

# Report Of The Committee On Electric Utility Regulation

## I. INTRODUCTION

In 1992, Congress made sweeping changes to the structure of the electric utility industry. In the first major legislation since 1978, the Energy Policy Act of 1992 (Act or Energy Policy Act),<sup>1</sup> Congress amended the Public Utility Holding Company Act of 1935 (PUHCA)<sup>2</sup> to remove barriers to the development of independent power projects, and broadened the Federal Energy Regulatory Commission's (the FERC or Commission) transmission authority under the Federal Power Act (FPA).<sup>3</sup> Congress further amended PUHCA to permit investments in foreign utility systems by domestic utilities, subject to certain regulatory approvals. The Act also created the potential for an increased role for integrated resource planning (IRP) in utility decision-making.

On the administrative side, the FERC attempted to encourage the role of competition in the industry through several rulemakings and a number of litigated cases. Also, the Securities and Exchange Commission (SEC) was presented with several novel issues, and made decisions which could affect the future structure of the industry.

## II. LEGISLATION - THE ENERGY POLICY ACT OF 1992

### A. *Exempt Wholesale Generators*

Section 711 of the Energy Policy Act added section 32 to PUHCA which defines exempt wholesale generators (EWG) and provides that an EWG will be exempt from regulation under PUHCA (including the definition of electric utility companies) under section 2(a)(3) of PUHCA. Section 711 also provides that ownership of one or more EWGs will not cause the owner to be deemed "primarily engaged in the generation or sale of electric power" under the FPA.

Section 711 defines an EWG as a person determined by the FERC to be in the business of owning or operating all or part of an "eligible facility." An "eligible facility" is a facility (including a leased facility) used to generate electricity exclusively for wholesale, including interconnection transmission facilities. Eligible facilities may not make retail sales, except facilities in foreign countries so long as none of the energy generated by the eligible facility is sold to consumers in the United States. The FERC must respond to requests for EWG status within sixty days and issue rules implementing section 711 within one year of enactment.<sup>4</sup>

If a rate or charge for the construction of a facility or for electricity pro-

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1. 16 U.S.C.A. § 2621 (West Supp. 1993).

2. 15 U.S.C. §§ 79a to 79z-6 (1988).

3. 16 U.S.C. §§ 824-824k (1988).

4. 16 U.S.C.A. § 2621 (West Supp. 1993) (amending section 32(a)(1) of PUHCA, 15 U.S.C. §§ 79a to 79z-6 (1988)).

duced by the facility was subject to the jurisdiction of a state public utility commission on the date of the enactment of section 711, the facility can become an EWG only if every state commission with jurisdiction makes a specific determination of eligibility. Each state commission must determine that allowing the facility to be an EWG (1) will benefit consumers; (2) is in the public interest; and (3) does not violate state law. In addition, no EWG may own or operate a portion of any facility if another portion of that facility is owned or operated by an electric utility company that is an affiliate company of the EWG unless the portion owned or operated by the utility becomes an eligible facility as a result of such state consent.

Exempt holding companies and registered holding companies under PUHCA will be permitted, without condition, limitation, or SEC approval, to acquire and hold the securities of, or an interest in, the business of one or more EWGs. However, actions by a registered holding company related to EWGs (such as issuance of securities for financing the acquisition of an EWG, guaranteeing of securities of an EWG, entering into contracts, and the creation or maintenance of other relationships) will remain within the SEC's PUHCA jurisdiction.

Section 711 also provides that an electric utility may not enter into a contract to purchase power from an affiliated EWG unless every state commission having jurisdiction over the affected retail rates makes a specific determination allowing the contract. Specifically, each state commission must determine in advance that it has sufficient regulatory authority to exercise its duties and that the transaction (1) will benefit consumers; (2) does not violate any state law; (3) would not provide an EWG any unfair competitive advantage by virtue of the affiliation; and (4) is in the public interest. Finally, section 711 prohibits reciprocal arrangements among unaffiliated companies that are entered into in order to avoid the provisions of the section.

#### *B. Transmission Access and Pricing*

The Energy Policy Act amendments to the FPA significantly expand the FERC's authority to order transmission services. Those amendments are summarized below.

##### *1. Section 3*

Existing subsection (22) of section 3 was amended and three new subsections, (23), (24), and (25), were added. Existing subsection 3(22) defined an "electric utility" as "any person or state agency which sells electric energy" and specified that the term included the Tennessee Valley Authority, but did not include any federal power marketing agency. The Act amends section 3(22) to include "any municipality" which sells electric energy within the definition of "electric utility."

New subsection (23) adds the definition of "transmitting utility." "Transmitting utility" has replaced "electric utility" whenever "electric utility" had been used to refer to the utility which is subject to the FERC's order requiring the wheeling services. "Transmitting utility" is defined as "any electric utility, qualifying co-generation facility, qualifying small production facil-

ity, or federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.”

New subsection (24) defines “wholesale transmission services” as “the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.”

## 2. Section 211(a)

Section 211(a), as amended, authorizes any electric utility, federal power marketing agency, or any other person generating electric energy for resale to apply to the FERC for an order requiring a transmitting utility to provide wheeling services to the applicant, provided the applicant had asked the affected transmitting utility for such service sixty days prior to the filing of the application. The FERC is authorized to issue such an order if it finds that the requirements of section 212 have been met and that issuance of the order is in the public interest.

## 3. Section 211(b)

Existing section 211(b) is eliminated and a new subsection (b) is substituted, which provides that no orders may be issued under section 211 or section 210 (authorizing the FERC to require physical connection of facilities if certain requirements are met), if the FERC finds upon consideration of consistently applied regional or national reliability standards, guidelines, or criteria, that the order would unreasonably impair the continued reliability of electric systems affected by the order.

## 4. Section 211(c)

The amendments eliminate section 211(c)(1), which prohibited the issuance of any order under subsection (a) of section 211, unless the FERC determined that the order would preserve existing competitive relationships. This requirement significantly limited the FERC’s authority to order wheeling services under this section.

Section 211(c)(2) is amended so that its terms apply to a “transmitting utility” by substituting that term for “electric utility.” Otherwise, the existing provisions of subsection (c)(2) and its subdivisions (A) and (B) remain unamended. Subsections (c)(2)(A) and (B) prohibit the issuance of a wheeling order requiring the transmitting utility to wheel electric energy which replaces any amount of electric energy required, during the wheeling period, to be delivered to the applicant pursuant to a rate schedule on file with the FERC, or pursuant to a contract.

Subsections (c)(3) and (4) of section 211 are eliminated. These subsections prohibited retail wheeling orders. The subject of retail wheeling is dealt with in section 212, as amended, which is described below.

## 5. Section 211(d)(1) and (d)(3)(B)

The only amendment to existing subsections (d)(1) and (d)(3)(B) of sec-

tion 211 is the substitution of "transmitting utility" for "electric utility." A new subsection (d)(1)(C) was also added to section 211. This section authorizes the FERC to terminate or modify an order requiring wheeling services if the transaction necessitates the construction of transmission facilities, and the transmitting utility, after a good faith effort, fails to obtain the necessary governmental approvals or property rights.

6. Section 212(a)

New section 212(a) permits the transmitting utility to recover all cost incurred in connection with the wheeling and necessary associated services, including, but not limited to, an appropriate share, if any, of "legitimate, verifiable, and economic costs, taking into account any benefits to the transmission system of providing the transmission services and the costs of any enlargement of transmission facilities." The rates, charges, terms, and conditions must be necessary to promote economically efficient transmission and generation of electricity and must be just, reasonable, and not unduly discriminatory or preferential. To the extent practicable, the transmitting utility should recover the costs properly allocable to the transmission service from the applicant and not from the transmitting utility's existing wholesale, retail, and wheeling customers.

7. Section 212(e)(1)

As amended, subsection (e)(1) of section 212 provides that the provisions of sections 210, 211, 212, and 214 should not be construed to require any person to utilize the authority of any of these sections in lieu of any other authority of law. Subsection (e)(1) also states that the provisions of sections 210, 211, 212, and 214, except as otherwise provided therein, shall not be construed as limiting or impairing the authority of the FERC under any other provision of law.

8. Section 212(e)(2)

New subsection (e)(2) provides that sections 210-214 shall not be construed to modify, impair, or supersede the antitrust laws.

9. Sections 212(g) and (h)

Section 212(g) prohibits the issuance of a wheeling order which is inconsistent with any state law governing retail marketing areas of electric utilities. Sections 212(g) and (h) prohibit use of the FERC's authority to order transmission service in connection with retail sales of electric energy. However, section 212(h) exempts certain federal and state agencies or instrumentalities, quasi-government agencies, and conventional electric distribution utilities which were providing electric service at retail on the date of enactment of the Act or which use transmission or distribution facilities owned or controlled for the delivery of electric energy to the ultimate consumer.

The Conference Report, referring to the savings clause for state laws which either prohibit or permit retail wheeling, states that such laws are unaf-

fectured by section 212(h), and, if otherwise valid, remain in full force and effect.<sup>5</sup> The Conference Report also states that the Conferees “do not intend to limit or modify the authority of State commissions to review the prudence or imprudence of wholesale purchases by retail utilities under their jurisdiction.”<sup>6</sup>

#### 10. Section 212(i) and (j)

Subsections (i) and (j) of section 212 are new subsections. They authorize the FERC to order the Administrator of the Bonneville Power Administration (BPA) to provide wheeling services and to establish the terms and conditions for such services. There are, however, numerous restrictions on the FERC’s ability to exercise this authority vis-a-vis the BPA.

#### 11. Section 212(k)

Subsection (k) of section 212 is a new subsection. This subsection provides that electric utility members of the Electric Reliability Council of Texas, which are not subject to the FERC’s general rate jurisdiction under sections 205 and 206 of the FPA, are subject to the FERC’s jurisdiction under section 211(a), as amended by the Energy Policy Act. As “transmitting utilities,” they must provide wheeling services over their transmission facilities, insofar as practicable and consistent with amended section 211(a), but they are entitled to receive compensation for such services on the basis of the transmission ratemaking methodology used by the Public Utility Commission of Texas.

#### 12. Section 213(a) and (b)

Subsection 213(a) states that, whenever a transmitting utility receives a good faith request for wholesale services that requests specific rates, charges, terms, and conditions, the transmitting utility must offer to provide the services at acceptable rates, terms, and conditions within sixty days of receipt of the request or other mutually agreed upon period, or provide the requester with a detailed explanation of the basis for its proposed rates, terms, and conditions for the services and an analysis of the physical or other constraints affecting provision of the services.

Subsection (b) directs the FERC to promulgate a rule within one year of enactment of section 213 which requires transmitting utilities to submit information annually to the FERC which is adequate to inform potential wheeling customers, state regulatory authorities, and the public of projected available transmission capacity and known constraints.

#### 13. Section 214

Section 214 makes it unlawful for an EWG to give an undue preference or advantage to an associate company or affiliate of the EWG.

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5. 138 CONG. REC. H12,157 (daily ed. Oct. 5, 1992)(joint explanatory statement of the Conference Committee).

6. *Id.*

#### 14. Sections 315 and 316

Sections 315 and 316 are amended by adding an identical new subsection (c). The new subsection provides that the sanctions set out in sections 315 and 316 do not apply to the violation of wheeling orders and rules under sections 211, 212, 213, or 214.

#### 15. Section 316A(a) and (b)

Section 316A is a new section. Subsection (a) provides that violations of any rule or order issued under the provisions of sections 211, 212, 213, or 214 shall be unlawful. Subsection (b) provides a monetary civil penalty for each day that a violation continues and establishes procedures for assessment of the penalty.

### C. *Investment in Foreign Utilities*

In the Energy Policy Act, Congress also amended PUHCA to permit U.S. utilities to invest in foreign utility companies. Section 33(a)(1) of the Act amends the definition of "public utility companies" under PUHCA to exclude foreign utility companies, thus enabling domestic utilities to invest overseas without becoming subject to PUHCA.

The Act prohibits a domestic utility from investing in foreign utility companies until the state commission with jurisdiction over the domestic utility's retail rates has certified that the state commission has the jurisdictional authority and resources to protect ratepayers under its jurisdiction and that it intends to exercise that authority. The Act also permits foreign investment by registered holding companies, subject to SEC review of securities issuances, guarantees, sales and service contracts, and the creation of any other relationship between a foreign utility and the holding company and its affiliate and associate companies.

The Act prohibits any domestic utility company subject to the jurisdiction of a state commission from encumbering its assets with respect to a foreign utility company. Section 33 permits investment in foreign companies engaged in the generation, transmission, and distribution of retail electricity, or manufactured or natural gas for light, heat, or power.

## III. ADMINISTRATIVE ACTIVITY

### A. *Federal Energy Regulatory Commission*

#### 1. Transmission Issues

In 1992, the FERC issued a number of orders regarding third party transmission pricing which limited a utility to the higher of its standard embedded cost rate or the incremental cost of necessary additions to its transmission facilities.<sup>7</sup> In response to the Act, which was enacted after most of those

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7. See Opinion No. 364-A, *Northeast Utils. Serv. Co.* (Re Public Serv. Co. of N.H.), 58 F.E.R.C. ¶ 61,070 (1992), *reh'g denied*, Opinion No. 364-B, 59 F.E.R.C. ¶ 61,042 (1992), *appeal dismissed*, *Northeast Utils. Serv. Co. v. FERC*, 59 F.E.R.C. ¶ 61,089 (1992) [hereinafter *NU Merger Case*]; *Entergy Servs., Inc.*, 58 F.E.R.C. ¶ 61,234 (1992), *order on reh'g*, 60 F.E.R.C. ¶ 61,168 (1992), *appeal pending sub. nom.* Cajun Elec.

orders were decided, the FERC is currently analyzing the new law to determine its impact on transmission pricing issues. The FERC is expected to solicit public comment on transaction pricing rate designations such as distance sensitive rates, pricing of parallel flows, and other related matters in the near future.<sup>8</sup>

## 2. Opportunity and Out-of-Rate Cost Recovery

### a. Northeast Utilities Orders

On January 29, 1992, the FERC issued two orders which conditionally approved recovery by Northeast Utilities Service Co. (Northeast) of opportunity costs<sup>9</sup> and out-of-rate costs<sup>10</sup> in Northeast's transmission rates. The first order held that, in the context of Northeast's request for approval of its merger with the Public Service Co. of New Hampshire (*NU Merger Case*), Northeast was generally entitled to recover legitimate and verifiable opportunity costs through its firm transmission rates.<sup>11</sup> The second order generally approved Northeast's ability to recover legitimate and verifiable opportunity costs through its non-firm transmission rates and legitimate and verifiable out-of-rate costs through its firm transmission rates.<sup>12</sup>

In the first order, Opinion No. 364-A, the FERC announced three basic principles that will guide its deliberation on transmission pricing issues: (1) native load customers should be held harmless; (2) transmission customers should be charged the lowest reasonable cost-based rate for third party transmission service; and (3) pricing should prevent the collection of monopoly rents by the transmission owner and promote efficient transmission decisions.<sup>13</sup> The FERC did not identify one particular costing methodology as best, but emphasized that any methodology that meets these goals would be accepted.

The FERC also delineated the issues a utility must address in making a proposal to recover opportunity costs:

- (1) Whether opportunity costs should be capped by incremental costs associated

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Power Coop. v. FERC, (D.C. Cir. filed Sept. 24, 1992); *Consumers Power Co.*, 59 F.E.R.C. ¶ 61,106 (1992), *reh'g pending*, *Public Serv. Co. of Colo.*, 59 F.E.R.C. ¶ 61,311 (1992), *reh'g denied*, 62 F.E.R.C. ¶ 61,013 (1993), *Pennsylvania Elec. Co.*, 58 F.E.R.C. ¶ 61,278 (1992), *reh'g denied*, 60 F.E.R.C. ¶ 61,034 (1992), *appeal pending*, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992); *Southern Co. Servs.*, 60 F.E.R.C. ¶ 61,273 (1992).

8. *Public Serv. Elec. & Gas Co.*, 62 F.E.R.C. ¶ 61,014, mimeo at 1 (Jan. 13, 1993).

9. The FERC has defined opportunity costs as "the revenues lost or costs incurred by a utility in providing third-party transmission service when transmission capacity is insufficient to satisfy both a third-party wheeling request and the utility's own use." *NU Merger Case*, 58 F.E.R.C. ¶ 61,070, at 61,200-01 (1992).

10. The FERC has described out-of-rate charges as costs incurred "when a particular wheeling transaction may necessitate that . . . [a utility or power pool] . . . operate certain generating units out of economic dispatch." *Northeast Utils. Serv. Co.*, 58 F.E.R.C. ¶ 61,069, at 61,167 (1992) [hereinafter *NU II*].

11. *NU Merger Case*, 58 F.E.R.C. ¶ 61,070, at 61,203-04.

12. *NU II*, 58 F.E.R.C. ¶ 61,069, at 61,179, 61,182.

13. *NU Merger Case*, 58 F.E.R.C. ¶ 61,070, at 61,203.

with the system expansion necessary to avoid the lost opportunity or another cap;

- (2) Whether current wheeling and wholesale requirements customers should be treated differently from future wheeling and wholesale requirements customers, e.g., by receiving "grandfather" rights to embedded cost rates for the amount of transmission capacity they already use;
- (3) How NU will identify those customers responsible for growth on its system and the new facilities that are necessary to serve such customers;
- (4) Whether and how third parties would be protected from uncertainty regarding fluctuations in opportunity costs;
- (5) How the proposed rates will prevent the collection of monopoly rents; and
- (6) How the proposed opportunity costs will be verified.<sup>14</sup>

The second Northeast order involved consolidated transmission rate dockets in which Northeast (on behalf of its affiliates, Connecticut Light & Power and Western Massachusetts Electric Co.) requested approval to recover opportunity costs, including out-of-rate costs. The FERC found that Northeast could include provisions to recover opportunity costs in its non-firm transmission rates. "However, such costs will not be allowed as an 'adder' to the basic non-firm rate. We will, therefore, permit Northeast to charge the greater of (1) the basic non-firm rate stated on an hourly basis, or (2) validated opportunity costs."<sup>15</sup>

In addition, the FERC generally approved Northeast's proposal to recover out-of-rate charges in its firm transmission rates as a legitimate means of recovering identifiable costs. "However, . . . the Commission is deferring final approval of the proposed out-of-rate charges until it has the opportunity to review Northeast's compliance filing to Opinion Nos. 364 and 364-A."<sup>16</sup>

#### b. *Pennsylvania Electric Company*

In *Pennsylvania Electric Co.*,<sup>17</sup> the FERC addressed the extent to which a utility may recover opportunity costs in its firm transmission rates to third parties. Applying the principles enunciated in the *Northeast Utilities Orders*,<sup>18</sup> the FERC denied the utility's request for a lost opportunity adder to its embedded cost rates. In doing so, the FERC extended to firm transmission pricing the principles it had previously applied in determining the justness and reasonableness of non-firm service pricing.<sup>19</sup>

*Pennsylvania Electric Co.* involved a rate proceeding concerning a transmission agreement filed under section 205 of the FPA,<sup>20</sup> whereas the *Northeast*

14. *Id.* at 61,203-04.

15. *NU II*, 58 F.E.R.C. ¶ 61,069, at 61,165.

16. *Id.*

17. 58 F.E.R.C. ¶ 61,278 (1992), *reh'g denied*, 60 F.E.R.C. ¶ 61,034 (1992), *appeal pending*, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992).

18. *See NU Merger Case*, 58 F.E.R.C. ¶ 61,070, *reh'g denied*, 59 F.E.R.C. ¶ 61,042, *appeal dismissed*, *Northeast Utils. Serv. Co. v. FERC*, 59 F.E.R.C. ¶ 61,089 (1992); *NU II*, 58 F.E.R.C. ¶ 61,069.

19. *Pennsylvania Elec.*, 60 F.E.R.C. ¶ 61,034, at 61,124.

20. On March 10, 1992, Pennsylvania Elec. Co. (Penelec) filed with the Commission a transmission services agreement with Penntech Papers, Inc. (Penntech). The agreement provided for the firm transmission of capacity and energy from Penntech's Qualified Facility (QF) that Penntech is developing in Pennsylvania to Niagara Mohawk Power Corp. which agreed to purchase the power. *Id.* at 61,121.



*Utilities* Orders pertained to an open access tariff filed in consideration of a merger under section 203.<sup>21</sup> The FERC rejected any distinction and held that although the rates resulted from an arms-length transaction and were acceptable to both parties, the voluntary nature of the transmission service does not obviate the need to address issues of transmission pricing.<sup>22</sup>

In analyzing the *Pennsylvania Electric Co.* agreement within the framework of the *Northeast Utilities* Orders, the FERC set out three types of system conditions that must be addressed differently in connection with a pricing proposal. The first is where the system is not constrained and there is enough capacity to meet all transmission requests, the needs of native load, and opportunity transactions. Here, under the FERC's traditional rate treatment, the utility may charge an embedded cost price which "allow[s] recovery of variable operating and maintenance costs plus up to a 100 percent contribution to fixed-costs."<sup>23</sup>

The second type of system condition exists when the "system is constrained and the utility chooses to expand its system to remove the constraint."<sup>24</sup> Upon expansion, the utility will be able to relieve the constraint. "[U]nder this condition, the utility may charge a transmission rate that does not exceed the higher of (1) an embedded cost price, or (2) a price reflecting the incremental cost of expanding the system."<sup>25</sup>

The third type of system condition, present in *Pennsylvania Electric Co.*, exists where the system is constrained, but the utility chooses not to expand the system.<sup>26</sup> Here the utility may charge the higher of embedded cost or opportunity cost (capped at the utility's incremental cost of expansion to relieve the constraint), but not both. This reflects a balancing of the two goals set out in the *Northeast Utilities* cases.<sup>27</sup> Thus, in *Pennsylvania Electric Co.*, the FERC concluded that the utility's proposal went "well beyond holding its native load customers harmless, and conflict[ed] with the second goal of charging the lowest reasonable rate for firm, third party transmission service."<sup>28</sup> As in *Northeast Utilities*, the FERC viewed the utility's proposed pricing as "double dipping." The FERC found when the utility cannot use the same capacity at the same time for two different purposes, it would be unrea-

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21. *Id.* at 61,124.

22. *Pennsylvania Elec.*, 58 F.E.R.C. ¶ 61,278, at 61,874-75.

23. *Pennsylvania Elec.*, 60 F.E.R.C. ¶ 61,034, at 61,123.

24. *Id.*

25. *Id.* at 61,124. In the *NU Merger Case*, the FERC stated that it would allow incremental cost pricing if the utility could show that the facilities would not have been needed "but for" the third-party wheeling request. 58 F.E.R.C. ¶ 61,070, at 61,205 (emphasis added); *See also* Opinion No. 364, *NU Merger Case*, 56 F.E.R.C. ¶ 61,269, at 62,030-31 (1991).

26. In a constrained system, the utility cannot simultaneously accommodate third-party transmission requests and the utility's own economy purchases, sales, or transfers. *Pennsylvania Elec.*, 60 F.E.R.C. ¶ 61,034, at 61,124.

27. The two goals are holding harmless the native load customers and charging the lowest reasonable cost-based rate for third party firm transmission service. *Id.*

28. *Pennsylvania Elec.*, 58 F.E.R.C. ¶ 61,278, at 61,873.

sonable to allow it to charge rates reflecting the dual use of the same capacity.<sup>29</sup>

The FERC more recently applied the principles of *Pennsylvania Electric Co.* in a deficiency letter in *United Illuminating Co.*<sup>30</sup>

### 3. Expansion Cost Recovery

In *NU Merger Case*, the FERC held, in its initial order, that "transmission upgrades necessitated by third-party, firm transmission use should be paid for by the requesting party and not by native load customers."<sup>31</sup> However, the FERC limited the amount that utilities can charge third parties where the facilities are fully integrated and support the entire transmission system.

[On fully integrated systems, the utility] . . . will not be permitted to charge both an embedded cost rate and an incremental cost rate for firm wheeling service, since both rates would unjustifiably require a wheeling customer to pay rates for part of . . . [the utility's] . . . costs based on cost causation while paying rates for other costs based on use of the system.<sup>32</sup>

Utilities may charge the higher of embedded cost rates or incremental cost rates.<sup>33</sup> In charging incremental cost rates, however, the utility must first justify incremental pricing.<sup>34</sup> This justification is the threshold issue and the utility seeking to specifically assign the incremental costs of upgrades bears the burden of proof. Thus, the FERC's position in Opinion 364 remains unchanged:

[w]hile the Commission is willing to accept incremental cost-pricing for third-party transmission service, we believe the proper forum to decide the details of cost responsibility questions is a separate section 205 rate case. In such a case, . . . [the utility] . . . must justify any direct assignments of costs and support any arguments that reliability is degraded by a particular firm transmission service.<sup>35</sup>

The FERC generally directed Northeast to identify to the prospective transmission service customer the specific upgrades needed and to provide an initial cost estimate of expanding the system. Thus, under the General Terms and Conditions of Northeast's open access tariff:

[Northeast] shall have the obligation: (1) to identify, prior to the time of contracting, the constraints on its transmission system that it anticipates reasonably

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29. *Id.*

30. Director, Division of Applications, Office of Electric Power Regulation, Deficiency Letter (July 2, 1992) (unpublished); 60 F.E.R.C. ¶ 61,214 (1992).

31. *NU Merger Case*, 56 F.E.R.C. ¶ 61,269, at 62,030.

32. *NU Merger Case*, 58 F.E.R.C. ¶ 61,070, at 61,206; *See also Entergy*, 58 F.E.R.C. ¶ 61,234, at 61,769.

33. *See supra* note 7 and accompanying text. *See also United Illuminating Co.*, 60 F.E.R.C. ¶ 61,214, where the Commission Staff recently required United Illuminating to revise its transmission tariff to allow the recovery of only the higher of embedded or incremental costs, not both.

34. *NU Merger Case*, 58 F.E.R.C. ¶ 61,070, at 61,206; *See also Public Serv. Co. of Colo.*, 59 F.E.R.C. ¶ 61,311, at 62,150, *reh'g denied* 62 F.E.R.C. ¶ 61,013, mimeo at 5-9 (1993); *Consumers Power Co.*, 59 F.E.R.C. ¶ 61,106, at 61,394-95 (clarified 60 F.E.R.C. ¶ 61,257 (1992)).

35. *NU Merger Case*, 58 F.E.R.C. ¶ 61,070, at 61,207 (citing 56 F.E.R.C. ¶ 61,269, at 62,031).

could require the construction of additional facilities during the term of the wheeling contract, (2) to provide the best estimate of the maximum cost to that wheeling customer . . . to remove each identified potential constraint, and (3) to include in its planning adequate provision for wheeling services (other than non-firm wheeling) which [Northeast] has contracted to provide for others.<sup>36</sup>

In *Entergy*, the FERC directed a revision in Entergy's tariff provision concerning expansion cost recovery. Entergy had filed a tariff that provided that it would not re-dispatch its system and forego economic transactions to accommodate a third party transmission request. Even if the re-dispatch would alleviate the system constraint, Entergy's tariff would have required that new facilities be built at the customer's expense. The FERC held that such a provision would result in inefficient capacity additions because a transmission request could be more cheaply fulfilled through re-dispatch. The FERC determined that Entergy should not expand its system until additional re-dispatch costs exceeded the cost of expansion.<sup>37</sup>

In its January 13, 1993 Order Denying Rehearing in *Public Service Co. of Colorado*, the FERC reaffirmed that utilities may charge the higher of "an incremental cost rate or the applicable embedded cost rate, but not both."<sup>38</sup>

#### 4. Stranded Investment Cost Recovery

In *Entergy*, the FERC approved the utility's request to recover stranded investment costs.<sup>39</sup> By filing the open access tariff, Entergy has provided an opportunity for wholesale power market participants in its relevant market area to trade with each other more easily. Provision of these wholesale opportunities, however, may cause economic dislocations and stranded investments. Recognizing this, the FERC rejected the claim that recovery of stranded investment costs constitutes the collection of monopoly rents, and allowed Entergy to recover from customers "*legitimate and verifiable* stranded investment costs already incurred, and only when those customers choose to transact with . . . other suppliers."<sup>40</sup>

In reaching this decision, the FERC provided guidance on the types of stranded investment costs which may be recovered.

- (1) The utility must be able to demonstrate that it has incurred generation investments or other obligations on the customer's behalf based on a reasonable expectation at that time the expense was incurred that the customer's power contract would be renewed;
- (2) The customer's cost liability for stranded investment may be no more than what the customer would have contributed to fixed costs under its existing rate had the customer remained on the utility's system; and

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36. *Id.*

37. *Entergy Servs., Inc.*, 58 F.E.R.C. ¶ 61,234, at 61,769-70.

38. *Public Serv. Co. of Colo.*, 59 F.E.R.C. ¶ 61,311, at 62,150.

39. Stranded investment costs are the costs of any production, transmission, or distribution facilities that are unrecovered by a utility as a result of providing service under its open access tariffs to a wholesale power customer who terminates power purchases from that utility, and seeks to obtain transmission service only. While transmission and distribution costs are generally available for stranded investment cost recovery, the most likely stranded costs are production-related. *Entergy*, 58 F.E.R.C. ¶ 61,234, at 61,770.

40. *Id.* See also Deficiency Letter at 4-5, *United Illuminated Co.*, 60 F.E.R.C. ¶ 61,124 (Commission Staff applies *Entergy* standard for stranded investment cost recovery).

- (3) The utility shall mitigate a customer's stranded investment obligation when the customer decreases its purchases under or terminates a power sales agreement.<sup>41</sup>

Furthermore, the FERC set out a procedure to inform a potential transmission customer of the potential stranded investment for which the customer might be liable so that the customer can assess whether to contract for new generation service from another supplier:

- (1) Within thirty days of a request for transmission service, the utility shall provide the customer with the specific stranded investment charge;
- (2) If the requester finds the proposed stranded investment charge unreasonable, the requester shall have thirty days in which to respond to the utility, explaining why it disagrees with the charge;
- (3) The utility and the requester then have ninety days to attempt to resolve the dispute;
- (4) If the dispute cannot be resolved in ninety days, the requester may:
  - (i) file a complaint with the FERC; or
  - (ii) wait until the utility files the proposed stranded investment charge as part of the its proposed transmission rate under FPA section 205, and contest it at that time.<sup>42</sup>

## B. Access

### 1. NUG Access

#### a. Prior to passage of the Energy Policy Act

Before the passage of the Energy Policy Act, the FERC refused to order transmission access for Qualifying Facilities (QF) that elected not to waive their rights under the Public Utility Regulatory Policies Act of 1978 (PURPA).<sup>43</sup> In *NU Merger Case*, the FERC rejected requests to grant QFs access.<sup>44</sup> The FERC utilized the analysis it developed in *Utah Power & Light Co., PacifiCorp*, and *PC/UP&L Merging Corp. (Utah Power)*.<sup>45</sup> Thus, it determined that requiring Northeast to wheel for QFs is "neither in the FERC's authority nor required in order to mitigate the merger's likely anti-competitive harms and make the merger consistent with the public interest."<sup>46</sup>

The FERC concluded that PURPA provided no statutory basis to force utilities to wheel for QFs. Furthermore, Congress excluded QFs from the group of entities that may seek a wheeling order from the FERC under section 211 of the FPA.<sup>47</sup> Accordingly, denying wheeling rights to QF's did not constitute undue discretion.

In *Entergy*, the FERC refused to require the utility to amend a provision

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41. *Entergy*, 60 F.E.R.C. ¶ 61,168, at 61,631.

42. *Id.* at 61,631-32.

43. 15 U.S.C.A. §§ 3301-42 (1982 & Supp. 1992).

44. 58 F.E.R.C. ¶ 61,070, at 61,217-18.

45. In particular, the Commission relied on *Utah Power & Light Co., PacifiCorp*, and *PC/UP&L Merging Corp.*, order on remand, 57 F.E.R.C. ¶ 61,363 (1991).

46. *Id.* at 61,217.

47. 16 U.S.C.A. § 824j (1985 & Supp. 1992). In contrast, Congress permitted QFs to seek an interconnection order under section 210 of the FPA. *Id.* § 824(i).

in its tariff under which QFs may obtain transmission service only if they waive their PURPA rights to make sales at avoided cost rates.<sup>48</sup> The FERC based this decision on its reasoning in its series of orders in *Utah Power*.<sup>49</sup>

In *Consumers Power Co.*,<sup>50</sup> the FERC was presented with a slightly different QF access issue. Here the utility proposed an open access tariff that discriminated between QFs. Under the Service Schedule, which provided the terms under which eligible utilities may request Consumers Power Company (Consumers) to transmit non-firm, coordination-type power to utilities with which Consumers has an Interconnection or Operating Agreement, Consumers sought to exclude QFs which are exempt from section 205 of the FPA. QFs not exempt from section 205 of the FPA, i.e., those qualifying small power production facilities with power production capacities over 30 MW, would be eligible for service.<sup>51</sup>

The FERC rejected Consumers' proposed Service Schedule. Although it has no authority to order transmission access involuntarily, the FERC held it could not accept an unduly discriminatory provision.<sup>52</sup> The FERC directed Consumers to either exclude all QFs from the Service Schedule or to include all QFs as eligible utilities.

#### b. FERC Response to the Energy Policy Act

Section 211 of the FPA, as amended by the Energy Policy Act, now provides that "any other person generating electric energy for sale for resale" may request, and the FERC may order, wholesale transmission service. This amendment eliminated the basis for the FERC's rationale for allowing utilities to exclude QFs from open access transmission service.

In an order issued in early January 1993, the FERC stated:

[b]ecause there is no longer a basis for treating QFs that generate electric energy for sale for resale different from utilities . . . PacifiCorp shall, as a condition of the merger, provide for mandatory transmission access to QFs that generate electric energy for sale for resale, at cost-based rates, on the same terms and conditions that apply to utilities.<sup>53</sup>

### 2. Retail Access

#### a. Retail Customers

In *Entergy*, the FERC accepted Entergy's exclusion of retail customers

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48. 58 F.E.R.C. ¶ 61,234, at 61,763.

49. 57 F.E.R.C. ¶ 61,363 (1991), *order on reh'g*, 59 F.E.R.C. ¶ 61,035, at 61,113-19; *accord* Opinion No. 364-A, *NU Merger Case*, 58 F.E.R.C. ¶ 61,070.

50. 58 F.E.R.C. ¶ 61,323 (1992).

51. *Id.* at 62,041; *See* PURPA § 210(e)(2), 16 U.S.C. § 824a-3(e)(2) (1982 & Supp. 1992); 18 C.F.R. § 292.601 (1992).

52. 58 F.E.R.C. ¶ 61,323, at 62,044-45.

53. *Utah Power & Light Co., PacifiCorp, and PC/UP&L Merging Corp.*, 62 F.E.R.C. ¶ 61,018, *mimeo* at 4 (1993).

from transmission access.<sup>54</sup> Entergy, a wholly owned subsidiary of Entergy Corporation, had filed a transmission service tariff, and two rate schedules under which Entergy would sell up to 2500 MW of excess power at market prices in exchange for Entergy offering firm and non-firm transmission service over its system to electric utilities at cost based rates.<sup>55</sup> Because Entergy's market-based rate filing dealt solely with wholesale markets, the FERC held that any consideration of discrimination against retail customers would go beyond the scope of the proceeding.<sup>56</sup>

#### b. Newly Formed Electric Distribution Systems

In *Entergy*, the FERC allowed the utility to exclude new electric distribution systems from eligibility for transmission service.<sup>57</sup> The FERC rejected the arguments of intervenors who argued that exclusion was discriminatory and anti-competitive. To the contrary, the FERC found that the exclusion was consistent with the general exclusion of retail customers from access to transmission as it prevented a "back-door" attempt by Entergy's customers to obtain retail wheeling. The exclusion, however, was limited to new electric distribution systems that are established *solely* "to facilitate transmission service for retail customers."<sup>58</sup> This result was not intended to bar legitimate, new electric distribution systems from obtaining transmission service.<sup>59</sup>

### 3. Discretion Regarding Available Capacity

#### a. Prevention of off-system sales

In *Entergy*, the FERC rejected Entergy's definition of excess capacity. In its transmission filing, Entergy defined excess capacity as "the amount of capacity available in excess of that needed to meet native load requirements plus any planned generating units."<sup>60</sup> The FERC found that this definition would allow Entergy to reserve capacity for itself in excess of its load to make off-system sales. To prevent the utility from effectively reserving capacity for its own off-system sales, the FERC directed Entergy to define capacity available for transmission requests as that amount of capacity in excess of native load reliability requirements. According to the FERC, native load includes those customers on whose behalf the Entergy companies, "by statute, franchise or contract, have undertaken the obligation to plan, construct and operate its system to provide reliable power supply services."<sup>61</sup>

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54. 58 F.E.R.C. ¶ 61,234, at 61,763.

55. 60 F.E.R.C. ¶ 61,168, at 61,616.

56. *Id.* at 61,626.

57. 58 F.E.R.C. ¶ 61,234, at 61,763.

58. *Id.*

59. "[W]hether systems are established to 'facilitate' transmission service for retail customers is a question of fact that can be raised in a section 206 complaint proceeding." 60 F.E.R.C. ¶ 61,168, at 61,626.

60. 58 F.E.R.C. ¶ 61,234, at 61,764.

61. *Id.*

#### a. Regional Transmission Groups

Before the end of the conference committee deliberations on the Energy Policy Act, a cross-section of the electric utility industry presented to the conferees a consensus proposal on Regional Transmission Group (RTG) legislation under which the FERC would be required to certify RTGs which met certain criteria. RTGs meeting those criteria would have to be open to all interested entities, would have to impose on all members the obligation to provide transmission service, would have to provide for coordinated regional planning, and would have to provide for equitable decision making and dispute resolution procedures.

The consensus RTG proposal was not submitted to the conferees until after the conferees had voted on the electricity portions of H.R. 776 and was thus not included in the final legislation. On November 10, 1992, the FERC requested comments on whether it should propose a rule under which it would approve jurisdictional RTG agreements and how the consensus proposal could be drafted into rulemaking language.<sup>62</sup> The FERC found that the major elements of the RTG proposed could be incorporated in a rulemaking without the need for additional legislation. The FERC expressed the belief that RTGs could provide substantial benefits to the public and the FERC by relieving some of the regulatory burden created by the transmission access provisions of the Act and that properly structured RTGs could channel the expertise of the electric utility industry toward resolving difficult technical issues relating to transmission system operations and planning.

### 4. Ratemaking

#### a. Incentive Ratemaking

On October 30, 1992, the FERC issued a Policy Statement on Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities.<sup>63</sup>

The FERC has recently allowed companies to depart from traditional cost-of-service regulation and has approved market-based rates where the utility has been able to show a lack of market power. The FERC emphasized in its Policy Statement that incentive ratemaking is not intended for competitive markets where market-based rates would be appropriate. On the other hand, where utilities have market power the FERC will now allow incentive rate mechanisms as alternatives to traditional cost-of-service ratemaking. In its Policy Statement, the FERC set forth certain principles according to which it will evaluate incentive rate proposals.

The FERC provided five regulatory standards for implementing specific

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62. Request for Public Comments on Regional Transmission Group Proposal, 61 FERC ¶ 61,232 (1992).

63. 61 FERC ¶ 61,168 (1992).

ratemaking proposals; the incentives should (1) be prospective (incentive regulation is not designed to reward past efficient, cost-saving behavior); (2) be voluntary (during an experimental period); (3) be understandable; (4) result in quantified benefits to consumers compared to cost of service regulation with the projected cost of service rates providing a cap on incentive rate increases to limit consumer risk; and (5) maintain and enhance incentives to improve the quality of service (for example, programs that diminish safety or increase scheduling problems would be unacceptable).

The FERC stated that, in general, incentive mechanisms should encourage efficiency, reward reductions in costs, and penalize inefficiency. Accordingly, opportunities for reward should be offset by a symmetric downside risk. Initially, utilities must establish that their starting rates meet the traditional just and reasonable standard. For this purpose, rates that have been litigated and approved by the FERC within the past eighteen months are presumed to be just and reasonable while settlement rates bear the burden of proof of justness and reasonableness. Each utility must include in its proposal projected cost of service rates which will serve as a cap to ensure that the incentive rate is no higher than it otherwise would have been under cost of service ratemaking. In addition, each incentive proposal should include a specific mechanism for periodic rate reviews.

The FERC discussed five different possible types of incentive mechanisms in the Policy Statement. First, automatic rate adjustment mechanisms provide incentives by extending the regulatory lag period and permitting greater flexibility in responding to intermediate price changes. Rates would be indexed and would change automatically to correspond to an index developed by the utility and approved by the FERC. Second, performance targets can encourage companies to cut costs. Under this approach, if a company achieves a target, it obtains a benefit; if it does not, it is sanctioned by a reduction in profits. Targets could be set for almost any cost, with rates designed using the targets rather than actual costs. Third, flexible pricing encourages better utilization of existing facilities and should be allowed in all markets as long as the pricing is not unduly discriminatory. Fourth, benefit-sharing mechanisms, where stockholders retain a portion of the savings with the remaining benefits going to ratepayers, are essential features of incentive regulation. Finally, a consumer welfare bonus, where the rate of return increases depending on how well the utility improves services or cut prices, can also provide incentives. For example, demand-side management programs for electric utilities can act as consumer welfare bonuses.

To support its legal authority to enact incentive ratemaking, the FERC stated that it is not required to follow any specific type of ratemaking formula and is not limited to designing rates based on cost-of-service. The FERC concluded that it is free to set rates to provide incentives so long as there is a correlation between the incentive and the result to be induced.



### b. Exempt Wholesale Generators

On November 10, 1992, the FERC issued a notice of proposed rulemaking<sup>64</sup> implementing section 32 of PUHCA, as added by section 711 of the Energy Policy Act. PUHCA section 32 requires persons seeking determination of EWG status to file for a determination with the FERC. The proposed regulations establish filing requirements and ministerial procedures for persons seeking EWG status. On February 10, 1993, the FERC issued Order 550, which established procedures for securing EWG status.<sup>65</sup>

An EWG is a person determined by the FERC to be engaged directly, or indirectly through one or more affiliates, and exclusively in the business of owning and/or operating all or part of eligible facilities, as defined in PUHCA section 32, and selling electric energy at wholesale. An EWG may sell power generated by it or others. An eligible facility may include transmission facilities used for interconnection to effect wholesale power sales. Certain hybrid facilities may also be eligible with approval of affected state commissions. Persons granted EWG status will not be considered electric utility companies under PUHCA section 2(a)(3) and will be exempt from regulation under PUHCA.

An applicant that has applied in good faith for EWG status is deemed an EWG until the FERC makes such a determination. The FERC must notify the SEC whenever it determines that a person is an EWG, and the FERC is required to provide implementing rules for determining EWG status within one year of the enactment of the Energy Policy Act.

In its notice, the FERC stated that due to the narrow focus of the FERC's inquiry under section 32, it will not allow persons commenting on applications to raise issues that fall outside of the purview of the statutorily-fixed determination. In the few determinations of EWG status that the FERC has acted on so far, the FERC has merely determined whether the information presented by the applicant satisfied the statutory definition of a EWG.<sup>66</sup>

Under the EWG rule, the FERC must act within sixty days of receipt of an application. If the FERC does not act within sixty days, the application will be deemed granted. Since there are no rehearing requirements under PUHCA, Commission action will be final action.

### c. Market-based Pricing

The FERC denied rehearing of its order approving blanket market rates for the operating companies of Entergy and Entergy Power, Inc. (EPI) in return for open access transmission across the Entergy system.<sup>67</sup> The FERC

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64. 62 F.E.R.C. ¶ 61,127 (1993).

65. 62 F.E.R.C. ¶ 61,182 (1993).

66. See, e.g., *Hartfwell Energy Ltd Partnership*, 61 F.E.R.C. ¶ 61,283 (1992); *Doswell Ltd Partnership*, 61 F.E.R.C. ¶ 61,325 (1992); *Constanera Power Corp.*, 61 F.E.R.C. ¶ 61,335 (1992).

67. *Entergy*, 58 F.E.R.C. ¶ 61,234.

defended its summary approval without a trial-type or paper hearing on grounds that no intervenor had made an adequate proffer of evidence showing there were genuine issues of material fact. All such claims, the FERC said, raised only legal or policy issues, were premature, speculative, or immaterial, or better addressed in other on-going proceedings or by a complaint under section 206 of the FPA. Although intervenors only had six days from the notice of filing to file their comments, the FERC found that the comment period was not too short, since intervenors could have requested additional time to submit supplemental comments.

An Entergy marketing affiliate fared less well with its application for transaction-specific market rates for sales to Northeast Texas Electric Cooperative, Inc. (NTEC) and Oglethorpe Power Cooperative (Oglethorpe). Even though the buyers received bids from numerous suppliers totaling more than the amount they informally solicited, the FERC rejected the application of EPI because the affiliated Entergy companies had not received approval of their open access transmission tariff at the time EPI negotiated the contracts and because EPI could not show that it offered potential sales competitors specific and comparable transmission access. EPI subsequently filed cost-based rates for NTEC and Oglethorpe. EPI's cost-based rate to Oglethorpe is under investigation.<sup>68</sup>

The Department of Justice (DOJ) and Commissioner Trabandt challenged the structure of the FERC's transaction-specific market rate analysis in response to a July 2, 1992, deficiency letter rejecting the market rates of United Illuminated Company (United) for a power sale to UNITIL Power Corporation (UNITIL).<sup>69</sup> United, surrounded by the transmission system of Connecticut Power and Light Company (CP&L), was one of five successful bidders to supply UNITIL, surrounded by the transmission system of Public Service Company of New Hampshire (PSNH). CP&L and PSNH are wholly-owned subsidiaries of Northeast Utilities which provides open access transmission.

The FERC rejected United's rate on grounds that United had not committed to transmit to any seller which wanted to locate in United's service territory and had subordinated its transmission service to United's off-system sales. The DOJ intervened and argued that transaction-specific market rates for power sales should be analyzed on the basis of actual competition for the sale as seen from the buyer's point of view and not used as a quid pro quo for requiring open access transmission of the winning seller. On rehearing, the FERC accepted United's market rate on the grounds that United lacked generation and transmission market power, but did not address the arguments of

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68. 60 F.E.R.C. ¶ 62,284 (1992).

69. Director, Division of Applications, Office of Electric Power Regulation, Deficiency Letter (July 2, 1992) (unpublished).

the DOJ.<sup>70</sup> In his concurring opinion, Commissioner Trabandt embraced and extended the DOJ analysis, while Commissioner Moler doubted the wisdom of requiring open access of the winning seller, no matter how robust the bidding to supply the buyer.<sup>71</sup>

The FERC reiterated its three-step market analysis (no or mitigated market power in generation, transmission, or other barriers to competition) plus a check on affiliate abuse or self-dealing issues for market rate approval which had been enunciated in *Hartwell Energy Ltd Partnership*.<sup>72</sup> Hartwell, which owned no other regional generation and no regional transmission, won an all-source competitive solicitation by Oglethorpe. Hartwell's occasional purchase of gas and transportation from affiliated Transcontinental Gas Pipe Line Corporation (Transco) did not show market power in other barriers to competition, since Transco was an open-access pipeline and two other power bidders relied upon Transco transportation. Affiliate abuse considerations were not raised since Hartwell moved its plant site to an area served by Transco at Oglethorpe's request and because Oglethorpe retained the right to choose the gas supplier and transporter.

In *Ocean State Power II*,<sup>73</sup> the FERC revisited the affiliate abuse standards of *Boston Edison Co. ex rel. Edgar Electric Energy Co.*,<sup>74</sup> approving, without a hearing, market rates for power sales by Ocean State II to three affiliated buyers, but limiting its opinion "to the specific circumstances presented by Ocean State II."<sup>75</sup> Comparing the price of delivered long-term baseload capacity and energy for the period the buyers contracted with Ocean State II, the FERC found that Ocean State's price was below the rates of ten projects of comparable size. Though most of these projects were QF's, the FERC distinguished *Edgar's* rejection of QF projects for benchmark purposes on grounds that the projects in this case used pricing similar to Ocean State II and sold power at price-competitive rates, i.e. their rates were not at a buyer's avoided cost above the market. Finally, the FERC found that this benchmark price was not skewed by the market power of the affiliated buyers: New England Power Company, Montaup Electric Company, and Newport Electric Corporation, since none of the benchmark projects were affiliated with those buyers, none of the Ocean State II power competed in the benchmark transactions, and none of the buyers exercised market power in transmission or other barriers to entry.

Intervenors in two cases argued that a seller's average cost-based rates were unjust and unreasonable because the seller could have charged lower

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70. *United Illuminating Co.*, 60 F.E.R.C. ¶ 61,214 (1992).

71. *Id.* at 61,735 - 38.

72. 60 F.E.R.C. ¶ 61,143 (1992).

73. 59 F.E.R.C. ¶ 61,360 (1992).

74. 55 F.E.R.C. ¶ 61,382 (1991).

75. *Ocean State Power II*, 59 F.E.R.C. ¶ 61,360, at 62,332.

market-based rates. In *Philadelphia Electric Co.*,<sup>76</sup> Maryland People's Counsel and the Maryland Public Service Commission argued that the cost-based rate charged by Philadelphia Electric Company and Susquehanna Electric Company to an affiliate distribution company, Conowingo Power Company, was unjust for failure to include "competitive pricing discount." The FERC found that, in the absence of evidence that the cost-based rate was unjust, unreasonable or unduly discriminatory, affiliate abuse issues were irrelevant and that the sellers had no obligation to charge market-based rates. In *New England Power Co.*,<sup>77</sup> the FERC set for hearing a claim by Bangor Hydro-Electric Company that the rate for transmission was so high that it denied effective transmission access, since "the current market price for power in southern New England is less than the total cost of transmission to northern suppliers under the proposed transmission rates."<sup>78</sup>

In another case, the FERC summarily approved a negotiated (market) rate for transmission over the buyer's protest on grounds a Commission-calculated average cost rate would have been higher.<sup>79</sup> On appeal, the D.C. Circuit remanded the case to the FERC, ordering the FERC to disclose its calculations.<sup>80</sup>

#### d. Miscellaneous Ratemaking Issues

In *Town of Norwood v. FERC*<sup>81</sup>, the D.C. Circuit affirmed the FERC's approval of New England Power Company's marginal cost wholesale electric rates. The court found that there was substantial record support for the proposed rates, and rejected a customer's argument that the rates should not be allowed due to their alleged volatility. The court did not consider the rate tilt issue for procedural reasons. The court also affirmed the FERC's approval of the new rate's use of coincident peak billing demands.

In *Southwestern Public Service Co. v. FERC*,<sup>82</sup> the D.C. Circuit affirmed the FERC's decision to make a spot adjustment to Southwestern Public Service Company's cost of service reflecting the 1986 Tax Reform Act. The FERC had adjusted Southwestern's Period II cost of service, which ended before the new tax rates took effect, reflecting the new tax rates. The FERC found a substantial difference between the old and new tax rates and that the use of the old rates would produce unreasonable results. The court accepted the FERC's reasoning, but found the FERC's refusal to set off purchased

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76. 58 F.E.R.C. ¶ 61,060 (1992).

77. 61 F.E.R.C. ¶ 61,009 (1992).

78. *Id.* at 61,062.

79. *Northeast Utils. Serv. Co.*, 52 F.E.R.C. ¶ 61,097 (1990), *reh'g denied*, 52 F.E.R.C. ¶ 61,336 (1990).

80. *City of Holyoke Gas & Elec. Dept. v. FERC*, 954 F.2d 740 (D.C. Cir. 1992), *reh'g denied* 1992 U.S. App. Lexis 8841 (1992), *on order* 60 F.E.R.C. ¶ 61,012 (1992).

81. 962 F.2d 20 (D.C. Cir. 1992).

82. 952 F.2d 555 (D.C. Cir. 1992).

power cost increases against the tax decrease was inadequately supported. The court remanded the case to the FERC.

In *Towns of Concord v. FERC*,<sup>83</sup> the D.C. Circuit affirmed the FERC's decision not to require Boston Edison Company to refund fuel adjustment clause overcharges. Boston Edison had collected certain prior burn spent nuclear fuel disposal costs through its fuel adjustment clauses. Boston Edison conceded that those changes were not recoverable under its filed rate. The court ruled that the FERC is not required to order refunds where the rate charged exceeded the filed rate.

In *Indiana & Michigan Municipal Distributors Ass'n v. Indiana Michigan Power Co.*,<sup>84</sup> the FERC affirmed in part and reversed in part an initial decision reviewing Indiana Michigan Power Company's rates in a combined section 205/206 rate case. The FERC affirmed the Administrative Law Judge (ALJ) on the issue of Rockport deferral costs, ruling that, based on earlier settlement agreements, Indiana Michigan could not recover Rockport costs deferred for the benefit of a departing customer from the remaining customers. The FERC affirmed the ALJ's rejection of Indiana Michigan's effort to accelerate the recovery of the deferred expenses. The FERC also reversed the ALJ's requirement that Indiana Michigan adjust its test year transmission equalization payments, and generally accepted Indiana Michigan's decommissioning expense accrual (but required quarterly compounding of trust fund earnings and new decommissioning filings every five years).

In Opinion No. 374,<sup>85</sup> the FERC summarily affirmed an initial decision finding that Canal Electric Company, Montaup Electric Company, and the Seabrook Unit No. 1 management were prudent as to the emergency planning for the Seabrook plant. The Massachusetts Attorney General had asserted that Seabrook management was imprudent in not submitting an emergency evacuation plan to the NRC by 1985. The FERC affirmed the ALJ's ruling that Seabrook's management was prudent in its development of the emergency action plan, that Canal and Montaup were prudent in their oversight of the plan, and that in any event there was no evidence that the NRC would have considered a utility-sponsored plan prior to late 1987.

In *Northern Electric Power Co.*,<sup>86</sup> Northern Electric requested FERC approval of rates for the sale of hydroelectric QF power to Niagara Mohawk. Noting that the New York public utility commission had not made a final determination as to the purchasing utility's avoided costs (and refusing to substitute its own judgment for the state commission's), the FERC rejected the proposed rates because of the absence of a state determination that the sale price was at or below the utility's avoided cost.

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83. 955 F.2d 67 (D.C. Cir. 1992).

84. 59 F.E.R.C. ¶ 61,260 (1992).

85. *Canal Elec. Co.*, 60 F.E.R.C. ¶ 61,126 (1992).

86. 60 F.E.R.C. ¶ 62,232 (1992).

The FERC issued a number of orders concerning the recovery of fuel expenses through fuel adjustment clauses (FAC). Two Commission orders addressed the question of whether a utility may recover the costs of "buying out" obligations under its coal supply agreements. In *Wisconsin Public Service Corp.*,<sup>87</sup> the FERC stated that a utility may recover "buy-out" costs through a FAC if the utility can verify that its customers would achieve actual savings from the "buy-out". The FERC set for hearing the verification of the claimed savings. In *Cities & Villages of Albany & Hanover, Illinois v. Interstate Power Co.*,<sup>88</sup> the FERC found that a utility's "minimum take" payments to its coal supplier, which were renegotiated long after the execution of the supply contract, were not "buy-down" or "buy-out" payments, and were properly recoverable through FAC.

The FERC issued several other orders concerning FACs. In *Northern States Power Co.*,<sup>89</sup> the FERC denied Northern States' request to recover, through its FAC, future reclamation costs associated with past coal deliveries, permitting the recovery of only those costs associated with future deliveries. In *Central Maine Power Co.*,<sup>90</sup> the FERC clarified that a utility's "base period" for calculating its fuel adjustment recovery should be the same as its "test period", and determined that test year fuel costs and revenues should be synchronized. In *Central Illinois Public Service Co.*,<sup>91</sup> the FERC determined that litigation expenses, auditing fees, and administrative and general expenses are not recoverable through a FAC.

Several other cases deserve mention. In *Yankee Atomic Electric Co.*,<sup>92</sup> the FERC declined to use summary disposition to extend its Opinion No. 295 canceled plant policies to prematurely retired plant, setting the matter for hearing instead. In *United Illuminating Co.*,<sup>93</sup> the FERC directed United Illuminating to reflect the value of capacity received in an exchange transaction in setting its rates. In Opinion No. 377,<sup>94</sup> the FERC affirmed an initial decision finding the Southern Company's operating companies' revised intercompany interchange contract just and reasonable, but rejected Southern's and the parties' various proposals regarding the classification of production O&M expenses. In Opinion No. 371,<sup>95</sup> the FERC affirmed an initial decision finding that Pennsylvania's gross receipts tax was recoverable in Metropolitan Edison's rates to cooperatives. In *Southern Co. Services*,<sup>96</sup> the FERC held that an interchange agreement between The Southern Company's operating subsid-

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87. 59 F.E.R.C. ¶ 61,252 (1992).

88. 61 F.E.R.C. ¶ 61,037 (1992).

89. 58 F.E.R.C. ¶ 61,119 (1992).

90. 59 F.E.R.C. ¶ 61,348 (1992).

91. 58 F.E.R.C. ¶ 61,186 (1992).

92. 60 F.E.R.C. ¶ 61,104 (1992).

93. 61 F.E.R.C. ¶ 61,027 (1992).

94. *Southern Co. Servs., Inc.*, 61 F.E.R.C. ¶ 61,075 (1992).

95. *Metropolitan Edison Co.*, 58 F.E.R.C. ¶ 61,178 (1992).

96. 59 F.E.R.C. ¶ 61,238, *reh'g denied*, 60 F.E.R.C. ¶ 61,297 (1992).

iaries and Duke Power Company was a single integrated agreement, and that the sixty day period for action under section 205 of the FPA did not commence until both utilities completed the filing. In *Palisades Generating Co.*,<sup>97</sup> an ALJ ruled that a power sale agreement was unjust and unreasonable on the ground that, among other things, the low capacity factor would produce wind-fall profits and the long-term cost estimates were too speculative to use to establish rates. Before the FERC ruled on the initial decision, Palisades filed a notice of cancellation of the rate schedule, which the FERC had not ruled on at the time of this writing.

## 5. Mergers

### a. *Iowa Public Service Company/Iowa Power*

In *Iowa Public Service Co.*,<sup>98</sup> the FERC authorized the merger of Iowa Public Service Company and Iowa Power, Inc., two wholly-owned subsidiaries of Midwest Resources, Inc. Iowa Public Service and Iowa Power had previously been subsidiaries of two public utility holding companies that had merged into Midwest Resources, Inc. The FERC had declined to assert jurisdiction over that merger, since the merging entities were not public utilities.<sup>99</sup> In the 1992 utility merger, the FERC rejected the applicants' argument that the utilities' affiliate relationship precluded the FERC from considering the competitive impact of the merger, but found that the merger would not have a significant adverse effect on competition.

### b. *Entergy/GSU*

On June 5, 1992, Entergy Corporation, which wholly owns four electric utility operating companies (Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company, and New Orleans Public Service, Inc.), and Gulf States Utilities Company announced a plan to reorganize and merge their operations. Under the terms of the proposed \$2.3 billion merger, Gulf States would become a sister company of Entergy's existing operating companies, although it would remain headquartered in Beaumont, Texas.

On August 28, 1992, Entergy and Gulf States filed merger applications with the FERC and projected cost savings of approximately \$1.7 billion over the next ten years.<sup>100</sup> The companies requested that the FERC expeditiously approve the merger based on the applications and testimony without further proceedings or, in the event the FERC ordered further proceedings, that it order a focused "paper" hearing. Entergy and Gulf States also have a pending

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97. 59 F.E.R.C. ¶ 63,023 (1992).

98. 60 F.E.R.C. ¶ 61,048 (1992).

99. *Missouri Basin Mun. Power Agency v. Midwest Energy Co. and Iowa Resources, Inc.*, 53 F.E.R.C. ¶ 61,368 (1990), *reh'g denied*, 55 F.E.R.C. ¶ 61,464 (1991).

100. *Entergy Services, Inc. and Gulf States Util. Co.*, 62 F.E.R.C. ¶ 61,073 (1993).

merger application before the SEC and are engaged in hearings before the Louisiana and Texas state regulatory commissions. The shareholders of each company have already approved the merger. The FERC had not issued an order ruling on the merger at the time of this writing.

#### 6. *Central Maine*

In an order issued August 2, 1991, involving filings by Central Maine Power Company, the FERC announced an amnesty period within which utilities could make late filings of rate schedules and retain the amounts collected under those rate schedules up to 100% of their fixed costs.<sup>101</sup> Utilities failing to make such filings within the amnesty period, which ended on October 7, 1991, would be required to refund with interest all amounts collected in excess of their variable costs.

A number of utilities made filings after the end of the amnesty period and were ordered to make refunds. The FERC ordered PacifiCorp to refund revenues collected under a jurisdictional transmission service agreement.<sup>102</sup> It also required Green Mountain Power Company to refund revenues under two unit power sales agreements and a related capacity exchange agreement.<sup>103</sup> The FERC ordered several utilities to refund amounts collected under tariffs of general applicability because the utilities had not filed tariff service agreements within the amnesty period<sup>104</sup> and required a number of utilities to refund contributions-in-aid of construction (CIACs) not filed until after the end of the amnesty period.<sup>105</sup>

In ordering refunds in these cases, the FERC rejected objections that the refunds were penalties which the FERC had no authority to impose, that the FERC circumvented the rulemaking procedures required by the Administrative Procedure Act in adopting the *Central Maine* policy, that the refunds violated contractual obligations, and that there was no clear obligation at the time of the *Central Maine* amnesty period to file tariff service agreements or CIACs.

The FERC clarified its policy on waiver of the notice requirement in a case where filings by a number of utilities were disposed of in the same

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101. *Central Me. Power Co.*, 56 F.E.R.C. ¶ 61,200 (1991), *order on reh'g*, 57 F.E.R.C. ¶ 61,083 (1991).

102. *PacifiCorp Elec. Operations*, 58 F.E.R.C. ¶ 61,283 (1992), *reh'g denied*, 60 F.E.R.C. ¶ 61,292 (1992).

103. *Green Mountain Power Corp.*, 59 F.E.R.C. ¶ 61,291 (1992), *reh'g denied*, 60 F.E.R.C. ¶ 61,158 (1992).

104. *Mississippi Power Co.*, 58 F.E.R.C. ¶ 61,286 (1992), *reh'g granted*, 61 F.E.R.C. ¶ 61,014 (1992); *New England Power Co.*, 59 F.E.R.C. ¶ 61,253 (1992), *reh'g granted*, 61 F.E.R.C. ¶ 61,015 (1992); *Central Power & Light Co. and West Texas Utils. Co.*, 60 F.E.R.C. ¶ 61,211, *reh'g granted*, 61 F.E.R.C. ¶ 61,065 (1992).

105. *Florida Power Corp.*, 58 F.E.R.C. ¶ 61,161 (1992), *reh'g denied*, 60 F.E.R.C. ¶ 61,003 (1992); *Western Mass. Elec. Co.*, 59 F.E.R.C. ¶ 61,091 (1992), *reh'g denied*, 61 F.E.R.C. ¶ 61,182 (1992); *Blackstone Valley Elec. Co.*, Doc. No. ER92-206-001 (unpublished letter order issued June 26, 1992), *reh'g granted* (unpublished letter order issued Dec. 4, 1992). In Western Massachusetts, the Commission held that CIACs made by Qualifying Facilities under PURPA are jurisdictional when the utility receiving the CIAC wheels all or some of the output of the Qualifying Utility to another utility or utilities. 61 F.E.R.C. ¶ 61,182, at 61,662.



order.<sup>106</sup> The FERC announced there that it will waive the notice requirements for filings involving rate decreases or having no rate impact or involving rate increases where the increases are contractually required.<sup>107</sup> The FERC also said it will generally waive the notice requirement for short-term opportunity transactions as long as the filing is made before the transaction begins. A showing of extraordinary circumstances will be required to support waiver of the notice requirement for a filing made after service begins. On October 5, 1992, the FERC allowed a further amnesty until November 9, 1992, for utilities to file tariff service agreements.<sup>108</sup>

On October 13, 1992, the FERC allowed an amnesty until November 18, 1992 for the filing of CIACs.<sup>109</sup> On November 16, 1992, it granted requests by the Edison Electric Institute and Consolidated Edison Company of New York to stay the end of the CIAC amnesty period pending a comprehensive and orderly review of utilities' filing obligations, including the extent of their obligation to search their files, whether expired agreements need to be filed, whether rate schedules dating back to the passage of the FPA need to be filed, and what agreements are considered jurisdictional.<sup>110</sup> The FERC stayed the end of the CIAC amnesty period until a date to be established in a further order addressing the merits of the filings made by the Edison Electric Institute and Consolidated Edison.

On December 9, 1992, the FERC issued a notice of a technical conference to be held on January 28, 1993, and solicited comments on these issues by January 11, 1993.<sup>111</sup> The FERC remarked in the notice that it had hoped that its *Central Maine* order would clarify the need for compliance with notice and filing requirements, but that hope had been dashed by the number of filings made after the end of the *Central Maine* amnesty period.<sup>112</sup> It stated that it had also hoped that the additional amnesty windows for tariff service agreements and CIACs, as well as the issuance of the *Central Hudson* order, would resolve all remaining ambiguity, but that hope had proved to be short-lived in view of the uncertainty pointed out by the Edison Electric Institute and others concerning the obligation to file.<sup>113</sup> The FERC concluded that it needed to consider all arguments by all affected entities at one time. It stated: "[h]opefully, this will allow us to achieve the intended purpose of the *Central Maine* policy, which was to add clarity and certainty to the filing obligations of public utilities, not to add further ambiguity."<sup>114</sup>

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106. *Central Hudson Gas & Elec. Corp.*, 60 F.E.R.C. ¶ 61,106 (1992), *reh'g denied*, 61 F.E.R.C. ¶ 61,089 (1992).

107. 60 F.E.R.C. ¶ 61,106 at 61,339.

108. *New England Power Co.*, 61 F.E.R.C. ¶ 61,015 (1992).

109. *Florida Power Corp.*, 61 F.E.R.C. ¶ 61,063 (1992).

110. *Florida Power Corp.* 61 F.E.R.C. ¶ 61,244 (1992).

111. Prior Notice and Filing Requirements Under Part II of the Federal Power Act; Technical Conference and Request for Comments, 62 F.E.R.C. ¶ 62,128.

112. *Id.*

113. *Id.*

114. *Id.*

## 7. Miscellaneous Cases

### a. Ohio Power

Ohio Power Company, a subsidiary of American Electric Power Company, purchases coal from an affiliated coal supplier, Southern Ohio Coal Company (SOCCO). The price that SOCCO charges Ohio Power for coal is fixed at SOCCO's cost by the SEC under the PUHCA. The FERC, however, refused to allow Ohio Power to recover through its wholesale fuel clause that portion of the price paid to SOCCO which exceeded the market price for coal.<sup>115</sup> In 1989, the U.S. Court of Appeals for the District of Columbia reversed the FERC on the ground that section 318 of the FPA<sup>116</sup> insulated SOCCO's SEC-approved prices from FERC alteration.<sup>117</sup> In 1990, ruling that section 318 did not address the conflict, the Supreme Court reversed and remanded to the D.C. Circuit to consider whether the FERC's decision should be reversed on other grounds.<sup>118</sup>

In 1992, the D.C. Circuit reversed the FERC on the ground that the FERC was required by the terms of its fuel clause regulations to allow Ohio Power to recover the price paid to SOCCO as approved by the SEC through the wholesale fuel clause.<sup>119</sup> Section 35.14(a)(7) of the FERC's rules contains the controlling language: "[w]here the utility purchases fuel from a company owned or controlled source, the price of which is subject to the jurisdiction of a regulatory body, such cost shall be deemed to be reasonable and includable in the adjustment clause."<sup>120</sup>

Rejecting the FERC's argument that this language established only a rebuttable presumption in favor of SOCCO's price as approved by the SEC, the D.C. Circuit found that the word "deemed" created a presumption that was conclusive.

The D.C. Circuit found that the SEC's statutory mandate to set SOCCO's price at cost under PUHCA was more specific than the "just and reasonable" mandate entrusted to the FERC in Part II of the FPA and thus was controlling. The court rejected an argument by the FERC that the FERC had acted reasonably because the SEC had the authority to "cap" the cost-based rates charged by SOCCO at the market price, but had not exercised that authority. The court found that the FERC was free to attempt to affect the price approval process before the SEC but could not "trap" costs incurred by Ohio Power under SEC-approved prices.

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115. *Ohio Power Co.*, 39 F.E.R.C. ¶ 61,098 (1987), *reh'g denied*, 43 F.E.R.C. ¶ 61,046 (1988).

116. 16 U.S.C. § 825(q) (1988).

117. *Ohio Power Co. v. FERC*, 880 F.2d 1400, 110 (D.C. Cir. 1989).

118. *Arcadia, Ohio v. Ohio Power Co.*, 111 S.Ct. 415 (1990).

119. *Ohio Power Co. v. FERC*, 954 F.2d 779 (D.C. Cir. 1992).

120. 18 C.F.R. § 35.14(a)(7) (1990).

b. EPI Spin-off

The City of New Orleans, Louisiana, a retail regulator of the Entergy Corporation operating companies which serve the City, filed a complaint on August 20, 1990, against Entergy, Arkansas Power & Light Company (AP&L), New Orleans Public Service, Inc., Louisiana Power & Light Company, Mississippi Power & Light Company, and System Energy Resources, Inc.<sup>121</sup> New Orleans alleged that the transfer of certain generating facilities owned by AP&L to EPI was imprudent and would produce unjust and unreasonable rates under the FPA. The FERC ordered a hearing on the case, in two phases, with Phase One to determine whether increased costs would accrue to the operating companies other than AP&L as a result of the transfer, and Phase Two to determine whether those higher charges would reflect prudently incurred costs.

In his decision on Phase One, the presiding ALJ found that such increased costs did occur, and ordered a hearing on Phase Two of the case.<sup>122</sup> In Phase Two, the ALJ found the transfer decision was prudent from the standpoint of the system. He based his decision on the impossibility of knowing the true impact of the transfer until the future, indicating that at present imprudence could not be found.

c. SERI Audit Case

In Opinion No. 375,<sup>123</sup> the FERC affirmed an initial decision's rejection of certain System Energy Resources, Inc. (SERI) accounting entries relating to the Grand Gulf No. 1 nuclear power plant. SERI had increased its Grand Gulf plant account to reflect the 35% reduction in investment tax credits (ITC) resulting from the Tax Reform Act of 1986. The FERC held that SERI's ratepayers should not bear the ITC loss and thus rejected SERI's accounting treatment. In addition, the FERC ruled that SERI had to record a loss on the sale of accounts receivable in Account 426.5 and had to file a request with the FERC in order to recover the loss in its rates.

d. Boston Edison

In Opinion No. 376,<sup>124</sup> the FERC affirmed in part and reversed in part an initial decision reviewing Boston Edison's subtransmission rates to two towns. The FERC ruled, among other things, that the costs of a transformer that was used, if at all, in rare emergency situations, should be allocated based on a coincident peak demand allocation basis rather than on a use right basis.

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121. *City of New Orleans v. Entergy Corp.*, 54 F.E.R.C. ¶ 61,298 (1991).

122. 59 F.E.R.C. ¶ 63,016 (1992).

123. *System Energy Resources, Inc.*, 60 F.E.R.C. ¶ 61,131 (1992).

124. *Boston Edison Co.*, 61 F.E.R.C. ¶ 61,026 (1992).

e. EEI

In *Edison Electric Institute*,<sup>125</sup> the FERC ruled that neither Commission authorization nor Commission notification is required for an officer or director of a public utility also to serve as an officer or director of a commercial bank which places third-party public utility commercial paper. FERC noted, however, that since commercial banks or their affiliates may engage in other activities, individuals would have to examine on a case-by-case basis whether those activities necessitated a section 305 filing.

C. *Securities and Exchange Commission*

1. EPI Spin-off

In *City of New Orleans v. Entergy Corp.*,<sup>126</sup> the City of New Orleans, the State of Mississippi and the Louisiana Public Service Company (LPSC) contested Entergy Corporation's transfer of several generating units from one of its operating companies, AP&L, to a new subsidiary, EPI, as inconsistent with the integration requirements of PUHCA. The SEC rejected the intervenors' arguments, finding that a spin-off was not inconsistent with the integration requirements of PUHCA.<sup>127</sup> Moreover, the SEC found that because there would be no adverse impact on ratepayers in Arkansas, the transfer could go forward.

The City of New Orleans appealed the case to the U. S. Court of Appeals for the D. C. Circuit. In an opinion issued July 17, 1992,<sup>128</sup> the D.C. Circuit agreed that the integration requirement was not offended by the transfer. However, the court remanded the case to the SEC for further proceedings, finding that the SEC had not adequately addressed the impact of the transfer on all consumers on the Entergy System.

2. Foreign Investment

a. *SCEcorp*

SCEcorp, an exempt public utility holding company under PUHCA, sought SEC approval to obtain a 40%<sup>129</sup> interest in Loy Yang B, an electric generating facility in Victoria, Australia. The SEC approved the application, finding that the acquisition would not be detrimental to the investors or consumers, a necessary finding for approval under PUHCA. The SEC, pursuant to section 3(b), granted an unqualified exemption from the requirements of PUHCA.

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125. 60 F.E.R.C. ¶ 61,294 (1992).

126. 54 F.E.R.C. ¶ 61,298 (1991).

127. Memorandum Opinion and Order Authorizing Issuance, Sale and Acquisition of Securities, Rel. No. 35-25,136 1990 W.L. 312079 (S.E.C. Aug. 27, 1990).

128. *City of New Orleans v. SEC*, 969 F.2d 1163 (1992).

129. Memorandum Opinion and Order Granting Exemptions Under section 3(B) to Foreign Public Utility Subsidiary Companies, Rel. No. 35-25,564 1992 W.L. 160031 (S.E.C. June 29, 1992).

b. *The Southern Co.*

The SEC also granted authorization for the Southern Company (Southern), a registered holding company and one of SCEcorp's competitors, to acquire a 40% ownership interest in the Australian Loy Yang facility.<sup>130</sup> The SEC found that PUHCA allows the acquisition of foreign utilities by U.S. utilities with substantial domestic properties because the securities market and federal securities laws adequately protect investors. In addition, the company's separation of non-utility and utility businesses would serve to protect ratepayers.

c. *Entergy Corp. I; and Entergy Corp. II*

The Entergy Corporation, a member of a consortium, sought to invest in two foreign utilities, an Argentine generating facility (Costanera facility, *Entergy Corp. I*<sup>131</sup>) and an Argentine distribution system (Edesur system, *Entergy Corp. II*<sup>132</sup>), which provide electric service to the City of Buenos Aires. Entergy also sought to have certain Entergy subsidiaries provide consulting services to the Argentine utilities. The proposed investment totalled \$100 million.

After passage of the Energy Policy Act, the SEC approved both of Entergy's applications.<sup>133</sup> However, the SEC orders made the approved ventures subject to certain consumer protection conditions. The consumer safeguard measures advocated by Entergy regulators and set out in a settlement agreement with Entergy were incorporated in the order as a means of protecting consumers from the risks of utility diversification.

3. Investments in Demand-Side Technology — *Entergy Corp.*

In a filing dated March 31, 1992, Entergy submitted an application to the SEC proposing to enter into a series of transactions relating to demand-side technology.<sup>134</sup> Entergy stated that it wished to create NEWCO as a new wholly-owned subsidiary which would offer services to customers of Entergy's subsidiaries. NEWCO's proposed energy services business would be distinct from that of the Entergy's existing subsidiaries.

NEWCO would provide energy management services, with the overall objective of promoting energy efficiency. NEWCO would enter into contracts with its clients pursuant to which NEWCO would perform a detailed analysis and audit of the customer's energy system and facilities to determine potential

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130. Memorandum Opinion and Order Authorizing Aquisition of Foreign Public Utility Subsidiary Companies and Certain Related Financing, Rel. No. 35-25,639, 1992 W.L. 252209 (S.E.C. Sept. 23, 1992).

131. Docket No. 70-8002 (filed May 1, 1992).

132. Docket No. 70-8010 (filed June 16, 1992).

133. Order Authorizing Aquisition of Subsidiary Companies and Certain Related Financing, Rel. No. 35-25,673, 1992 W.L. 345206 (S.E.C. Nov. 10, 1992) (Costanera); Memorandum and Opinion Order Authority Aquisition of Subsidiary Companies and Certain Related Financing, Rel. No. 35-25,705, 1992 W.L. 388764 (S.E.C. Dec. 14, 1992) (Edesur).

134. Docket No. 70-7947 (filed March 31, 1992).

energy savings. In addition, NEWCO would provide customer financing in connection with its services, either by acting as a broker or by providing direct financing.

After consultation with its retail regulators, Entergy agreed to a set of conditions intended to shield ratepayers from cross-subsidy issues. The SEC approved Entergy's application, subject to the conditions agreed to by Entergy and its regulators.<sup>135</sup>

#### IV. INTEGRATED RESOURCE PLANNING

##### A. Introduction

Integrated resource planning (IRP) is typically defined as the "systematic evaluation of resource options for meeting the needs of electric utility customers."<sup>136</sup> IRP has historically focused on demand-side management (DSM).

##### B. New Federal Emphasis on IRP

###### 1. New Guidelines for State Regulatory Authorities

One of the most visible developments in IRP is the recently passed Energy Policy Act which directs utilities to engage in IRP.<sup>137</sup> Section 111(a) amends PURPA<sup>138</sup> by adding to § 111(d): "(7) [e]ach electric utility shall employ integrated resource planning. All plans or filings . . . must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented."

The Act adds the following language to PURPA § 111(d):

(8) The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

It is important to note the definition of IRP for electric utilities as used in the Act. 16 U.S.C. § 2602 is amended by adding the following definition of IRP:

(19) [A] planning and selection process for new energy sources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. . . . The process

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135. Memorandum Opinion and Order Authorizing Acquisition of Non-Utility Interest and Certain Related Financing Transactions, Rel. No. 35-25718, 1992 W.L. 400665 (S.E.C. Dec. 28, 1992).

136. E.g., Adam Borison & Girish Balachandran, *Choosing Options: Integrated Resource Planning Meets Decision Analysis*, PUB. UTIL. FORT., Dec. 15, 1992, at 22.

137. 42 U.S.C. § 13,201 (West Supp. 1993).

138. 16 U.S.C. § 2601-2645) (West Supp. 1993).

shall take into account the ability to verify energy savings achieved through energy conservation and efficiency. . . .

Finally, the Act also amends PURPA section 111(c) to require that, if a state regulatory agency chooses to implement the IRP standard (set out above), the agency is to consider the impact on small businesses engaged in energy conservation, energy efficiency, or other DSM measures. The agency must ensure that the IRP standard is implemented in such a way that the utility's actions do not provide it with an unfair competitive advantage over the small business.<sup>139</sup>

## 2. IRP for Federal Facilities

Section 113 of the Energy Policy Act mandates that the Tennessee Valley Authority (TVA) institute a least-cost planning program. In order to carry this out, the TVA is to employ and implement a planning and selection process for new energy resources which evaluates the full range of existing and incremental resources.

Section 114 of the Act amends Title II of the Hoover Power Plant Act of 1984<sup>140</sup> to require IRP. The section defines IRP in the same manner § 111 of the the Act does. Within one year of the enactment of the Energy Policy Act, the Administrator of the Western Area Power Administration (WAPA) shall, by regulation, require each customer that purchases electric energy under a long-term firm power service contract with the WAPA to implement IRP. Each customer must submit an integrated resource plan to the Administrator for review.

## C. State Experiment with IRP

IRP remains largely the province of state legislatures and regulators. Currently, IRP at the state level consists primarily of analyses of the potential costs and benefits of DSM programs.<sup>141</sup>

### 1. DSM Strategies

In addition to the more traditional DSM considerations, interest is growing in "decoupling"<sup>142</sup>, and shareholder incentive mechanisms.<sup>143</sup> There is also growing support for demand-side transmission and distribution (T&D) programs.

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139. 16 U.S.C.A. § 2621 (West Supp. 1993). See also, Jeffrey H. Howard, *Secret Weapon, The Energy Act's Assault Against In-house Utility DSM*, PUB. UTIL. FORT., Jan. 15, 1993, at 29.

140. 42 U.S.C. §§ 7275-76 (1988).

141. RATE REGULATION DEPT., EDISON ELECTRIC INST., INTEGRATED RESOURCE PLANNING IN THE STATES: 1992 SOURCEBOOK [hereinafter EEI 1992 SOURCEBOOK].

142. Chamberlin, *Weighing Decoupling Alternatives*, INTEGRATED RESOURCE PLANNING Q. 4 (Oct. 1992) ("Decoupling" is a method of determining all or part of utility prices or earnings in a way that separates revenue or earnings levels from capacity or energy sales).

143. Shareholder incentive mechanisms provide incremental financial incentives for shareholders to invest in DSM. EEI 1992 SOURCEBOOK, *supra* note 141, at xiii.

a. Factoring Environmental Externalities

An externality is any cost or benefit incurred or enjoyed in producing or consuming a product that is not directly reflected in price. Such costs are assumed to be borne by society as a whole.<sup>144</sup> In particular, the environmental externalities being considered by utilities are negative in nature and consist of the "residual discharges that cause injury to human health or property."<sup>145</sup> Environmental externalities are currently of interest to regulators and utilities and are often considered in connection with IRP. Utilities in sixteen states give explicit consideration to environmental externalities in some form. Of those, eight states give only qualitative consideration;<sup>146</sup> the other half give quantitative consideration to environmental externalities.<sup>147</sup> Where states give quantitative consideration to environmental externalities then explicit monetization, adder/discounts and ranking/points are used in connection with IRP.<sup>148</sup>

The DOE has become interested in the consideration of externalities in IRP. Accordingly, a study commenced by the DOE is being conducted by the Oak Ridge National Laboratory and Resources for the Future and is expected to be completed by mid to late 1993. Preliminary results of the study suggest that health and ecological impacts can only be assessed on a site-specific basis, so that use of general externality values may be inaccurate.

b. The Clean Air Act

In connection with evaluating externalities in integrated resource planning, some utilities are focusing on Clean Air Act Amendment (CAAA) compliance issues. California and Massachusetts are among those states which have formally considered strategies for CAAA compliance by including consideration of those non-price factors in the IRP process.<sup>149</sup> California's policy includes revision of Final Standard Offer No. 4 to incorporate consideration of environmental impacts. Massachusetts' policy incorporates estimates of monetized values of environmental externalities. As a result, QFs' employing cleaner technologies will receive an air quality adder.

c. Broad-based Environmental Externality Evaluations

In late 1992, the New York State Public Service Commission (PSCNY)

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144. *Id.* at xix.

145. FREDRICK R. ANDERSON ET. AL., ENVIRONMENTAL PROTECTION: LAW AND POLICY 35 (Little, Brown & Co. 2d ed. 1990).

146. The eight states giving only qualitative consideration are Arizona, Connecticut, Hawaii, Illinois, Iowa, Ohio, Pennsylvania, and Texas. EEI 1992 Sourcebook, *supra* note 141, at xxi.

147. *Id.* The eight states giving some form of quantitative consideration are California, Colorado, Massachusetts, Nevada, New Jersey, New York, Vermont, and Wisconsin.

148. *Id.*

149. Final Standard Offer No. 4, Revising QF Purchase Rates for Environmental Externalities, Decision 91-06-022, Docket I-89-07-004, RRS No. 91-043619 (July 1991)(California Policy); EEI 1992 SOURCEBOOK, DPU 89-239, *supra* note 141, at 175 (Massachusetts Policy).



decided to undertake a review of its power generation externalities policy. The purpose of the review was to update New York policy to reflect current environmental issues. The review considered incorporating externality costs into long-range electric utility resource planning decisions, as well as whether to require valuation of externality costs as they affect utility power purchases from non-utility power producers.<sup>150</sup>

PSCNY was the first regulatory commission to initiate an externalities policy in competitive bidding for new capacity when, in 1989, it ordered utilities to collaborate on a study of environmental externalities.<sup>151</sup> The PSCNY also requires that consideration of the externalities in calculating the costs and benefits of demand side management.

Centerior Energy Corp. has incorporated acid rain compliance into its DSM strategy by developing a plan that rewards energy conservation and emission allowance purchases as low-cost SO<sub>2</sub> reduction methods. The commitment is a three-year \$35 million plan to help Centerior's two utilities meet their Phase I acid rain compliance requirements. This program is based on the theory that energy conservation can be a low-cost acid rain compliance method in addition to control technologies or allowance purchases.<sup>152</sup>

## 2. Revenue Decoupling

Revenue decoupling separates revenue (earning levels) from energy sales (capacity).<sup>153</sup> There are currently five states in which utilities have either partially or fully decoupled, and several other states are engaged in discussions of the issue. States that currently utilize decoupling are California, Connecticut, Maine, New York, and Washington.<sup>154</sup>

Decoupling eliminates revenue gains due to sales growth. The decoupled utility receives a fixed annual amount of revenues so there is no tie between increased sales of electricity and short-term profitability. Theoretically, this decoupling removes the rationale for focusing on sales growth so a utility can put more effort into DSM and other conservation programs.<sup>155</sup> In addition, because revenue is held constant, short-term savings in profitability are lessened.

California adopted a revenue decoupling mechanism more than ten years ago. The program is called the Electric Revenue Adjustment Mechanism (ERAM) and has been in place at Pacific Gas and Electric (PG&E) for years. The system was adopted to remove any disincentive the utilities might have to promote conservation and efficiency measures. The system is set up so that the cash revenues received will always match the revenue requirement pre-

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150. Mary O'Driscoll, *New York PSC Plans Externality Review*, THE ENG. DAILY, Dec. 4, 1992, at 1.

151. Opinion No. 89-15, Case 28,223 (May 1989).

152. George Lobenz, *Centerior Pushes DSM In Acid Rain Strategy*, THE ENG. DAILY, Nov. 10, 1992, at 1.

153. Chamberlin, *Weighing Decoupling Alternatives*, INTEGRATED RESOURCE PLAN. Q. 4, (Oct. 1992).

154. *Id.*

155. *Id.* at 16.

scribed by the CPUC, regardless of sales volume.<sup>156</sup>

### 3. Demand Side Transmission and Distribution Programs

Transmission and distribution costs will rise substantially over the next few years as suburban diaspora continues. By 1997, T&D costs are expected to reach nearly 80% of total construction outlays, an increase of 30% over recent years. The prospect of costs, estimated to reach \$107 billion, is driving many utilities to develop DSM programs aimed at deferring T&D construction.<sup>157</sup>

To date, only Pacific Gas & Electric Company has implemented a DSM-T&D program. By implementing "Delta Project," PG&E hopes to reduce its anticipated costs of upgrading transmission lines and expanding distribution by 30% (a savings of \$35.9 million). The program works by reducing peak-load demand and delaying expensive construction by targeting distribution. PG&E plans to begin another pilot program at a substation in Fresno, California. PG&E installed photovoltaic panels at the substation that will generate 500 kilowatts of electricity to meet new demand.

### 4. Shareholder Incentive Mechanisms

DSM incentives are the subject of continuing debate as to their effectiveness. Such incentives may stimulate utility innovation in efficiency and conservation development, but they may also increase customer costs, at least in the short term. Twenty-six states now offer some combination of shareholder incentives, including shared savings, return on equity adjustment, rate base premium, performance premium, and DSM mark-up mechanisms.<sup>158</sup>

A recent proposal by San Diego Gas & Electric involved a performance-based incentive plan for its natural gas and electricity operations and new power contracts. Under the proposal, shareholders and customers would share both the rewards and penalties of the utility's operating results. If the utility is successful in its least-cost strategies, the shareholders and customers would share in that success. They would also share in the penalties if the utility fails to operate efficiently.<sup>159</sup>

Public Service of Colorado has an incentive in place equal to approximately 5% of its approved DSM programs. Southern Indiana Gas & Electricity has in operation an incentive/penalty mechanism that applies to its allowed equity return. Potomac Electric Power has an approved stipulation

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156. *Id.* at 6.

157. The statistics contained in this section are taken from the Electric Power Research Institute's newsletter that focuses on DSM and T&D issues and from information provided by Grayson Heffner, manager of EPRI's DSM and T&D division.

158. "Shared savings" allows the utility to retain for its shareholders a pre-determined portion of any savings realized through the use of DSM. "Return of Equity" adjustments consist of adjusting allowed returns on equity to reward or penalize utilities for relative progress in developing DSM potentials. "Rate base premiums" are return premiums for rate-based DSM investments. A "performance premium" is a premium given per unit of resource saved in excess of the set nominal goal. A "DSM mark-up" is a fixed mark-up on DSM expenditures. EEI 1992 SOURCEBOOK, *supra* note 140, at xiii-xiv.

159. Mary O'Driscoll, *San Diego Gas & Electric Wants California OK of Incentive Rate Proposal*, THE ENG. DAILY, Oct. 20, 1992, at 1.

that provides a 5% bonus when program goals are exceeded by at least 10% expressed in terms of DSM program savings. These are a few examples of the types of incentive mechanisms that are in place.<sup>160</sup>

### 5. Competitive DSM Contract Bidding

It is estimated that \$45 billion will be allocated for DSM over the next decade. In an attempt to address the cost issue, utilities are finding new ways to fund the programs, as opposed to the traditional method of utilities performing the DSM themselves or through a subsidiary and then passing the costs and savings onto the ratepayers. The current trend is toward opening up DSM programs to competitive bidding by third parties.<sup>161</sup> Currently, twenty-two states have bidding in place, and utilities in six states have procured energy conservation services pursuant to a bidding process.<sup>162</sup>

In addition to these new bidding mechanisms, geographic targeting is also being used. A plan proposed by Rochester Gas & Electric Co. (RG&E) would open up only selected RG&E service areas to bidding. The targeted areas would be those served by overloaded substations. The objective is to focus the expensive DSM projects only in areas where capacity is oversubscribed and not within the entire service territory.<sup>163</sup>

San Diego Gas & Electric Co. (SDG&E) recently announced that it would be seeking third-party bids for DSM programs for residential customers. SDG&E has set aside \$19 million (9% of its DSM budget) for these programs. The Public Service Electric & Gas Co. of Newark, N.J. has also announced recently that it intends to contract out almost two-thirds of its DSM programs by the year 2000. Likewise, PG&E is planning to begin an experimental DSM bidding program. The CPUC requires utilities to create demonstration bidding programs to see if third parties can deliver reliable, low-cost, effective energy efficiency services.<sup>164</sup>

### 6. Renewables

Consideration of renewable resources in integrated resource planning is another emerging trend. The first examples can be seen in specific set asides and exemptions in utilities' competitive bidding protocols. Both Connecticut and New Jersey have competitive bidding rules requiring that renewables be offered contracts at utility bid price ceilings. Colorado also favors renewables over fossil generation in its bid evaluation scoring mechanism. California legislation takes a different approach by requiring electric resource acquisition programs to include value for resource diversity from renewable resources. Finally, Arizona requires that utility resource plans include consideration of

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160. These examples are taken from the state summaries found in the EEI's 1992 SOURCEBOOK, *supra* note 141.

161. Dan Kaplan, *N.Y. Utility Proposes Innovative DSM Strategy*, THE ENG. DAILY, Sept. 18, 1992, at 3.

162. EEI 1992 SOURCEBOOK, *supra* note 141, at xxvii.

163. *Id.*

164. Re Rules and Procedures Governing Utility and Demand Side Management, 137 PUB. UTIL. REP. 4th 34 (Cal. Pub. Util. Comm'n. Oct. 6, 1992).

unconventional resources, including solar energy.<sup>165</sup>

#### 7. Industry Opt-Out

An interesting twist has recently been put on DSM. The PSCNY recently approved a plan allowing Niagra Mohawk Power Corporation's largest industrial and commercial customers to "opt-out" of the utility's conservation rebate program. Those customers would then get a rate decrease of about 2%. The industrial customers claim they will be able to develop more flexible and cost-effective conservation efforts by investing their savings in selected projects of their own choosing.<sup>166</sup>

#### D. Regional IRP Planning for Registered Holding Companies

There is growing support for regional IRP. The New England Electric System and regulators in four New England states agreed this past summer to a proposal for regional, systemwide least-cost planning for registered holding companies. Under the plan, registered holding companies would propose systemwide least-cost plans to their state regulators every two years. A similar plan proposed by Arkansas/Entergy would also require all registered holding companies to develop systemwide least-cost or IRP plans to be approved by the state regulators and filed with the FERC.

#### E. Regional Power Planning

Another emerging concept in the IRP arena is that of "regional power planning" as a substitute for integrated resource planning. The Florida Public Service Commission has proposed such a program for multi-state utilities instead of the regional IRP proposed by the Arkansas PSC, Entergy Corp., and the city of New Orleans. Florida opposes the IRP proposal because it includes both demand-side and supply-side measures as a solution to the allocation problem presented by multistate systems; Florida contends that the

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165. Resource Planning, 128 P.U.R. 4th 448 (Ariz. Corp. Comm'n Oct. 1991).

166. George Lobsenz, *N.Y. PSC Approves Contested DSM Experiment*, THE ENG. DAILY, Feb. 1, 1993, at 1.

Arkansas proposal gives the FERC a new and inappropriate preemptive role in IRP.<sup>167</sup>

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167. *Florida PSC Proposes 'Regional Power Planning' for Energy Bill*, ELECTRIC UTIL. WKLY, Aug. 10, 1992, at 3.