that so long as an electric utility in any given territory (is) rendering adequate and proper service, the public interest (is) better served by public supervision and regulation than by competition." *In re* Clinton Appeal, Pub. Util. Rep. Digest (PUR) 2147 (1912).

That the natural monopoly justification for the regulation of the electrical industry has been a continuing motivating force in regulatory policy can be seen in the following 1960 statement of the Oregon Public Service Commission:

> The basic premise of the free enterprise system is that free competition among business acts as a natural regulator of prices and service. Enterprises which furnish electrical utility service, however, are natural monopolies, that is for the most part there is no adequate substitute for the service they furnish and they must invest huge sums in permanent physical plant and extend it to the very locations where it is used. . . . The existence of competition between such enterprises is contrary to the public interest since it results in unnecessary and wasteful duplication of capital facilities, increased operating expenses, and a splitting of revenue, which ultimately results in higher costs and consequently higher rates to consumers.

In re Portland General Electric Co., 32 Pub. Util. Rep. 3d (PUR) 497, 517 (1960).

17. The twenty states in this survey were the most populous states as of 1960. Of the fifteen exercising some sort of regulatory control, all controlled the price of service, eleven controlled the issuance of securities, ten controlled the commencement of service and eight controlled mergers or transfer of assets. JONES, *supra* note note 8, at 67.

18. A typical definition of "electrical corporation" provides as follows:

> [E]very corporation, company, association, partnership and person, their lessees, trustees or receivers appointed by any court whatsoever (other than a railroad or street railroad corporation generating electricity solely for railroad or street railroad purposes or for the use of its tenants and not for sale to others) owning, operating, or managing any electrical plant except where electricity is generated or distributed by the producer solely on or through private property for railroad or street railroad purposes or for its own use or the use of its tenants and not for sale to others.

N.Y. PUB. SERV. LAW § 2(13) (McKinney 1955).

be subject to regulation.[19] Others did not. The Missouri Supreme Court, in determining that a brewing company selling surplus electricity to nearby businesses and residences was not a public utility, noted that in the few cases in which this issue previously had arisen, "the holdings of the courts thereon, while not absolutely unanimous, [were] usually against the contentions of the appellants here . . ., while a very few courts, and the public service commissions rather unanimously, have held to the contrary."[20]

The contradictory decisions noted by the Missouri Supreme Court, however, were an early sign of future regulatory difficulty and uncertainty for cogenerators. Another sign was the conflicting policies of state commissions toward mining and lumber companies. When moving into new territory, these firms frequently erected power plants to meet production needs, and then provided electricity to the camp towns that grew up nearby. Sometimes they also installed water systems. These "company towns" were remote and often would have lacked such services if the company had not provided them. Courts and commissions in some states determined that these company operations were subject to PUC jurisdiction[21] and did not in others.[22] These cases subsequently were used as precedents to determine whether other manufacturers who sold surplus electricity also were subject to commission jurisdiction. States that already had classified mining companies or lumber firms as public utilities for supplying electricity or water to their workers were likely to view industrial cogenerators as utilities as well.

A parallel issue that was adjudicated during the same period concerned utilities that engaged in the steam heating business. By

19. This justification for regulation as we know it today was first set forth in Munn v. Illinois, 94 U.S. 113 (1877). In this case the Supreme Court held that when "one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good, to the extent of the interest he has thus created."

20. State *ex rel.* M.O. Danciger and Co. v. Public Service Comm'n, 275 Mo. 483, 205 S.W. 42 (1918). As well as surveying the holdings of other states and commissions, the court also noted that the brewery owner did not serve all people within the area, did not own any transmission or distribution equipment (people who desired power were required to run a line to the plant's door), had no franchises or licenses, made no assertion of eminent domain, nor ever professed public service. Thus, the court did not feel the definition should be applied literally.

21. *See, e.g., In re* Commonwealth Mining and Milling Co., 1915B Pub. Util. Rep. (PUR) 536 (Ariz); Public Service Comm'n v. Valley Mercantile Co., 1921D Pub. Util. Rep. (PUR) 803 (Mont); Sandpoint Water and Light Co. v. Humbird Lumber, 1919B Pub. Util. Rep. (PUR) 535 (Idaho); Wyoming Valley Water Supply Co. v. Public Service Comm'n, 1932D Pub. Util. Rep. (PUR) 86 (Pa.).

22. Courts have often overturned commission rulings assuming jurisdiction over firms selling surplus energy. *See* Humbird Lumber v. Public Utilities Comm'n, 1925A Pub. Util. Rep. (PUR) 225 (Idaho); Holdred Colleries v. Boone City Coal Corp., Pub. Util. Rep. Digest (PUR) 2674 (1924). In Public Service Comm'n v. Montana Water and Power Co., 1926A Pub. Util. Rep. (PUR) 689, the Montana Supreme Court offers a good review of decisions both upholding and rejecting assignment of public utility status to firms selling electricity as an incidental part of their business.

1917, for example, Union Electric found that it was losing money on the long-term, fixed price leases it had made to entice cogenerators to forego operation of their own plants in favor of U-E produced steam and electricity.[23] Thus, U-E asked the Missouri Public Service Commission to allow an increase in the rates charged for steam and electricity to these long-lease customers. In requesting this, the utility requested that its steam operation come under the jurisdiction of the PSC.[24]

Not surprisingly, the affected customers opposed the PSC assuming jurisdiction and raising the rates.[25] Unlike in the brewery case, however, the Missouri Supreme Court this time supported the PSC in its jurisdictional claim. The court also upheld the upward revision of contract rates, noting that the United States Supreme Court already had held that "contract prices count for naught in the fixing of rates by the Public Service Commission."[26]

A number of states joined Missouri in declaring steam heating operations to be public utilities.[27] Others, however, ruled that exhaust steam or heat furnished under contract was not a public service because it was not furnished to the public generally. The Illinois Commerce Commission upheld the right of a utility to terminate the supplying of heat to four properties, and declared that

> the fact that a company may be a public utility as to electric service [does not] tend in any way to constitute it a public utility as to other commodities, products or service in which it may deal by private contract. Even as to the same service a company may as to one class of customers be a public utility, and as to another a private corporation not subject to regulation.[28]

Interestingly, in the vast majority of these cases, the PSC or state court ruled in a manner that strengthened the utility's economic

23. *See supra* notes 5, 13.

24. *In re* Union Electric Light & Power Co., 1918E Pub. Util. Rep. (PUR) 490. The Public Service Commission willingly granted U-E's request. It held that because U-E's charter permitted it to enter the steam heating business, even a business limited in scope and confined to private contracts was in fact a public service and therefore subject to commission jurisdiction.

25. The customers argued that U-E's district heating operation was a private enterprise since U-E did not own the production equipment in question, but leased it under private contract. Since these contracts had been entered into prior to the passage of the public service commission law, and there was no distribution network requiring franchises, the contracts could not be abrogated. *Id.* at 496.

26. State *ex rel.* Washington University v. Public Service Comm'n, 1926A Pub. Util. Rep. (PUR) 764, 767 (Mo.).

27. In 1960, twenty-four states controlled the sale of steam heating. JONES, *supra* note 8, at 67. The Pennsylvania Supreme Court had held that a utility that had only *one* steam contract came under the jurisdiction of the state PUC and could file a new tariff higher than the old contract price if the PUC approved. Beetem v. Carlisle Light, Heat & Power Co., 1922D Pub. Util. Rep. (PUR) 258 (Pa.).

28. Scheinger v. Central Illinois Public Service Co., 1925B Pub. Util. Rep. (PUR) 334, 339 (Ill.). The Washington Supreme Court similarly ruled that a utility furnishing steam heat to a kiln was not rendering public service. Sunset Shingle Co. v. Northwest Electric & Water Works, 118 Wash. 416, 203 P. 978 (1922).

position. For example, the Missouri commission upheld U-E's request to have its steam operations be considered a public service because the old contract prices then could be raised to improve U-E's overall financial position. In the Illinois case, the utility wished to discontinue uneconomic operations, and it could only do this if it was not bound to serve the public. The Commission obliged by declaring that the steam operations were private.

Courts and commissions, however, became increasingly unsympathetic towards "competition" with the public electricity utility. In 1908, the New York Public Service Commission had ordered public utilities to provide central station service to private plant owners when their equipment broke down. Utility managers disliked providing this service and argued that the policy of permitting private plants to undercut the utility's prices by using this service instead of providing their own backup equipment was unfair. In 1919, New York Edison asserted this argument and refused to provide backup service for a grocery, which operated a private plant that generated electricity for the grocery and for three other buildings on the block. The commission ordered provision of the service, but the appeals court reversed the order, holding that when the grocery supplied customers other than its tenants, it assumed a "public function" and therefore was in competition with New York Edison. The court stated that "one competitor need not serve another."[29]

By 1935 the New York Public Service Commission appeared to hold views similar to the appeals court. In a major proceeding reviewing the rates and regulations for backup service, the Commission asked, "Why should [the utility's] competition be relieved of all responsibility and the central station company compelled to take over the obligations of private plants?"[30] The Commission found that the utilities were within their rights in denying parallel operation to private plant owners[31] and recommended segregated wiring, with the private firm prohibited from switching any unsegregated part of the plant to the central station unless the whole system was switched. Only reluctantly did the Commission permit "multiple throw switching"[32] on a temporary basis. Thus, private generators had to install a second transmission and distribution system if they wished to have utility-provided backup service.

The Commission also found that utilities should "require instal-

29. People *ex rel.* New York Edison v. Public Service Comm'n, 191 A.D. 237, 181 N.Y.S. 259 (1920).

30. *In re* New York Edison Co., 16 Pub. Util. Rep. (NS) 120, 126 (1937).

31. Parallel operation permits the private generator to send electricity to the central station or draw from the station at will.

32. Multiple throw switching permits connection of the private system part-by-part to the utility's system.

lation of equipment to positively prevent contracted for demand being exceeded except to private plant operators who do not sell electrical energy."[33] Consequently, self-generators who sold any surplus electricity had to buy their own reserve capacity. If a self-generator could not meet the peak load of his customers, then, in the Commission's view, "he should segregate a portion of the system and turn it over to the central station for its service."[34] In response to an objection that the proposed regulations did not take account of possible off-peak use of the central station by private owners or the "diversity factor,"[35] the Commission merely commented that such factors were of "little significance" and were difficult to ascertain. There was no consideration of whether small plants should be required to supply their own reserve capacity when the central station already had such reserve capacity in place.

The Massachusetts Department of Public Utilities (DPU) similarly tightened regulations over the years with respect to private resale of electricity. As already noted, Boston Ed originally had instituted sub-metering to induce private generators to forfeit their plants and to join the Edison system.[36] In the 1930's, however, the DPU noted an increase in sub-metering from large property owners buying power at wholesale and reselling it to their tenants at retail. No action was taken to halt this abuse until 1948, however, when Boston Edison refused to accept any new resale customers. In 1953, Boston Edison decided to abolish resale of electricity altogether. The DPU approved the abolition and stated that "if anyone sees fit to become an electrical company as defined in the statutes, we shall promptly assume jurisdiction over its rates and practices to precisely the same extent as we do over those of Edison."[37] This admonition was directed to "any building which decides that there is an economic advantage to be derived form installing an electric generating plant."[38]

In many states utilities were required to obtain a "certificate of public convenience and necessity" before they could begin construction of a new facility. Even if a commercial or industrial firm was willing to file the necessary reports and to subject itself to scrutiny as a public utility, commissions often still were reluctant to issue a cer-

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33. *In re* New York Edison Co., 16 Pub. Util. Rep. (NS) 120, 126 (1937).

34. *Id.* at 140.

35. The diversity factor is the figure assumed as representing the incidence of simultaneous breakdown of private plants. If one assumes, for example, that only half of these plants are likely to break down at any one time and require backup service, then only one-half their rated capacity would have to be provided in reserve capacity in a centralized backup system.

36. *See supra* note 5.

37. *In re* Boston Edison, 98 Pub. Util. Rep. (NS) 427, 459 (1953).

38. *Id.* The Boston Realty Board appealed this ruling, but the Massachusetts Supreme Court upheld the DPU. *See* Boston Real Estate Bd. v. Massachusetts Dep't of Public Utilities, 334 Mass. 497, 136 N.E.2d 243 (1956).

tificate of convenience to a nonutility business. Commissions perceived the cogenerator as a competitor of the entrenched utility, the solvency of which the commissions felt bound to protect. If a utility already could supply the electrical load for the firm and its proposed customers, then installation of a cogeneration unit would have been an unnecesary duplication of resources, in view of the commissions.[39]

Thus, when the "total energy" system,[40] a new form of cogeneration emerged in the 1960s, proponents rapidly found that regulations made operation of such systems very tricky, if not impossible. For example, a Massachusetts developer applied for an advisory ruling on whether a total energy system would be subject to regulation. The DPU noted that, although in other states the public nature of the activity might determine whether it should be regulated or not, in Massachusetts it was the *sale* of the electricity that subjected the system to regulation. If the developer metered the gas or electricity, the activity would be a sale subject to DPU regulation; if the gas and electricity were included as part of the rent, then the activity would not be subject to DPU regulation.[41]

In Utah the United States Circuit Court for the Tenth Circuit ruled that a shopping center, which already had installed a total energy system at a cost of $1,500,000, could not operate the plant because the shopping center had no certificate of convenience.[42] All the stores except one in the mall were tenants of the mall owner. The court ruled, however, that because that one store was not a tenant and because the public used the mall, the mall was dedicated to public use. The federal court, deciding the issue in the context of an antitrust suit by the mall owner against the utility, concluded that it did

> not think Utah would permit this intrusion into the field of public utility by one who would be unregulated both from the standpoint of what it could do to its customers and, more so, the damage it could do to the public good by an uneconomic duplication of facilities and a raid on power company's customers to the detriment of all public power users.[43]

39. In some states, utilities were granted exclusive rights to serve an area. Thus, it was not legally possible for a commission to give a certificate of convenience to another business even if it might have been willing to do so. N. DEAN, ENERGY EFFICIENCY IN INDUSTRY 159 (1980) [hereinafter cited as DEAN].

40. A total energy plant is an isolated unit, usually gas-fired, that provides all the heating, cooling and lighting needs of a large apartment complex or shopping center. Unless a hookup for backup service is included, these systems are entirely isolated from the electric utility.

41. The DPU did acknowledge, however, that the developer might meter the tenants for two years to establish a fair basis for the rental charge. *In re* Frank Properties, Inc., 72 Pub. Util. Rep. 3d (PUR) 305 (1968).

42. Cottonwood Mall Shopping Center, Inc. v. Utah Power & Light Co., 440 F.2d 36, 42 (10th Cir. 1971).

43. *See id.* The Wisconsin Supreme Court upheld a Public Service Commission decision

C. Local Regulation: The Franchise

Cogenerators not only suffered from adverse state rulings, but they also encountered difficulties obtaining franchises[44] from municipalities. Some states gave municipalities the privilege of granting exclusive franchises. Because a franchise is considered a property right, if an exclusive franchise was issued, an industrial cogenerator could not obtain a franchise from a local government unless the incumbent utility agreed to its issuance or unless the government exercised its power of eminent domain and compensated the utility.[45] In the early 1970s, nearly one half the states still permitted local governments to issue exclusive franchises.[46]

Even nonexclusive franchises were difficult and expensive to obtain. In some states, the local legislature had to approve the issuance of a franchise; others required a community referendum. Such approval was not easy to obtain if a well-funded utility opposed an alternative power source.[47]

D. Federal Impediments

In addition to all these difficulties, the United States Department of Justice prosecuted a number of paper companies on antitrust grounds. Because of their huge energy needs, paper companies made extensive use of their hydro and waste-wood resources to generate electricity. Through a series of court cases in the 1930s, however, the Justice Department forced paper companies to choose between the paper business or the electric power business. Most gave up their power business—although a few developed independent subsidiaries that became public utilities.[48]

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denying jurisdiction over a developer who wished to install a total energy system because the developer would be selling energy to his tenants only and not to the public at large. *See* Sun Prairie v. Wis. Public Service Comm'n, 71 Pub. Util. Rep. 3d (PUR) 417 (1968); *In re* Sun Prairie, 57 Pub. Util. Rep. 3d 525 (PUR) (1965). The uncertainty and inconsistency in these state decisions, however, severely retarded the development of total energy systems.

44. A franchise is a special privilege or right granted to a corporation or an individual by a local or state government. In this case it is the right to cross a street or public right-of-way with an electrical line.

45. DEAN, *supra* note 39, at 163. *See* regulations cited *infra* note 80.

46. DEAN, *supra* note 39, at 163.

47. In Oklahoma, a developer proposed to install a total energy plant in a new development. The plant was to serve residences and businesses within the project area only. Oklahoma Gas and Electric sued both the developer and the energy company, saying that they first had to obtain a franchise. Although Oklahoma Gas and Electric's franchise was nonexclusive, the Oklahoma Supreme Court held that the developer could not keep a perpetual easement on the streets of the development, and therefore a franchise was required before any electricity could be transmitted or distributed. (This effectively blocked the project because obtaining a franchise required approval by the voters of the entire municipal area, not just residents of the development.) Oklahoma Gas & Electric Co. v. Total Energy, Inc., 499 P.2d 917 (Okla. 1972).

48. C. Berg, *Conservation in Industry,* SCIENCE, April 19, 1974, at 264-70. (The author has been unable to find the cases alluded to here.)

At the same time, the passage of the Public Utilities Holding Company Act (PUHCA) raised the issue whether paper companies that were in the power business also came under the Act's jurisdiction. At least one paper company apparently divested itself of its electric power subsidiaries when the Securities and Exchange Commission was determining whether the firm was a holding company under PUHCA.[49] A number of paper companies that originally called themselves "paper and power" companies dropped "power" from their titles after divesting themselves of power production subsidiaries.[50]

Thus, while the economies of scale and decreasing marginal cost curves associated with the new generating technologies were compelling economic factors encouraging central station generation, the legal process clearly abetted the move to central station generation. Commissions permitted rates that were below embedded costs in the belief that the more electrical production was encouraged, the cheaper electrical production would become for all. Similar reasoning also induced commissions to acquiese to utility desires for high rates for backup or standby service. Such acquiescence, of course, made self-generation even less economical.

Once the idea that the production of electricity was a natural monopoly gained wide acceptance, questions of economic efficiency that might have favored cogeneration never were raised. Cogeneration never was differentiated from general resale of utility electricity in producing bans on sub-metering, nor from less efficient forms of electrical generation in narrowing definitions of those exempt from public service commission jurisdiction. Few incentives motivated firms to seek competitive technological developments in cogeneration, while extra difficulties and expense with the regulatory process created strong disincentives. For these reasons cogeneration slowly died away; by 1975, only four percent of electricity in the United States still was cogenerated.[51]

III. The Federal Attempt to Revive Cogeneration

In the extensive congressional hearings prior to passage of the

49. Between 1939 and 1941, the International Paper and Power Company divested itself of its power operations in accordance with an order issued by the Securities and Exchange Commission. MOODY'S INDUSTRIAL MANUAL 1982 (1956).

50. Subsequent to its divestiture, the International Paper and Power Company changed its name to the International Paper Company. *Id.* Abitibi Paper and Power made a similar change, to Abitibi Paper in 1965. MOODY'S INDUSTRIAL MANUAL 2201 (1979).

51. S. REP. NO. 442, *supra* note 2, at 7918. The major part of this decline in percent is attributable to the increase in electrical consumption that has occurred. Since 1969, however, there has been a real number decline in cogeneration. R. Barnes & P. Hodiak, *Cogeneration in Industrial Plants,* in COGENERATION OF ELECTRICITY AND USEFUL HEAT 28 (B. Wilkinson & R. Barnes, eds. 1980) [hereinafter cited as Wilkinson & Barnes].

bills that comprised the National Energy Act of 1978, cogeneration repeatedly was put forward as a known technology that substantially could improve energy efficiency.[52] It also was noted, however, that legal and institutional barriers inhibited the development of much cogeneration that otherwise would be commercially feasible. To remedy this situation, Congress inserted provisions to encourage cogeneration in four of five of the enactments that comprise the National Energy Act.[53]

A. *The Minor Elements of the Legislative Package: FUA, NGPA, NECPA*

Two of these acts merely prevented, or offered the possibility of preventing, the erection of more institutional barriers to cogeneration's development. Congress desired to reduce the country's dependence on imported oil and to conserve its increasingly scarce natural gas resources. Thus in the Powerplant and Industrial Fuel Use Act (FUA), Congress prohibited electric utilities and major industrial fuel burners[54] from burning oil or natural gas as the primary fuel in any new installations and authorized conversion of existing oil and natural gas burning plants to other fuels where feasible. The FUA would have prevented installation of any large oil or gas-fired cogeneration units; Congress, however, inserted a provision authorizing the Secretary of Energy, in his discretion, to issue cogenerators a permanent exemption from these restrictions.[55]

Similarly, the incremental pricing provisions of the Natural Gas

52. *See supra* note 1.

53. The National Energy Act actually was composed of five acts: The Public Utilities Regulatory Policy Act, Pub. L. No. 95-617; The Energy Tax Act of 1978, Pub. L. No. 95-618; The National Energy Conservation Policy Act, Pub. L. No. 95-619; The Powerplant and Industrial Fuel Use Act of 1978, Pub. L. No. 95-620; The Natural Gas Policy Act of 1978, Pub. L. No. 95-621. Only the Energy Tax Act lacked provisions to encourage cogeneration.

54. A major fuel-burning installation (MFBI) was defined as

> a stationary unit consisting of a boiler, gas turbine unit, combined cycle unit, or internal combustion engine which—i) has a design capability of consuming any fuel (or mixture thereof) at a fuel heat input rate of 100 million BTU's per hour or greater or, ii) is in a combination of two or more such units which are located at the same site which in the aggregate have a design capability of consuming any fuel (or mixture therefore) at a fuel input rate of 250 million BTU's per hour or greater.

42 U.S.C.A. § 8302(10(A) (West Supp. 1982).

55. 42 U.S.C.A. § 8322(c) (West Supp. 1982) offered the discretionary exemption to new facilities. 42 U.S.C.A. § 8352(c) (West Supp. 1982) offered the exemption to existing facilities. Both sections read as follows:

> After consideration of a petition (and comments thereon) for an exemption from one or more of the prohibitions of part A for a cogeneration facility, the Secretary may, by order, grant a permanent exemption under this subsection with respect to natural gas or petroleum, if he—(1) finds that the petitioner has demonstrated that economic and other benefits of cogeneration are unobtainable unless petroleum or natural gas, or both, are used in such facility, and (2) includes in the final order a statement of the basis for such finding.

The discretionary aspect of this exemption has created almost as many difficulties for MFBIs that desire to burn oil or gas as the FUA prohibitions themselves. *See infra* note 121 and accompanying text.

Policy Act (NGPA) made one of the most efficient forms of cogeneration, the gas-combustion turbine, less attractive economically. Congress, therefore, authorized the Federal Energy Regulatory Commission (FERC) to promulgate rules providing an exemption from these provisions to qualifying cogenerators;[56] the FERC has promulgated such rules.[57]

A third act in the legislative package, the National Energy Conservation Policy Act (NECPA) amended the Energy Policy and Conservation Act of 1974 to provide grants for cogeneration systems.[58] Since cogeneration projects were only one type of project among many competing for the limited funds available in this program,[59] the chief virtue of this provision probably was that it highlighted a new congressional awareness and approval of cogeneration.

B. The Major Element of the Legislative Package: PURPA

In the fourth piece of legislation, the Public Utilities Regulatory Policy Act (PURPA), Congress attempted to grapple with the regulatory barriers to cogeneration which had developed. Congress authorized exemption of both cogeneration and small power production facilities from most of the onerous licensing requirements and regulations imposed under the Federal Power Act (FPA), PUCHA and the state rules and regulations governing utility rates and financial organization. At the same time, Congress discouraged the recalcitrance of some utilities in offering interconnection services and providing reasonable backup services by requiring that utilities purchase from, sell to and provide interconnection services to qualifying facilities at fair rates.

Congress gave the FERC great flexibility in implementing PURPA. For example, while defining the term "cogeneration facility,"[60] Congress left to the FERC to determine by rule the requirements for a "qualifying cogeneration facility." Congress did, however, specify that such a facility could not be owned "primarily" by an electric utility.[61]

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56. Pub. L. No. 95-621, § 206(c)(3) (1978).

57. 45 Fed. Reg., 38080 (1980).

58. Pub. L. No. 95-619, § 302 (1978).

59. Congress authorized $875,000 over a three year period, beginning September 30, 1978. *Id.*

60. 16 U.S.C.A. § 796(18)(A) (West Supp. 1982) defined a "cogeneration facility" as "[a] facility which produces—(i) electric energy, and (ii) steam or forms of useful energy (such as heat) which are used for industrial, commercial heating, or cooling purposes." Similar definitions were used in other acts of the 1978 energy legislation.

61. The FERC interpreted "primarily" to mean that electric utilities, public utility holding companies, or their subsidiaries could not own more than 50 percent of any cogeneration facility. If an electric utility owned more than 50 percent of a facility, then the facility would not qualify for PURPA benefits. 45 Fed. Reg. 17959, 17973 (1980). This provision effectively prevented utilities from having a controlling interest in an operation that might be exempted from traditional utility regulation.

Congress also extended the FERC's power to order interconnections to situations in which qualifying cogenerators[62] wished to buy power from, or to sell power to, the electric utility.[63] The Commission, however, had to meet certain procedural requirements and to make certain findings specified by the FPA.[64] Congress also added a new section to Part II of the FPA authorizing the Commission to order the wheeling[65] of power by one electric utility upon application of another electric utility or a federal marketing agency.[66] The Conference Report explicitly stated that this provision was included "to require a third party to provide transmission services between a willing buyer and a willing seller."[67] Before the FERC could order wheeling, it had to meet certain requirements of the FPA, just as with interconnection.[68]

In section 210 of PURPA,[69] Congress authorized the FERC to establish rules governing electric utilities' sales to and purchases from qualifying cogenerators.[70] These perhaps were the most novel provisions relating to cogenerators; never before had the FERC been asked to regulate a utility's retail rate. Rates for the purchase of power were required to be "just and reasonable to the electric consumers of the electric utility and in the public interest" as well as nondiscriminatory against cogenerators.[71] In no case were these rates to exceed the "incremental cost of alternative electric energy" to the utility.[72] Rates for sale of electricity to cogenerators also were

62. Most of these PURPA provisions also apply to small power producers, but most references to small power producers are omitted from this article.

63. 16 U.S.C.A. § 824i(a) (West Supp. 1982).

64. In particular, the Commission was to "afford an opportunity for an evidentiary hearing," and make findings that such an order "(1) is in the public interest, (2) would—(A) encourage overall conservation of energy or capital, (B) optimize the efficiency of use of facilities and resources, or (C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies." 16 U.S.C.A. §§ 834(i)(b)(2), (c) (West Supp. 1982). Additionally, an interconnection order was not to "result in a reasonably ascertainable uncompensated economic loss for any electric utility [or] qualifying cogenerator," "place an undue burden on an electric utility [or] qualifying cogenerator," "unreasonably impair the reliability of any electric utility affected by the order," or "impair the ability of any electric utility affected by the order to render adequate service to its customers." *Id.* § 824(k).

65. Wheeling is the process by which an electric utility with surplus power may send power to an electric utility in need of power over the transmission lines of a third utility.

66. 16 U.S.C.A. § 824(j) (West Supp. 1982).

67. H.R. REP. NO. 1750, 95th Cong., 2d Sess., *reprinted in* 1978 U.S. CODE CONG. & AD. NEWS 7826.

68. The findings and requirements were similar to those required in the case of interconnection. *See* 16 U.S.C.A. §§ 4824j(a), 824k (West Supp. 1982). However, further requirements were imposed that required the preservation of "existing competitive relationships." *Id.* § 824j(c).

69. Codified at 16 U.S.C.A. § 824a-3 (West Supp. 1982).

70. 16 U.S.C.A. § 824a-3(a) (West Supp. 1982).

71. *Id.* § 824a-3(b).

72. The "incremental cost of alternative electric energy" was defined as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." *Id.* § 824a-3(d).

to be just and reasonable, in the public interest and nondiscriminatory.[73]

In addition, if found necessary by the FERC, the FERC could prescribe rules exempting cogenerators in whole or in part from the PFA, the PUCHA and state utility regulation, with the exception of the interconnection and wheeling provisions of the FPA and any state regulations necessary to implement section 210 of PURPA.[74] The state regulatory body that had ratemaking authority or, in the case of a nonregulated utility, the utility itself, was to implement all of these rules.[75]

Congress gave the FERC wide discretion in implementing PURPA's cogeneration provisions, and the Commission took seriously its mandate to encourage cogeneration. In its final rules issued February 19, 1980,[76] for example, the FERC used its discretionary powers to exempt qualifying cogenerators from the FPA, the PUCHA and state regulation to the full extent permitted by section 210.[77]

Moreover, while section 210(b) stated that the purchase rate of power from cogenerators should not exceed "the incremental cost to the utility of alternative electric energy,"[78] the FERC appeared to mandate this maximum rate as the only purchase rate which should be offered to new[79] cogeneration facilities. The Commission determined that purchase rates should equal the *full* avoided costs of the utility after consideration of the following factors: The availability of power from the qualifying facility during daily or seasonal peak load periods; the reliability of the cogeneration facility; the presence of a firm contract to supply power; the ability of the facility to coordinate outages with the utility; the willingness of the facility to accept interruption of power; and the adaptability of the facility to system emergencies.[80] To the extent that the cogenerator could perform these services, the utility could avoid more costs, and the cogenerator

73. *Id.* § 824a-3(c).

74. *Id.* § 824a-3(e).

75. *Id.* § 824a-3(f). Subsequent subsections of § 210 dealt with judicial review and enforcement, as well as Commission enforcement of the preceding rules and regulations. In particular, an action could be brought by any person against any electric utility or qualifying cogenerator who violated any rule implemented by a state pursuant to the rules of the Commission. *Id.* § 824a-3(g)(2). Alternatively, an electric utility or cogenerator could petition the Commission to enforce such rules. *Id.* § 824a-3(h)(2)(B). Judicial review could be obtained of any proceeding of a state regulatory authority regarding the implementation of section 210 regulations. *Id.* § 824a-3(g)(1), and the Commission could initiate proceedings against any state for failure to implement its rules. *Id.* § 824a-3(h)(2)(A).

76. 18 C.F.R. § 292 (1980).

77. *Id.* § 292.601, .602.

78. 16 U.S.C.A. § 824a-3(b) (West 1980).

79. "New" cogeneration facilities were those on which construction commenced after the enactment of PURPA, November 9, 1978.

80. 18 C.F.R. § 292.304(e) (1980). The relationship of these factors to purchase rates is discussed further in 45 Fed. Reg. 12,226-27 (1980).

should be rewarded with a higher purchase rate. States could offer rates more encouraging to cogeneration,[81] but they could not approve purchase rates at less than full avoided costs unless they determined that such rates still would encourage cogeneration and meet the nondiscriminatory tests of PURPA,[82] or unless they obtained a waiver of the rules from the FERC.[83]

The factors that the Commission determined should be considered established two components in avoided cost calculations: "avoided energy cost" and "avoided capacity cost." If a cogenerator offered an electric utility power only on an "as available" basis, then the cogenerator was entitled only to an energy cost credit. The purchase rate would be based on the incremental cost to the utility of the last unit of power that otherwise would be necessary for the utility to produce at that time of day.[84] Typically, utilities operate their most expensive generating equipment last when meeting rising demand. Therefore, a cogenerator offering power at times of peak utility demand theoretically would receive a higher purchase rate than one supplying power in off-peak periods.

If the cogenerator, however, was willing to enter a firm contract to supply power for a specified time period, then a capacity credit might be included in the purchase rate. With a reliable power source, the utility might postpone or even avoid the construction of an otherwise necessary new plant. In this case, the Commission felt the cogenerator should receive a payment equal to the costs the utility would have incurred to build or to buy an equivalent amount of new capacity.[85] An electric utility could avoid this payment, however, by showing that it had no need for additional capacity or currently had a capacity surplus.[86]

Regarding sales of power to cogenerators, the FERC determined that nondiscriminatory rates required that utilities offer cogenerators the same rates that they offered other customers with similar load or cost-related characteristics.[87] If additional services were provided, such as backup or maintenance power,[88] the Com-

81. 45 Fed. Reg. 12,221 (1980).

82. 18 C.F.R. § 292.304(b)(3) (1980).

83. 18 C.F.R. § 292.403(a) (1980).

84. In effect, the energy cost credit represents the short-run marginal costs avoided by the utility by the purchase of cogenerated power, that is, variable operation and maintenance and fuel costs.

85. The capacity credit represents the long-run marginal costs avoided by the utility with firm purchases of power. It might include payment for the deferral of capital costs, rather than outright avoidance of new capital costs. *See* 45 Fed. Reg. 12,225-26 (1980).

86. 45 Fed. Reg. 12,227 (1980).

87. 18 C.F.R. § 292.305 (1980).

88. The FERC defined backup power as power supplied by an electric utility to a facility during an unscheduled outage of equipment. Maintenance power was defined as power supplied during a scheduled outage. Thus, the two are differentiated by the emergency nature of the former. 18 C.F.R. § 292.101(9), (11).

mission stated that these rates should not be based on the assumption that all qualifying facilities would require this service simultaneously.[89]

Additionally, the FERC mandated the simultaneous purchase and sale of power.[90] With simultaneous "buy-and-sell," cogenerators did not need to sell surplus electricity only to the utility, but could sell their total power output at the avoided cost rate and buy their total power needs at the applicable retail rate. Since most utilities base retail rates on average or embedded costs, the FERC hoped that this provision would offer a significant economic incentive to cogenerators whenever rising marginal costs exceeded average costs.

At the same time, the Commission declared that utilities had an obligation to interconnect with any qualifying facility wishing to purchase or sell power.[91] An exception was permitted only if an otherwise unregulated utility became subject to regulation under Part II of the FPA. While acknowledging that section 210 of PURPA did not exempt qualifying facilities from the complex interconnection provisions of the FPA, the Commission nevertheless argued that "the obligation to interconnect with a qualifying facility is subsumed with the requirement of section 210(a) that electric utilities offer to sell electric energy to and purchase electric energy from qualifying facilities."[92] To hold otherwise would subject qualifying facilities to these complex and onerous provisions and thus would negate the mandate to encourage cogeneration.[93]

In a second set of rules issued a few weeks later, the Commission set forth criteria defining "qualifying cogenerator" and "qualifying cogeneration facility."[94] Again the FERC took its mandate to encourage cogeneration seriously and established lenient criteria aimed primarily at preventing abuse of the "qualifying" status. Beyond the ownership restriction specified by Congress,[95] cogeneration facilities were required to meet only two other criteria for qualification. Topping cycle facilities[96] had to meet a minimum operating standard,[97] while oil and gas cogenerators were required to meet an efficiency standard.[98]

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89. That is, the Commission wished that such rates would take account of the diversity factor. *See supra* note 36. If facilities do not all break down simultaneously, then they should not have to pay a demand charge for breakdown service equal to their aggregate capacity, but equal only to some fraction thereof.

90. 18 C.F.R. § 292.304(b)(4) (1980).

91. *Id.* § 292.303(c).

92. 45 Fed. Reg. 12,220 (1980).

93. *Id.* at 12,221.

94. 18 C.F.R. § 292 (1980).

95. *See supra* notes 18, 62.

96. *See supra* note 1.

97. At least 5 percent of the total energy output had to be in the form of useful thermal energy. 18 C.F.R. § 292.205(a)(1) (1980).

98. For a topping cycle facility, the useful power output of the facility plus one-half the

The topping cycle operating standard was included to prevent someone from gaining qualification by runing a conventional electricity generating plant and using only a trickle of the waste heat to gain the benefits of qualifying status. The efficiency standard was imposed to meet the concerns of those who felt that encouraging oil and gas cogeneration was counter to other provisions of the National Energy Act. Thus, the FERC sought a standard that "would ensure that qualifying facilities product heat and power more efficiently than a 8500 Btu/kwh combined cycle generating station and a 90 percent efficient process steam boiler."[99] If an oil or gas cogeneration facility met such a standard, then it offered some real efficiency gains over good conventional heat and power production.[100]

Pending the outcome of an environmental impact statement, diesel cogeneration temporarily was excluded from qualifying status. In June 1981, however, the FERC removed this prohibition and gave generic qualification to diesel cogeneration.[101] It decided that while an increased number of cogeneration facilities might cause air quality to deteriorate and increase acid rainfall, the number attributable directly to PURPA incentives would not be significant.[102]

Upon meeting the ownership and relevant operating and efficiency standards, cogenerators could certify themselves as "qualified."[103] Alternatively, cogenerators could supply some additional information and apply to be certified as "qualifying" by the Commission.[104] If the Commission wished to deny qualification or to set a hearing, it was required to do so within 90 days of receiving the application for qualification. Otherwise, qualifying status was deemed granted.

These two sets of regulations were seen by most commentators as a significant step forward in redressing the balance of power between electric utilities and smaller, independent power producers.[105]

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useful thermal energy output during any calendar year had to be no less than 42.5 percent of the total energy input of natural gas or oil to the facility. If the useful thermal energy output was less than 15 percent of the total energy output, then the computed efficiency must be no less than 45 percent. For any bottoming cycle facility using oil or gas for supplementary firing, the useful power output of the facility had to be no less than 45 percent of the energy input of the natural gas or oil used for supplementary firing. 18 C.F.R. § 292.205(a)(2) (1980).

99. 45 Fed. Reg. 17,968 (1980).

100. This efficiency standard was also used by the FERC to determine the gas cogenerators who should be exempted from the incremental pricing provisions of the NGPA. 18 C.F.R. § 292.205(c) (1980).

101. 46 Fed. Reg. 33,026 (1981).

102. The Commission thought that in the New York area, the high municipal taxes attached to Consolidated Edison's retail rates would be more of an incentive to install cogeneration than the rates available under PURPA. *Id.* at 33,026.

103. 18 C.F.R. § 292.207(a) (1980).

104. *Id.* § 292.207(b).

105. *See, e.g.*, J. Schillaci, *The Simultaneous Buy and Sell Provisions of PURPA Section 210 Regulations,* 106:8 PUBLIC UTILITIES FORTNIGHTLY at 43-45; D. SILVERSTONE, PURPA PROVISIONS ON COGENERATION AND SMALL POWER PRODUCTION (1980); Alden Meyer, *Gen-*

The FERC clearly had carried out the congressional mandate to encourage cogeneration.

C. Subsequent Legislative Initiatives Affecting Cogeneration

Although Congress did register a desire to encourage cogeneration, no tax credits were explicitly offered to would-be cogenerators in the 1978 energy legislation. Congress remedied this omission in 1980, however, when it added "cogeneration equipment" to the tax code definition of energy property eligible for the ten percent energy investment tax credit.[106] The credit was made available to add-on property that enabled new cogeneration or increased existing cogeneration in facilities already existing as of January 1, 1980.[107] To receive the credit, oil and gas could only be burned for startup, backup or flame control.[108]

In the Biomass Energy and Alcohol Fuel Act of 1980,[109] Congress made $1,450,000,000 available to approved "biomass energy projects" and "municipal waste energy projects."[110] Both types of projects included cogeneration facilities,[111] but priority for financial assistance was to be given to projects that used a primary fuel other than oil or gas to produce a biomass fuel, that used new or improved technologies to expand possible feedstocks or to produce biomass energy,[112] or that produced a liquified fuel from municipal waste.[113] After the change in administrations in 1981, funding levels were cut in the bills that permitted grants to cogeneration projects, but these cuts affected all eligible projects—not just cogeneration.[114]

On the other hand, the Small Business Act was amended to permit the Small Business Administration to make loans for "energy measures" that included "industrial cogeneration of energy, district heating, or production of energy from industrial waste."[115] No restrictions were imposed on the fuel sources eligible for this credit. The Economic Recovery Tax Act of 1981 extended accelerated cost

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erate Your Own: FERC Rules Give Small Power Producers a Break, 6 THE POWERLINE 2 (1980).

106. 26 U.S.C.A. § 48(1), (3), (14) (West Supp. 1982).

107. If a boiler had to be replaced to cogenerate, it was only eligible to the extent that additional capacity was required for the cogeneration function. Furthermore, the credit was only available until December 31, 1982, unless part of the project had "a normal construction period of 2 years or more." In this case, the credit was extended to December 31, 1990, providing certain interim deadlines were met. 26 U.S.C.A. § 36-46(a) (West Supp. 1982).

108. 26 U.S.C.A. § 48(1)(14) (West Supp. 1982).

109. Pub. L. No. 96-29 (1980).

110. These funds were to be available for a two year period beginning October 1, 1980, or until expended. 42 U.S.C.A. § 8803(a) (West Supp. 1982).

111. *Id.* § 8802(5), (15).

112. *Id.* § 8817(a)(1).

113. *Id.* § 8835(a)(1).

114. For example, the funding level of the BIAFA was reduced to $1,170,000,000 in The Omnibus Budget Reconciliation Amendment of 1981, Pub. L. No. 97-35, § 1061 (1981).

115. Pub. L. No. 97-35, §§ 1902(a)(12), 1903(g)(5) (1981).

recovery to investments that received an investment tax credit, including energy credits.[116]

In 1982, a movement began to amend the sections of PURPA that affected cogeneration. As originally introduced, S.1885 would have removed the restriction on utility ownership of qualifying cogeneration facilities.[117] Numerous witnesses in Senate hearings[118] testified that, without a clearer congressional mandate ordering interconnection, utilities easily could become unfair competitors with private cogenerators.[119] Therefore, S.1885 was amended to allow state regulatory agencies to limit utility ownership of qualifying facilities and to mandate a streamlined interconnection procedure. More hearings were held,[120] but this time utility interests opposed the bill, and the legislative effort died.

While cogeneration intially attracted congressional attention because it was a "known" technology that promised substantial fuel savings, Congress did not choose to support this "known" technology enthusiastically. Tax credits and financial assistance were not offered to oil or gas cogeneration, but only to coal-fired or biomass-fueled cogeneration. Nevertheless, the major incentives for cogeneration from this federal package probably came not from the relatively meager appropriations or tax credits offered, but from the attempt to remove institutional barriers to cogeneration, and this legislation applied to all forms of cogeneration. Certainly if the court cases that have emerged as the result of this legislation are any indication, PURPA's section 210 has offered the greatest boost to cogenerators and the greatest threat to entrenched utility interests.

IV. Court Challenges to the Federal Legislation

The significant court challenges to federal legislation affecting cogeneration have centered almost exclusively on PURPA. Two cases are prominent because of their wideranging implications for both independent cogenerators and the electric utility industry: *FERC v. Mississippi*[121] and *American Electric Power v. FERC*.[122]

116. Pub. L. No. 97-34, § 211 (1981).

117. *See supra* note 61 and accompanying text for ownership restrictions.

118. *Hearing Before the Subcommittee on Energy Regulation of the Committee on Energy and Natural Resources on S. 1885—Part I,* S.R. REP. No. 1885, 97th Cong., 2d Sess. (1982) [hereinafter cited as *Senate Hearing, Part I*].

119. In the interim period, the District of Columbia Circuit Court had overturned the FERC's interconnection rule, thus throwing the ability of qualifying facilities to obtain connection to the electric utility's grid into doubt. *See supra* text accompanying notes 156-57.

120. *Hearing Before the Subcommittee on Energy Regulation of the Committee on Energy and Natural Resources on Amendment No. 1452 to S. 1885—Part II,* S. REP. No. 1885, 97th Cong., 2d Sess. (1982) [hereinafter cited as *Senate Hearings Part II*].

121. FERC v. Mississippi, 102 S. Ct. 2126 (1982).

122. American Paper Institute, Inc. v. American Electric Power Service Corp., 51 U.S.L.W. 4547 (1983); American Electric Power v. FERC, 675 F.2d 1226 (1982).

While industry has mounted numerous challenges to the implementation of the fuel use restrictions in the FUA, these cases have not received much attention. Frequent changes in DOE's regulations[123] have made it difficult, if not impossible, to sustain a major court challenge. Moreover, requirements for obtaining a cogeneration exemption have been somewhat eased,[124] and potential cogenerators will not necessarily be involved in any future litigation.

A. The Mississippi Case

In April 1979, the State of Mississippi and the Mississippi Public Service Commission commenced an action against the FERC and claimed that Titles I and III and section 210 of Title II of PURPA should be declared unconstitutional. Mississippi maintained that Congress had exceeded its commerce clause power and that PURPA was an invastion of state sovereignty in violation of the tenth amendment.[125]

The district court, in an unreported opinion, agreed with the State that Congress had exceeded its power under the commerce clause. The court noted that public electric utilities were not even in existence at the time of the writing of the Constitution and that the legislation was "a clear usurpation of the power and authority which the United States simply does not have under the Commerce Clause of the Constitution."[126] The court went on to conclude that PURPA also violated state sovereignty. Relying on *National League of Cities*

123. To illustrate the frequency of changes in the FUA regulations, the following brief history is offered: Interim rules, issued in 1979 in 44 Fed. Reg. 28,594, 36,002, 43,176 (1980), were challenged almost immediately by both utilities and industry. The United States Court of Appeals for the Fourth Circuit consolidated these cases for review and then held them in abeyance pending the issuance of final rules. Final rules were issued piecemeal in June, August and December 1980. 45 Fed. Reg. 38,276, 38,302, 53,682, 84,967 (1980). With the change of administration, however, came the suspension and re-evaluation of most major regulations promulgated at the end of the Carter administration. New final rules subsequently were issued in December 1981, 46 Fed. Reg. 59,872 (1981), and then modified in still later rulings, e.g., 47 Fed. Reg. 15,311, 17,037 (1982). For a more complete early history of the FUA and the restrictions imposed, see Irwin & Sisk, *The Fuel Use Act and DOE's Regulations,* 29 U. KAN. L. REV. 319-36 (1981).

124. Regulations for obtaining the cogeneration exemption were first proposed in August 1980 in 45 Fed. Reg. 53,368 (1980). No further action was taken on these rules, however, until the Reagan administration adopted them, substantially as proposed by the previous administration, in December 1981 in 46 Fed. Reg. 59,872 (1981). At this time the Department of Energy noted, "DOE received many comments and expressions of concern about the failure to expeditiously proceed with the Notice of Proposed Rulemaking regarding cogeneration or, alternatively, to propose and adopt a less onerous standard for applying for and obtaining the permanent cogeneration exemption." The Department went on to say it was "considering several alternatives to simplify these provisions." *Id.* at 59,882. This it ultimately did in final rules issued July 6, 1982. 47 Fed. Reg. 29,209 (1982).

125. The commerce clause of the United States Constitution states that Congress shall have the power "to regulate commerce with foreign nations, and among the several States, and with the Indian tribes." The tenth amendment states, "The powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people." U.S. CONST. art. III, amend. X.

126. 102 S. Ct. 2126, 2134 (1982).

v. Usery,[127] the court declared the PURPA provisions void because they constituted "a direct intrusion on integral and traditional functions of the State of Mississippi."[128]

The FERC and the Secretary of Energy appealed this decision directly to the Supreme Court, and in a split decision issued in June 1982, the high Court reversed the decision of the lower court. Regarding the commerce clause, the entire Court felt that the lower court's decision was without merit. Justice Blackmun, writing for the majority, declared that "it is difficult to conceive of a more basic element of interstate commerce than electric energy,"[129] and noted that utilities in Mississippi itself bought electricity from other states for retail sales to their consumers and provided similar service in return.

Justice Blackmun also noted that there was ample evidence presented in congressional hearings to show that promoting energy conservation and efficiency would help alleviate the nation's grave energy situation. Even if PURPA would not significantly improve the nation's energy situation, "[i]t is sufficient that Congress was not irrational in concluding that limited federal regulation of retail sales of electricity and natural gas, and of relationships between cogenerators and electric utilities, was essential to protect interstate commerce."[130]

The Court found the tenth amendment challenge to be "novel." Section 210 required the states to enforce standards promulgated by the FERC, while Titles I and III directed the states to consider specific rate-making standards and imposed certain procedural requirements. The majority of the Court upheld Titles I and III on tenth amendment grounds by noting that these titles merely required the consideration of federal standards. "There [was] nothing in PURPA 'directly compelling' the States to enact a legislative program."[131] Moreover, since the regulation of electricity was preemptible under the commerce clause, federal law "necessarily controls," even if it is executed in a manner that is "extraordinarily intrusive."[132]

The majority acknowledged that, superficially, section 210 was

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127. 426 U.S. 833 (1976).

128. 102 S. Ct. 2126, 2134 (1982).

129. *Id.* at 2136.

130. *Id.* This holding applied a standard that the Court had just reiterated in the previous term in Hodel v. Indiana, 452 U.S. 314 (1981), that "legislative Acts adjusting the burdens and benefits of economic life come to the Court with a presumption of constitutionality. . . . A court may invalidate legislation enacted under the Commerce Clause only if it is clear that there is no rational basis for a Congressional finding that the regulated activity affects interstate commerce, or that there is no reasonable connection between the regulatory means selected and the asserted ends." *Id.* at 2134.

131. *Id.* at 2140.

132. *Id.* at 2141.

the "most intrusive of PURPA's provisions."[133] The majority also thought, however, that section 210's constitutionality was the easiest to resolve. This section exempted qualified facilities from state laws and regulation and thus did nothing more than "pre-empt conflicting state enactments in the traditional way."[134] Because of its commerce clause powers, Congress could have chosen to regulate retail sales of electricity completely.

While the requirement that states implement the buy-and-sell rule for all utilities over which they had ratemaking authority was more troublesome, one way states could do this was by "an undertaking to resolve disputes between qualifying facilities and electric utilities arising under [PURPA]."[135] This, the Court noted, was precisely the kind of activity in which the Mississippi Public Service Commission customarily engaged. Moreover, since state courts are required to enforce federal law, the Mississippi Commission had jurisdiction to enforce section 210.[136]

The two partial dissents[137] supported the substantive provisions of PURPA that related to cogeneration facilities.[138] Justice O'Connor specifically noted her concurrence with the majority's decision to uphold section 210 of PURPA.[139] While the rules requiring state implementation were "distrubing," Justice O'Connor agreed that states might "satisfy § 210's implementation requirement simply by adjudicating private disputes arising under that section."[140] While she thought there might be "hidden constitutional defects" in section 210, these could only be considered in a "concrete controversy" and should not preclude accepting section 210 as constitutional at that time.

Thus, the power of Congress to legislate retail electricity rates and to exempt certain forms of power production from state and federal regulation appears to have been upheld unanimously. If the federal law may be implemented by states simply through adjudicating private disputes, the Court is willing to let federal imposition of state implementation stand. Only when federal laws impose more extensive administrative and judicial requirements on states do the

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133. *Id.* at 2137.

134. *Id.*

135. *Id.* (quoting 18 C.F.R. § 292.401(a) (1980)).

136. The Court cited Testa v. Katt, 330 U.S. 386 (1947), as controlling on this point. *Id.* at 2137.

137. Justice Powell and Justice O'Connor, with whom Chief Justice Burger and Justice Rehnquist concurred, both wrote partial dissents.

138. Justice Powell objected to some of the procedural provisions of section 210 of PURPA, saying that they intruded on core areas of a state's administrative and judicial procedure. *Id.* at 2144.

139. *Id.* at 2146. Justice O'Connor's dissent focused on the Court's tenth amendment analysis of the constitutionality of Titles I and III of PURPA.

140. *Id.*

Court's opinions become divisive. Regarding PURPA's section 210, the mandate for states to continue establishing avoided cost rates for cogenerators was quite clear.

B. The American Electric Power Case

The *American Electric Power (AEP)* case arose out of a challenge by three utilities[141] to the FERC's final rules implementing PURPA. The utilities specifically challenged the "full avoided cost" rule,[142] the "simultaneous buy-and-sell provision,"[143] the blanket authority granted to cogenerators to interconnect[144] and the lack of "fuel use" criteria in determining "qualifying" cogenerators.[145]

In analyzing the "full avoided cost" rule, the appeals court held that the FERC had not adequately considered the provision that purchase rates be "just and reasonable to the electric consumers of the electric utility and in the public interest."[146] The court stipulated that the FERC must demonstrate the "factual basis" for its claim that setting purchase rates at less than full avoided costs would result in insignificant savings for consumers. The court agreed that the commission could not adopt a "split-the-savings" approach to ratemaking, since this would subject cogenerators to precisely the kind of scrutiny that PURPA was meant to avoid. The court nevertheless felt that alternatives such as "some percentage of avoided costs" could have been examined. Such an approach, the court asserted, "would not necessarily require any inquiry into the cogenerator's costs, but only into those of the utility."[147] Thus, the court asked the commission to take a "harder look" at this alternative.

The court endeavored to demonstrate that payment of full avoided costs to cogenerators might not always be in the public interest and that some cogeneration might be induced at less than full avoided costs.[148] Nonetheless the court ignored the factors that the

141. American Electric Power Service Corporation, Consolidated Edison Company of New York, and Colorado-Ute Electric Association were the petitioners.

142. 18 C.F.R. § 292.304(b)(2)-(4) (1980). *See supra* note 20.

143. 18 C.F.R. § 292.304(b)(4) (1980). *See also supra* note 22.

144. 18 C.F.R. § 292.303(c)(1) (1980). *See also supra* note 22.

145. Fuel use criteria restrict qualification to facilities burning specified fuels. There was nothing in the statute specifically requiring the FERC to include fuel use criteria when qualifying cogenerators.

146. 16 U.S.C.A. § 824a-3(b)(1) (West Supp. 1982).

147. 675 F.2d 1226, 1234 (1982).

148. For example, the court offered some hypothetical cases in which payment of full-avoided costs might not be in the public interest—such as pollution control standards or taxes making the utility's avoided costs higher than the cogenerator's. Yet, this was precisely the type of incentive Congress was trying to make available to cogenerators to encourage more efficient use of energy, since the utility, by definition, would have had to pay the higher costs anyway. The court also argued that if a utility had excess capacity, then paying full-avoided costs to cogenerators would result in higher costs for other customers of the utility because there would be fewer purchased kilowatt-hours over which the utility could spread its fixed costs. In this same decision, however, the court was upholding the simultaneous buy-and-sell

FERC declared should be considered in setting purchase rates for power,[149] factors that already appeared to encourage the setting of a range of avoided cost rates dependent on the cogenerator's characteristics. The court also did not recognize that the FERC had permitted voluntary purchase agreements to be set at less than full avoided cost rates.[150] One state commission, commenting on this decision, noted that a number of utilities and cogenerators already had made contracts with less than full avoided cost payments.[151]

Almost as an afterthought, the court added that this discussion assumed "that the utilities, as well as the cogenerators, are subject to some competitive restraints" and that if utilities were found to be monopsonists, then the commission's present rate might be justified. If, indeed, the commission had made this determination, it should have so stated.[152] Because the court already had noted the utility abuses that had prompted the enactment of section 210 of PURPA,[153] and cogenerators still were limited by PURPA to selling power wholesale only to utilities,[154] it is difficult to understand the court's willingness to assume these restraints.

Having thus vacated the FERC's full avoided cost rule, the court then upheld the FERC's simultaneous buy-and-sell provision and supported the decision record as adequate. The court termed it "anomalous" to treat the cogenerator that sells all its power differently from one that sells only surplus power. Once again the court noted the unwillingness of utilities to purchase power at an appropriate rate from cogenerators prior to PURPA and stated that "[u]nder these circumstances we are inclined to give a great deal of deference to FERC's regulations."[155]

Acting upon the utilities' third challenge, the court vacated the FERC's interconnection rule. Here the court noted, "By requiring 'any' utility to make interconnections with 'any' cogenerator FERC designates, the commission would in effect exempt qualifying cogenerators from the other procedural and substantive requirements . . . [of] FPA sections 210 and 212, and deprive utilities of the safeguards afforded by those provisions."[156] This contravened the

rule, and under this scheme the utility is not losing any purchased kilowatt-hours because the cogenerator is still purchasing all power needs from the utility.

149. These are the factors, like cogenerator reliability and usefulness of energy produced that are set forth in 18 C.F.R. § 292.304(e)(2) (1980). *See supra* note 20.

150. 18 C.F.R. § 292.301(b) (1980).

151. *In re* Cogeneration and Small Power Production, 47 Pub. Util. Rep. 4th (PUR) 327 (Me. 1982).

152. 675 F.2d 1226, 1236.

153. *Id.* at 1230-31.

154. 16 U.S.C.A. § 824a-3(a) (West Supp. 1982).

155. 675 F.2d 1226, 1238.

156. *Id.* at 1239.

prohibition in section 210(e)(3)[157] of exemption from the interconnection provisions of the FPA.

In response to the FERC's arguments that compliance with the literal meaning of the statute would place an "undue burden" on cogenerators and would restrict its mandate to encourage cogeneration, the court suggested that the commission adopt "streamlined procedures." The court noted that a general grant of authority to encourage cogeneration did not permit the FERC "to consign detailed provisions of PURPA itself to the wastebasket as meaningless surplusage."[158] If streamlined provisions were still too burdensome, then "the necessary amendment must come from Congress."[159]

Finally, the court upheld the commission's decision not to include any fuel use criteria in the definition of a qualifying cogeneration facility. The court agreed that congressional use of the term "may" and not "must" demonstrated that inclusion of such criteria was not mandatory. Furthermore, Congress already had offered the possibility of exemption from the Fuel Use Act to large cogenerators;[160] thus, Congress apparently did not wish that small facilities be restricted in their use of oil and gas simply by becoming cogenerators. Efficiency in the allocation and use of the nation's electric energy supplies, rather than conservation of oil and gas, was the principle reason for the passage of PURPA. The court again stated its deference to the commission and held that the commission gave reasoned and adequate consideration to its regulations.

Thus, the appeals court vacated two of the FERC's rules, the full-avoided cost rule and the blanket authority to interconnect, and upheld two other rules, the right of cogenerators simultaneously to buy and sell power and the rejection of a fuel use criteria for qualification. Upon the issuance of this decision, the FERC, with the support of the American Paper Institute, petitioned for a rehearing by the court en banc. The petition circulated to the full court, and a rehearing was denied.[161] In a "highly unusual" move,[162] the original panel subsequently issued a memorandum explaining its decision,

157. *See supra* note 64 and accompanying text for a discussion of FPA provisions. Specifically, § 210(e)(3)(B) said that no qualifying facility could be exempted from "the provisions of section 210 . . . or 212 of the Federal Power Act or the necessary authorities for enforcement of any such provision under the Federal Power Act. . . ."

158. 675 F.2d 1226, 1240.

159. *Id.*

160. *See supra* notes 54-55 and accompanying text.

161. Only five of the eleven judges of the District of Columbia Circuit Court of Appeals voted on the petition. Of these five, three were on the original panel and voted to deny the rehearing. The other two voted to grant the rehearing. The remaining six did not participate in the decision.

162. Nowak, *Contract Negotiations under PURPA and the Import of Recent Developments in Transactions Between Electric Utilities and Cogeneration and Small Power Production Facilities,* 3 ENERGY L.J. 273, 283 (1982) [hereinafter cited as Nowak].

and the dissenting judges issued a strong statement of dissent.[163]

Upon denial of the request for rehearing, the FERC and the American Paper Institute petitioned the Supreme Court for a writ of certiorari, which was granted in October 1982. The order to the circuit court was stayed, pending the outcome of the Supreme Court decision.

Between January 1982, when the circuit court first issued its opinion, and June 1983, when the Supreme Court finally stated its decision, the *AEP* case caused great consternation for both the FERC and potential cogenerators. The chairman of the FERC, C.M. Butler, stated that, if the Supreme Court upheld the circuit court and thus required a full consideration of market forces and a substantial evidence standard of review, then a complete review of the avoided cost rule could take one to two years.[164] Moreover, states that had passed "mini-PUPRAs" of their own could expect that their rate-making and interconnection orders also would be challenged.

If the interconnection order was upheld, then the FERC would be required to issue notices for interconnection and to conduct a full evidentiary hearing. The entire process could take three to four years.[165] Moreover, the commission necessarily would make some contradictory findings.[166] Thus, the process could become prohibitively expensive and time consuming for cogenerators seeking to obtain utility hook-ups.[167]

Furthermore, cogenerators were uncertain about state commissions' reactions to the potential vacation of the full avoided cost rule.

163. The two judges who supported a rehearing thought the panel had erroneously applied a heightened standard of review to the full-avoided cost rule and that the FERC had not acted arbitrarily and capriciously. They also found the interconnection ruling "troublesome," and thought that the "[FERC's] alternative reading should receive a closer scrutiny by this court before it erects a formidable, perhaps insurmountable, roadblock to a major energy program." 675 F.2d 1226, 1247.

The panel may have been somewhat taken aback by the harsh interpretation put on their ruling by both the FERC and the two dissenting judges. In its supporting memorandum, the panel expressed the need to restate "the essence of the court's decision" in light of "the distortions . . . served up in the petition for rehearing. . . .' It stated that it had not struck down the full-avoided cost rule, but merely required the Commission "to explain its rationale and process of consideration." It then went on to say that, with respect to the interconnection issue, the court had not been unsympathetic to the FERC's aims, but "a court is not the proper forum to repair a congressional product that may have been less than fully considered." *Id.* at 1246.

164. *Senate Hearings Part I, supra* note 118, at 229.

165. *Id.* at 236-37.

166. For example, according to the provisions in the FPA, the Commission would have to find that interconnection would encourage the overall conservation of energy, but not result in a "reasonably ascertainable uncompensated economic loss for any electric utility or qualifying cogenerator." *See supra* note 64 and accompanying text.

167. As the result of the testimony of Chairman Butler and others, S.1885 was amended to strengthen the FERC's power to order interconnections without following the procedures specified by the FPA. However, as already noted, this legislation did not reach the floor of the Senate. *See supra* notes 118-20 and accompanying text.

Some states already had delayed action on implementing section 210 rules while awaiting the outcome of the Mississippi case;[168] the *AEP* circuit court decision gave new cause for delay. Although only a few states which had section 210 rules in place reviewed these rules in light of the *AEP* decision, none vacated their rules. Of those that then did not have rules in place, a number adopted a "go slow" attitude, pending the outcome of the *AEP* case.[169] Kansas, for example, based purchase rates on embedded costs rather than on incremental costs because, the *AEP* decision would require rates based on full avoided costs to be reset after the high Court's decision—an undesirable situation for would-be investors.[170]

Despite the uncertainty among commentators,[171] the Supreme Court unanimously upheld the FERC's decision.[172] The Court held that the FERC did not act arbitrarily or capriciously in promulgating the full-avoided cost rule.[173] Because both a waiver of the full-avoided cost rule[174] and the opportunity to negotiate a contract at less than full-avoided cost [175] were available, "it was not unreasonable for the Commission to prescribe the maximum rate authorized by PURPA."[176]

In upholding the FERC's interconnection rule, the Court determined that the section 210(a) authority[177] of the FERC to promulgate any rules necessary to complete sales and purchases of power between qualifying facilities and utilities included the power to order interconnections. Interconnection was essential to consummating the sales and purchases of power mandated by the PURPA. The FERC was correct to interpret section 210(e)(3)[178] "as forbidding [the] FERC to exempt qualifying facilities from being the 'target' of

168. Georgia, Mississippi and West Virginia all acknowledged suspending § 210 proceedings while awaiting the outcome of the *Mississippi* case. Energy User's News, Apr. 5, 1982, 19-22.

169. Arkansas, Kansas, Mississippi, New York and West Virginia all appear to have taken the "go slow" approach pending the outcome of the *AEP* case. Energy User News, Apr. 5, 1982, 21; *id.* May 23, 1983, at 16; *Order on Cogeneration and Small Power Production (Kansas), in* THE APPROPRIATENESS AND FEASIBILITY OF VARIOUS METHODS OF CALCULATING AVOIDED COSTS. B-141 (1982) (Draft Document, National Regulatory Research Institute [hereinafter cited as NRRI Draft].

170. *Id.*

171. One commentator called the interconnection issue a "close one." Nowak, *supra* note 162, at 288.

172. Justice Powell did not participate in the decision.

173. 51 U.S.L.W. 4547 (1983).

174. 18 C.F.R. § 292.403 (1980).

175. *Id.* § 301(b)(1).

176. 51 U.S.L.W. 4547, 4550.

177. Section 210(a) grants the Commission authority to promulgate "such rules as it determines necessary to encourage cogeneration and small power production which rules require electric utilities to offer to—(1) sell electric energy to qualifying cogeneration facilities . . . and (2) purchase electric energy from such facilities." *See* 16 U.S.C.A. § 824-3(a) (West Supp. 1982).

178. *See supra* note 157.

interconnection applications by other facilities under the FPA, but not as forbidding FERC to grant qualifying facilities the right to obtain interconnections under PURPA without applying for an order under the FPA."[179] The Court noted that, to uphold the FERC rule, it only needed to find that the FERC's interpretation was *a* reasonable interpretation, and not that it was the *only* reasonable interpretation.[180]

Apparently the major court challenges to the PURPA provisions relating to cogenerators are over. Both the constitutionality of the law and the reasonableness of the Commission's rules enacting the law have been upheld. It is difficult to foresee any further challenges that states or utilities could mount on the federal level. After nearly six years of uncertainty, the federal mandate to encourage cogeneration has been upheld. A remaining question is whether the states diligently have pursued this federal mandate.

V. State Implementation of PURPA

The FERC gave the states one year to implement the section 210 rules and regulations. By the March 20, 1981 deadline, however, only sixteen states had final rules in place,[181] and some of these still had to establish purchase rates based on their final rules. Five other states had reversed the process and had established temporary purchase rates, pending the outcome of final proceedings.[182] Most of the other states appeared to have proceedings pending. Initial delays apparently were not caused by recalcitrance, but by delayed starts in initiating proceedings, unanticipated difficulties in calculating avoided costs and limited resources for the cogeneration proceeding because of other administrative burdens.[183] With the success of the Mississippi challenge to PURPA in the lower court, though, several states suspended proceedings to await the outcome of the Supreme Court's decision on PURPA's constitutionality.[184]

Nevertheless, by March 1982, only fourteen states did not have final rules in place. Thirty states had final rates in effect, and another half dozen were nearing implementation.[185] In June, the Supreme Court upheld PURPA's constitutionality, which meant that those states that had suspended proceedings once again were compelled to initiate action on section 210. The District of Columbia

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179. 51 U.S.L.W. 4547.

180. *Id.* at 4552.

181. *State's Cogeneration Rate-Setting Under PURPA,* Energy User News, Apr. 20, 1981, 13-14.

182. *Id.*

183. *States Move on Small Power, Cogeneration,* 16 POWERLINE, no. 9.

184. *See supra* note 168.

185. *States Cogeneration Rate-Setting Under PURPA,* Energy User News, Apr. 5, 1982, 19.

Circuit Court had rendered its decision on FERC's avoided cost rules in the interim, however, and state commissions still had cause to proceed slowly with section 210 implementation.[186] As a result of the uncertainty created by the two court decisions, six states and the District of Columbia still did not have final rules or rates established in March 1983, two years after the FERC mandated deadline and over four years after the passage of PURPA.[187]

A. State Proceedings on Section 210

While giving the states a great deal of flexibility in implemenation, the FERC's rules also placed a number of responsibilities on state public service commissions. Of greatest importance to most interested parties was the requirement that the state commissions set standard purchase rates for small cogenerators, those with a generating capacity of less than 100 kilowatts,[188] and establish a method of purchase from larger qualifying facilities.[189] PURPA also required the state commissions to set the rates or means of sale by utilities to cogenerators of supplementary, backup, maintenance and interruptible power.[190] Additionally, the state commissions were required to set the conditions of interconnection including the operational standards required[191] and the costs to be borne by the cogenerator.[192] Finally, the state commissions had to establish data filing requirements that would permit the would-be cogenerator to determine or verify the avoided costs likely to be paid by the utility.[193]

In their initial orders, only a few states addressed the issues of sale of power to cogenerators or establishment of guidelines for interconnection. Most states concentrated almost entirely on establishing the methods for determining utility avoided costs and the rates for purchase of power by utilities from qualifying facilities (QFs). In pursuing this task, state commissions adopted diverse approaches to the task most of them pursued, the establishment of purchase rates based on avoided costs.

186. *See supra* note 169.
187. *Questions and Answers,* Energy User News, Mar. 7, 1983, 2.
188. 18 C.F.R. § 292.304(c) (1980).
189. 16 U.S.C.A. § 824a-3(f) (West Supp. 1982).
190. *See supra* note 88 for definition of backup and maintenance power. The FERC defined interruptible power as "energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions." 18 C.F.R. § 292.101(b)(10) (1980). Supplementary power was defined as "energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself." *Id.* § 292.101(8) (1980). For the general obligation to provide such rates, see *id.* § 292.305(b) (1980).
191. *Id.* § 292.308 (1980).
192. *Id.* § 292.306 (1980).
193. *Id.* § 292.302(b) (1980).

B. *State Approaches To Setting Purchase Rates*

Traditionally, utility rates have been based on average or embedded costs. Although numerous commentators have noticed a rising marginal cost curve for the electric utility industry in recent years,[194] few state commissions studied marginal pricing concepts until PURPA mandated a review of rates based on these principles.[195] Thus, most state commissions required to set rates for self-generators based on the incremental costs avoided by the utility from such purchases were completely unfamiliar with the procedures to carry out this mandate.[196] Moreover, since all these states simultaneously were initiating procedures to establish these rates, no state could model its laws after the laws of another state.[197]

Theoretically, to set avoided cost rates one must calculate a utility's costs before any purchases of power from qualifying facilities. Then the costs must be calculated after allowing for purchases from these facilities. The difference between these two figures is prorated among all facilities supplying power to the utility. Commissions immediately discovered that this system of calculation hid numerous complexities. Not only do the numerous projections and hypotheses of the analytical model make commission verification of allowed costs difficult, but the various factors that the FERC mandated commissions to consider when setting purchase rates[198] implied that commissions might have to set a variety of purchase rates. Even the FERC noted that "the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise."[199]

While a utility might purchase 100 MW of cogenerated power, only 50 MW of this power might flow into the grid at the time of day when high demand requires the burning of expensive oil or the use of inefficient old plants. Moreover, of this 50 MW production, only

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194. *See, e.g.,* A. Thompson, *The Strategic Dilemma of Electric Utilities—Part I,* 109 PUBLIC UTILITIES FORTNIGHTLY 19, 19-28 (Mar. 18, 1982); A. Alm & D. Dreyfus, *Utilities in Crisis: A Problem in Governance,* Forum Sponsored by the Committee on Energy of the Aspen Institute for Humanistic Studies, July 16, 1981, New York, Aspen Institute for Humanistic Studies, 1982, cited in *Senate Hearing, Part I, supra* note 118; J. Pace & J. Landon, *Introducing Competition Into the Electric Utility Industry: An Economic Appraisal,* 3 ENERGY L.J. 1 (1982); W. Primeaux, Jr., *Some Problems with Natural Monopoly,* 24 ANTITRUST BULL. 63, 68-85 (1979).

195. *See* 16 U.S.C.A. § 2621(d) (West Supp. 1982).

196. The Utah Public Service Commission, for example, conceded that "[t]he concept of avoided-cost based rates is new to this Commission and [presents] difficulties that are yet to be satisfactorily resolved." *In re* Implementation of Rules Governing Cogeneration and Small Power Production in the State of Utah, in NRRI Draft, *supra* note 169, at B-364.

197. The Idaho Public Utility Commission noted that "we are writing on a clean slate with little guidance from other commissions around the country." Rulemaking Proceeding for Consideration of Cogeneration and Small Power Production, 40 Pub. Util. Rep. 4th (PUR) 563, 565 (1981).

198. *Supra* note 20.

199. 45 Fed. Reg. 12,226 (1980).

25 MW might be committed to the grid on long-term contract. Commissions, therefore, grappled with questions like the following: How much more valuable is available power at peak hours than at off-peak hours? Is it necessary to know a utility's avoided costs and a self-generator's supply pattern on an hourly basis, or would such regulation place an undue transactional burden on all parties? Should QFs supplying the 25 MW of long-term power be entitled to higher rates because the utility can depend on their capacity in system planning, or, since all QFs are not likely to cease production simultaneously, is it possible to assign some capacity value to non-contractual power in system planning? The manner in which commissions resolved these and a myriad of other issues greatly affected the final purchase rates and the resultant incentive for cogeneration.

Some states, believing either that self-generated power was likely to be an insignificant source of power for their utilities or that specifying detailed retail rates or methodologies was not an appropriate commission activity, did little more than restate the PURPA guidelines in their orders. These states left the development of appropriate methodologies and rates to utility discretion.[200] This approach avoided the thorny issues raised by avoided-cost ratemaking.

Other states, however, took the PURPA mandate seriously and promulgated lengthy orders detailing the procedures to be followed in setting purchase rates.[201] Some held extensive hearings on rates proposed for cogenerators by jurisdictional utilities.[202] In all, twenty-two states[203] decided to direct the procedures used by jurisdictional utilities in the establishment of purchase rates.

1. The Energy Credit.—The most common methodology prescribed by state commissions for determining avoided fuel costs has been termed the "incremental heat rate approach."[204] This method involves estimating the heat rate of a certain increment of system load[205] and then multiplying this figure by the cost of the fuel re-

200. *See, e.g.,* 4 MO. ADMIN. CODE 240-20.060 (1982); WASH. ADMIN. CODE R. 480-105 (1982).

201. *See, e.g.,* Rulemaking Proceeding for Consideration of Cogeneration and Small Power Production, 38 Pub. Util. Rep. 4th (PUR) 352 (Idaho 1981); 40 Pub. Util. Rep. 4th (PUR) 563 (Idaho 1981) (same case); *See also In re* Idaho Power Co., 44 Pub. Util. Reg. 4th (PUR) 160 (Idaho 1981); *In re* Cogeneration and Small Power Production, 42 Pub. Util. Rep. 4th (PUR) 536 (Me. 1981); 47 Pub. Util. Rep. 4th (PUR) 327 (Me. 1982) (same case).

202. *See, e.g., In re* Cogeneration and Small Power Production, 48 Pub. Util. Rep. 4th (PUR) 465 (Mich. 1982); *In re* Consolidated Edison Company of New York, 48 Pub. Util. Rep. 4th (PUR) 94 (N.Y. 1982).

203. The twenty-two states are: California, Connecticut, Florida, Idaho, Iowa, Kansas, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Utah, Vermont and Virginia.

204. *See* NRRI Report, *The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs,* 85 (June 1982) [hereinafter cited as NRRI Report].

205. The heat rate indicates the amount of energy (in British thermal units) required to

quired to produce these BTUs. Thus, at a time of day when system load requires only modern baseload plants fueled by coal or uranium, the energy cost of a kilowatt of electricity is quite low.[206] When inefficient older plants, peaking plants or oil-fired plants must come on line, fuel costs rise considerably.[207]

The final value assigned as avoided fuel cost, however, depends on a number of variables commissions may or may not leave to utility discretion. One such variable is the size of the incremental block that is used for determining heat rates and fuel costs. The FERC guidelines stated that a utility may use an incremental block of 100 MW or 10 percent of system load, whichever is less.[208] Some commissions, however, made the incremental block much smaller,[209] which theoretically should have increased the avoided cost payment to cogenerators.[210]

A variation on the incremental approach mandated by some commissions involved the use of system lambda[211] data and production cost models. The Florida PSC mandated that utilities use a production cost model to isolate the last 1 MW of power produced and calculated its estimated costs on an hourly basis. Initial payments to QFs would be based on these estimates, but payments later would be adjusted according to the real time costs reported in system lambda data.[212] The Massachusetts DPU also mandated use of a production

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produce a kilowatt-hour of electricity. The heat rate can vary considerably depending on the efficiency of the generating units in operation.

206. Florida Power and Light estimated its fuel costs to be 4.46 mills/kwh for a nuclear power plant in 1981. MOODY'S PUBLIC UTILITY MANUAL 730 (1982).

207. Florida Power and Light estimated its fuel costs to be 46.28 mills/kwh for oil generating units and 52.36 mills/kwh for gas turbine peaking units in 1981. *Id.*

208. 18 C.F.R. § 292.301(b)(1) (1980).

209. Rhode Island, for example mandated a block representing a 1 percent decrement in system load, while Maine required the use of 10 or 50 MW blocks, depending on the size of the utility. *In re* Cogeneration and Small Power Production, 42 Pub. Util. Rep. 4th (PUR) 609, 614 (R.I. 1981); *In re* Cogeneration and Small Power Production, 42 Pub. Util. Rep. 4th (PUR) 536, 540 (Me. 1981).

The Massachusetts DPU, however, noting that theory does not always mirror reality, required utilities to calculate avoided costs for both 10 and 20 percent decrements in system load and then to base rates on the larger of the two incremental costs figures thus obtained. Analysis of the Rules Promulgated by the Department of Public Utilities Governing the Sales of Electricity by Small Power Producers and Cogenerators to Utilities and the Sales of Electricity by Utilities to Small Power Producers and Cogenerators, NRRI Draft, *supra* note 169, at B-177.

210. If the electric utility's last ten MWs of power is generated by a gas turbine unit with a fuel cost of 52 mills/kwh, then this would be the avoided energy cost payable to cogenerators if the incremental block chosen was also 10 MW. *See supra* note 204. If, however, the previous 90 MW had been generated by coal at a cost of 12 mills/kwh and the incremental block chosen was 100 MW, then the avoided energy cost payable to cogenerators would be .9(12) + .1(52) = 16 mills/kwh.

211. System lambda is the cost of the next MWh to be produced and delivered to the grid, or, the marginal running cost of the utility. Typically, utilities dispatch units to minimize system lambda. To do this, they estimate system lambdas for each hour of the day throughout the year.

212. *In re* Cogeneration and Small Power Production, 47 Pub. Util. Rep. 4th (PUR) 281, 284 (1982).

cost model. In Massachusetts' case, however, payments to cogenerators were based on the *projected* savings to the utility rather than on real time running costs as in Florida.[213]

Instead of specifying an incremental block, the Oklahoma and North Carolina commissions ordered the use of system lambda curves to determine which generating unit the utility next should bring on line.[214] Energy costs then were calculated on the basis of the fuel and variable operating costs of this plant. In pursuing this "marginal unit" approach, a commission could authorize the use of the energy costs of the *last* unit already brought on line or the costs of the *next* unit to be brought on line. Choosing the last unit already on line would benefit ratepayers, but choosing the next unit to come on line would encourage more cogeneration.

If a production costing model was not used, then a suitable value was required to be ascertained for the fuel cost applicable to the incremental heat rate. Since fuel costs are the major component of the energy credit, they also were an important variable in establishing the final purchase rate. The California PUC, for example, decided that, since California utilities burned oil extensively,[215] the appropriate measure of avoided fuel costs was the *estimated* or projected cost of low sulfur fuel oil.[216] Although Connecticut's utilities also burned oil extensively,[217] the Connecticut DPUC mandated the use of the *historical, average* fossil fuel cost as determined over the previous twelve month period.[218] Not surprisingly, Connecticut's approach resulted in a fuel credit lower than California's.[219]

213. NRRI Draft, *supra* note 169, at B-176.

214. North Carolina chose to use an elaborate production model that calculated system lambda on an hourly bases throughout the year. The commission then pro-rated these costs to obtain purchase rates covering daily and seasonal off-peak and on-peak periods. *Findings of fact and pursuant evidence and conclusions of the North Carolina Utilities Commission with respect to rates for cogenerated power,* in NRRI Draft, *supra* note 169, at B-240.

The Oklahoma commission in its interim order chose merely to specify that the energy component of the avoided cost payment should be based on the cost per kilowatt-hour of energy generated by the next generating unit to be brought on line. *See* NRRI Draft, *supra* note 169, at 17.

215. One survey showed the aggregate fuel composition of California utilities to be 67% oil, 25% hydro, 4% nuclear, 1% natural gas and 3% miscellaneous. H. Lock & J. VanKuiken, *Cogeneration and Small Power Production: State of PURPA 210 Implementation,* 3 SOLAR L. REP. 657, 688 (1981) [hereinafter cited as Lock & VanKuiken].

216. *In re* Pacific Gas & Electric Company, 34 Pub. Util. Rep. 4th (PUR) 140, 160 (1980).

217. *See* Lock & VanKuiken, *supra* note 215, at 689. This survey reported the aggregate fuel composition of Connecticut utilities to be 60% oil, 38% nuclear and 2% hydro.

218. This figure then was multiplied by the ratio of the marginal heat rate to the system average heat rate to obtain the fuel credit. That is, cogenerators providing firm power received 117% the average fossil fuel cost at on-peak periods and 92% the average fossil fuel cost at off-peak periods if they sold power to Connecticut Light & Power or the United Illuminating Company. *Self-Generator Rate Development, Connecticut Department of Public Utility Control,* in NRRI Draft, *supra* note 169, at B-77.

219. *See supra* note 85 for sample PURPA rates. Other commissions permitted several of the above approaches. For example, Idaho decided that fuel costs could be based either on historical or actual costs. If based on actual costs, however, then time-of-day metering had to

Some commissions decided to avoid the difficulty of verifying utility production models and the expense to commissions and would-be cogenerators in independently duplicating these purchase figures, by specifying a generating unit for utilities to use in calculating avoided energy costs. While not as accurate in mirroring system costs, this approach made it easier for cogenerators to ascertain the energy credit they would receive for power produced. Thus, New Hampshire set a purchase rate based on the most modern oil generating station in the state,[220] while the Oregon PUC was required by an act of the state legislature to set a minimum rate for cogenerators at the fuel cost of the highest cost baseload plant currently serving that state.[221]

Another approach used by commissions to provide a simpler and more easily verifiable purchase rate was to require the use of the energy component of power purchased from a pool[222] as a proxy for avoided costs. Both Iowa and New Jersey authorized the billing rate for energy purchased from a pool as the acceptable measure of avoided energy costs for utilities participting in pool arrangements.[223]

While the billing rate of power from a pool might be an appropriate proxy of avoided costs for nongenerating utilities or utilities that could never meet full load, participation in pools by generating utilities to gain the advantages of central dispatch created more thorny issues for state commissions. With central dispatch of power, the pool brings lower cost units on line first and often charges the participating utilities a price midway between the costs of pool power and the costs the utility would have incurred but for the pool.

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be employed to correlate power delivery with production costs. *Cogeneration and Small Power Production (Idaho),* 107 PUBLIC UTILITIES FORNIGHTLY 58 (May 7, 1981).

220. An allowance was made for more expensive generation when this unit was down. R. Lock *Statewide Purchase Rates Under § 210 of PURPA,* 3 SOLAR L. REP. 419, 419-52 (1981) [hereinafter cited as Lock].

221. The Portland General Electric coal-fired plant at Boardman, Oregon has been used to calculate this base rate. Order No. 82-515 (reported in 12 REG. INFO. EXCHANGE BULL. 53 (Oct. 1982)) [hereinafter cited as REG. INFO. EXCHANGE].

Some Commissions left this unit-specified approach as an option for at least some utilities. While mandating the production costing approach for large utilities, for example, Massachusetts allowed small utilities that might not have elaborate production models to specify an appropriate unit to be used for such calculation instead. NRRI Draft, *supra* note 169, at B-177.

222. A power pool is a group of utilities which conduct sales and purchases of electricity among the member utilities to meet peak power needs more reliably or to provide more economical service. For example, if two utilities have peak demand at different times of the day, then if they pool their resources they need fewer generating units than if each operated independently.

223. *In re* Iowa State Commerce Commission Rules Regarding Rates for Cogeneration and Small Power Production, NRRI Draft, *supra* note 167, at B-118. New Jersey actually authorized an energy credit 10% above the billing rate. *See supra* note 49 and accompanying text. *In re* the Consideration and Determination of Cogeneration and Small Power Production Standards Pursuant to the Public Utility Regulatory Policies Act of 1978 (New Jersey), NRRI Draft, *supra* note 169, at B-224.

Thus, utilities with low cost, efficient plants become sellers to the pool and reap a profit that is half the difference between their running costs and those of the purchasing utilities. The purchasing utilities save a similar amount in running costs. This "split-the-savings" approach raised the question whether avoided costs should be calculated on the running costs a utility would have incurred *but for* the pool, or on a utility's actual costs of power as the result of obtaining pool savings.

Utilities purchasing power from such a pool argued to the Connecticut DPUC that their ratepayers would lose the savings that these purchases permitted if the utilities were to forfeit this cheaper pool power and to pay avoided cost rates based on the power they otherwise would have generated without pool participation. The Department responded to this argument and permitted a 5 percent reduction in the energy credit paid by these utilities to reflect the loss of a power pool savings share when a utility purchased from a qualifying facility instead of from the pool.[224] The Massachusetts DPU noted, however, that selling utilities *gained* from QF purchases; QF purchases gave selling utilities more power to sell to the pool but maintained the amount of avoided costs. The Department, therefore, developed a formula through which rates for a QF would be increased or decreased depending on whether the utility was a net seller or buyer during the period in question.[225]

Other commissions concentrated on the manner in which pools affected generating utilities' running costs rather than billing rates. Both the Florida and New York state commissions, for example, noted that selling utilities incurred higher energy costs than they otherwise would have if they did not make off-system sales to the pool. Purchasing utilities, on the other hand, incurred lower costs than they would have if they had run their less efficient equipment instead of making economy purchases. Supporters of cogeneration argued that maximum incentives would result if avoided costs were calculated on a selling utility's running costs after all off-system sales were made, and a purchasing utility's costs were calculated as if it could make no off-system purchases. Utility and ratepayer advocates argued that avoided costs should be calculated for both buying and selling utilities before any off-system sales or purchases were made.

224. NRRI Draft, *supra* note 218, at B-75.

225. The DPU specified the "Savings Share Avoided Cost" as $SS=[(EX - IM)/(EX + IM)] \times VSS$, where: SS is the avoided cost of the pool savings share; EX is the number of hours of export of power to the pool in the same seasonal period one year before the rating period, adjusted for scheduled maintenance; IM is the number of hours of import over the same time period; VSS is the weighted average value of pool savings share per kilowatt-hour from the most recent period of the same length as the projected period. *Id.* at B-178.

The Commissions that investigated these problems most thoroughly tended to compromise. Florida decided that selling utilities should calculate avoided energy costs before off-system sales were made, but purchasing utilities should make such calculations after economy purchases were made.[226] New York decided that the energy credit should be based on the average of the running costs of the pool and of the plant the utility would have run, but for the pool.[227] Vermont reasoned that, since all its jurisdictional utilities belonged to NEPOOL,[228] and NEPOOL was virtually always burning oil, the running cost of three of the pool's most efficient oil-fired baseload plants was the most appropriate measure of the energy credit due cogenerators.[229]

If a nongenerating utility did not belong to a pool but bought power from a single utility system, commissions employed similar approaches. Some, like Kansas, chose the energy component of the wholesale billing rate as the appropriate measure of avoided costs.[230] These commissions argued that the energy component of the billing rate was the only cost that a nongenerating utility actually could avoid. Other commissions, like Rhode Island, however, asked that the nongenerating utility supply the avoided cost data of its supplying utility.[231] Many commissions argued that the wholesale billing rate often reflects average energy costs rather than the costs avoided by the supplying utility on the margin. Again commissions were required to choose between maintaining ratepayers' benefits and encouraging cogeneration.

Only one commission whose orders were reviewed expressly stated that the energy credit offered by jurisdictional utilities should be based on embedded energy costs. The Kansas commission, which issued its order while the *AEP* case was pending, justified this approach on the grounds that the FERC rule might be changed at any time as the result of the uncertainty surrounding that rule.[232] Lowering the rate offered in the near future after an adverse decision would have been detrimental to investors. The Kansas commission further reasoned that, since other utility rates were based on embedded energy costs, cogenerator rates also should be based on embedded costs.

226. *In re* Cogenerators and Small Power Producers, 47 Pub. Util. Rep. 4th (PUR) 281, 286 (1982).

227. This approach benefited purchasing utilities, in particularly, Consolidated Edison. It gave slightly higher avoided costs than would otherwise have been the case to upstate utilities that sold power. *In re* Consolidated Edison Co., 48 Pub. Util. Rep. 4th (PUR) 94, 101 (1982).

228. NEPOOL is the New England Power Pool Agreement.

229. Lock, *supra* note 220, a 426.

230. NRRI Draft, *supra* note 169, at B-143.

231. 42 Pub. Util. Rep. 4th (PUR) 609, 613 (1981).

232. NRRI Draft, *supra* note 169, at B-143.

At least half the states offered a "net billing" option. By running the meter backwards when the cogenerator is supplying power to the utility, this method effectively pays the embedded costs of both energy and capacity.[233] Only the net surplus or deficit of power generated is noted on the cogenerator's bill at the end of the month. Many commissions justified the use of this approach for small cogenerators on the basis of the extensive costs associated with dual metering and with calculation of time-of-delivery payments. Without this approach, the commissions argued, there would be a strong economic disincentive for small self-generators, which was contrary to the intent of PURPA.[234]

A number of states included in the energy credit other allowances or incentives based on some of the factors the FERC guidelines had required commissions to consider.[235] Many of the commissions that did not use production costing models, for example, specifically requested that variable operation and maintenance costs be included in the energy credit. While most commissions left the exact amount of this allowance to utility discretion, the Maine PUC established a rebuttable presumption that the allowance was 3 mills/kwh.[236] Most other commissions specified the source of these costs to be, for example, system lambda data or section 133 filings.[237]

An allowance for line losses in the transmission of power was another frequently specified item. Because cogenerators often are

233. The exact number of states offering this option is difficult to ascertain, since some states simply assumed that cogenerators would supply only surplus energy to the grid and did not discuss the metering options available in their orders. Missouri, for example, made this assumption. Telephone Interview with Bill Washburn, Missouri PSC.

Other states specifically noted this option while expressing some limitation on its use. Arkansas, Idaho, Maine, Massachusetts and Pennsylvania all limited the size of cogenerators to whom this option was available, while California determined that any facility using this option must then have a rate schedule with standby and backup rates. *In re* Rules Regulating the Rates and Service of Cogenerators and Small Power Producers (Arkansas), NRRI Draft, *supra* note 169, at B-19; 38 Pub. Util. Rep. 4th (PUR) 352, 376 (Idaho 1980); 42 Pub. Util. Rep. 4th (PUR) 536, 539 (Me. 1981); *supra* note 209, at B-175 (Mass.); 52 PA. ADMIN. CODE § 57.34(b)(i) (Shepard's 1983); 34 Pub. Util. Rep. 4th (PUR) 148, 162 (Cal. 1980).

234. The FERC itself appeared to be somewhat equivocal about the appropriateness of this option, stating that it did not believe that "this is the only practical or appropriate method to establish rates for small qualifying facilities," and that "net energy billing is likely to be appropriate when the retail rates are marginal cost-based, time-of-day rates." 45 Fed. Reg. 12,224 (1980).

235. *Supra* note 20; 18 C.F.R. § 292.304(e) (1980).

236. 42 Pub. Util. Rep. 4th (PUR) 536, 543 (1981).

237. Section 133 of PURPA required utilities with retail sales in excess of 500 million kwh per year to file certain data on their marginal costs. While not directly translatable into PURPA rates, this data could be useful in establishing or verifying components of the purchase rate offered. Connecticut, Florida, Massachusetts, Montana, New Hampshire, North Carolina and Kansas all specified the inclusion of variable operation and maintenance and some source for obtaining avoided cost data. *In re* Connecticut Light and Power Co., 41 Pub. Util. Rep. 4th (PUR) 1, 46 (Conn. 1981); 47 Pub. Util. Rep. 4th (PUR) 281, 284 (Fla. 1982); *In re* Cogenerators and Small Power Producers, 45 Pub. Util. Rep. 4th 196, 202 (Mont. 1982); Lock, *supra* note 217, at 423 (N.H.); NRRI Draft, *supra* note 169, at B-142 (Kan.), B-236 (N.C.).

situated more closely to the actual points of power consumption than are remote central generating stations, commissions felt that cogenerators should receive an allowance for the transmission losses the utility would avoid. Some commissions set a specific figure for this allowance.[238] Others varied the credit according to the voltage level of the cogenerators.[239] Rhode Island, however, followed the theoretically correct approach and asked utilities to determine the line loss credit on a case-by-case basis.[240]

A number of allowances were mandated by only one or two commissions. Montana and North Carolina both asked for the inclusion of an allowance for changes in working capital,[241] while Connecticut and New Hampshire mandated an allowance for reductions in inventory, handling and depreciation.[242] The Maine PUC offered a 3 percent increase in payment for utility dispatch[243] and a 1 percent increase for co-ordinated maintenance.[244] Vermont included a generous "inflation factor" of 20 percent.[245] Connecticut, although it did not offer a capacity payment, determined that firm energy was nevertheless worth more than as-available energy and offered a 3 percent incentive for firm power.[246] New Jersey mandated a 10 percent increase in the energy credit based on the benefit to the state and to the nation in reducing use of imported oil.[247]

Of the thirty-six states for which information on the standard purchase rates was available,[248] the energy component of the rate varied by more than a factor of eight. Vermont offered the highest rate: 9 cents per kilowatt-hour generated on peak and 6.6 cents per

238. Montana, for example, specified a line loss factor of 8.3% to be paid by the Montana Power Company—the load weighted transmission losses of the utility system. 45 Pub. Util. Rep. 4th (PUR) 196, 201 (Mont. 1982). Florida issues a more general order requiring utilities to pay the inverse of their fuel and purchase power cost recovery factors. 46 Pub. Util. Rep. 4th (PUR) 282, 286 (Fla. 1982). Kansas only offered one-half the authorized line-loss factor. NRRI Draft, *supra* note 169, at B-152.

239. Connecticut varied the line loss factor according to the time-of-day, the distribution level and the voltage level of the qualifying facility. Credits ranged from 2.4% if power was supplied off-peak, at over 2.4 kV and at the primary distribution level, 8.7% if supplied on-peak, at under 2.4 kV and at the secondary distribution level. NRRI Draft, *supra* note 218, at B-77. Massachusetts set different rates for those transmitting power at less than 4 kv, between 4 and 14 kv, between 14 and 115 kv, and over 115 kv. *See* Energy User News, Apr. 5, 1982, 20.

240. 42 Pub. Util. Rep. 4th (PUR) 609, 612 (1981).

241. 45 Pub. Util. Rep. 4th (PUR) 196, 202 (Mont. 1982); NRRI Draft, *supra* note 169, at B-241 (N.C.).

242. 41 Pub. Util. Rep. 4th (PUR) 1, 46 (Conn. 1981); Lock, *supra* note 220, at 424 (N.H.).

243. Utility dispatch permits the utility to control the dispatch of the cogenerator's power. 42 Pub. Util. Rep. 4th (PUR) 536, 551 (1981).

244. Co-ordinated maintenance permits the scheduling of the qualifying facility's maintenance at the convenience of the utility. *Id.*

245. Lock, *supra* note 220, at 426.

246. NRRI Draft, *supra* note 169, at B-78.

247. *Id.* at B-224.

248. These rates generally applied in the spring of 1982 and were reported in Energy User News, Apr. 5, 1982.

kilowatt-hour generated off peak.[249] An Indiana utility offered the lowest rates: 1.36 cents per kilowatt-hour generated on peak and .81 cents per kilowatt-hour generated off peak. Even within a state the energy credit could vary considerably, presumably because of utility differences in fuel mixes. Table A-1 in the Appendix demonstrates a considerable difference in the purchase rates of Gulf Power and Tampa Electric in Florida.[250]

While a large part of this variation can be attributed directly to fuel costs,[251] the variation also is due to the methologies chosen by commissions to calculate avoided energy costs and the additional costs or incentives they chose to include in this credit. Commissions often were required to choose between approaches that minimized costs to utilities and, presumably, costs to ratepayers and ones that offered more encouragement to cogenerators. Some commissions felt that the extrinsic values of cogeneration, like reducing the use of imported oil, increasing source diversification and keeping power purchases within the local economy, more than offset the small additional burden that marginal cost ratesetting might place on ratepayers. Others did not.[252]

2. *The Capacity Credit.*—Because the FERC mandated payment of a capacity credit only if a utility needed new capacity,[253] all commissions did not include a determination of or a method for determining a capacity component in the standard rate. Alabama, Connecticut, Delaware, Rhode Island and Vermont all declared that their utilities had excess capacity[254] and thus rendered unnecessary the development of a methodology for determining qualification for a capacity credit.

Other commissions, often appearing to be overwhelmed by the burden of ascertaining the accurate cost of avoided capacity, left the payment of a capacity credit to the discretion of the utility. The Florida PSC vacated its original rule on capacity payments as giving too little guidance and left such payments to the discretion of the

249. Although one of Consolidated Edison's tariffs is higher than Vermont's, it includes a capacity component and thus is inappropriate for comparison.

250. *See supra* text accompanying note 267.

251. In 1981 coal accounted for 89% of the fuel burned in Indiana utilities. Lock and VanKuiken, *supra* note 215, at 691. Vermont utilities, however, as participants in NEPOOL, virtually always burned oil on the margin. *See supra* note 47.

252. The New York PSC flatly stated, "Our goal is to see that the Con Edison tariffs are neither an artificial barrier, nor a spur, to the development of on-site generation in its service territory." 48 Pub. Util. Rep. 4th (PUR) 94, 99 (1983). To date no one appears to have raised the issue whether this goal is in harmony with the PURPA mandate to encourage cogeneration.

253. *See supra* note 86 and accompanying text.

254. *Calculating Capacity Costs in Cogenerated Rates,* 108 PUBLIC UTILITIES FORTNIGHTLY 57, 58 (Ala.) (Sept. 24, 1981); NRRI Draft, *supra* note 169, at B-3 (Del.); B-80 (Conn.); 42 Pub. Util. Rep. 4th (PUR) 609, 615 (R.I. 1981); Lock, *supra* note 220, 426.

utility in case-by-case negotiation until such time as the PSC could return to rulemaking on the issue.[255] The Illinois Commerce Commission also found it difficult to ascertain a utility's avoided costs and decided to leave such payments indefinitely to "good faith" negotiations between the utility and the QF.[256]

Some commissions appeared to be irritated with the FERC for requiring them to implement the payment of a credit that the FERC itself had admitted was difficult to determine. The Massachusetts DPU, while dutifully prescribing a procedure for calculation of a capacity credit for the standard rate, called such a determination a "fool's errand."[257] In spite of the difficulties involved, however, over half the states whose orders were reviewed made an attempt to prescribe a method for calculating the capacity credit.

The most common method prescribed for determining the capacity credit is the unit specified approach. Under this approach the commission determined an appropriate generating unit for calculating the capacity payment. For example, the California PUC decided that, since new capacity was required only because of demand in peak generating hours, the appropriate measure of avoided capacity was a gas turbine generating unit.[258] New Jersey also chose such a unit, not because of the need for new capacity, but because either a gas turbine unit or cogeneration would offer a more optimal mix in a utility system overly dependent on oil.[259]

North Carolina chose a gas turbine unit as the appropriate measure of avoided capacity for a short-term contract, but felt that a more expensive baseload generating unit was the appropriate measure if a QF entered into a contract of 11 years or more (the approximate time it takes to bring a baseload plant on line).[260] Other variations on this approach included that the Pennsylvania commission's, which permitted any QF willing to enter a long-term contract to choose the unit on which the capacity payments would be based if the utility had planned more than one plant addition.[261] The Oregon Legislature mandated a minimum capacity credit, like its minimum energy credit, based on the highest cost baseload plant in the state. The size of the credit was tied to the length of the contract.[262]

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255. 47 Pub. Util. Rep. 4th (PUR) 282, 288 (1982).

256. *Calculating Capacity Costs in Cogenerated Rates,* 108 PUBLIC UTILITIES FORTNIGHTLY 59 (Sept. 24, 1981).

257. NRRI Draft, *supra* note 169, at B-166.

258. 34 Pub. Util. Rep. 4th (PUR) 148, 160 (1980).

259. NRRI Draft, *supra* note 169, at B-255.

260. *Id.* at B-237. Montana took an approach similar to North Carolina's, but authorized the higher capacity payment if a QF entered a contract for more than four years. 45 Pub. Util. Rep. 4th (PUR) 196, 202 (1982).

261. 52 PA. ADMIN. CODE § 57, 34(c)(4)(C)(iv) (Shepard's 1983).

262. Again, the Portland General Electric plant was used to calculate avoided costs. The minimum capacity credit to be offered, based on this plant's cost, was: $2.20 + n(.04975),

The determinations made by Utah and Idaho regarding Utah Power present a graphic example of the manner in which commission decisions radically could affect the size of payments to cogenerators. The Utah commission approved a capacity credit of 26 mills per kilowatt-hour based on the composite cost of 35 mills per kilowatt-hour of Utah Power's planned Hunter II nuclear power plant. The Idaho commission approved a composite capacity credit of 51.7 mills per kilowatt-hour based on Utah Power's planned Hunter III and IV nuclear power plants.[263] While the unit specified approach may have simplified the task of both commissions in determining a capacity credit, the discrepancy in choices demonstrates the inaccuracies involved in choosing one unit on which to base avoided costs instead of considering system-wide savings resulted from the addition of cogenerators.

A second method chosen by a number of state commissions for its simplicity and ease of administration was pricing the capacity credit at the cost of capacity bought form a pool. Both Massachusetts and New Jersey determined that capacity deficient utilities should pay cogenerators at the rate of the capacity deficiency charge the utilities paid to their respective power pools.[264] A number of other commissions also adopted this approach towards nongenerating utilities and specified that the capacity component of the wholesale rate of power purchased from another utility was an acceptable measure of avoided cost.[265]

The Texas Task Force on Cogeneration, however, noted that nongenerating utilities often are tied into long-term capacity contracts and cannot avoid these payments merely by purchasing power from cogenerators. The Task Force thus recommended avoidance of capacity payments by nongenerating utilities unless the nongenerating utilities then could reduce their contracted capacity payments to supplying utilities.[266] The FERC, however, noted in its commentary on the section 210 rules that "the mandate of PURPA to encourage cogeneration and small power production requires that obligations to purchase under this provision supercede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility."[267] The Texas position, therefore, does not appear to conform with the FERC's guidelines.

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where n is the number of years in the contract (varying from 1 to 35) and payment is in $/kw-month. *See supra* REG. INFO. EXCHANGE note 221, at 54.

263. The Utah PSC noted this discrepancy along ith Utah Power's belief that the Idaho figure represented an "unwarranted subsidization of qualifying facilities." NRRI Draft, *supra* note 169, at B-362.

264. *Id.* at B-181 (Mass.); B-224 (N.J.).

265. Oklahoma and Iowa approved this approach where applicable. *See id.* at 17; B-118.

266. *Id.* at B-339.

267. 45 Fed. Reg. 12,219 (1980).

A third approach embraced by commissions has been to set the capacity credit at the utility's carrying charge for prospective capacity. Thus, the Oklahoma Corporation Commission required an estimate of the annual carrying charge of the next generating unit to come on line, which then was divided by the anticipated number of hours this unit would operate per year, to determine the capacity payment per kilowatt hour available to cogenerators.[268]

The most sophisticated approach to determining the capacity payment has been termed the "differential revenue requirement method."[269] Under this formula, a utility or commission determines its optimum capacity expansion plan without QFs. Then it reoptimizes the plan considering the input of QFs to the grid. The difference in capital costs between these two plans represents the avoided capacity costs available to QFs. Both Maine and Texas have implemented variations of this approach.[270]

The differential revenue requirement method, though theoretically correct, requires highly sophisticated planning models for implementation. Many commissions simply do not have the computer or human resources to utilize such an approach or to verify utility computations using this approach.[271] Furthermore, implementation requires many assumptions about future load requirements and the relative costs of various types of new generating capacity.

A number of commissions noted the FERC's comment that payment of an energy credit based on current high fuel prices and a capacity credit based on the high costs of a baseload plant to a cogenerator results in an overpayment of avoided costs by the utility. These commissions, therefore, when approving a capacity credit, revised the energy credit to reflect the cost of energy for the unit specified plant.[272]

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268. That is, $CC = [AC/(8760 \times \text{capacity utilization})]REP$, where CC is the capacity component, AC is the present value of the annual carrying charge, 8760 is the number of hours in the year, and REP is the "relative efficiency at peak" of the power producer (an estimation of the correlation of self-generation with utility peak demand). NRRI Draft, *supra* note 169, at 17. This approach has been called the "simplified incremental cost approach" by the NRRI, since it can also be applied to system wide planned additions to achieve an average capacity carrying charge. NRRI Report, *supra* note 204, at 97.

269. NRRI Report, *supra* note 204, at 94.

270. 42 Pub. Util. Rep. 4th (PUR) 536, 541 (Me. 1981); *see also* NRRI Draft, *supra* note 169, at B-351 (Tex.).

271. In 1980 it was reported, for example, that Colorado had only fourteen professionals on its PUC staff dealing with electric utility regulation. Dean, *supra* note 40, at 157. Furthermore, a study by the National Association of Regulatory Utility Commissioners (NARUC) revealed that only 23 states perform in-house load forecasting or hire consultants for forecasting. The remaining states either rely on utility forecasts or indicate no involvement with load forecasting at all. NRRI Report, *supra* note 204, at 72 (citing NARUC, *1980 Annual Report on Utility and Carrier Regulation* 675 (1981)).

272. Montana stated that the energy component of long-term rates should be based on the "projected running costs of the next baseload plant," whereas the energy component of short-term rates was based on a "one contract year projection of annual load weighted average system lambda." 45 Pub. Util. Rep. 4th (PUR) 196, 203 (1982). Commissions that chose a

A final issue confronted by commissions in setting both energy and capacity credits involved the frequency of rate update. If payment was based on actual time of delivery costs, this issue did not arise. If rates were based either on projections of costs or historical averages, however, the commissions had to decide the frequency with which the averages or projections would be updated. Most commissions chose to require review of the standard rates in conjunction with some related activity—for example, as part of the utility's regular rate review case[273] or the biennial submission of system cost data required by section 133 of PURPA.[274]

Some commissions, however, determined that other schedules of review might offer more encouragement to cogenerators. Because industries like to be able to project future costs and returns with some certainty before making investment commitments, the New Hampshire PUC decided that the energy price set in its final order would prevail until the Seabrook nuclear plant came on line, and in any case, would be available to any QF, currently entering a contract, for the life of that contract.[275] Granite State Electric Company, however, appealed this ruling, and the New Hampshire Supreme Court reversed the commission's decision, and stated that the ruling "violated the commission's duty to set rates from time to time as condition warranted."[276]

The California PUC, conversely, noting rapidly rising oil prices at the time, declared the QFs should have the advantage of these rises and thus mandated quarterly updates of fuel costs for the energy credit.[277] Other commissions chose to adjust the energy credit by tracking the movement of the fuel cost adjustment factor.[278] With the recent fall in oil prices, these adjustments are now decreasing and not increasing cogenerators' payments.[279]

Table 1 in the Appendix presents a compilation of the standard PURPA purchase rates and residential retail sales rates of selected

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relatively inexpensive type of generating unit on which to base the capacity credit, like a gas turbine peaking unit, did not necessarily adjust the energy component. *See, e.g.,* North Carolina's Order, *supra* note 214.

273. Massachusetts required the energy credit to be adjusted whenever utilities filed for their fuel adjustment charge, while Kansas required that the capacity credit be adjusted as the utility's authorized rate of return per unit was. *See* NRRI Draft, *supra* note 169, at B-178, B-148.

274. *See supra* note 237 for a discussion of § 133. North Carolina decided to update both energy and capacity credits at these times—with fuel cost adjustment factors being applied in the interim. *See* NRRI Draft, *supra* note 169, at B-249.

275. Lock, *supra* note 220, at 424.

276. Appeal of Granite State Electric Company, 121 N.H. 787, 435 A.2d 119 (1982).

277. 34 Pub. Util. Rep. 4th (PUR) 148, 160 (1980).

278. *See supra* note 274 for a discussion of North Carolina law.

279. *See* Table 1 (Appendix). Since the spring of 1982, utilities marked with a (-) have lowered their PURPA purchase rates, presumably because of lower fuel costs.

utilities.[280] Not only does the table show the variety of methods that commissions chose to structure both purchase and sales rates, but also illustrates the extent to which a single utility may have been treated differently by different commissions. The capacity credits payable by Utah Power, for example, ranged from 26 to 35 to 47.9 mills per kilowatt-hour, depending on whether the cogenerator was located in Wyoming, Utah or Idaho, respectively.

While comparisons of residential rates and standard PURPA rates are probably more meaningful for small power producers, a glance at this table shows that, for many utilities, commercial rates would have to be considerably lower than these residential rates to make simultaneous buy-and-sell attractive to a cogenerator.[281] In spite of the full-avoided cost mandate, the PURPA rates are lower than the average cost based residential retail rates in nearly every case. Under these circumstances, the main incentive to cogenerate probably is avoidance of payment of retail electricity rates, rather than sale of power to the utility. If relatively low purchase rates are offered, industries presumably would choose to sell only excess power to the utility.

C. *Determining Eligibility for PURPA Purchase Rates*

While the FERC already had set minimum ownership and efficiency standards for certification of cogenerators as qualifying facilities,[282] state commissions frequently added criteria of their own for obtaining certain incremental payments on the energy credit or payment of the capacity credit. In some cases, commissions also relaxed the FERC's criteria for full avoided cost payments. In particular, a number of states decided that the standard purchase rates should be available to "old" as well as to "new" cogenerators.[283]

280. Information for this table was compiled from *States Cogeneration Rate-Setting Under PURPA,* Energy Users News, Apr. 5, 1982, 19-22; May 23, 1983, 16-17; May 30, 1983, 17-18; Lock, *supra* note 220, at 688-701; MOODY'S PUBLIC UTILITY MANUAL (1982); REG. INFO. EXCHANGE, *supra* note 221.

281. For those who produce and consume similar amounts of electricity, simultaneous buy-and-sell is only attractive if purchase rates are greater than sales rates. For example, if a cogenerator sold 1000 kwh of electricity to Public Service of Indiana at the standard PURPA rate of 1.33/kwh, while simultaneously purchasing 1000 kwh from the utility at its lowest residential rate of 3.580/kwh (see Table A), the transaction would result in a net loss to the cogenerator of $25.47. Only a net billing option or direct consumption of the electricity self-generated (without sending it to the utility) would result in total avoidance of the utility's $35.80 charge for 1000 kwh.

Purchase rates that are lower than utility sales rates could be attractive if the individual or firm could install equipment that generated enough surplus power to produce an adequate return on the capital invested. No one appears to suggest, however, that a payment of 1.33/kwh would produce such a return.

Commercial rates were not included here because of the large number of categories utilities often have for commercial and industrial firms and the difficulty of obtaining information on comparable categories.

282. *See supra* note 61.

283. For definition of a "new" vs. "old" cogenerator, see note 79. California and Virginia

Similarly, the FERC only required that standard purchase rates be made available to qualifying facilities of less than 100 kw capacity. A number of commissions determined, however, that the availability of standard rates to larger cogenerators would simplify their administrative burden and would encourage good faith negotiation between utilities and cogenerators. Both parties then would know the minimum purchase rate that the cogenerator legally could demand. Accordingly, of the thirty-six states for which purchase rate information was available, twenty-two offered the standard rates to larger cogenerators. One state[284] limited the availability of the rate to cogenerators with less than 500 kw capacity, and six[285] limited it to cogenerators with less than 1000 kw (1 MW) capacity.

Most states that offered a capacity credit made payment of the credit contingent upon the cogenerator's fulfillment of certain qualifying conditions. The most common condition was that the cogenerator deliver "firm" power. The cogenerator was required to contract to supply a certain amount of capacity. Some states, arguing that unless the outside power supply could be depended on for a certain number of years, utilities could not integrate it into their system planning, specified a minimum contract length. Thus, Pennsylvania required a minimum contract length of ten years, the approximate time required to bring a new baseload plant on line.[286] Maine, however, required a minimum contract term of only half that length, and declared that a five year time frame was sufficient for a utility to defer or alter system planning.[287] Other states determined thresholds to be rather arbitrary and instituted graduated payment schemes through which a QF received a small capacity payment for a one year contract, but a very significant payment for a maximum length contract of thirty-five years.[288]

Some state commissions made the capacity credit contingent on the cogenerator's reliability. Some utilities feared that a QF might build a plant with a 10 MW rated capacity, enter a long-term con-

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decided to give qualifying status to old facilities. 34 Pub. Util. Rep. 4th (PUR) 148, 163 (Cal. 1980); 51 Pub. Util. Rep. 4th (PUR) 315, 317 (Va. 1982). North Carolina chose to phase the capacity credit in for old facilities at the rate of 10 percent per year. NRRI Draft, *supra* note 169, at B-252. Pennsylvania, however, offered PURPA rates only to old facilities that could show that they would have to go out of business with the rate they would otherwise receive. 52 PA. ADMIN. CODE § 57.34(g) (Shepard's 1983).

284. PA. ADMIN. CODE § 57.34(f)(1) (Shepard's 1983).

285. 11 REG. INFORMATION EXCHANGE Q. BULL. 14 (1982) (Ark.); 10 REG. INFORMATION EXCHANGE Q. BULL. 34 (1982) (Del.); 42 Pub. Util. Rep. 4th (PUR) 536, 539 (1981 Me.); NRRI Draft, *supra* note 169, at B-70 (Conn.); B-225 (N.J.); B-366 (Utah).

286. 42 PA. ADMIN. CODE § 57.34(c)(7)(i) (Shepard's 1983).

287. 42 Pub. Util. Rep. 4th 536, 548 (1981).

288. *See supra* note 261 for Oregon's formula. North Carolina and Montana did not give graduated payments but changed the payment basis from a peaking unit to a baseload generating unit at 11 and 4 years respectively. NRRI Draft, *supra* note 169, at B-237 (N.C.); 45 Pub. Util. Rep. 4th (PUR) 595, 597 (1982).

tract to supply this amount of power and then actually deliver power only a small fraction of the time. Thus, the utility would pay a capacity credit that exceeded its cost to generate a similar amount of power. Both Montana and Idaho, therefore, required QFs to meet a minimum capacity factor[289] to obtain a full capacity credit.[290] If the QF failed to meet this capacity factor, then the capacity payment was prorated.[291] Utah, however, required QFs to meet a specified capacity factor or to forfeit any capacity payment;[292] Maine required only that contracted capacity be "reliable."[293]

Other states evaded the necessity of determining a minimum capacity factor by requiring the cogenerator to contract for supplying a certain amount of energy, rather than a certain amount of capacity. Thus, the Massachusetts DPU required the cogenerator to contract to supply "x" kilowatt hours per billing period or forfeit the capacity payment for that period.[294]

Since only power produced in the hours of peak system demand helps to avoid the need for new capacity, a number of states required peak hour production for a full capacity payment. North Carolina based its capacity payment on the average number of kilowatt-hours generated per peak hours;[295] California offered a graduated series of credits based on power production in off-, mid-, or on-peak hours.[296] Other states offered a higher capacity payment in the season of peak demand, usually the summer months.[297] Pennsylvania, however, only required that the cogenerator be a "relatively stable source" in peak hours to qualify for the capacity credit.[298]

While the above requirements for receiving the capacity credit of the standard rate were common to a number of states, a few of the idiosyncratic conditions mandated highlight the range of issues explored and attitudes expressed by state commissions. The New Jersey BPU, for example, thought that there was "an intrinsic value to smaller, decentralized cogeneration," and therefore determined that a QF only had to meet the general reliability criteria of the util-

289. The capacity factor of a unit is the ratio of the energy it actually produces to the energy it could have produced if it had operated continuously.

290. Montana, 45 Pub. Util. Rep. 4th (PUR) 196, 205 (1982), assumed an 85% capacity factor, and Idaho, 44 Pub. Util. Rep. 4th (PUR) 160 (1981) assumed a 65 or 75% one, depending on the utility in question.

291. Idaho pro-rated this figure both up and down. Thus, a facility that operated at a capacity factor above the minimum required could actually receive a payment for a capacity greater than its nameplace rating. 44 Pub. Util. Rep. 4th (PUR) 160, 162 (1981).

292. NRRI Draft, *supra* note 169, at B-367.

293. 42 Pub. Util. Rep. 4th (PUR) 536, 552 (1981).

294. NRRI Draft, *supra* note 169, at B-180.

295. *Id.* at B-242.

296. 34 Pub. Util. Rep. 4th (PUR) 148, 161 (1980).

297. Some South Carolina utilities used this approach. *See Cogeneration Rate-Setting Under PURPA,* Energy User News, May 30, 1983, 18.

298. Pa. Admin. Bull., Dec. 11, 1982, at 4240.

ity system to obtain the capacity credit.[299] The Missouri PSC, on the other hand, saw little use for self-generated power unless a large enough increment already was on the line for the utility to avoid the deployment of new capacity and asked its jurisdictional utilities to state the aggregate of QF capacity that would be needed to avoid a capacity cost. No capacity payment would be received by any QF until there was enough QF capacity to meet this minimum threshold aggregate.[300]

Only three states mandated a capacity payment to *all* cogenerators. While Kansas termed its capacity credit an "incentive" payment,[301] Idaho and Montana attached a certain minimum value to "aggregate" capacity.[302] These commissions found that, even if QFs did not commit their capacity under long-term contract, the stochastic nature of new QFs coming on line as old ones drop off would ensure that a utility could depend on some fraction of this nonfirm capacity in long-term system planning. Therefore, all QFs should be entitled to at least a small capacity credit.

Table 2 in the Appendix summarizes some of the major options that commissions considered when setting section 210 purchase rates.[303] Even a brief examination reveals the wide variety of approaches adopted by state commissions in determining both eligibility for purchase rates and the factors that should be included when calculating full avoided costs.

D. Setting Rates for Sales to Cogenerators

Most of the states' initial orders focused on setting avoided cost purchase rates. Generally, rulings on sales to cogenerators merely repeated the FERC guidelines.[304] Some commissions, most notably California and Idaho,[305] noted that the QF, with simultaneous buy

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299. NRRI Draft, *supra* note 169, at B-224, 225.

300. 4 MO. ADMIN. CODE 240-20.060(3)(A)(1) (1982).

301. NRRI Draft, *supra* note 169, at B-148.

302. Idaho chose 3 mills/kwh as an acceptable minimum, while Montana asked for one based on the 42.5% availability of a gas combustion turbine. 40 Pub. Util. Rep. 4th (PUR) 563, 567 (Idaho 1981); 45 Pub. Util. Rep. 4th (PUR) 196, 203 (Mont. 1982).

303. This table is not meant to be an exhaustive representation of state implementation proceedings. Rather, it is illustrative of the diversity of state approaches to PURPA purchase rates. Moreover, because a state's final order did not explicitly specify a particular allowance does not mean that the commission did not subsequently approve utility purchase rates that included such an allowance. Information for this table was compiled from commission orders; 6-12 REG. INFORMATION EXCHANGE Q. BULL.; Energy User News, Apr. 5, 1982, 19-22; Mar. 7, 1983, 2; May 23, 1982, 16-17; May 30,1983, 17-18; Lock, *supra* note 220; *Calculating Capacity Costs in Cogenerated Rates,* 108 PUBLIC UTILITY FORTNIGHTLY 57-60 (Sept. 24, 1981); Memo, *Status of PURPA Section 210 Implementation By 17 Selected State Commissions* (FERC 1983).

304. Rates for sales should be "just and reasonable and in the public interest" and should not "discriminate against any qualifying facility in comparison to rate for sales to other customers served by the electric utility." 18 C.F.R. § 292.305(a) (1980).

305. 34 Pub. Util. Rep. 4th (PUR) 148, 164 (Cal. 1980); 38 Pub. Util. Rep. 4th (PUR) 352, 378 (Idaho 1981).

and sell, always is buying electricity from the utility. Therefore with an outage of QF equipment, there is a reduction only in utility purchases; utility sales to cogenerators remain constant. Because outages of QF equipment do not affect sales by utilities, cogenerators should be treated just like other customers with similar load characteristics and should pay similar rates. Rates for backup and supplementary power thus become irrelevant.

The New York Public Service Commission, however, dealt extensively with the question of appropriate rates for sales to cogenerators. The commission authorized the use of a backup rate for cogenerators that purchased power which they normally supplied themselves.[306] To qualify for the backup rate, the customer had to have a summer and winter load factor[307] of less than ten percent.[308] The low load factor requirement was to ensure that, except for system demands, QFs were not drawing power from the utility at times of utility seasonal peak demand.

This backup charge contained a marginal transmission cost recovery component based on the assumption that thirty-six percent of the backup usage of this class would be required in the eighty-nine hour "load sensitive period" of the summer.[309] The rate was to be charged, however, over the full 504 hour summer period and contained a distribution cost component, imposed for usage during summer peak and shoulder periods.[310] Additionally, the PSC mandated a penalty charge of twelve times the applicable amount if demand exceeded contracted demand by up to ten percent, and twice this if demand exceeded the contract by more than ten percent.[311] Finally, there was a fixed monthly charge relating to other fixed, customer-related costs.[312]

The commission set rates for supplementary power in a similar

306. Presumably the commission concurred with FERC in its assessment that Con Ed's high retail was the major factor inducing cogeneration in its service area, and therefore QFs would wish to sell surplus power only under the rate structure being authorized.

307. The load factor in this case is the ratio of the average amount of energy, or average load, drawn by the QF during these two periods to the peak load drawn. In other words, a 10% load factor assumes the QF's equipment is operational 90% of the time if power use is constant.

308. *In re* Consolidated Edison of New York, Inc., 48 Pub. Util. Rep. 4th (PUR) 94, 112 (1983).

309. *Id.* at 114. The 89 hour load sensitive period represents those hours in the summer that are most likely to elicit such high electricity consumption that the utility system is likely to be overtaxed and require expensive emergency measures.

310. A shoulder period is a period of intermediate demand. In both the shoulder and peak cases, the distribution cost was recovered in a demand charge set at the highest demand of the previous 11 months or at the current month's demand—whichever was higher. *Id.* at 119.

311. *Id.*

312. These included a $6.00 per month metering charge for small cogenerators and a $50 per month charge for large ones (over 900 kw). *Id.* at 120.

fashion.[313] The commission noted that under the FERC's rules, the cogenerator had the option of choosing firm service rates until the necessity for a separate charge system was proved. The commission, however, chose the above described staff-proposed rate schedule to encourage a load pattern that might help Consolidated Edison.[314]

The New Jersey BPU adopted an approach appearing more favorable to QFs. This approach forgave the demand charge if maintenance was scheduled at the utility's convenience and established a "standby service" to which QFs could subscribe to obtain emergency power.[315] The standby charge reflected the cost of investment necessary to provide capacity at the rate of fifteen percent coincident in QF outages at the generation and transmission level and seventy-five percent at the distribution level.[316]

A number of states have set PURPA purchase rates well below utility retail sales rates. Thus, the only real incentive for cogeneration is the substitution of self-generated power for costly utility purchased power. Under these circumstances, the QF wishes to sell only surplus power to the utility. If net billing, or running the meter backwards, is not permitted,[317] then surplus sales require the use of two meters and more complex interconnection equipment. Not only does this considerably increase the cogenerator's installation costs, but few states have grappled with the thorny issues of backup rates under these conditions. For example, is it assumed that all QFs selling surplus power would require backup service at the same time, and thus need to be charged the full demand rates of regular service customers, or could an assumption of only a limited amount of "coincidence" be assumed to lower these rates? Until such issues are resolved, high rates for sales to cogenerators may be as strong a disincentive to cogeneration as low purchase rates.

E. Establishing Procedures and Costs for Interconnection

Many commissions did not explore in detail the requirements for interconnection or the allocation of interconnection costs. Some repeated the FERC rule stating that incremental interconnection costs were to be borne by the QF[318] and suggested various payment schedules. Most left the determination of the amount and type of interconnection equipment necessary for utility safety and reliability to the purchasing utility. Rhode Island, in a typical order, deter-

313. That is, they should recover transmission and distribution costs and contain a contract charge to recover peak distribution costs. *Id.* at 122.

314. *Id.* at 123.

315. NRRI Draft, *supra* note 169, at B-226.

316. *Id.* at B-227.

317. Neither Michigan, 48 Pub. Util. Rep. 4th (PUR) 465, 471 (1983), nor Utah, NRRI Draft, *supra* note 169, at B-367, permit net billing, for example.

318. 18 C.F.R. § 292.306 (1980).

mined that interconnection costs relating to sales by the utility should be borne by the utility and that those relating to QF purchases should be borne by the QF. The utility could prescribe any equipment necessary to prevent flow of electricity into the grid when the system was out of service, and the QF could pay its interconnection costs in monthly installments over a five-year period.[319]

Perhaps due to Consolidated Edison's activity in the *AEP* case, the New York Commission issued one of the most extensive orders on interconnection. While Consolidated Edison argued that, as the result of *AEP* it could not be required to interconnect with on-site generators, the New York Commission determined that Congress had not preempted its power to require such connections.[320] The commission, therefore, required Consolidated Edison to interconnect on its radial system and left interconnection to its network system on a case specific basis.[321] Like Rhode Island, New York required the QF to pay costs incurred in delivery of power to the utility, which it further specified as: (1) the incremental metering charge; (2) a nine percent carrying charge to cover taxes, operation and maintenance; (3) up front payment of first time interconnection costs; and (4) any costs associated with engineering and feasibility studies related specifically to parallel operations.[322]

The New York order shows how interconnection costs also might be a disincentive for small cogenerators. If a utility requires extensive studies and numerous system protection devices, as well as up front payment of the costs associated with these items, then the additional costs thus incurred might make many small projects financially unattractive.

The diversity of approaches adopted to set purchase and sale rates, as well as to allocate and collect interconnection costs, have resulted in rates in some states that are much more encouraging of cogeneration than rates in other states. Commission attitudes towards cogeneration varied considerably. Some states did little more than implement PURPA procedurally, while others endeavored to give cogeneration the substantive encouragement that they believed the PURPA mandate required. The FERC rules appear to have given states great flexibility in setting purchase rates, and, while a few states may have set rates above "real" avoided costs, a much greater number of states have set rates below embedded costs, and thus below the long run marginal costs.

319. 42 Pub. Util. Rep. 4th (PUR) 609 (1981).

320. 48 Pub. Util. Rep. 4th (PUR) 94, 134 (1983).

321. *Id.* at 135. The technical details are beyond the scope of this article, but the network system accepts only a uni-directional flow of electricity and therefore presents more complications when cogenerators attempt to put power into the system.

322. *Id.* at 139.

VI. Industrial Response to the Federal Legislation

While much has been written about the intent and substance of the federal legislative effort regarding cogeneration, there has been little study of the actual results of this effort. Some of the more interesting industrial ventures into cogeneration have received attention from the newspapers,[323] but virtually no attempt has been made to evaluate the impact of this legislation on industry as a whole.

A. Direct Response to PURPA

Because of the need to obtain qualifying status to receive the benefits of PURPA, perhaps the best indicator of PURPA's effects is the FERC's quarterly report on cogeneration facility filings.[324] This report lists by region the name, address, facility type and rated capacity of those firms that either notify the FERC of their qualifying status or request FERC certification. While such a report clearly indicates the number and dispersion of firms that have been encouraged to evaluate cogeneration by PURPA, the report probably does not indicate accurately the amount of cogeneration that actually will come on line in the next few years. A request for certification may be made at the initial planning stage of a project, but the project may then be altered or abandoned as the result of subsequent evaluation or unforeseen events.[325]

Additionally, the filings list has not been verified for definitional accuracy. Not only is there the possibility of error inherent in self-classification, but there is also the problem of dual qualification. Two cogeneration filings in California, for example, specify "solar" as the cogeneration fuel. While one exceeds the size limitation for small power production facilities,[326] the other presumably could have filed for certification as a small power producer. Similarly, there are a number of firms with "Cogeneration" in their names that have applied for certification as small power production facilities. Firms using biomass as their primary fuel appear to qualify under

323. *See, e.g., Industry Examines Profit Prospects of Selling 'Cogeneration' Energy,* Wall St. J., Feb. 19, 1981, at 31; *More Companies Burn Waste to Generate Energy, Cutting Fuel and Disposal Costs,* Wall St. J., Apr. 15, 1981, at 48.

324. Quarterly Report on Qualifying Small Power Production and Cogeneration Facility Filings, compiled by the Federal Energy Regulatory Commission.

325. Bi-State Development of St. Louis, Missouri, for example, filed notice of qualification as a cogeneration facility for an 80 MW trash-to-energy project for the City of St. Louis. The projected start-up of this plant is 1986, but Bi-State has been unable to obtain from Union Electric what it feels to be a fair purchase rate for the electricity to be generated from this project. Without an acceptable conclusion to negotiations with the utility, a plant half this size will be built merely to supply steam to the city steam loop—although a boiler plate would be installed in case the PURPA purchase rate improved in the future. Telephone Interview with Paul Mydler, Bi-State Development Agency, April 22, 1983.

326. Small power production facilities were limited by Congress to 80 MW in size. 16 U.S.C.A. § 796(17)(A)(ii) (West Supp. 1982).

either heading.[327] Firms presumably have applied for the type of certification that would yield the greatest tax benefits or other incentives for the project.[328] Since the FERC does not require notification of qualification under both definitions, only four filings note the possibility of this dual certification.[329]

Table A is a listing of the FERC's qualifying cogeneration fil-

Table A

FERC Filings for Qualification as New Facilities

State	Number of Filings	Rated Capacity (kw)
Alabama	1	37,400
Arizona	1	375
California	55	1,009,975
Connecticut	1	150
Florida	13	383,120
Georgia	2	76,600
Hawaii	1	19,400
Idaho	1	5,000
Kansas	1	33,730
Louisiana	1	100,000
Maine	1	46,700
Massachusetts	3	583,400
Michigan	1	22,400
Mississippi	4	7,177
Missouri	1	80,000
Nebraska	Not Available	Not Available
New Hampshire	1	1,800
New Jersey	2	35,300
New York	1	100
North Carolina	2	58,000
North Dakota	1	9,000
Ohio	1	16,500
Oregon	2	100,000
Pennsylvania	2	55,500
Tennessee	7	27,228
Texas	4	750,000
Virginia	6	55,507
Washington	2	29,000
Wyoming	1	5,000
TOTALS	119	3,548,362

327. That is, production of electricity and another form of useful energy qualifies it as a "cogeneration facility" and producing energy solely by use of "biomass, waste, renewable resources, or any combination thereof" qualifies it as a small power producer if it is less than 80 MW in size. *See* 16 U.S.C.A. § 796(17)(A), (18)(A) (West Supp. 1982).

328. Many states have offered tax credits, state energy tax exemptions, or loans to firms investing in cogeneration or alternative energy systems. Often, however, such financial incentives are offered to only certain specified types of energy systems, like solar or biomass systems. For a listing of various incentives available, see COUNCIL ON STATE GOVERNMENTS, BOOK OF THE STATES (1982).

329. Two of these filings are in Oregon, one in Kentucky, and one in Connecticut. They represent a total capacity of 101,150 kw. *Quarterly Report on Qualifying Small Power Production and Cogeneration Facility Filings,* January 1, 1983 [hereinafter cited as FERC's filings].

Table B
Characteristics of New Capacity Facilities
(Total=119)

A. Facility Size

100kw or Less	101-1000kw	1001-10,000kw	More Than 10,000kw
7	26	39	47

B. Fuel Type

NG	CO	BIO	CO/BIO	WA	FO	SO
60	11	29	5	7	5	2

Key:
NG=natural gas
CO=coal
BIO=biomass
CO/BIO=mixture of coal and biomass
WA=waste product (filer defined)
FO=fuel oil #2 or #6
SO=solar

ings by state.[330] It includes those small power filings that also noted their cogeneration status, but does not include those filings from which cogeneration might only be inferred from the firm's name, technology and fuel type. In the first three years of reports, 119 cogenerators have filed for qualification of approximately 3500 MW of new capacity. (This is equivalent to three to four new baseload plants.) Nearly half of these filings (fifty-five) have come from California. Slightly over two-thirds have come from just four states: California, Florida, Tennessee and Virginia. In terms of rated capacity, however, Texas and Massachusetts combine with California to produce two-thirds of the total capacity offered by these new cogenerators. Thus, PURPA appears to have had minimal impact on cogeneration in the remaining forty-four states.

The greater encouragement of cogeneration in these six states, as compared to the remaining forty-four, results from a number of factors. First, the rates offered to cogenerators appear to make simultaneous sale and purchase attractive. The PURPA purchase rates of Pacific Gas and Electric in California, for example, are higher than some of their retail sales rates. This also appears to be true of Tampa Electric in Florida, Boston Edison in Massachusetts, the TVA in Tennessee and Houston Light and Power in Texas.[331] With the exception of Virginia, these states offer standard rates to cogenerators with a rated capacity of more than 100 kw.[332] As Table

330. Compiled from FERC's filings, *id.*
331. *See* Comparisons of PURPA standard purchase rates and residential retail rates in Table 1, Appendix.
332. *See* Table 2, Appendix.

B illustrates, only seven of the 119 qualifying facilities had a rated capacity of less than 100 kw. Thus, unless state commissions explicitly offered the standard PURPA rates to larger installations, the remaining 112 facilities would have had to resort to individual negotiation. Apparently the availability of a standard rate strengthened the cogenerators' bargaining position by serving as a legal minimum to which cogenerators were entitled if negotiations faltered.[333]

All six of these states also had rules and rates in place by either the FERC deadline of March 1981 or shortly thereafter.[334] In contrast, three of the five states which still did not have final rules or rates in March 1983 had no filings.[335] Uncertainty about commission attitudes toward sale and purchase rates, therefore, also may have cast a cloud over the development of cogeneration in some states.

Indeed, the perceived attitudes of state commissions toward cogeneration may be a major factor in its development. The California commission, for example, not only set favorable purchase rates, but also permitted cogenerators to pay the same rate for natural gas as electric utilities pay.[336] Additionally, the commission gave cogenerators priority over other industrial users during gas shortfalls.[337] As a further mark of its support of cogeneration, the commission reduced Pacific Gas and Electric's authorized return on equity by 0.2 percent because of its lack of effort to promote cogeneration. The return could only be regained if PG&E signed contracts for at least 600 MW of new cogeneration capacity within the next

333. The unwillingness of utilities to negotiate with qualifying facilities was noted repeatedly in the Senate Hearings of April and May 1982. For example, the American Paper Institute noted that increased unwillingness of utilities to enter negotiations after the circuit court vacated the FERC's avoided cost and interconnection rules. *See Senate Hearing, Part I, supra* note 118, at 333.

334. Florida issued final rules April 22, 1981, Massachusetts on July 23, 1981, and Texas on August 20, 1981. Virginia issued orders on all its jurisdictional utilities except Virginia Electric Power Company between June 18, and August 14, 1981, while the TVA, which covers most of Tennessee, was offering a PURPA purchase rate by April 1981. California did not issue its final PURPA Order until January 21, 1982, but the commission had been implementing state legislation encouraging cogeneration since 1979, CAL. PUB. UTIL. CODE § 922 (West 1979), and had purchase rates in effect in the interim. Information on California, Florida, Massachusetts, Texas and Virginia from Memorandum, *Narrative Status Report on Progress by Certain State Regulatory Agencies Toward Implementation of PURPA Section 210,* (FERC 1983). Information on the TVA from *States' Cogeneration Rate-Setting Under PURPA,* Energy User News, Apr. 20, 1981, at 14.

335. Maryland, Minnesota and Wisconsin still had their PURPA rules pending and no filings of qualified facilities as of January 1983. *See* Table A; Table 2, Appendix.

336. Cogenerators could get this preferred rate up on to the amount of gas that the utility would have used to generate the same amount of electricity. That is, if Pacific Gas and Electric required 11,000 BTUs to generate a kwh of electricity, and an industry could generate a kwh with 5000 BTUs (on a pro-rated basis), then it could apply the remaining 6,000 BTUs allowed to its industrial process. *In re* Pacific Gas and Electric Company, 43 Pub. Util. Rep. 4th (PUR) 1 (1982).

337. *In re* Pacific Gas and Electric Company, 34 Pub. Util. Rep. 4th (PUR), 1, 114 (1980).

two years.[338] No other commission has assumed such an active role in the support of cogeneration, nor has any other state encouraged as much new cogeneration capacity. The natural gas incentives appear to have been particularly significant, since forty of the fifty-five new filings in the state have listed natural gas as their fuel type.

California offers a particular contrast with New York. Both states are similarly populous and have similar fuel compositions in the statewide utility systems.[339] The New York commission, however, has appeared to respond in a lukewarm fashion to cogeneration. Because of the perceived lethargy of the New York commission in setting PURPA purchase rates, the state legislature set its own minimum rate for all nonoil fired facilities at six cents per kilowatt hour.[340] The commission did not issue a final order until May 1982, and then, while upholding the full avoided cost standard, the commission stated its desire neither to encourage nor to discourage potential cogenerators in the Consolidated Edison service area.[341] Subsequent to the order's issue, purchase rates still had to be put in place by all jurisdictional utilities. New York has generated only one cogeneration filing, and that for a facility of only 100 kw. The great disparity between California and New York may be the result of the lack of any strong encouragement of cogeneration by the New York commission and of the overt opposition of Consolidated Edison to cogenerators in its service area.[342]

In states with PURPA purchase rates set below retail sales rates, cogeneration still might be encouraged, if qualifying facilities would be given the option of net billing. Such an option allows the QF to avoid retail, embedded cost payments for power used while permitting sales of surplus power generated. A number of commissions, however, either prohibited the net billing option or restricted it to small QFs.[343] Under these conditions, the extra expense involved in setting surplus power only to the utility[344] may be the financial straw that deters the development of cogeneration. Sales of excess power only require the establishment of reasonable backup or standby rates. Otherwise, the cogenerator pays a full service demand charge

338. *Id.* at 116.

339. In 1981, the fuel composition of the California utility system was 67% oil, 25% hydro, 4% nuclear, 1% gas and 3% other. The fuel composition of the New York utility system was 63% oil, 15% hydro, 13% nuclear, 8% coal and 1% gas and other. Lock, *supra* note 220, at 688.

340. *In re* Consolidated Edison Co. of New York, 48 Pub. Util. Rep. 4th (PUR) 94, 148 (1983) (citing N.Y. PUB. SERV. LAW § 66-c).

341. *Id.* at 99; *supra* note 252.

342. Consolidated Edison had been one of the plaintiffs in the *AEP* case. It has been very outspoken about its dislike of cogeneration in its service area. *See* Schwartz, *Urban Cogeneration: A Wolf in Sheep's Clothing,* 108 PUBLIC UTILITIES FORTNIGHTLY No. 4 (Aug. 13, 1981). (The author is senior vice-president of Consolidated Edison.)

343. *See supra* note 317.

344. *See supra* note 63.

year round to cover service required during the two to four weeks of equipment outages necessitated by scheduled maintenance and emergency repair.[345]

Commissions cannot be faulted in all states that show few or more filings of cogeneration capacity. The Idaho Commission, for example, perceiving Idaho Power's efforts to encourage cogeneration to be inadequate, not only threatened to set its rate of return at the "lower end of a range found to be reasonable," but also declared that "[f]ailure to exhaust all power supplies available from cogeneration and small power production shall be grounds for rejection of applications for certificates of convenience and necessity regarding construction of conventional thermal units or for the issuance of securities to finance such units."[346] Despite this activist stance, there has been only one cogeneration filing in Idaho.[347]

Vermont has had no cogeneration filings, although it has offered one of the highest standard purchase rates in the country—9.0 cents per kilowatt hour at on-peak times and 6.6 cents off-peak.[348] The obvious inference from the Vermont and the Idaho cases is that a certain level or type of industrial activity already must be present in a state for even strong PURPA incentives to have any effect. Such incentives are not enough to bring new industry into an area, although they may be sufficient to alter the energy consumption patterns or technologies of established industries.[349]

Moreover, development almost everywhere has been discouraged by the uncertainties associated with PURPA itself. The American Paper Institute, for example, noted that PURPA could not become a factor in plant planning until the FERC issued its rules. After those rules were promulgated, many industries still felt that they had to wait until their state commission implemented the rules. In the middle of the implementation process, however, the *AEP* decision was rendered, thus raising a cloud of doubt around the full avoided cost rule and automatic access to interconnection.[350]

Additional uncertainty has been created by an inability to pre-

345. To alleviate this impediment, the FERC suggested a variety of sales schedules to cover emergency and scheduled outages of QF equipment. *See supra* notes 89 and 190.

346. 44 Pub. Util. Rep. 4th (PUR) 160, 164 (1982).

347. Idaho has had five hydro projects qualify as small power production facilities. Presumably the industrial base is lacking, but the water is not. FERC's Filings, *supra* note 329.

348. *See* Table 1, Appendix, for the favorable comparison of these rates with Central Vermont Public Service's residential retail rates.

349. Some commentators have argued that high electricity rates in certain areas of the country may not be a significant inducement to cogenerate because energy intensive industries have long ago left these areas. For those industries that remain, energy costs are too small a proportion of their total overhead to induce much interest in energy conserving technologies like cogeneration. *See Good News For New England: Energy-Cost Problems Easing,* Wall St. J., March 22, 1983, at 37.

350. *See supra* note 31 and accompanying text.

dict fuel prices. In recent months, oil prices have declined considerably, resulting in a decline in the energy credit payment for those cogenerators who are paid on a real time or quarterly update basis.[351] The American Paper Institute has concluded that few businessmen who are faced with these uncertainties will be willing to make the incremental investment PURPA requires. "What is again missing as it was prior to PURPA, is a price signal that will be reasonably durable and certain."[352]

B. Other Factors Affecting Industrial Response

Several surveys of industrial attitudes toward cogeneration have been conducted to ascertain either its development potential or the factors restricting its growth.[353] Furthermore, the Senate hearings on proposed amendments to PURPA elicited extensive industry comment on PURPA's effectiveness. The general tenor of all this comment has been that, while PURPA was a step in the right direction, numerous factors remain to inhibit the development of industrial cogeneration.

Many firms remain distrustful of utilities. Not only did a number of industrial witnesses cite the *AEP* case as proof of the general unwillingness of utilities to negotiate fairly with them,[354] but several also cited other instances of utility obstructionism. The American Paper Institute noted that Consolidated Edison had been insisting that a cogenerator must obtain an FPA interconnection order to conduct sales "*even where it is already physically interconnected for a two-way flow of electricity.*"[355] An executive of the Potsdam Paper Corporation related that firm's difficulties in trying to extract a long-term contract from the Niagara-Mohawk Power Corporation.[356]

Other government regulations also have been disincentives. Several surveys found that firms in nonattainment areas regarding certain criteria pollutants of the Clean Air Act, or in areas where the pollution increments were very limited, preferred to reserve the lim-

351. *See* Table 1, Appendix, and note those utilities that experienced a decline in purchase rates.

352. *Senate Hearing, Part I, supra* note 118, at 333.

353. Resource Planning Associates, Edison Electric Institute and Arkansas Power and Light all have done surveys that were reported in the Senate Hearings. *See id.* at 67, 78, 90. In addition, a number of states have conducted surveys to determine the potential for cogeneration in their states. *See Cogeneration Blueprint for State Facilities,* State of California (1981) (prepared by the Dep't of General Services, Office of Appropriate Technology and Department of Water Resources).

354. The Manager of External Energy Affairs at the Weyerhauser Company, for example, said, "Achievement of the goals of PURPA has been handicapped primarily due to utility unwillingness to offer an appropriate avoided cost." *Senate Hearing, Part I, supra* note 118, at 164.

355. *Id.* at 336.

356. *Id.* at 401.

ited increments they might have for changes in production related processes.[357] Thus, although cogeneration might reduce overall pollutants because less fuel is burned by the dual production of electricity and thermal energy than by producing each separately, the individual firm would experience an increase in pollution emittants, which it might be unable or unwilling to assume because of the permitting requirements.[358]

The Powerplant and Industrial Fuel Use Act (FUA),[359] has also acted as a disincentive. Gas turbine and diesel topping engines can save more fuel than any other types of cogeneration.[360] They also produce a higher electricity to steam ratio than conventional steam boilers, are economical in small plant sizes and are more environmentally beneficial than coal-fired boilers. FUA, however, mandated all feasible conversion of major fuel burning installations (MFBIs) from oil and gas to coal and prohibited new oil or gas installations.[361] Powerplants were subject to even broader prohibitions.[362] Since an installation was defined as a powerplant if it sold more than one-half its generated electricity, any cogenerators participating in simultaneous buy and sell would have been subject to these broader restrictions, even if only a small proportion of total fuel use was attributable to power generation. Cogenerators participating in simultaneous buy and sell subsequently were excluded from the powerplant definition.[363] In the interim, the regulations appear to have dampened development of some cogeneration.[364]

Furthermore, until August 1982 the procedure for obtaining the FUA cogeneration exemption for MFBIs was exceedingly burdensome.[365] At that time the requirements for exemption were simplified substantially,[366] but a new administration once again could

357. Both the Edison Electric Institute and Arkansas Power and Light mentioned this disincentive. *Id.* at 67, 90.

358. California has tried to mitigate this disincentive by expediting air pollution permits for cogenerators. 34 Pub. Util. Rep. 4th (PUR) 146, 168 (1980).

359. Pub. L. No. 95-620. *See supra* notes 54, 55.

360. B. WILKINSON & R. BARNES, COGENERATION OF ELECTRICITY AND USEFUL HEAT 11 (1980).

361. *See supra* notes 54, 55.

362. While the fuel-use restrictions applied only to boilers for MFBIs, they also applied to diesel engines and gas turbines for power plants. In addition, new power plants were required to have the capability of burning an alternate fuel. G. Comstock, *FUA: The Transition to Alternate Fuels in the Industrial and Electric Utility Sectors,* 29 U. KAN. L. REV. 337, 337-68 (1980).

363. *See* the discussion of this exclusion in 47 Fed. Reg. 29,209 (1982).

364. For a good discussion of the history of the regulations imposed for obtaining the cogeneration fuel use exemption, see D. Irwin & K. Sisk, *The Fuel Use Act and DOE's Regulations,* 29 U. KAN. L. REV., 319, 319-36 (1980).

365. For a discussion of the burdens these regulations would impose on a firm seeking to cogenerate, see B. Beckman & M. Prairie, *Problem Areas in the Exemption Process Under the Powerplant and Industrial Fuel Use Act of 1978, id.* at 370-403.

366. *See* 47 Fed. Reg. 29,209 (1982). The oil and gas savings test for qualification for the exemption was expanded to include the savings of the utility or other nonjurisdictional unit, as

tighten the exemptions for cogenerators and force mandatory conversion, at least on those facilities that sell less than one-half their generated electricity. In any event, the uncertainty that has surrounded these regulations since their inception has been another reason large industries have been reluctant to embrace cogeneration.

Finally, economic disincentives have slowed the initiation of cogeneration. For most industrial processes, firms tend to use low-pressure "package" boilers that are relatively inexpensive and mass-produced. Most cogeneration projects, however, require custom built, high-pressure boilers. Equipment specifications vary according to the thermal versus electrical load needs of the firm. Such custom designing greatly increases the capital costs of a new boiler.[367] In times of economic recession and high interest rates, firms are reluctant to make these "nonessential" capital investments. A survey of thirteen industries with cogeneration potential by the Edison Electric Institute revealed capital limitations and the financial health of the particular business to be major inhibiting factors for five of the industries.[368]

To justify an investment in a nonproductive venture, firms often require a higher rate of return or a shorter payback period. One study found that firms require at least a thirty percent rate of return from such projects.[369] Setting a "higher hurdle" rate for cogeneration projects than for production related projects results in the elimination of many projects that would meet a lower threshold of economic feasibility. When energy costs are a relatively small proportion of a firm's operating costs, there is little incentive to invest in a cogeneration project unless the return from sale of the electricity is attractive.

Another inhibiting factor for some firms has been the risk associated with an unfamiliar business venture. Most firms view themselves as lacking expertise in the electrical generation business. Not only are there risks in choosing the appropriate technological configuration for a given plant's production and power needs, there is the need to have experts on the plant staff who can maintain this more sophisticated equipment. Many plant managers are unwilling to invest in the additional training and labor costs necessary to reduce these risks.

A final disincentive for plant managers considering cogeneration investments has been the general uncertainties connected with

well as the MFBI itself, 10 C.F.R. § 503.37(b) (1982). In addition, the evidentiary requirement in the ten year forecast was replaced by a Regional Estimates Table which the cogenerator could use to estimate savings over this period. 10 C.F.R. § 503.37(e) (1982).

367. Diesel engines and gas turbines can be sold as packaged systems, but they are not always suited to industrial process needs.

368. *Senate Hearing, Part I, supra* note 118, at 79, 90.

369. Resource Planning Associates, in *Senate Hearing, Part I, supra* note 118, at 94.

market behavior. Most states only permit the capacity credit if the cogenerator is willing to sign a contract to be a firm supplier of power.[370] The minimum contract length required may be as long as ten years. Thus, to acquire this more attractive payment rate, an industry must be confident of its minimum thermal needs and power output for a relatively long time span. It is not unreasonable to assume that the economic climate of the past two years has made many firms wary of making long-term commitments of future production levels. Yet, levelized payments usually are only available to those firms which sign such contracts. Nonfirm and sometimes even short-term contract suppliers must accept payments that track the changes in fuel prices. The more uncertain future fuel prices appear, the less attractive this option becomes, since the future rate of return obtainable becomes increasingly uncertain.

Thus, cogeneration generally appears to be attractive only to industries in which at least one of three conditions prevail: (1) the company already is a cogenerator and has existing expertise on its staff for making the most of the PURPA incentives; (2) a state commission or utility actively is encouraging potential cogenerators; or (3) the firm has an ancillary benefit to gain from cogeneration. In the first category are firms like Dow Chemical and a number of paper companies that traditionally were cogenerators. Their previous experience has placed them in the forefront of the return to cogeneration.[371]

California is the outstanding example of a state whose regulatory policy actively has encouraged cogeneration. By removing potential barriers to cogeneration in natural gas regulation, offering accelerated depreciation on new cogeneration equipment and instituting strong PURPA incentives, California has managed to encourage almost as many filings as the remainder of the United States.

The companies responding to the third condition, the ancillary benefit, are perhaps the most interesting. In this class are a number of firms with a waste product that is combustible. Faced with environmental regulation and increasing costs for disposal of this product, these companies have decided to burn the product to meet thermal and electrical needs. One of the most publicized of these ventures has been the cogeneration plant of the Diamond Walnut Growers Cooperative in Stockton, California. By burning walnut shells, this group expects to earn $1,000,000 each year on electricity

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370. *See supra* note 58.

371. Dow Chemical, for example, has been involved with cogeneration since the 1920s. It already had 600 MW of cogeneration capacity at its Brazoria City, Texas plant, but subsequent to PURPA, it has filed for qualification of 440 MW of additional capacity. *See* FERC Filings, *supra* note 329.

sales and natural gas savings.[372] Even in states where the price for cogenerated power is not favorable, however, the cogeneration option still may be attractive if there are substantial waste disposal costs to be saved by its adoption.

Many factors still inhibit the development of cogeneration, but the decline of cogeneration has been reversed. Firms again are installing cogeneration equipment if they perceive the state regulatory climate to be supportive of such ventures, or if they can avoid substantial energy or waste disposal costs.

VII. Assessing the Future

The FERC estimated that by 1995 there would be 16,600 megawatts of cogenerated electricity and the PURPA would have induced 5900 megawatts of that total.[373] Table C shows the annual filings of new cogeneration capacity.[374] If filings continue at the rate of about 1000 megawatts a year, then there would be about 16,000 MW of new cogenerated electricity by 1995.

Table C

Annual Filings of New Cogeneration Capacity (kw)

FY 80	187,700
FY 81	796,694
FY 82	2,142,383
FY 83*	283,267
TOTAL	3,410,044

* First quarter only

As already noted, however, a filing does not necessarily mean a firm commitment to produce power. A concern may file an application for qualification, while still evaluating a project, and subsequently decide against its construction. Indeed, two large projects may not materialize because of failures to obtain purchase rates for the electricity produced to make the projects economically feasible.[375] Thus, a systematic follow-up of the FERC filings should be done to determine the amount of cogeneration actually coming on line. It is entirely possible that no more than half of the capacity projected by these filings is being developed, in which case the

372. *Industry Examines Profit Prospects of Selling 'Cogeneration' Energy,* Wall St. J., Feb. 19, 1981, at 31. Four new cogeneration projects in Florida involve the use of waste heat from chemical processes, while a number of paper and pulp companies have filed projects that burn waste wood and black liquor—a combustible, but highly polluting waste product. *See* FERC Filings, *supra* note 329.

373. 45 Fed. Reg. 23,608 (1980).

374. FERC Filings, *supra* note 329.

375. A spokesman for the Bi-State Development Project and another that did not wish to be identified both spoke of the difficulty of implementing a project without an adequate rate of return. *See supra* note 325.

FERC may have overestimated significantly the amount of cogenerated electricity that will be available by 1995.

Another point of concern is the drop in filings for fiscal year 1983. If filings do not accelerate in later quarters, then the year's total will be significantly lower than in the previous year. While some of this drop may be attributed to the uncertainty created by the *AEP* case, a continuation of this pattern almost undoubtedly would be caused by falling fuel prices and the declining use of oil on the margin by electric utilities. These two conditions have been producing lower energy credit payments and may have discouraged some firms even from proceeding to the filing stage. Certainly when most estimates of the potential of various energy technologies were done in the late 1970s, few, if anyone, anticipated a fall in oil prices.

On the basis of the filings themselves, PURPA itself apparently has not given a strong boost to cogeneration; when PURPA is coupled with a comprehensive state regulatory policy to encourage cogeneration, however, the results can be quite dramatic. The large number of filings induced in California show that a coherent regulatory policy designed to remove a wide variety of institutional barriers can be an effective means of encouraging the growth of a technology.

The flexibility afforded states by the FERC's implementation of PURPA, however, apparently has resulted in wide variations in the degree of encouragement offered cogeneration. By leaving the determination of energy and capacity credits to jurisdictional utilities, rather than prescribing detailed methods themselves, many commissions essentialy have permitted utilities to offer cogenerators whatever rates they desire. The lack of standard rates for facilities with capacities above 100 kw, resulting in the need to engage in case-by-case negotiation with the utility, appears to have discouraged filings in a number of states. Industrial representatives have testified repeatedly about the problems of negotiating directly with many utilities. Even though utilities may be required to interconnect, unwilling utilities effectively can discourage development of private projects by offering low avoided cost purchase rates.

With the resolution of the *AEP* case, the federal challenges to the full avoided cost standard now should be over. The *Energy User News* issues on cogeneration rate-setting under PURPA, however, note the challenge of the final orders of Florida, Idaho, Kansas, Montana, New York and Pennsylvania in state courts by one or more jurisdictional utilities.[376] Since all these states wrote fairly comprehensive orders detailing methods to determine PURPA rates,

376. *States' Cogeneration Rate-Setting Under PURPA,* Energy User News, May 23, and May 30, 1983.

it appears that disgruntled utilities have adopted a new forum in which to oppose the avoided cost rule.

Between the reluctance of many utilities to negotiate fair purchase rates with potential cogenerators and the litigious stance of some of the more stringently regulated utilities, industrial concerns considering cogeneration still will face difficulties initiating projects for some time. In particular, these conditions will discourage firms that have little use for the electrical output themselves, but would wish to sell virtually all electricity generated to the utility. Unless cogenerators can sell all electrical output to the utility at a price that produces an acceptable return on the incremental investment, projects are likely to be either terminated or wrongfully sized.[377]

Under these circumstances, cogeneration would receive more encouragement if the FERC would mandate standard purchase rates for larger facilities and set more explicit guidelines for calculating purchase rates. In particular, a more uniform approach to offering capacity credits would be useful. Since the Commission acknowledged that setting capacity payments was indeed a difficult task, it seems reasonable to give states more guidance regarding the conditions under which such rates should be offered and the items that should be included in them.

Some states currently offer mandatory capacity payments, while others offer none and give no indication of a time when such payments might be offered. It might be required, for example, that utilities offer capacity payments if they bring on line a new generating unit, or plan the addition of a new generating unit, after a certain date. A greater uniformity in approach, with clearer guidelines for payments to be offered, would give potential cogenerators greater certainty in evaluating cogeneration projects.

While many industries oppose amending PURPA to enable utilities to have majority ownership of qualifying facilities, such an amendment might encourage more cogeneration if private projects were not obstructed as the result. By requiring utilities to set standard rates applicable to any qualifying facilities, including their own cogeneration subsidiaries, utilities then might be more motivated to set true avoided cost rates.

Finally, if cogeneration is to be encouraged, a coherent regulatory policy must be applied. Removal of utility barriers to cogeneration while simultaneously erecting fuel-use barriers does not provide

377. Maximum energy savings from cogeneration are only obtainable when the thermal and electrical loads are at the proper ratio for the mode of cogeneration employed. If a firm cannot use or profitably sell all the electricity it can produce from a plant that meets its thermal needs, then it may operate equipment to produce less electricity and thereby reduce energy efficiency. For detailed figures on thermal/electrical loads for various modes of cogeneration, see R. Barnes, *Introduction and Overview,* Wilkinson and Barnes, *supra* note 51, at 12.

a strong incentive for increased cogeneration. Thus, the recommendation of the Government Accounting Office for the creation of an office within the Department of Energy to co-ordinate and oversee federal cogeneration policy appears to be reasonable.[378] This office should identify the constraints on cogeneration that could be removed, as well as the potential problems of encouraging certain forms of cogeneration.

Once the legal barriers to a technology have been erected, it is a difficult task to remove them. Removing the barriers in one sector offers little encouragement if barriers remain in another. Furthermore, there is ample opportunity for vested interests to wage legal battles to halt the removal process. Many businesses are unwilling to commit funds to projects that are perceived to be nonessential, while these battles rage. Thus, while the federal legislative effort to encourage cogeneration has made notable gains, the revival still is a tenuous one.

378. United States Comptroller General, *Industrial Cogeneration—What It Is, How It Works, Its Potential* iii (1980).

APPENDIX

Table 1**

Comparison of Standard PURPA Rates and Residential Retail Rates: Selected Utilities (Spring 1982)

State	Utility	Std. PURPA Rate (cents/kwh)	Retail Rate (cents/kwh)
Cali- fornia	Pacific Gas & Electric (-)	7.759 on-pk 7.334 of-pk 6.548 of-pk + opt. cap. cr. $33-110/kw/yr	5.798 Tier I 7.566 Tier II 10.560 Tier III
Connect- icut	Connecticut Light & Power	5.5 on-pk n-f 4.29 of-pk, n-f 5.65 on-pk, f 4.95 of-pk, f	$7.35/mth + 7.52
Florida	Gulf Power (+)	2.629 on-pk, <100kw 2.213 of-pk, <100kw 2.052 on-pk, >100kw 2.106 of-pk, >100kw	$5.00/mth + 5.903–S 5.368–W
	Tampa Electric (-)	6.813 on pk, <100kw 4.378 of-pk, <100kw 6.446 on-pk, >100kw 4.142 of-pk, >100kw	$3.65/mth + 4.188–750kwh 3.961–>750kwh
Idaho	Utah Power (-)	2.2 n-f 4.79 f	6.8732–S 5.2532–W
	Pacific Power & Light	1.3 of-pk, n-f 2.0 on-pk, n-f 6.0 1-t	2.677 $6.00/mth-min
Illinois	Commonwealth Edison	5.31 on-pk, <1000kw,S 2.90 of-pk, <1000kw,S 5.17 on-pk, <1000kw,W 3.37 of-pk, <1000kw,W 5.23 on-pk, >1000kw,S 2.86 of-pk, >1000kw,S 5.09 on-pk, >1000kw,W 3.32 of-pk, >1000kw,W	$1.00/mth + 5.96–S 4.96–W
	Union Electric	1.77 fl-r,S 1.52 fl-r,W	$2.45/mth + 5.45–S 4.62–1000kwh,W 2.40–>1000kwh,W
Indiana	Northern Indiana Public Service	2.83 on-pk,S 2.46 of-pk,S 3.33 on-pk,W 2.75 of-pk,W	11.810–50kwh 8.479–150kwh 6.690–200kwh 4.843–exc,W
	Public Service of Indiana	1.33	$5.00/mth + 7.108–300kwh 4.264–700 kwh 3.580–exc

Table 1 (con't)

State	Utility	Std. PURPA Rate (cents/kwh)		Retail Rate (cents/kwh)
Maine	Bangor Hydro-Electric (-)	5.0 (temp)		$3.51/mth + 3.308-15kwh 14.642-60kwh 7,214-425kwh
	Central Maine Power (-)	5.5 (temp)	 t-o-d:	$3.38/mth-50kwh 6.7701->50kwh $9.69/mth + 8.7134 on-pk 4.0093 of-pk
Massa-chusetts	Boston Edison (-)	8.000 on-pk, <4kv 4.967 off-pk. <4kv 6.350 flat rate, <4kv		2.67-15kwh 7.12-35kwh 5.47-50kwh 4.46-50kwh 3.71-84kwh 4.96-616kwh 1.92-exc,W 3.84-exc,S
	Western Mass. Electric (-)	5.813 on-pk 4.238 of-pk 4.979 fl-4		$3.77/mth-12kwh 7.75-338kwh 4.51-650kwh 3.52-exc
Missouri	Union Electric	2.36 on pk,S 1.47 of-pk,S 1.73 int,S 2.07 on-pk,W 1.52 of-pk,W 1.49 int,W		8.06-100kwh 5.80-exc,S 4.53-900kwh,W 2.76-exc,W
Montana	Montana-Dakota Utilities	2.16 fl-4,s-t 5.58 fl-r,l-t		5.562-300kwh 6.900->300kwh
New Hampshire	Public Service Company of New Hampshire	7.7 n-f 8.2 f	 t-o-d:	$4.50/mth + 7.249-200kwh 9.911-300kwh 8.499-exc $4.50/mth + $2.50/mth-mtr.chg.+ 10.67-on-pk 6.22-off-pk
New York	Consolidated Edison	6.0 fl-r, st.min. 12.37 on-pk,S 4.77 of-pk,S 6.57 on-pk,W 4.37 of-pk,W		$4.06/mth + 11.95-1500kwh,W 11.26->1500kwh,W 13.095-1500kwh,S 12.766->1500kwh,S
	New York State Electric & Gas	6.0 fl, min.		$3.25/mth + 6.84-500kwh 5.90->500kwh

Table 1 (con't)

State	Utility	Std. PURPA Rate (cents/kwh)	Retail Rate (cents/kwh)
North Caro-lina	Carolina Power & Light (+)	2.8 on-pk, s-t 5.5 on-pk, l-t 2.07 of-pk,s-t 4.04 of-pk,l-t + 2.39 opt. cap.,S + 2.08 opt. cap.,W	$6.75/mth + 5.831,S 5.831–800kwh,W 5.101–>800kwh,W
	Duke Power (+)	2.12 on pk,s-t 5.02 on-pk,l-t 1.60 of-pk,s-t 1.60 of-pk,s-t 3.78 of-pk,l-t + 1.17 opt. cap., pk mths + .69 opt.cap., of-pk mths	$5.40/mth + 4.0462–360kwh 6.2562–950kwh 5.5262–exc,S 4.7762–exc,W
Oregon	Pacific Power & Light	2.2 fl-r,n-f,st.min 2.47-4.399 f,st.min. 3.59 fl-r, 100kw +$2.25-3.94/kw-mth	2.101–200kwh 3.043–1000kwh 4.164–exc.
Rhode Island	Blackstone Valley (-)	6.67 on-pk 5.08 of-pk 5.78 fl-r	$2.95/mth + 5.2
South Caro-lina	Carolina Power & Light	2.8 on-pk 2.07 of-pk +$3.89/kw-mth cap,S +$3.35/kw-mth cap,W	$6.00/mth + 5.285,S 5.25–800kwh,W 4.339–>800kwh,W
	Duke Power	1.98 on-pk 1.49 of-pk +$5.00/kw-mth cap.	$4.30/mth + 5.1307–1000kwh 5.5807–>1000kwh
Ten-nessee	Tennessee Valley Authority	3.2 fl-r, 100 kw 4.49 on-pk 2.8 on-pk	$2.30/mth + 4.115–500kwh 4.559–>500kwh
Texas	Houston Light & Power	FCA × (1.01-1.64) (FCA = 3.0)	$6.00/mth–30kw 3.845 exc,S 2.345 exc,W
Utah	Utah Power & Light (-)	2.2 fl-r,n-f 3.5 fl-r,f	7.0315
Vermont	Central Vermont Public Service Corp.	9.0 on-pk 6.6 of-pk 7.8 fl-r	$5.78/mth + 3.375,S 3.375–200kwh,W 11.813–>200kwh,W
Vir-ginia	Virginia Electric & Power (-)	3.815 on-pk,pk mths 1.815 of-pk,pk mths 3.441 on-pk,of-pk mths 1.815 of-pk,of-pk mths	$5.50/mth + 6.500–800kwh,S 7.719–>800kwh,S 6.500–800kwh,W 5.003–>800kwh,W
Wyoming	Utah Power & Light	2.2 n-f 2.6 f	$4.25/mth + 7.0235–500kwh,S 5.2962–exc,S 5.2471–500kwh,W 3.9687–exc,W

Table 1 (con't)

State	Utility	Std. PURPA Rate (cents/kwh)	Retail Rate (cents/kwh)
	Montana-Dakota Utilities	.405 + opt cap cr	$1.25/mth + 3.9968–50kwh 3.4968–100kwh 2.9968–200kwh 2.7468–exc.

** Key to abbreviations:
on-pk–power supplied at times of peak demand.
of-pk–power supplied at times of low demand.
int–power supplied at times of intermediate demand.
fl-r–power supplied at a flat, non-time differentiated rate.
n-f–power supplied on a non-firm, "as available" basis.
f–power supplied on a firm contractual basis.
s-t–a short-term contract rate.
l-t–a long-term contract rate.
W–winter or low season rate.
S–summer or low season rate.
st. min.–state minimum rate.
temp–temporary rate.
kw–rate kilowatt capacity of supplier
kwh–kilowatt-hours supplied.
mth–month.
exc–excess kilowatts supplied.
met. chg.–meter charge.
FCA–fuel cost adjustment factor.
opt. cap. cr.–optional capacity credit.
(+)–PURPA rates revised upward since spring 1982.
(-)–PURPA rates revised downward since spring 1982.

APPENDIX

Table 2**

Summary of States' Action on PURPA Purchase Rates (January 1983)

State	Rule Status	Std. Rates Above 100kw	Capacity Payment	Information on Rates
Alabama	Final	No	No	
Alaska	Final	N.A.	Opt.	
Arizona	Final	No	Opt.	
Arkansas	Final	<1000kw	Opt.	net billing opt. if <1000kw
California	Final	Yes	Opt.	graduated cap.cr. E cr. based on oil
Colorado	Final	No	N.A.	
Connecticut	Final	<1000kw	No	Allow:VO&M, LLF, I&H, firm power
Delaware	Final	<1000kw	No	min. 1 yr. contract
Florida	Final	Yes	Neg.	sys. E cr. + LLF
Georgia	Pending	N.A.	N.A.	
Hawaii	Final	N.A.	N.A.	
Idaho	Final	No	Man. + Opt.	net bill opt. if <100kw, min.c.f., graduated cap.cr.
Illinois	Final	Yes	Neg.	
Indiana	Final	Yes	N.A.	
Iowa	Final	No	Neg.	credits based on pool billing rates
Kansas	Final	No	Opt.	rates based on embedded costs
Kentucky	Final	N.A.	N.A.	
Louisiana	Final	No	Opt.	
Maine	Final	≦1000kw	Opt.	net bill opt. if <10kw; Allow: VO&M, LLF, UD, CM.
Maryland	Pending	N.A.	N.A.	
Massachusetts	Final	Yes	Opt./ Neg.	net bill opt. if <30kw; Allow: VO&M, LLF, SS; pk. hr.
Michigan	Final	Yes	Opt.	no net billing
Minnesota	Pending	N.A.	N.A.	

Table 2 (con't)

State	Rule Status	Std. Rates Above 100kw	Capacity Payment	Information on Rates
Mississippi	Pending	N.A.	N.A.	
Missouri	Final	No	No	threshold for cap. cr.
Montana	Final	Yes	Yes	net bill opt.; Allow: VO&M, LLF, WC; graduated cap. cr., min.c.f.
Nebraska	No state regulatory commission			
Nevada	Final	N.A.	Opt.	
New Hampshire	Final	Yes	Opt.	statewide rate; net bill opt.; Allow: VO&M, I&D
New Jersey	Final	<1000kw	No/ Opt.	no cap. cr. if <100kw; E cr.=pool billing rate
New Mexico	Final	No	Neg.	
New York	Final	Yes	Opt.	state min. rate; pk. hrs. cap. cr.
North Carolina	Final	Yes	Opt.	graduated cap. cr.; Allow: VO&M, LLF, WC
North Dakota	Final	No	Opt.	
Ohio	Final	No	Neg.	
Oklahoma	Final	No	Opt.	rates to reliability; Allow: LLF
Oregon	Final	Yes	Opt.	state min. rate; graduated cap.cr.
Pennsylvania	Final	<500kw	Opt.	Allow: VO&M
Rhode Island	Final	Yes	No	Allow: LLF
South Carolina	Final	Some	Opt.	
South Dakota	Final	N.A.	N.A.	
Tennessee	Final	Yes	N.A.	
Texas	Final	Yes	Opt.	

Table 2 (con't)

State	Rule Status	Std. Rates Above 100kw	Capacity Payment	Information on Rates
Utah	Final	<1000kw	Opt.	no net billing; min. c.f.
Vermont	Final	Yes	No.	statewide rate
Virginia	Final	No	Opt.	net bill opt.
Washing-ton	Final	No	Neg.	
West Virginia	Final	N.A.	N.A.	
Wisconsin	Pending	N.A.	N.A.	
Wyoming	Final	No	Neg.	

** Key to abbreviations:
N.A.–information not available.
Opt.–capacity payment dependent upon QF meeting certain conditions.
Neg.–capacity payment left to QF and utility negotiation.
Man.–capacity payment mandatory.
Man. & Opt.–small capacity payment required, larger one available upon meeting certain conditions.
Opt./Neg.–QFs above a certain capacity must negotiate payment.
Allow:–allowances permitted in the energy credit.
VO&M–variable operation and maintenance allowance.
LLF–line loss factor allowance.
I&D–inventory and depreciation allowance.
WC–working capital allowance.
UD–utility dispatch allowance.
CM–co-ordinated maintenance allowance.
SS–shared savings.
min. c.f.–minimum capacity factor required for capacity credit.
E cr.–energy credit.
cap. cr.–capacity credit.