

AN INDUSTRY IN TRANSITION: REPORT OF THE COMMITTEE ON ELECTRIC UTILITY REGULATION

I. DEREGULATION INITIATIVES	246
A. <i>Federal Energy Regulatory Commission</i>	246
1. GigaNOPR	246
a. Introduction	246
b. Summary of Open Access Rule	247
c. Summary of Stranded Cost Rule	250
d. Jurisdictional Issues	251
2. Regional Transmission Groups	251
3. Real-Time Information Networks	254
4. Pools	254
B. <i>Congress</i>	255
C. <i>States</i>	256
1. California	256
2. Michigan	257
3. New Hampshire	258
4. New York	258
5. Wisconsin	258
6. Utah	259
7. Pennsylvania	259
II. MAJOR TRENDS IN CASES	259
A. <i>Pricing</i>	259
B. <i>Open Access Filings</i>	261
C. <i>Access to Transmission Services</i>	263
III. THE DECADE OF MARKETS, MARKETERS, AND MARKET- BASED RATES	266
A. <i>Power Marketers</i>	266
B. <i>Changing Market Power Analysis</i>	267
1. Generation Market Power	267
2. Market Power over Transmission	268
3. Other Barriers to Market Entry	268
C. <i>Confidentiality</i>	269
D. <i>Futures</i>	269
IV. MERGERS AND DIS-AGGREGATION	270
A. <i>Major Cases</i>	270
1. Impact of the GigaNOPR	270
2. <i>Delmarva/Conowingo</i>	271
3. <i>Midwest Power/Iowa-Illinois</i>	271
4. <i>Cincinnati Gas & Electric/PSI Energy</i>	273
5. <i>Washington Water Power Company/Sierra Pacific Power Company</i>	274
6. <i>El Paso/Central and South West</i>	274

7. Further Guidance Orders.....	275
B. <i>Re-engineering the Utility: Major Developments in Functional and Other Unbundling</i>	275
V. DOES ANYONE REMEMBER THE NATIONAL ENERGY ACTS? ...	277
A. <i>PURPA Reform Efforts</i>	277
B. <i>Federal Preemption of State Initiatives</i>	277
VI. PUHCA—LEGISLATIVE REFORM EFFORTS	279

I. DEREGULATION INITIATIVES

A. *Federal Energy Regulatory Commission*

1. GigaNOPR

a. Introduction

The year 1995 was a watershed year for electric utility regulation at the Federal Energy Regulatory Commission (FERC or Commission). In 1994, the Commission had pursued its long-standing goal of open access transmission through a series of orders applying the Commission's new "comparability" standard to utilities' open access transmission tariffs.¹ On March 29, 1995, the Commission issued a Notice of Proposed Rulemaking (GigaNOPR) requiring each utility to have an open access transmission tariff that met the Commission's "comparability" standards sixty days after the Commission's issuance of a final open access rule.² The purpose of the open access requirement was "to facilitate the development of competitive wholesale bulk power markets by ensuring that wholesale purchasers of electric energy and wholesale sellers of electricity can reach each other by eliminating anticompetitive practices and undue discrimination in transmission services."³ The Commission included *pro forma* point-to-point and network tariffs.

A key part of the Commission's open access initiative was its treatment of "stranded costs." The Commission's 1994 Stranded Cost NOPR, which addressed the circumstances in which a utility could seek to recover stranded costs from a departing customer,⁴ was supplemented as part of the GigaNOPR.⁵ The Commission declared that the recovery of legitimate and verifiable stranded costs is critical to the successful transition to a com-

1. See, e.g., *American Elec. Power Serv. Corp.*, 67 F.E.R.C. ¶ 61,168, at 61,490 (1994); *Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,326, at 62,147-48 (1994).

2. Notice of Proposed Rulemaking, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, 60 Fed. Reg. 17,662 (1995) (to be codified at 18 C.F.R. pt. 35) (hereinafter *GigaNOPR*) (also referred to by certain segments of the industry as the *MegaNOPR*).

3. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,078.

4. See *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, IV F.E.R.C. STATS. & REGS. ¶ 32,507, 59 Fed. Reg. 35,274 (1994).

5. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,110-14.

petitively-priced electric industry.⁶ The Commission is currently expected to issue a final rule by mid-1996.⁷

b. Summary of Open Access Rule

The Commission premised its authority to require open access on its authority to remedy undue discrimination under the Federal Power Act (FPA), sections 205 and 206.⁸ The FERC also relied on *Associated Gas Distributors v. FERC*,⁹ which had affirmed FERC Order No. 436, requiring natural gas pipelines to provide non-discriminatory open access transportation.¹⁰ The Commission distinguished cases that limited its authority under FPA section 211¹¹ to order wheeling,¹² and concluded that reliance on section 211 alone could, in some cases, perpetuate undue discrimination and anticompetitive effects.¹³

The Commission also found that the electric industry today is in many ways analogous to the natural gas industry before FERC Order Nos. 436 and 636,¹⁴ with transporters offering bundled sales services rather than non-discriminatory transmission access.¹⁵ Thus, despite the increased competitiveness of the electricity industry and substantial changes in transmission and generation economics and technology, including growth in the qualifying facility and independent power producer industry,¹⁶ transmission remains a natural monopoly and transmission owners restrict access to their systems through discriminatory practices.¹⁷

6. *Id.* at 33,113-16. The Commission also initially determined that it was not required to prepare an environmental impact statement (EIS) for the rule. *Id.* at 33,151. However, on further consideration, the Commission directed its staff to prepare an EIS. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 72 F.E.R.C. ¶ 61,022 (1995). The staff's draft EIS concluded that (1) the proposed rule would have a minimal effect on NO_x emissions, (2) the effect would be slightly positive or negative, depending upon fuel costs, and (3) the rule would have a minimal effect on other environmental values.

7. *See A Salute: 75 Years for the FPC and FERC*, 16 ENERGY L.J. 293, 296 (1995).

8. 16 U.S.C. §§ 824d, 824e (1995). *See GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,053.

9. 824 F.2d 981 (D.C. Cir), *cert. denied*, 485 U.S. 1006 (1987); *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,053-54.

10. *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [1982-1985 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 30,665, 50 Fed. Reg. 42,408 (1985).

11. 16 U.S.C. § 824j (1995).

12. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,057.

13. *Id.*

14. *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, *supra* note 10; *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III F.E.R.C. STATS. & REGS. ¶ 30,939, 57 Fed. Reg. 13,267 (1992).

15. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,076.

16. *Id.* at 33,060-70.

17. *Id.* at 33,070.

The Commission addressed three comparability issues previously set for hearing in individual proceedings.¹⁸ First, the Commission found that all utilities use their own transmission systems in two basic ways: on a point-to-point basis and on a network basis.¹⁹ The Commission proposed that all public utilities be required to provide these services.²⁰ Second, the Commission stated that it believed that there were no potential impediments to providing comparable service, other than siting considerations.²¹ Third, the Commission stated that there were no differences in the costs incurred by a transmission provider in providing transmission service to itself or to a third party.²²

The Commission concluded that all public utilities must offer non-discriminatory open access transmission service in accordance with the FERC's proposed rule²³ and "functionally unbundle" their wholesale services.²⁴ Functional unbundling means three things: (1) utilities must take transmission services under the same tariffs of general applicability under which others take service;²⁵ (2) transmission owners must include in their open access tariffs separately stated rates for transmission and ancillary services;²⁶ and (3) public utilities must utilize the same electronic network that their transmission customers rely upon to obtain transmission system information.²⁷ The unbundling requirement would apply only to transmission services under new requirements contracts and new coordination transactions.²⁸

The proposed rule specifies a host of tariff provisions that must be included in the utility tariffs; the *pro forma* tariffs contain the minimally acceptable terms and conditions of transmission service.²⁹ Among them are the following:

- (1) CUSTOMER ELIGIBILITY. Transmission service must be available to any entity that can request transmission service under section 211.³⁰
- (2) EXPANSION OBLIGATION. A public utility must offer to enlarge its transmission capacity (or expand its ancillary service facilities) if necessary to provide transmission services.³¹

18. *Id.* at 33,079-80.

19. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,079.

20. *Id.*

21. *Id.* at 33,080.

22. *Id.*

23. *Id.* at 33,078.

24. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,080.

25. *Id.*

26. *Id.*

27. *Id.* However, the proposed rule does not require a transmission owner to take unbundled transmission service under the same tariff as third parties in order to serve its retail customers. *Id.* at 33,081.

28. *Id.* at 33,093.

29. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,092.

30. *Id.* at 33,083.

31. *Id.*

- (3) SERVICES OFFERED. The utility must offer flexible point-to-point and network transmission services and "ancillary services."³²
- (4) SERVICE PERIODS. The service durations should be the same as the transmission provider itself faces.³³
- (5) REASSIGNMENT RIGHTS. The tariff must allow reassignment of firm service entitlements.³⁴
- (6) RECIPROCITY. The tariff should contain a reciprocity provision.³⁵
- (7) AVAILABLE TRANSMISSION CAPACITY (ATC). The utility must make its ATC available for use for third-party wheeling, must specify the uses for which capacity will be excluded from ATC, and must make ATC determinations consistent with FERC Form No. 715.³⁶
- (8) PROCEDURES FOR OBTAINING SERVICE. The tariff must specify all notice and response requirements, and the advance notice for short-term service should be as brief as possible.³⁷
- (9) PRIORITY OF REQUESTS FOR SERVICE. Firm service requests should receive priority over non-firm service requests, and all firm service (utility and third party) should have the same priority.³⁸
- (10) SERVICE INTERRUPTION PRIORITY. Customers' firm transmission service must have the same interruption priority as the transmission provider's.³⁹
- (11) TRANSMISSION PRICING. Transmission pricing must be consistent with the Commission's Transmission Pricing Policy Statement.⁴⁰

Under Stage One of the implementation of the proposed rule, the Commission proposed to put the *pro forma* tariff rates, terms and conditions in effect for most jurisdictional utilities sixty days after the final rule is issued.⁴¹ Embedded cost transmission rates for each utility would be set according to the Commission's Fixed Charge Methodology, which would be applied to each utility's costs, as reported in its FERC Form 1.⁴² Under Stage Two, on the day after the new tariffs took effect, utilities and customers could make filings under FPA sections 205 or 206 to amend the rates.⁴³

For utilities with ongoing open access tariff proceedings, however, the rates, terms and conditions for service would be determined in those ongoing proceedings.⁴⁴ The Commission later gave those utilities the option of replacing their pending tariffs with the *pro forma* tariffs.⁴⁵

32. *Id.* at 33,084-87. Ancillary services include reactive power/voltage control service, loss compensation service, scheduling and dispatching service, load following service, system protection service, and energy imbalance service.

33. *Id.* at 33,087.

34. *Id.* at 33,088-89.

35. *Id.* at 33,089.

36. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,089.

37. *Id.* at 33,089-91.

38. *Id.* at 33,091.

39. *Id.* at 33,091-92.

40. *Id.* at 33,092. See *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, III F.E.R.C. STATS. & REGS. ¶ 31,005 (1994), clarified, 71 F.E.R.C. ¶ 61,195 (1995).

41. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,146.

42. *Id.* at 33,148-50.

43. *Id.* at 33,147.

44. *American Elec. Power Serv. Corp.*, 70 F.E.R.C. ¶ 61,358, at 62,052 (1995).

45. *American Elec. Power Serv. Corp.*, 71 F.E.R.C. ¶ 61,393, at 62,542 (1995). For utilities selecting this option, the proceedings on their superseded tariffs would be held in abeyance pending Commission action on the revised filing; for utilities not selecting this option, litigation would continue

c. Summary of Stranded Cost Rule

The Commission found that stranded cost recovery is the most significant transition issue associated with the move toward competition in the electric industry.⁴⁶ Recognizing that utilities have invested many billions of dollars in facilities, the Commission concluded that utilities should be able to recover costs prudently incurred under the old regulatory regime according to the expectations of cost recovery established under the old regime.⁴⁷ Legitimate and verifiable stranded costs would be assigned directly to the departing customer, as proposed in the 1994 Stranded Cost NOPR.⁴⁸

The Commission, however, proposed several limitations on stranded cost recovery. For stranded costs associated with new (i.e., post-July 11, 1994) contracts, a public utility could not seek stranded cost recovery unless such recovery was provided for by an exit fee or other explicit contract provision.⁴⁹ For stranded costs associated with existing (i.e., July 11, 1994 or earlier) contracts that are not renewed and do not provide for exit fees or recovery of stranded costs, stranded cost recovery would be permitted if the seller could demonstrate that it had a reasonable expectation that the contract would be renewed and can meet other evidentiary criteria.⁵⁰ The Commission departed from the 1994 Stranded Cost NOPR's proposed three-year limit on negotiating and filing stranded cost provisions⁵¹ by allowing proposals for stranded cost recovery to be filed any time prior to the expiration of the contract.⁵² The recovery of stranded costs resulting from retail wheeling would be left to state regulatory authorities with authority to address the recovery of such costs,⁵³ but the FERC would be the primary forum for determining the recovery of stranded costs resulting from wholesale wheeling to former retail customers.⁵⁴ Finally, stranded cost recovery should be based on the amount of revenues lost due to the customer's departure.⁵⁵ The utility would have a duty to minimize its lost revenue.⁵⁶

as to the terms and conditions of service. *Id.*; *American Elec. Power Serv. Corp.*, 72 F.E.R.C. ¶ 61,287, at 62,238 n.14 (1995).

46. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,095.

47. *Id.*

48. *Id.* at 33,097.

49. *Id.*

50. *Id.*

51. See generally *Recovery of Standard Costs by Public Utilities*, *supra* note 4.

52. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,097.

53. *Id.* at 33,098.

54. *Id.*

55. *Id.* at 33,123.

56. *Id.* at 33,122-23.

d. Jurisdictional Issues

With respect to the dividing line between FERC-jurisdictional transmission facilities and state-jurisdictional local distribution facilities, the Commission affirmed its jurisdiction over any facilities of a public utility used to deliver electric energy in interstate commerce to a wholesale purchaser.⁵⁷ The Commission found that it had jurisdiction over all of the facilities of a public utility used to wheel power to the utility that previously provided bundled retail service to the retail customer.⁵⁸ Under the Commission's "functional" test, the Commission proposed to look at several technical and functional indicators to evaluate the jurisdictional dividing line in each case of facilities used for retail wheeling.⁵⁹

2. Regional Transmission Groups

In 1994, two Commission orders involving the Western Regional Transmission Association (WRTA)⁶⁰ and the Southwest Regional Transmission Association (SWRTA)⁶¹ cleared the way for the development of the first two Regional Transmission Groups (RTGs) approved by the Commission. In both Orders, the Commission noted that RTGs can play an important role in providing transmission services to potential users and resolving disputes relating to such services voluntarily.⁶² By serving as a forum for resolving such disputes, RTGs may minimize the number of applications filed with the Commission by entities seeking wheeling orders pursuant to section 211 of the FPA. The Commission will accord an "appropriate degree" of deference to decisions of an RTG if the underlying agreement mitigates the market power of transmission owner members and establishes fair decision-making processes.⁶³

In reviewing the SWRTA and WRTA proposals, the Commission applied its seven basic components for RTGs established in its earlier Policy Statement on RTGs:⁶⁴

- (1) **BROAD MEMBERSHIP.** The RTG agreement should provide for broad membership and, at a minimum, permit any entity eligible to apply for a transmission order (eligible transmission applicant) under section 211 of the FPA to be a member.
- (2) **COORDINATION.** The RTG must have adequate procedures for consulting and coordinating with relevant State regulatory, siting and other authorities.
- (3) **RECIPROCAL TRANSMISSION ARRANGEMENTS.** Member transmitting utilities must provide transmission services to other members, and must agree to enlarge facilities consistent with the FPA.

57. *Id.* at 33,144.

58. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,144.

59. *Id.* at 33,145.

60. *See PacifiCorp*, 69 F.E.R.C. ¶ 61,099, *modified*, 69 F.E.R.C. ¶ 61,352 (1994).

61. *See Southwest Regional Transmission Assoc.*, 69 F.E.R.C. ¶ 61,100 (1994).

62. 69 F.E.R.C. ¶ 61,100, at 61,388.

63. *Id.*

64. *See Policy Statement Regarding Regional Transmission Groups*, III F.E.R.C. STATS. & REGS. ¶ 30,976, 58 Fed. Reg. 41,626 (1993).

- (4) REGIONAL TRANSMISSION PLANNING AND SHARING OF INFORMATION. The RTG should have a coordinated regional transmission plan that facilitates sharing of transmission planning information and incorporates the needs of non-members so that the regional grid can be efficiently used and expanded.
- (5) GOVERNANCE. Fair and non-discriminatory decision making and voting procedures must be included.
- (6) DISPUTE RESOLUTION. The RTG must have voluntary dispute resolution procedures as an alternative to resorting to filing actions under the FPA.
- (7) EXIT PROVISIONS. The agreement should permit RTG members to leave the RTG and specify any obligations of departing members.

The Commission found the SWRTA and WRTA filings generally consistent with these guidelines, and approved them subject to certain conditions. For example, transmission owning members of both these RTGs must offer comparable transmission services to other members through individual transmission tariffs or a generic regional tariff (and to non-members at the RTG's election).⁶⁵ In addition, both RTGs must develop a regional transmission plan for all members and incorporate transmission needs of non-members into the planning process.⁶⁶ Moreover, both RTGs must make appropriate filings with the Commission to ensure that the RTG covers a sufficiently wide geographic area.⁶⁷ Besides those conditions, to insure that SWRTA's voting procedures are fair, all committee actions must be subject to review by the SWRTA Board of Directors with its proportional class voting. The Commission also required SWRTA to clarify that its dispute resolution provisions will apply to the rates, terms and conditions of transmission services to be provided by members.⁶⁸

As to the WRTA filing, if this RTG "contracts out" its planning function to the Western Systems Coordination Council (WSCC), a coordination council in which a number of the WRTA members are also members, then the WSCC must open its membership to eligible transmission applicants and conform its governing and decisionmaking procedures to WRTA's.⁶⁹ Lastly, any changes to WRTA's governing agreement including termination of the agreement must first be filed with the Commission by each regulated public utility member of WRTA pursuant to section 205 of the FPA.

65. *Southwest Regional Transmission Assoc.*, 69 F.E.R.C. ¶ 61,100, at 61,396; *PacifiCorp*, 69 F.E.R.C. ¶ 61,099, at 61,380-81. The FERC has thus continued to apply its comparability standard first articulated in *American Elec. Power Serv. Corp.* with regard to open access tariffs. 67 F.E.R.C. ¶ 61,168 (1994). The Commission stated in *American Elec. Power* that in order for an open access tariff to not be unduly discriminatory and anti-competitive, it must provide for third party access on the same or comparable basis and under the same or comparable terms and conditions as the transmission provider's use of its own system. *Id.* at 61,490.

66. On rehearing, the Commission clarified that WRTA was not subject to any specific deadline in which to develop such a coordinated plan, and that state authority members need not adopt and promote the plan, but should participate in its formulation and implementation. *PacifiCorp*, 69 F.E.R.C. ¶ 61,352 (1994).

67. *PacifiCorp*, 69 F.E.R.C. ¶ 61,352, at 61,378 (WRTA required to file membership list); *Southwest Regional Transmission Assoc.*, 69 F.E.R.C. ¶ 61,100, at 61,392 (public utility members of SWRTA who withdrew from membership must notify Commission). *Southwest Regional Transmission Assoc.*, 69 F.E.R.C. ¶ 61,100, at 61,490.

68. *Southwest Regional Transmission Assoc.*, 69 F.E.R.C. ¶ 61,100, at 61,402-03.

69. *PacifiCorp*, 69 F.E.R.C. ¶ 61,352, at 61,381-82.

The Commission made clear in both orders that it could not require a RTG to provide retail wheeling, as several industrial intervenors had requested. Instead, the Commission required that the RTG agreements should be neutral as to whether retail wheeling occurs within the RTG, and the Commission stressed the importance of the respective state utility commissions participating in the RTG process.⁷⁰

The Commission's 1995 orders giving final approval to WRTA and SWRTA and to Northwest Regional Transmission Association (NWRTA) expanded and, in some measure, modified the requirements of its Policy Statement on RTGs. The 1995 order for WRTA⁷¹ answered questions about integrating the requirement for comparability of service and the treatment of foreign utilities into the governing agreement, issues the Policy Statement had not addressed. The Commission required regulated utilities to offer comparable service in FERC tariffs and the unregulated RTG-member transmission owners to file with the RTG and obtain necessary regulatory approval. Canadian entities could offer—and request—only as much transmission service as Canadian law allows.

The Commission also modified the Policy Statement in two respects. In *Western Regional Transmission Assoc.*, the Commission held that, as long as the RTG fashioned a comprehensive plan, it need not become mandatory for all the members, but the Commission would look to the plan for guidance in section 211 or section 205 proceedings involving an RTG member, even one that did not bind itself to the plan. Second, the Commission recognized that differences within a reliability council, such as the WSCC, necessitate several RTGs within the region. As long as the WRTA and the other western transmission associations coordinate with each other, they would satisfy the Policy Statement's requirement that the reliability council form the minimum size of an RTG.

In *Northwest Regional Transmission Assoc.*,⁷² the Commission applied the same policy as with the Canadian utilities to the Bonneville Power Administration. The Commission held that, if a particular transmission dispute fell within the confines of section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980,⁷³ the NWRTA arbitration must coordinate with hearings under the statute. The Commission's regulations would apply to disputes over wheeling rates under section 212 of the FPA.⁷⁴

The 1995 *Southwest Regional Transmission Assoc.*⁷⁵ order underlined that the governing agreement must not prohibit retail wheeling and must require parties to file with the Commission arbitration decisions that affect

70. *Southwest Regional Transmission Assoc.*, 69 F.E.R.C. ¶ 61,100, at 61,394-95; *PacifiCorp*, 69 F.E.R.C. ¶ 61,352, at 61,379.

71. *Western Regional Transmission Assoc.*, 71 F.E.R.C. ¶ 61,158 (1995).

72. 71 F.E.R.C. ¶ 61,397 (1995).

73. 16 U.S.C. §§ 839-839(h) (1994).

74. 16 U.S.C. § 824k (1994).

75. 73 F.E.R.C. ¶ 61,147 (1995).

jurisdictional service under the FPA and amendments to the governing agreement (including withdrawal of members).

3. Real-Time Information Networks

Spurred by the experience in its natural gas jurisdiction, the FERC has moved expeditiously to develop generic standards for reporting information on transmission availability. In conjunction with the GigaNOPR, the FERC determined that customers must have simultaneous access to the same information as is available to the transmission provider on transmission capacity availability, ancillary services, scheduling of power transfers, economic dispatch, current operations and economic conditions, system reliability, and responses to system conditions. Concurrent with the GigaNOPR, the FERC issued a Notice of Technical Conference and Request for Comments on the information that should be available on a Real-Time Information Network (RIN) and the technical standard for RIN format and operation.⁷⁶ The Commission stated its intention of having the RIN requirements in place prior to, or concurrent with, the final rule on the GigaNOPR. Nonetheless, even as the Commission has determined its intent to establish common technical and information standards within the electric industry for RINs, it has approved settlements that reflect differing RIN requirements.⁷⁷

4. Pools

In the GigaNOPR, the Commission indicated that power pools would have to comply with the non-discrimination requirements of the GigaNOPR. Power pools would have to make pool transmission services available to all wholesale transmission customers and offer service at rates, terms and conditions that are not unduly discriminatory. The Commission did not propose any specific rules to be applicable to power pools. In a technical conference on December 5 and 6, 1995, the Commission addressed comparability for power pools, focusing separately on tight power pools, loose pools and holding company pools. The major activity for power pools involved four pools. The New England Power Pool (NEPOOL) amended its membership criteria to provide non-voting membership for power marketers and power brokers. In late 1994, the Commission accepted an amendment to the Mid-Continent Area Power Pool (MAPP) Agreement that added a distance-based transmission service charge for short-term transmission services provided by MAPP members.⁷⁸ The Commission also directed MAPP to file revised membership criteria, especially with respect to how they would apply to power marketers. In response to MAPP's request for clarification or rehearing, the Commission set the membership criteria for hearing, but deferred the procedural sched-

76. 60 Fed. Reg. 17,662 (1995) (to be codified at 18 C.F.R. pt. 35) (proposed April 7, 1995).

77. See, e.g., *Louisville Gas & Elec. Co.*, 72 F.E.R.C. ¶ 61,078 (1995); *Kansas City Power & Light Co.*, 72 F.E.R.C. ¶ 61,218 (1995); *Wisconsin Power & Light Co. and Heartland Energy Servs., Inc.*, 73 F.E.R.C. ¶ 61,095 (1995).

78. *Mid-Continent Area Power Pool*, 69 F.E.R.C. ¶ 61,347 (1994).

ule to allow MAPP to revise the criteria as part of a consensual RTG process.⁷⁹

In responding to Duquesne Light Company's request that the Pennsylvania-New Jersey-Maryland Interconnection Association (PJM) Companies provide transmission service to Duquesne, the Commission (1) ordered the PJM Companies to provide transmission service; (2) required the PJM Companies to negotiate jointly; (3) concluded that a single system rate is not appropriate because the PJM Companies do not rely on a single system rate when providing transmission service to one another, do not operate a single integrated unit and are not commonly owned, and each company makes investment decisions and obtains financing on an independent basis; and (4) required the PJM Companies to describe thoroughly the reciprocity on which the PJM Companies rely in lieu of monetary charges and to compare the reciprocally provided services to the services requested by Duquesne.⁸⁰

B. Congress

In the summer of 1995, a group representing large industrial users of electricity—the Electric Consumers Resource Council (ELCON)—published a document outlining the industrials' vision of a comprehensive restructuring of the electricity industry. ELCON's "Blueprint for Customer Choice" provided a focal point for the beginnings of a discussion on restructuring issues among the members of Congress and affected constituencies.

The Blueprint, patterned after telecommunications legislation passed by the House and Senate earlier in the year, sought to achieve two objectives: (1) provide all customers, wholesale and retail, with the right to choose their own suppliers of electricity, and (2) deregulate all generation, from the construction of power plants to sales and marketing activities. To accomplish these objectives, the Blueprint called for the preemption of state retail franchise laws, and for regulation by the FERC of unbundled retail delivery services. The proposed increased role for the FERC at the expense of the states triggered controversy.

The Blueprint mitigates such controversy by proposing a joint federal/state board on universal service. This board would recommend rules guaranteeing all customers some form of last resort service, the characteristics of which the Blueprint left undefined.

The Blueprint also proposed a ban on restrictions on the ownership of transmission and distribution facilities, in particular, any prohibition on ownership of such delivery facilities by customers. Under this provision, customer-owned facilities which were not the sole delivery facilities in an area would be self-regulated, and therefore exempt from all federal and state jurisdiction. Further, the Blueprint would ensure a right for custom-

79. *Mid-Continent Area Power Pool*, 72 F.E.R.C. ¶ 61,223 (1995).

80. *Duquesne Light Co.*, 71 F.E.R.C. ¶ 61,155 (1995).

ers to acquire such facilities, from either municipal or private utilities, at cost.

Many investor-owned utilities have criticized the Blueprint's approach to the recovery of stranded costs. The plan called for explicit authorization of stranded cost recovery orders by federal and state regulators, but only to the extent such orders did not unduly impede or interfere with competition.

ELCON's Blueprint was not introduced in legislative form. Key members of the House Commerce Committee, however, have embraced an active Congressional role in the restructuring process. For example, the chairman of the House Subcommittee on Energy and Power, Dan Schaefer (R-Colo.), has stated that any Congressional action on reforming existing statutes, such as PUHCA and PURPA, should be undertaken only in the context of a comprehensive examination of the industry. Representative Tom Bliley (R-Va.), chairman of the Commerce Committee, has indicated that a bill proposing a comprehensive restructuring of the electricity industry would be introduced in 1996.

C. States

Virtually all states have considered whether to revise the manner in which the electric utility industry is regulated by the states.⁸¹ These issues have been and are being addressed in the state legislatures and before state regulatory authorities.

1. California

In the spring of 1995, the California Public Utilities Commission (CPUC) issued a proposed policy decision for the restructuring of the electricity industry in California. The majority decision supported a mandatory wholesale power pool, or power exchange structure (POOLCO). In a separate dissent, Commissioner Jessie Knight indicated support for a "direct access" structure allowing for bilateral contracts along with the development of a voluntary pool.

A coalition of major energy consumers within the state and Southern California Edison (SCE) formulated a Memorandum of Understanding (MOU), calling for a power pool and simultaneous phase-in of direct access, to be implemented over a five-year period. The direct access proposal would include a non-bypassable competition transition charge requiring the approval of both the CPUC and the FERC. An alternative set of proposed guidelines was prepared by a group of agricultural, small residential, and low-income customers.

In its December 20, 1995 final decision, the CPUC adopted a hybrid plan consisting of a wholesale power exchange, a separate independent system operator (ISO) to control the state-wide transmission system, and

81. See RETAIL WHEELING & RESTRUCTURING REPORT (Norman Jenks ed., Edison Electric Inst. Dec. 1995). The National Council on Competition and the Electric Industry also provided information for this summary of state issues.

direct access phased in over five years beginning January 1, 1998. The CPUC's plan would impose a competitive transition charge (CTC) on all retail customers to ensure full recovery of stranded costs by utilities.

Under the CPUC's plan, the power exchange (i.e., pool) would operate as a market clearing house into which generators would submit hourly or half-hourly bids. The exchange would then establish the uniform market price at the highest winning bid. The ISO would schedule delivery of power and monitor system congestion problems. Under direct access, customers would be able to contract directly with power producers and brokers, aggregate loads, hedge price risks through "contracts for differences," or continue to purchase bundled utility service.

The California legislature must enact legislation authorizing various elements of the plan, such as the CTC and direct access.⁸² In addition, a "road map" for implementing the restructuring plan remains to be developed by the CPUC. As an initial matter, however, the CPUC has directed the state's three investor-owned utilities to file proposals with the FERC for the creation of the power exchange and ISO, and to file with the CPUC corporate restructuring proposals to separate generation, transmission, and distribution into three different entities, possibly under a holding company structure. The CPUC desires to work in a spirit of "cooperative federalism" with the FERC, which will have FPA jurisdiction over the pool, the ISO, and transmission tariffs.

2. Michigan

In June 1995, the Michigan Public Service Commission (MPSC) issued a final decision finding that the MPSC has jurisdiction to order retail wheeling, and giving final approval to a retail wheeling experiment to be conducted over a five-year period by the Detroit Edison Company and Consumers Power Company. The decision would require the two utilities to implement the retail wheeling experiment on their respective systems when additional generating capacity is needed on the system. Industrial customers, with a minimum delivery capacity of 5 MW, will be eligible to participate in the experiment. If the retail wheeling experiment proves feasible, retail wheeling may be implemented on a larger scale.

In a separate undertaking (Proposal M), the MPSC issued a discussion paper regarding legislative issues in need of resolution in any restructuring of Michigan's electric utility industry. The MPSC proposed to mitigate the impact on residential and other captive customers of deregulated service to business customers by crediting business customer revenue toward the revenue requirements that arise from traditional tariff rate service.

82. The California legislature has previously passed bills addressing many restructuring issues, including funding and protection of public policy programs, acknowledgment of the need to address the impact of restructuring on residential and small business customers, the necessity for accurate estimation of transition costs, and the need to address recovery of costs.

3. New Hampshire

The New Hampshire legislature passed legislation that authorizes its Public Utilities Commission (New Hampshire PUC) to conduct a retail wheeling pilot program, effective January 1, 1996. The legislation would make the pilot program available in all franchise service areas and to all customer classes. In a separate "roundtable" on electric utility restructuring, the New Hampshire PUC worked with representatives from the electric utility industry to develop a draft report on competition and restructuring.

In a divided opinion, the New Hampshire PUC held that the Public Service Company of New Hampshire (PSNH) does not have an exclusive franchise over its service area. The PUC's ruling paves the way for Freedom Electric Power to make retail sales of power purchased wholesale outside the state to industrial customers located in PSNH's service territory. Final approval from the PUC is pending, as is Freedom Electric Power's petition before the FERC for determination of its eligibility under FPA sections 211 and 212 to require mandatory wheeling by PSNH of the power purchased by Freedom Electric.

4. New York

The New York Power Authority has proposed to offer service to federal government customers of Consolidated Edison Company of New York (Con Edison). Under legislation passed by the state senate in June 1995, such service would require Con Edison's consent. Con Edison has indicated its opposition to the plan because of the potential loss of revenues and shifting of costs to residential and low income customers.

The New York Public Service Commission (NYPSC) has adopted general guidelines and principles for the restructuring of the electric utility industry and the regulatory structure for a transition to enhanced competition. A primary principle requires access to reliable electric service at a reasonable price for all customers.

Two proposals for retail wheeling over Long Island Lighting Company's (LILCO) transmission system are also pending before the NYPSC. Each of these proposals seeks authority to purchase power from suppliers other than LILCO, for transmission on the LILCO system. Niagara Mohawk Power Corporation is fighting separate decisions of the NYPSC that would allow a qualifying facility to sell power at retail to a current customer and a prospective customer, and which would establish the stranded cost recovery amount to be paid to Niagara Mohawk.

5. Wisconsin

An advisory committee created by the Wisconsin Public Service Commission (WPSC) to examine restructuring of the electric utility industry in the state has been unable to reach consensus on the regulatory structure that should govern generation. With regard to transmission, however, the advisory committee indicated a preference for transmission facilities to be

transferred to a single entity, which could take the form of either public or private ownership, with an ISO. In order to further consider restructuring issues, the WPSC has postponed recommendations to the state legislature.

6. Utah

In Utah, the Public Service Commission and electric utility industry have engaged in informal discussions regarding the potential impact on Utah if other states in the region endorse and implement electric utility restructuring. The Utah courts are presently faced with the issue of the right of Utah cities to select the utility that will supply services within municipal boundaries.

7. Pennsylvania

The staff of the Pennsylvania Public Utility Commission (PPUC), in an investigative report issued in August 1995, declined to recommend retail wheeling at the present time. The staff found insufficient support for a restructuring of the electric utility industry, and an absence of readily apparent benefits that would result from restructuring. In a related investigation, the PPUC's Bureau of Conservation, Economics and Energy Planning and the Law Bureau collaborated to study competition and the potential effect of a bidding process for power supply. The PPUC also is considering a complaint filed by Findlay Township seeking to compel retail wheeling over Duquesne Light Company's system in retail wheeling.

II. MAJOR TRENDS IN CASES

A. Pricing

The FERC, in its 1994 Transmission Pricing Policy Statement,⁸³ formulated and announced "five pricing principles" against which it would judge whether a transmission pricing proposal comports with the requirements of the FPA that such pricing be both just and reasonable and not unduly discriminatory.⁸⁴ The Commission also stated, however, that it would be flexible in its approach to pricing proposals and consider "innovative pricing proposals" which both met the traditional revenue requirement and incorporated distance-based rates, such as MW-mile or zonal rates. In 1995, several utilities proposed open-access transmission tariffs which incorporated MW-mile or zonal pricing.

83. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, III F.E.R.C. STATS. & REGS. ¶ 31,005 (1994), clarified, 71 F.E.R.C. ¶ 61,195 (1995).

84. See *Report of the Committee on Electric Utility Regulation*, 16 ENERGY L.J. 529 (1995). A transmission pricing proposal (1) must meet the traditional revenue requirement, (2) must reflect comparability, (3) should promote economic efficiency, (4) should promote fairness, and (5) should be practical and easy to administer.

For example, in *Southern Co. Services, Inc.*,⁸⁵ the Commission rejected Southern's open access network and point-to-point tariff submissions⁸⁶ because Southern failed to submit any supporting testimony which addressed the Commission's five indispensable pricing principles. The Commission criticized Southern for failing to provide any support for or explain why (1) Southern's "zones" were based upon political and/or corporate subdivisions rather than "electric characteristics," (2) zonal pricing requires multiple tariffs with duplicate terms and conditions rather than a single system tariff with rate zones, and (3) under the zonal rate proposal, no customer would ever pay less than Southern's present postage-stamp rate. The Commission directed Southern to file supporting information and data as outlined in the order.⁸⁷ Southern, however, subsequently withdrew its zonal pricing proposal and submitted an open-access tariff using average-cost postage-stamp rates based upon the *pro forma* tariffs proposed by the Commission in the GigaNOPR.⁸⁸

In contrast, the Commission accepted the GPU Companies firm and non-firm point-to-point transmission tariffs.⁸⁹ The rate proposed by the GPU Companies for both "firm power transmission" service and "firm energy transmission" service incorporated a distance-sensitive "MW-mile" methodology which would allocate embedded costs according to the size of the transaction and the miles of transmission facilities affected by the transaction. For hourly energy transmission service, the GPU Companies proposed a "zonal" pricing methodology. The Commission held that, under certain circumstances, some combinations of average-cost pricing and opportunity-cost pricing may be permitted—for example, where the customer pays a *pro rata* share of the average embedded costs and average opportunity costs.⁹⁰

The Commission also addressed several applications for transmission service under sections 211 and 212 of the FPA.⁹¹ In *Tex-La Electric Cooperative of Texas, Inc.*,⁹² Texas Utilities (TU) had proposed to use a distance-sensitive, MW-mile rate methodology for pricing network transmission service requested by Tex-La Electric Cooperative (Tex-La). Tex-La objected to TU's use of a distance-sensitive rate as being unduly discriminatory and

85. *Southern Co. Servs.*, 71 F.E.R.C. ¶ 61,392 (1995).

86. Southern had divided its system into two zones, with each zone having a network tariff and point-to-point tariff. The network transmission tariffs required customers to pay separate load ratio shares, and if resources of one zone were used to serve loads in the other zone, customers would be required to pay additional point-to-point charges. Southern's point-to-point tariff service charged a postage-stamp rate that reflected the average cost of the operating units in that zone, although customers seeking service in both zones would be subject to "or" pricing, as well as being required to make separate arrangements in each zone and pay the sum of the two zone charges.

87. *Southern Co. Servs.*, 71 F.E.R.C. ¶ 61,392, at 62,534-36.

88. The Commission accepted Southern's submission for filing, subject to refund and to the outcome of the GigaNOPR proceeding. See *Southern Co. Servs.*, 72 F.E.R.C. ¶ 61,324, at 62,409 (1995).

89. *Jersey Cent. Power & Light Co.*, 72 F.E.R.C. ¶ 61,298 (1995).

90. *Jersey Cent. Power & Light Co.*, 72 F.E.R.C. ¶ 61,298, at 62,276 (citing *New England Power Co.*, 65 F.E.R.C. ¶ 61,153, at 61,757 (1993)).

91. 16 U.S.C. §§ 824j, 824k (1994).

92. 69 F.E.R.C. ¶ 61,269 (1994).

not comparable to TU's own practices. The Commission agreed that TU's proposed rate was unduly discriminatory because TU was not using a distance-sensitive rate to price the transmission component of its bundled service to retail customers, nor was any of TU's unbundled firm transmission services, except for the services requested by Tex-La,⁹³ priced using a distance-sensitive methodology. The Commission ordered TU to apply its average system cost, postage-stamp rate, which it used for other firm transmission uses, to the services requested by Tex-La. The Commission also held that a single system rate for affiliated companies that operate an integrated transmission system is appropriate.

In another section 211 application, the Commission faced the issue of whether to apply a single system rate to facilities owned by unaffiliated companies, but operated as an integrated transmission system.⁹⁴ The section 211 application filed by Duquesne Light Company (DQE) requested the Commission to direct the members of the Pennsylvania-Maryland-New Jersey Interconnection Association (PJM) to provide it with transmission services. The Commission held that because the PJM Member Companies do not use a single system rate when providing services to each other, a single system rate was inappropriate for transmission service provided to DQE. In addition, unlike the situation in *Southern Co. Services, Inc.*,⁹⁵ the PJM Member Companies are not commonly owned and do not operate as a single integrated unit. The coordination by independent utilities of operations in order to minimize operating costs provided no basis upon which to require a single system rate for transmission services over the utilities' combined systems.

Finally, in *Entergy Services, Inc.*,⁹⁶ the Commission rejected a "non-conforming tariff" which proposed to charge third-party customers for both system average costs and incremental costs of an addition, because Entergy had not shown that it applied pricing on a "comparable" basis for service to its native load and because Entergy did not explain why this non-conforming proposal was superior to a conforming rate design.

B. Open Access Filings

In 1995, the commission approved several open access tariffs on settlement offers, accepted others subject to hearing on rates, and accepted others subject only to the final rule on the GigaNOPR.⁹⁷ For example, the Commission approved, subject to certain modifications and the final rule on the GigaNOPR, a settlement on Louisville Gas & Electric Company's

93. TU's application of distance-sensitive rates to Tex-La was the only instance in which such application would result in an increase, rather than a decrease, from postage-stamp rates.

94. *Duquesne Light Co.*, 71 F.E.R.C. ¶ 61,155 (1995).

95. 60 F.E.R.C. ¶ 61,273 (1992), *reh'g denied*, 67 F.E.R.C. ¶ 61,080 (1994).

96. 70 F.E.R.C. ¶ 61,006 (1995).

97. See *American Elec. Power Serv. Corp.*, 70 F.E.R.C. ¶ 61,358, at 62,052-53 (providing general guidance concerning pending and future open access transmission cases and stating that settlements approved before issuance of final rule would be subject to outcome of final rule), *order on reh'g*, 71 F.E.R.C. ¶ 61,393; *American Elec. Power Serv. Corp.*, 72 F.E.R.C. ¶ 61,287 (1995).

(LG&E) proposed point-to-point and network transmission service tariffs.⁹⁸ The Commission found that the rates were cost-justified, subject to justification (or elimination) of the one mill/kWh adder and the filing of specified rates for ancillary services (rather than allowing the company to provide generation-related ancillary services at market-based rates). The Commission found that the tariffs sufficiently provided that LG&E would charge itself the appropriate transmission rate for its off-system transactions. In so doing, the Commission declined to require LG&E to (a) establish an implicit price floor for its bundled coordination sales; or (b) establish a revenue booking account for such sales under the tariffs.⁹⁹

In the absence of settlement, the Commission generally accepted open access transmission tariffs for filing without setting for hearing the basic non-rate terms and conditions of non-discriminatory transmission service, subject to the outcome of a final rule on the GigaNOPR. However, certain rate issues were set for hearing. For example, in *Pacific Gas & Electric Co.*,¹⁰⁰ the transmission tariffs included total system average pricing rather than the sub-functionalized pricing reflected in PG&E's existing agreements. The Commission denied motions for summary rejection of PG&E's proposed shift from sub-functionalized rates to a system-wide rate methodology, but on rehearing stated that the parties and staff would be allowed to challenge the methodology as well as the level of rates proposed by PG&E.¹⁰¹ In that proceeding, the rate for point-to-point service reflected the higher of a postage-stamp rate, average-cost rate, or incremental costs.¹⁰²

The Commission also accepted several network and point-to-point transmission tariffs that varied from the *pro forma* tariffs without setting either the terms and conditions or the rates for hearing, subject to the final outcome on the GigaNOPR. In *MidAmerican Energy Co.*,¹⁰³ for example, the company filed two sets of tariffs, both based on the *pro forma* tariffs,

98. *Louisville Gas & Elec. Co.*, 72 F.E.R.C. ¶ 61,078 (1995).

99. See also *Kansas City Power & Light Co.*, 72 F.E.R.C. ¶ 61,218 (1995) (conditionally approving contested settlement offer; accepting provision allowing assignment of transmission rights at a rate equal to higher of tariff rate or reseller's lost opportunity cost subject to FERC reporting requirement and posting on electronic bulletin board; accepting one-month minimum term for firm point-to-point service in return for treating economy energy purchases as non-firm uses of its transmission system).

100. 71 F.E.R.C. ¶ 61,394 (1995).

101. *Pacific Gas & Elec. Co.*, 72 F.E.R.C. ¶ 61,217 (1995).

102. See also *PacifiCorp*, 72 F.E.R.C. ¶ 61,179 (1995) (Commission set for hearing rate issues where company proposed rate for point-to-point transmission service equal to the higher of a postage-stamp rate, average-cost rate, or incremental costs); *Central Illinois Light Co.*, 73 F.E.R.C. ¶ 61,214 (1995) (open access transmission tariffs accepted, but hearing set for whether the proposed tariffs should be revised to include a rate based on full hours' utilization for service taken only in off-peak hours); *Public Serv. Co. of Colo.*, 73 F.E.R.C. ¶ 61,071 (1995) (transmission tariffs accepted; rates set for hearing; "Emergency Re-dispatch Service" summarily eliminated because firm point-to-point customer's payment of average cost rate plus costs incurred to avoid curtailment was opportunity cost pricing, which could not be charged in addition to an average-cost, postage-stamp rate); *Wisconsin Pub. Serv. Corp.*, 73 F.E.R.C. ¶ 61,048 (1995) (rates set for hearing; Wisconsin Public Service Corp. directed to revise its point-to-point transmission rates to reflect the use of the annual system peak (as a proxy for system capability), rather than the average of the 12 monthly peaks).

103. 73 F.E.R.C. ¶ 61,027 (1995).

and identical in all respects except that the "Alternate B" tariffs were the result of a settlement that: (1) created an additional type of non-firm service that has no reservation feature; (2) increased the specificity as to the order in which non-firm transmission service would be curtailed; (3) increased the time period for which a customer could extend commencement of service; and (4) further defined when a customer's obligation to pay for service begins. The Commission, in accepting the "Alternate B" tariffs, found that the terms and conditions of the tariffs accepted departed from the *pro forma* tariffs "in ways that are favorable to customers" and further found that the rates were cost-justified. MidAmerican had proposed rates reflecting a peak usage design for all (firm and non-firm) transmission service, and the Commission specifically declined to order MidAmerican to create a separate rate for firm, off-peak transmission service.¹⁰⁴

Finally, in *IES Utilities, Inc.*,¹⁰⁵ the Commission accepted transmission tariffs, without suspension or hearing, for new services only. The Commission directed the company to file appropriate rate schedule supplements and cost support in a separate docket if it sought to increase rates for transmission services to existing customers. In addition, the Commission declined to require cost support for the adoption of a 1 mill/kWh charge for ancillary services. Notwithstanding opposition from certain customers, the Commission reasoned that the charge could be avoided by obtaining ancillary services elsewhere.

C. Access to Transmission Services

During 1995, the FERC issued a number of orders directing that transmission services be provided in response to section 211 applications, as summarized below.¹⁰⁶

104. See also *Tampa Elec. Co.*, 73 F.E.R.C. ¶ 61,176 (1995) (rates developed based on full hours' utilization rather than the standard Commission methods of peak usage rate design, and results of the company-specific levelized fixed-charge method suggested by the Commission in the GigaNOPR reduced to reflect certain revenue credits); *Illinois Power Co.*, 73 F.E.R.C. ¶ 61,026 (1995) (accepting adjustments to rates designed on basis of GigaNOPR but reduced to reflect revenue credits, and directing utility to reduce its loss factors to reflect its own system analysis rather than *pro forma* 3% loss factor); *Delmarva Power & Light Co.*, 73 F.E.R.C. ¶ 61,126 (1995) (open access transmission service tariff accepted despite its variances from *pro forma* tariffs; variances include an exclusion from eligibility for service of designated agents of existing customers, a prohibition on provision of point-to-point service for transmission dependent utilities, limitations on access to interfaces with other control areas, a limitation on Delmarva's obligation to construct, and not permitting firm point-to-point customers to use alternate receipt and delivery points on a non-firm basis; proposal for distance-based pricing subject to hearing and justification under Rate Design Policy Statement).

105. 72 F.E.R.C. ¶ 61,296 (1995).

106. FPA § 211, 16 U.S.C. § 824j (1994). The Commission also dismissed two section 211 matters. See *Cleveland Pub. Power v. Centerior Energy Corp.*, 72 F.E.R.C. ¶ 61,189 (1995) (dismissing application naming holding company as the transmitting utility without prejudice to refile application naming the operating companies); *El Paso Elec. Co.*, 72 F.E.R.C. ¶ 61,292 (1995) (dismissing application based on substantial change in circumstances, *i.e.*, termination of proposed merger, but without prejudice to a new application being filed on current facts).

After the Borough of Zelenople (Zelienople) selected Duquesne Light Company to replace Pennsylvania Power Company (Penn Power) as its supplier, Penn Power agreed to provide the necessary transmission service, but Zelienople and Penn Power were unable to agree on the rates, terms and conditions for such transmission service. In its proposed order on Zelenople's section 211 application,¹⁰⁷ the Commission (1) made a preliminary determination that Penn Power should provide transmission service to Zelienople; (2) gave the parties the opportunity to negotiate specific rates, terms and conditions; and (3) provided guidance as to the appropriate cost basis for rates (i.e., average system transmission costs with reference to the combined integrated systems of Penn Power and its affiliate, Ohio Edison Company, and directly assigned distribution costs) and certain terms (dynamic scheduling and stranded cost provisions). The Commission provided for more detailed briefing procedures than in earlier section 211 cases to facilitate its review and disposition of any unresolved issues following the further negotiations.

After Old Dominion Electric Cooperative (ODEC) made a good faith request for transmission service over the system of Delmarva Power & Light Company (Delmarva), ODEC and Delmarva unsuccessfully attempted to negotiate a suitable transmission arrangement. ODEC then filed a section 211 application with the Commission requesting an order directing Delmarva to provide network transmission service. In response, Delmarva filed a transmission rate schedule under section 205 of the FPA to provide the requested service and a rate schedule to supply partial requirements service to ODEC for the balance of its requirements.

The Commission ordered Delmarva to provide transmission service for ODEC, and required further negotiations between the parties to resolve differences regarding terms, conditions, and rates for the service. In addition, the Commission found: (1) because the transmission services requested in ODEC's section 211 application materially differed from those contained in its good faith request for transmission service, only the services requested in the good faith request should be ordered; and (2) Delmarva's response to a request for transmission service under section 211 by filing a rate schedule under section 205 to provide services under different rates, terms, and conditions than requested was inconsistent with the spirit of section 211. Ultimately, the Commission accepted the parties' settlement agreement for transmission service.¹⁰⁸

In the *Duquesne Light Co.* case, in which Duquesne sought a section 211 order for transmission service across the PJM system,¹⁰⁹ the Commission directed PJM to provide Duquesne's requested transmission service and issued several significant findings in response to PJM's objections. First, the Commission stated that it "will not interpret an agreement's [alternative dispute resolution] procedures as preempting a person's statutory right to resolve access and pricing issues under section 211, unless it is

107. *Borough of Zelenople, Pennsylvania*, 70 F.E.R.C. ¶ 61,073 (1995).

108. *Delmarva Power & Light Co.*, 70 F.E.R.C. ¶ 61,339 (1995).

109. 71 F.E.R.C. ¶ 61,155 (1995).

clear that the parties so intended.”¹¹⁰ Second, with respect to the sufficiency of Duquesne’s application, the Commission reiterated its previous position that section 211 requests “need not be restricted to specific transactions or specific services.”¹¹¹ Third, the Commission found that because none of the PJM companies responded to Duquesne’s good faith request as required under section 2.20(c) of the Commission’s regulations,¹¹² Duquesne’s ability to compete effectively for a particular solicitation was impaired.¹¹³ Finally, the Commission rejected the PJM’s argument that the transmission service would unreasonably impair the reliability of the PJM system, especially in light of Duquesne’s concession that its service request was conditioned upon PJM taking whatever steps were necessary to maintain reliability.

In a related section 211 proceeding in which Duquesne requested an order requiring the Allegheny Power System to provide transmission service,¹¹⁴ the Commission directed Allegheny to provide the requested transmission service and provided preliminary guidance to help the parties resolve their dispute over rates. The Commission noted that, because Duquesne requested service with a curtailment priority equivalent to that of Allegheny’s native load (i.e., its retail customers and wholesale requirements customers in its control area), under the Commission’s principle of comparability, the rate Duquesne pays for service should reflect a pro rata share of transmission costs, including a share of revenue credits, that are assigned to Allegheny’s native load uses. In addition, the Commission found it inappropriate to use the cost to rebuild Allegheny’s entire existing grid at today’s costs when pricing the cost of providing an additional increment of transmission service.¹¹⁵

110. *Id.* at 61,504.

111. *Id.*

112. Section 2.20(c) provides that, in response to a section 211 request for transmission service, a transmitting utility must provide either (1) if the service can be provided from existing capacity, an executable service contract for the provision of the requested services, or (2) if the service cannot be provided from existing capacity, detailed information describing specific system constraints and an executable agreement for the performance of and reimbursement for necessary studies. 18 C.F.R. § 2.20(c) (1995).

113. *Duquesne Light Co.*, 71 F.E.R.C. ¶ 61,155, at 61,505. The Commission stated that such “dilatatory responses . . . reinforce the Commission’s observation that, even though section 211 allows a customer to request broad tariff-like arrangement, ‘case-by-case section 211 proceedings are not a substitute for tariffs of general applicability that permit timely, non-discriminatory access on request.’” *Id.* (quoting Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, *Promoting Wholesale Competition Through Open-Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, IV F.E.R.C. STATS. & REGS. [Proposed Regs.] ¶ 32,514, at 33,057 (1995)).

114. *Duquesne Light Co.*, 71 F.E.R.C. ¶ 61,156 (1995).

115. Allegheny later moved to suspend further section 211 proceedings and to consolidate that proceeding with its open access transmission service tariff proceeding; Allegheny stated that the transmission service requested by Duquesne would be provided under its network or point-to-point tariffs.

III. THE DECADE OF MARKETS, MARKETERS, AND MARKET-BASED RATES

A. Power Marketers

Power marketer applications continued at an accelerated pace, resulting in the largest number of FERC orders authorizing power marketers to sell power at market-based rates in a single year. By the end of 1995, over 100 power marketer tariffs had been authorized. The application of Delhi Energy Services, Inc., a wholly-owned subsidiary of USX Corporation, typified the power marketer applications. USX is a diversified company that is engaged in business related to energy (through its Marathon Group), steel (through U.S. Steel), and natural gas (through its Delhi Group).¹¹⁶

Affiliated power marketer applications have presented the greatest challenge to the FERC. The FERC clarified its definition of "affiliation" under Part II of the FPA by adopting two standards, one for Exempt Wholesale Generator (EWG) public utilities and one for non-EWG public utilities. The FERC applied the PUHCA section 2(a)¹¹⁷ definition of "affiliate," which includes a five percent voting interest test, to EWG public utilities. For non-EWG public utilities, the FERC relied upon its definition of affiliation of natural gas marketers and interstate pipelines and determined that, in its electric jurisdiction, a ten percent voting interest would constitute a rebuttable presumption of affiliation.¹¹⁸

The Commission requires affiliates of power marketers to maintain open access transmission tariffs. In *Energy Alliance Partnership*, for example, the FERC denied an application to sell power at market-based rates where a marketer's Canadian affiliate did not offer open-access transmission service in Canada to entities seeking to transact in the United States. Citing the potential for a competitor to require transmission in Canada to service U.S. markets, the FERC found the Canadian affiliate's transmission facilities relevant to a market power analysis and the absence of an open access tariff fatal to the application.¹¹⁹

Power marketers are not authorized to buy power from, or sell power to, affiliated investor-owned utilities (IOUs). Despite its disclaimer of jurisdiction over brokering activities, the FERC has limited the brokering of affiliate power. Power marketers have been authorized to broker affiliated IOU power on a non-exclusive basis, but the FERC has rejected an exclusive brokering arrangement.¹²⁰ In addition, the FERC has affirmed its complete bar against information-sharing between a power marketer and its IOU affiliate by rejecting a proposal to limit the bar to information obtained solely in relation to transmission service. However, the FERC limited the exchange of information on business and financial arrange-

116. See *Delhi Energy Services, Inc.*, Docket No. ER95-940-000, Letter Order, June 1, 1995 (unreported).

117. 15 U.S.C. § 79b(a) (1994).

118. See *Morgan Stanley Capital Group Inc.*, 72 F.E.R.C. ¶ 61,082 (1995).

119. 73 F.E.R.C. ¶ 61,019 (1995).

120. See *Wholesale Power Servs., Inc.*, 72 F.E.R.C. ¶ 61,284 (1995).

ments between the power marketer, or its affiliates, and entities that transact with the power marketer by eliminating this reporting requirement, except in respect to the actual electricity sales of the power marketer.¹²¹

B. *Changing Market Power Analysis*

In evaluating a request to make wholesale sales of electric power at market-based rates, the Commission reviews whether the marketer, and each of its affiliates, is able to exercise market power over transmission and generation.¹²² The Commission also analyzes whether the marketer is able to erect other barriers to market entry. If the marketer is a utility affiliate, the Commission also reviews whether there exists any potential for affiliate abuse or reciprocal dealing between the public utility and the affiliated marketer.¹²³

1. *Generation Market Power*

The Commission requires a marketer and its affiliate(s) to demonstrate that they do not possess market power over generation by showing that their market shares of installed and uncommitted capacity do not exceed a certain level so as to allow the marketer to exercise market power over the price of power. Although the Commission regularly maintains that it does not use a "bright line" in determining whether a marketer can exercise market power over generation, the Commission has generally held that a concentration of twenty percent or less is evidence that the marketer cannot exert market power over generation. In 1995, however, the Commission found that a utility may not have market power over generation even with higher levels of concentration. In *Southern Co. Services*,¹²⁴ for example, the Commission determined that in most of Southern's fifteen markets, Southern's concentration of installed capacity was above twenty percent. The Commission also found that Southern's concentration of uncommitted capacity was well below twenty percent in all of Southern's fifteen markets. The Commission determined that "[o]n balance, we conclude that [Southern] meets the Commission's generation market power requirements."¹²⁵

In *Energy Alliance Partnership*,¹²⁶ the Commission made clear that an affiliated power marketer must demonstrate that neither it nor any of its affiliates that owns or operates generation is dominant in the market. Energy Alliance Partnership, a general partnership consisting of subsidiaries of Consolidated Natural Gas Company, Hydro-Quebec, and Noverco, Inc., argued that because Hydro-Quebec's generation is located in Canada, the generation need not be included in its market study. The Commission,

121. See *Morgan Stanley Capital Group, Inc.*, 72 F.E.R.C. ¶ 61,082 (1995).

122. See *Report of the Committee on Electric Utility Regulation*, 16 ENERGY L.J. 529, 540-48 (1995).

123. *Id.*

124. 72 F.E.R.C. ¶ 61,324 (1995).

125. *Id.* at 62,406. The Commission subsequently applied the same "on balance" standard to later market-based rate filings. See, e.g., *Southwestern Pub. Serv. Co.*, 72 F.E.R.C. ¶ 61,208 (1995).

126. 73 F.E.R.C. ¶ 61,019 (1995).

however, held that because Hydro-Quebec power is available for sale in the United States and may impact Energy Alliance's ability to exercise market power, the resources must be included in the market study.¹²⁷ Because Energy Alliance did not include the resources in its study, the Commission dismissed the market-based rate filing without prejudice.

2. Market Power over Transmission

With the issuance of the GigaNOPR¹²⁸ and the *pro forma* tariffs contained therein,¹²⁹ the Commission currently requires utilities seeking to charge market-based rates to file the *pro forma* tariffs as the only way to mitigate market power over transmission. In *American Electric Power Service Corp.*,¹³⁰ the Commission announced that it would no longer allow a utility, or its affiliate, to charge market-based rates unless the utility has on file open access transmission tariffs that are consistent with, or superior to, the terms and conditions in the GigaNOPR tariffs. In *Duke Energy Marketing Corp.*,¹³¹ the Commission rejected Duke's request to charge market-based rates because its transmission tariffs deviated from the GigaNOPR *pro forma* tariffs. The Commission has since regularly rejected other utilities' market-based rate filings on the same basis even if the tariffs contained only minor deviations from the *pro forma* tariffs.

The Commission's order in *Energy Alliance Partnership*¹³² also applied to Hydro-Quebec's transmission facilities. The Commission required Energy Alliance to demonstrate that its Canadian affiliate had mitigated market power over transmission. The Commission acknowledged that it did not have jurisdiction over Hydro-Quebec and its transmission facilities located in Canada. Nonetheless, the transmission facilities' location in Canada might be used to exercise market power. Therefore, the Commission required Energy Alliance to demonstrate that Hydro-Quebec "offers non-discriminatory wholesale access to its transmission system that can be used by competitors of Energy Alliance" in order to mitigate Energy Alliance's market power over transmission.¹³³

3. Other Barriers to Market Entry

The Commission continues to analyze whether a utility seeking to charge market-based rates can erect other barriers to market entry. For example, if a marketer is affiliated with a gas distribution company, the Commission will consider whether the marketer will be able to take advantage of that affiliation to enhance its market power. However, the Com-

127. *Id.* at 61,030.

128. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514.

129. *See supra* part I.A.1.

130. 72 F.E.R.C. ¶ 61,287 (1995).

131. 73 F.E.R.C. ¶ 61,047 (1995).

132. 73 F.E.R.C. ¶ 61,019 (1995).

133. *Energy Alliance Partnership*, 73 F.E.R.C. ¶ 61,019, at 61,031. Commissioner Massey issued a concurring statement in which he urged that "the transmission access offered by Hydro-Quebec must meet the Commission's 'comparability' standard." *Id.* at 61,032.

mission has yet to issue an order in which it has found that a utility has erected such barriers. However, the Commission's orders authorizing the collection of market-based rates notes that it will be receptive to complaints that a utility is somehow erecting other barriers to entry, and that the market-based rates could be suspended if such a complaint has merit.¹³⁴

C. Confidentiality

The FERC continues to struggle to reconcile its traditional requirements to report on a non-confidential basis cost and price data with the realities of the new competitive markets in which competitors seek to keep trade data secret. Power marketers must file quarterly reports outlining the terms of the previous quarter's transactions, but they no longer have to report business and financial arrangements with entities which buy power from, sell power to, or transport power on behalf of the marketer.¹³⁵

However, regulated electric utilities must continue to disclose costs and rates. In *Consolidated Edison Co. of New York*,¹³⁶ for example, the FERC denied Consolidated Edison's (Con Ed) request to file confidentially certain cost data as part of its Form 1 report. The FERC held that the data was needed by customers to evaluate cost-based rates and that to grant the request would prejudice competing utilities which have publicly disclosed similar data.¹³⁷

The FERC has opted for full disclosure of available transportation costs and services. In a Notice of Proposed Rulemaking on Real-Time Information Networks and Standards of Conduct,¹³⁸ the FERC proposed that public utilities must give competitors and other users of the transmission system simultaneous access to the same information available to the utility's trading personnel. The FERC further proposed to require separation of the utilities' transportation functions from their wholesale merchant functions and to restrict access of their merchant function employees to the real-time information network.

D. Futures

The New York Mercantile Exchange (NYMEX) asked the FERC on September 28, 1995, to declare that electricity futures trading contracts listed on the NYMEX do not constitute "securities" under section 3 of the FPA.¹³⁹ Under the proposal, the contracts would not be subject to the FERC's jurisdiction under FPA sections 203 and 204,¹⁴⁰ but instead would

134. See, e.g., *Louisville Gas & Elec. Co.*, 62 F.E.R.C. ¶ 61,016, at 61,150 (1993); *Southwestern Pub. Serv. Co.*, 72 F.E.R.C. ¶ 61,208, at 61,968 (1995).

135. *Morgan-Stanley Capital Group, Inc.*, 72 F.E.R.C. ¶ 61,082 (1995).

136. 72 F.E.R.C. ¶ 61,184 (1995).

137. See also *Delmarva Power & Light Co.*, 70 F.E.R.C. ¶ 61,391 (1995) (denying attempt to file confidentially cost portions of service agreements with several municipal electric systems).

138. Notice of Proposed Rulemaking, *Real-Time Information Networks and Standards of Conduct*, 60 Fed. Reg. 66,182 (Dec. 21, 1995).

139. 16 U.S.C. § 796 (1994).

140. 16 U.S.C. §§ 824b, 824c (1994).

be regulated by the Commodities Futures Trading Commission (CFTC) under the Commodity Exchange Act.¹⁴¹ The NYMEX has also asked the CFTC for approval of two electricity futures trading contracts, using two western locations as the delivery points. If approved, futures contracts will be used to manage the risk of volatile price fluctuations of electricity purchases and sales, just as natural gas futures contracts have added stability to the natural gas industry.

IV. MERGERS AND DIS-AGGREGATION

A. Major Cases

1. Impact of the GigaNOPR

During 1995, FERC merger decisions were characterized by three dominant themes. First, the Commission continued to apply the *Commonwealth Edison*¹⁴² six-factor test in assessing whether proposed mergers are consistent with the public interest under section 203 of the FPA.¹⁴³ Second, the FERC continued to apply the policy announced in *El Paso Electric Co. and Central & South West Services, Inc.*,¹⁴⁴ that comparable open access transmission service is, in effect, an element of that standard, whether or not the merger causes an increase in market power. "Comparable open access transmission," in turn, became synonymous with the minimum terms and conditions articulated in the GigaNOPR.¹⁴⁵ Third, with one notable exception,¹⁴⁶ the Commission continued to decide merger cases based solely on the parties' pleadings.

The utility industry spawned an unprecedented number of new merger announcements. At the conclusion of 1995, proposed mergers had been announced between (1) Baltimore Gas & Electric Company and Potomac Electric Power Company (to form Constellation Energy Company); (2) Puget Sound Power & Light Company and Washington Energy Company (to form the largest combination electric and gas utility in the Northwest); (3) Southwestern Public Service Company and Public Service Company of Colorado (to form a holding company); (4) Northern States Power Company and Wisconsin Energy Corporation (to form Primergy); (5) Cleveland Electric Illuminating Company and the Toledo Edison Company (both of which are subsidiaries of Centerior Energy Corporation); and (6) CIPSCO, Inc. (Central Illinois Public Service Company) and Union Electric Com-

141. 7 U.S.C. §§ 1-25 (1994).

142. *Commonwealth Edison Co.*, 36 F.P.C. 927 (1966), *aff'd sub nom.*, *Utility Users League v. FPC.*, 394 F.2d 16 (7th Cir. 1968), *cert. denied*, 393 U.S. 953 (1968). The six *Commonwealth Edison* factors are: (1) the effect of the proposed merger on the applicants' costs and rate levels; (2) the proposed accounting treatment; (3) the reasonableness of the purchase price; (4) whether the proposed merger involves coercion; (5) the effect the proposed merger may have on the existing competitive situation; and (6) whether the proposed merger will impair effective regulation by this Commission or by the appropriate state regulatory authorities. *Commonwealth Edison Co.*, 36 F.P.C. at 932.

143. 16 U.S.C. § 824b (1994).

144. 68 F.E.R.C. ¶ 61,181, at 61,890 (1994).

145. *GigaNOPR*, IV F.E.R.C. STATS. & REGS. ¶ 32,514.

146. See text accompanying notes 155-158.

pany (to form Ameren Corporation). In addition, a three-way combination was announced among WPL Holdings, Inc. (parent company of Wisconsin Power & Light Company), and two Iowa utilities, Interstate Power Company and IES Industries, Inc. (to form Interstate Energy Corporation). Finally, PECO Energy announced a hostile takeover of Pennsylvania Power & Light Company, but retreated when PP&L showed little interest in the acquisition.

2. *Delmarva/Conowingo*

In *Delmarva Power & Light Co.*,¹⁴⁷ the FERC authorized Delmarva to acquire all of the outstanding common stock of Conowingo Power Company and approved the merger of Conowingo into Delmarva. Conowingo had previously been a subsidiary of PECO Energy. Under a related power purchase agreement, PECO Energy was to sell to Delmarva base load capacity and energy for approximately ten years. Delmarva also filed, in another docket,¹⁴⁸ a proposed transmission tariff providing for network and point-to-point transmission services.

Applying the *Commonwealth Edison* public interest criteria, the Commission summarily approved the stock acquisition and the proposed merger, finding net benefits in the form of (1) the favorable terms of the power purchase agreement, which would lower rates; and (2) the deferral of Delmarva's capacity expansion plan. The Commission also found that the proposed transmission tariff would mitigate any market power that Delmarva may possess post-merger, but conditioned its approval upon Delmarva's conforming its proposed transmission tariff to the GigaNOPR and making service available under the tariff.¹⁴⁹ The Commission approved the use of the purchase method of accounting to record a \$47.1 million acquisition adjustment reflecting the excess of the purchase price for the Conowingo common stock over the net book value of Conowingo's assets.

3. *Midwest Power/Iowa-Illinois*

Again applying the *Commonwealth Edison* standard, on June 22, 1995 the Commission summarily approved the proposed merger of Midwest Power Systems, Inc. and Iowa-Illinois Gas and Electric Company, to form MidAmerican Energy Company.¹⁵⁰ Applicants claimed that the merger created potential net cost savings of \$489 million over a ten-year period through the consolidation of management and administrative positions, deferral of capacity additions, single system dispatch, and in other areas. MidAmerican filed three open-access transmission tariffs in support of the

147. 71 F.E.R.C. ¶ 61,160 (1995).

148. *Delmarva Power & Light Co.*, Docket No. ER95-222-000, 1995 WL 633082 (F.E.R.C. Oct. 27, 1995).

149. 71 F.E.R.C. ¶ 61,160, at 61,609. See *Delmarva Power & Light Co.*, 71 F.E.R.C. ¶ 61,161 (1995).

150. *Midwest Power Sys., Inc. and Iowa-Illinois Gas & Elec. Co.*, 71 F.E.R.C. ¶ 61,386 (1995).

merger application.¹⁵¹ In addition, in an effort to mitigate concern about possible wholesale rate impacts, the applicants offered a unique "open season," during which any wholesale requirements customer would be allowed, during the five-year period after the merger, to terminate its existing contract and arrange an alternate power supply if the merged company sought a wholesale rate increase.

Intervenors contended that capacity deferral benefits claimed by the applicants could be achieved without a merger, but the Commission rejected this argument out-of-hand. Citing *Northeast Utilities Service Co.*,¹⁵² the Commission reaffirmed its long-held position that applicants need not demonstrate "that the capacity deferral savings, or other savings, can be achieved only through a merger."¹⁵³ The Commission further observed that the majority of claimed merger-related cost savings were not contested. Finding on the basis of the pleadings that any potential adverse effect of the merger on wholesale rates and competition would be mitigated by the "open season" and by the filing of comparable transmission tariffs, the Commission approved the merger without a hearing.¹⁵⁴

Commissioners Massey and Hoecker wrote a separate concurring opinion in which they supported the Commission's decision, but declared in no uncertain terms that "the time has come for the Commission to reexamine its merger policy, most aspects of which were first adopted years ago."¹⁵⁵ The concurring opinion describes the changes that already have occurred in the Commission's merger jurisprudence, contrasting past decisions under the "consistent with the public interest" test (which the opinion characterized as "extremely limited exercise[s]") with recent merger authorizations that have focused on the competitive consequences of mergers and the requirement to offer comparable transmission access. Disavowing any "distaste for mergers," Commissioners Massey and Hoecker predicted that, in an era defined by "fundamental and rapid change brought about by competition," a merger's effect on competition is likely to dominate Commission merger analysis in the future. In addition to requiring open access as a condition of mergers, the Commission will have other competition issues to address, including the importance of the concentration of discrete transmission and generation assets, the size and market power of the merged company, the extent of horizontal or vertical integration, the treatment of claimed benefits achievable outside the merger, and any decline in the number of generation or transmission alternatives that remain in the wake of the merger.¹⁵⁶

151. *Mid American Energy Co.*, Docket No. ER95-188-000, 1995 WL 583164 (F.E.R.C. Oct. 4, 1995). See *Midwest Power Sys., Inc.*, 71 F.E.R.C. ¶ 61,385 (1995).

152. 56 F.E.R.C. ¶ 61,269, at 61,995 (1991), *order on reh'g*, 58 F.E.R.C. ¶ 61,070, at 61,187 (1992), *reh'g denied*, 59 F.E.R.C. ¶ 61,042 (1992), *aff'd in part and remanded on other grounds*, *Northeast Utils. Serv. Co. v. FERC*, 993 F.2d 937 (1st Cir. 1993).

153. *Delmarva Power & Light Co.*, 71 F.E.R.C. ¶ 61,160, at 62,507 (Comm'rs Massey and Hoecker, concurring).

154. *Id.*

155. *Id.* at 62,512.

156. *Delmarva Power & Light Co.*, 71 F.E.R.C. ¶ 61,160, at 62,513.

4. *Cincinnati Gas & Electric/PSI Energy*

On August 16, 1993, the Commission conditionally approved a proposed corporate reorganization in which Cincinnati Gas & Electric Company and PSI Energy, Inc. would become subsidiaries of a newly-created registered holding company, CINergy Corporation.¹⁵⁷ The Applicants simultaneously filed tariffs providing for open access to their transmission systems, and the Commission required that they be modified to reflect Commission precedent.¹⁵⁸ On June 22, 1995, the Commission disposed of two requests for rehearing filed by the American Forest and Paper Association (AFPA) and American Electric Power System Companies (AEP).¹⁵⁹

The AFPA contended, relying on *Cajun Electric Power Cooperative, Inc. v. FERC*,¹⁶⁰ that the Commission erred in refusing to hold a hearing on whether the inclusion of opportunity costs in CINergy's proposed transmission rates would prevent the proposed tariff from mitigating CINergy's market power. On rehearing, the Commission rejected the AFPA's argument. The Commission relied on the fact that CINergy itself would be subject to opportunity costs because transmission by CINergy would be governed by the merged companies' tariff. The Commission also distinguished *Cajun* on the ground that opportunity cost charges, unlike stranded costs, are "not tied to any previous or current service that the third party transmission customer may have received or is receiving from the utility."¹⁶¹

AEP contended that the Commission failed to reconcile its conclusion that the merger was consistent with the public interest with what AEP called the merged companies' "planned use of the AEP System Companies' transmission facilities."¹⁶² The Commission rejected this contention, pointing to the applicants' "hold harmless" condition, which would protect wholesale customers in the event AEP obtained compensation for unauthorized flows of power on its transmission system.¹⁶³

157. *Cincinnati Gas & Elec. Co. and PSI Energy, Inc.*, 64 F.E.R.C. ¶ 61,237 (1993).

158. *Id.* at 62,717.

159. AFPA's and AEP's request for rehearing was directed at the Commission's October 3, 1994 Order, reported at 69 F.E.R.C. ¶ 61,005 (1994). The October 3 Order reinstated the Commission's conditional approval of the merger, which had been withdrawn because the Commission "was deeply concerned about the state of the record on the issue of whether this merger will impair effective regulation." See *Cincinnati Gas & Elec. Co. and PSI Energy Inc.*, 66 F.E.R.C. ¶ 61,028, at 61,022 (1994).

160. 28 F.3d 173 (D.C. Cir. 1994). In *Cajun*, the D.C. Circuit held that it was arbitrary and capricious for the FERC to decline to hold an evidentiary hearing on the issue of whether Entergy's transmission tariff allowed for meaningful access to alternative supplies before it approved the company's proposal to charge market-based rates for bulk power sales. Entergy's transmission rates included stranded investment charges, which the court generally described as a tying arrangement. 28 F.3d at 179 (citing *Western Sys. Power Pool*, 55 F.E.R.C. ¶ 61,099, at 61,317 (1991)).

161. *Cincinnati Gas & Elec. Co. and PSI Energy, Inc.*, 71 F.E.R.C. ¶ 61,380, at 62,481.

162. *Id.* at 62,482.

163. *Id.*

5. *Washington Water Power Company/Sierra Pacific Power Company*

On November 29, 1995, the Commission declined to approve a merger between Washington Water Power and Sierra Pacific Power, finding that the management savings claimed by the applicants were "unsubstantiated" and that the merger would cause a reduction in transmission capacity available to third parties.¹⁶⁴ The Commission consolidated the merger application with the applicants' open access tariff filing, and set both proceedings for hearing.¹⁶⁵

The two merging utilities operated two separate control areas, almost 400 miles apart, and did not intend to consolidate their capacity planning or electric operations. They would operate post-merger as two separate divisions, relying on 200 MW of firm transmission service over intervening utility systems to effectuate inter-divisional capacity-related coordination and energy transactions, at market-based rates. Due to the geographic and operational separation between the merging companies, the applicants claimed none of the usual operational and planning benefits associated with a merger. Rather, they claimed \$497 million of savings originating solely from projected reductions in administrative and general expenses.

In setting the matter for hearing, the Commission expressed concern that transmission service over Sierra's system would not immediately be available to third parties, but would have to await completion of a 345-kV transmission line. In addition, third parties would be foreclosed from utilizing the entire 200-MW contract path between the two utilities, because the merged company intended to use all of this capacity for inter-divisional transactions. Thus, the Commission concluded, firm transmission service between the two divisions would not be available to third parties on a basis comparable to applicants' intended use of their transmission system. In addition, the applicants declined to offer single-system pricing, as the Commission has required in the past even for non-contiguous utilities.¹⁶⁶ The Commission also criticized the applicants' market-based pricing proposal, in light of the fact that the merged company would stand on both sides of the transaction.

6. *El Paso/Central and South West*

On January 10, 1994, the applicants filed a joint application under section 203 requesting that the Commission approve a merger by which El Paso would become the fifth electric operating subsidiary of Central and South West (CSW). In order to coordinate the operations of the merged

164. *Washington Water Power Co. and Sierra Pac. Power Co.*, 73 F.E.R.C. ¶ 61,218 (1995).

165. *Id.*

166. For this proposition the Commission cited: *El Paso Elec. Co.*, 68 F.E.R.C. ¶ 61,181, at 61,914-17 (1994); *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095, at 61,300-01 (1988), *order on reh'g*, 47 F.E.R.C. ¶ 61,209 (1989), *remanded in part sub. nom.*, *Environmental Action, Inc. v. FERC*, 939 F.2d 1057 (D.C. Cir. 1991), *order on remand*, 57 F.E.R.C. ¶ 61,363 (1991); *Northeast Utils. Serv. Co. (Re: Pub. Serv. Co. of New Hampshire)*, 62 F.E.R.C. ¶ 61,294 (1993); 73 F.E.R.C. ¶ 61,218, at 61,596-97 n.29 (1995).

companies, the applicants sought to use firm and non-firm transmission services of Southwestern Public Service Company, and filed an application under sections 211 and 212 for an order directing Southwestern to provide flexible point-to-point, bi-directional service.

An Initial Decision was issued on April 11, 1995.¹⁶⁷ On June 9, 1995, after notifying El Paso that it was in breach, CSW terminated the merger agreement. On September 28, 1995, the Commission dismissed the merger proceedings. In the same order, the Commission granted Southwestern's motion to dismiss the section 211 and section 212 proceeding, over CSW's objection. The Commission determined that the transmission services CSW sought for unspecified coordination transactions were materially different than the services both CSW and El Paso initially sought in that docket.

7. Further Guidance Orders

In connection with its issuance of the GigaNOPR, the Commission issued a series of "guidance orders" with respect to pending transmission proceedings, the gist of which was to encourage utilities to "voluntarily" file the *pro forma* transmission tariffs proposed in the GigaNOPR. Merger applicants were no exception.

In the "Further Guidance Order," the Commission stated that merger applicants who filed the *pro forma* tariffs would obtain approval of their proposed combination, if no customer raised any genuine issue of material fact and "the applicant has met other findings for merger/acquisition approval."¹⁶⁸ Three months later, the Commission clarified its position, explicitly holding open to intervenors in merger cases the option of proving that the *pro forma* tariffs do not resolve market power issues, such that approval should be withheld until the terms and conditions of open access transmission service are established in the final rule.¹⁶⁹

B. Re-engineering the Utility: Major Developments in Functional and Other Unbundling

Certain public utilities have offered restructuring proposals. For example, Niagara Mohawk Power Corporation has proposed divestiture of its generation facilities, restructuring of qualifying facilities' (QF) contracts, a phase-in of retail access beginning in 1997, transmission governed by an Independent System Operator (ISO), and a substantial write-off of

167. *El Paso Elec. Co.*, 71 F.E.R.C. ¶ 63,001 (1995). The ALJ found that the proposed merger was in the public interest and met the requirements of section 203 of the FPA. The ALJ found that there were generalized benefits from the merger and that the net cost savings ranged from \$202 million to \$252 million, depending on actual transmission costs on the Southwestern utility system. The ALJ left transmission comparability issues to be resolved by the Commission and listed twenty-four law and policy issues which the parties agreed to submit directly to the Commission. Due to a Commission-ordered deadline for issuance of the Initial Decision, because of El Paso's bankruptcy status, the Initial Decision did not reconcile the record of the case with the GigaNOPR.

168. *American Elec. Power Serv. Corp.*, 71 F.E.R.C. ¶ 61,393, at 62,542 (1995).

169. *American Elec. Power Serv. Corp.*, 72 F.E.R.C. ¶ 61,287, at 62,239 (1995).

stranded generating assets and QF contracts with recovery of the remaining stranded costs. Niagara Mohawk's "PowerChoice" proposal would establish within its service territory a fully competitive wholesale generation market, comprising Niagara Mohawk's divested generation units as well as the QFs within its service territory under new contractual arrangements, with power sold at the wholesale and retail levels. The new competitive market would be administered by a voluntary Independent Power Exchange that would establish commercial terms and conditions of the market including bidding and pricing rules and settlement and dispute resolution procedures, and an ISO, which would control network operations, including the dispatch of individual plants participating in the market. Under Niagara Mohawk's proposal, unregulated generator contracts would be restructured, either by negotiation or condemnation under eminent domain powers delegated to utilities by the state. Condemned unregulated generator plants would be sold at auction so they could participate as independent competitors in the generation market. Unregulated generators, like Niagara Mohawk's divested generating units, would receive recovery of remaining strandable costs through contracts for differences.

New England Electric Service (NEES) proposed "Choice: New England," which would functionally unbundle services at the wholesale and retail levels and offer retail access to other suppliers. At the retail level, NEES's distribution companies would offer a new short-term market price option, along with contracts for differences or virtual direct access market transactions. NEES proposed to create a new corporation, New England Electric Transmission Company (NETCO), to provide open access transmission for New England Power (NEES's subsidiary), the distribution companies and third parties. The distribution companies would unbundle commodity prices from delivery rates, which would include non-bypassable charges to any customer taking delivery service for transition costs, including conservation, load management, above-market QF contracts, and nuclear costs. The commodity would be sold at market prices by new marketing affiliates competing with other suppliers.

In Illinois, Central Illinois Light Company filed a proposal with the Illinois Commerce Commission to establish two pilot retail wheeling programs, one that would apply to all customers located within designated "Open Access Sites," available for five years, and one for industrial customers with peak loads of 10 MW or more, available for two years. The programs provide for unbundled rates for transmission, distribution and ancillary services, and no stranded cost recovery charges. Illinois Power Company also filed a retail wheeling pilot program offering customer choice on an experimental basis to approximately twenty of its largest customers until December 31, 1999.

IPALCO Enterprises, Inc. published a white paper proposing a plan for restructuring the electric utility industry that calls for national legislation mandating customer choice, nondiscriminatory access to distribution facilities by all potential power suppliers, and establishment of three transmission "lakes" each run by an ISO. The proposal rejects stranded cost

recovery. State utility franchise laws would be preempted by the legislation which would establish equal transmission access to all generation sources for all electric power consumers, but states could continue to regulate rates for distribution access service.

V. DOES ANYONE REMEMBER THE NATIONAL ENERGY ACTS?

A. PURPA Reform Efforts

A number of PURPA reform proposals have been introduced in Congress. Senator Nickles of Oklahoma, Chairman of the Senate Energy Production and Regulation Subcommittee, introduced the Electric Utility Ratepayer Act¹⁷⁰ in April 1995. The bill would repeal on a prospective basis section 210 of PURPA,¹⁷¹ thereby eliminating the requirement that utilities purchase power from QFs under the statute. Senator Johnston, ranking minority member of the Subcommittee, proposed amending language that would require states to consider establishing all source competitive bidding for utilities.

Representative Stearns (R-FL) introduced a corresponding bill, the Ratepayer Protection Act,¹⁷² in the House of Representatives on October 31, 1995, which was referred to the House Energy and Power Subcommittee. Chairman Schaefer of that Subcommittee said that he preferred reforming PURPA in the context of more comprehensive reform of the electricity industry, but that he would convene a hearing on PURPA as well as other electricity issues. By the end of the year, neither the House nor the Senate bill had been reported by the respective subcommittees.

B. Federal Preemption of State Initiatives

In *Freehold Cogeneration Associates v. Board of Regulatory Commissioners, New Jersey*,¹⁷³ the Third Circuit held that a state commission was preempted by PURPA from requiring a QF to renegotiate a previously approved power sales contract with an electric utility that had since become uneconomical for the utility. Specifically, the court concluded that the state commission's effort to force the QF to amend its contract was tantamount to state rate regulation of QFs, from which QFs were exempted by FERC regulations promulgated under section 210(e)(1) of PURPA.¹⁷⁴

Similarly, in *Independent Energy Producers Ass'n v. California Public Utilities Commission*,¹⁷⁵ the Ninth Circuit held that a state commission's program for monitoring and enforcing QF compliance with the operating and efficiency standards of the FERC regulations implementing PURPA was preempted by PURPA where the state program authorized utilities to

170. S. 708, 104th Cong., 1st Sess. (1995).

171. 16 U.S.C. § 824a-3 (1994).

172. H.R. 2562, 104th Cong., 1st Sess. (1995).

173. 44 F.3d 1178 (3d Cir.), cert. denied, 116 S. Ct. 68 (1995).

174. 16 U.S.C. § 824a-3(e)(1) (1994).

175. 36 F.3d 848 (9th Cir. 1994).

determine whether a QF was in compliance with these standards and to pay lower rates to noncomplying QFs. The court reasoned that, under PURPA, the FERC had the exclusive authority to make QF status determinations, and FERC regulations "do not contemplate a role for the state in setting QF standards or determining QF status."¹⁷⁶

In *Industrial Cogenerators v. FERC*,¹⁷⁷ the D.C. Circuit concluded that it lacked original jurisdiction to review a FERC declaratory order, in which the FERC denied a QF petition requesting the FERC to take enforcement action against a state commission for allegedly failing to implement the FERC's PURPA regulations, because immediate review of such order in the courts of appeals would disrupt the enforcement scheme established by section 210 of PURPA. Such orders, the court held, must be reviewed, if at all, initially in federal district court, and "[t]he decision of the district court is reviewable in the court of appeals in the ordinary course."¹⁷⁸ In the wake of *Industrial Cogenerators*, the FERC has declared that the statutory rehearing procedure applicable to claims brought under the FPA does not apply to "cases that involve solely [PURPA] section 210 issues."¹⁷⁹ The Commission explained that requests for rehearing of PURPA section 210 orders will be treated as requests for reconsideration.¹⁸⁰

In *Connecticut Light & Power*,¹⁸¹ the FERC issued a declaratory order ruling that a Connecticut statute requiring an electric utility to purchase power from a QF at a rate in excess of the utility's avoided cost was preempted by PURPA. The Commission also declared that its ruling would not apply to pre-existing contracts where the avoided-cost issue could have previously been raised. The FERC adhered to the latter ruling in *Orange & Rockland Utilities, Inc.*¹⁸² This approach was likewise followed in *Southern California Edison Co.*,¹⁸³ in which the FERC declared that a California state commission order violated PURPA and the FERC's regulations to the extent that it excluded certain potential sources of alternative capacity from the measurement of an electric utility's avoided cost, and further stated that its ruling would not be applicable to preexisting QF contracts that have not been the subject of a timely legal challenge.

In *State of North Carolina ex rel. North Carolina Utilities Commission*,¹⁸⁴ the Supreme Court of North Carolina held that, where the same electric utility provided retail service in both North Carolina and Virginia,

176. *Id.* at 854.

177. 47 F.3d 1231 (D.C. Cir. 1995).

178. *Id.* at 1234.

179. *Connecticut Light & Power Co.*, 71 F.E.R.C. ¶ 61,035, at 61,148 n.2 (1995).

180. *Id.*

181. 70 F.E.R.C. ¶ 61,012 (1995), *recon. denied*, 71 F.E.R.C. ¶ 61,035 (1995), *appeal pending sub nom.*, *Niagara Mohawk Power Corp. v. FERC*, No. 95-1222 (D.C. Cir. 1995) (petition for review filed Apr. 24, 1995).

182. 70 F.E.R.C. ¶ 61,014, *recon. denied*, 71 F.E.R.C. ¶ 61,034 (1995), *appeal pending sub nom.*, *Niagara Mohawk Power Corp. v. FERC*, No. 95-1223 (D.C. Cir. 1995) (petition for review filed Apr. 24, 1995).

183. 70 F.E.R.C. ¶ 61,215 (1995), *order on recon.*, 71 F.E.R.C. ¶ 61,269 (1995).

184. 450 S.E.2d 896 (N.C. 1994), *petition for cert. pending*, 116 S. Ct. 813 (1996).

North Carolina's state commission was not bound by a Virginia state commission's determination of the utility's avoided cost for purchases, where Virginia and North Carolina used different standards for measuring "avoided costs," and where Virginia's determination of the utility's avoided cost was higher than North Carolina's calculation. Despite the fact that the utility had committed itself contractually to purchase a QF's power at a rate commensurate with Virginia's assessment of avoided cost, the court upheld the North Carolina commission's disallowance of \$1.39 million, the difference between the two states' determinations.

VI. PUHCA: LEGISLATIVE REFORM EFFORTS

Senator D'Amato, Chairman of the Senate Banking, Housing and Urban Affairs Committee, recently introduced the Public Utility Holding Company Act of 1995 (S. 1317).¹⁸⁵ If enacted, S. 1317 would implement recommendations by the Securities and Exchange Commission to repeal the Public Utility Holding Company Act of 1935 (PUHCA) and authorize the FERC and state PUCs to examine books and records of public utilities and their affiliates to protect ratepayers. The Chairman of the House Subcommittee on Telecommunications & Finance has announced his intent to introduce companion legislation in the House.

The repeal of PUHCA would allow fourteen existing registered holding companies to compete on the same basis as the approximately 100 holding companies presently exempt from PUHCA and other electric utilities not organized as holding companies. S. 1317 recognizes that the constraints imposed by PUHCA on the business activities of registered holding companies are no longer necessary because of the developments in the industry since PUHCA's enactment in 1935. Federal and state rate regulation would continue, however, to protect against unreasonable rates. For example, under the bill, the FERC would have access to books, records, accounts and other documents of a holding company and its affiliates and subsidiaries that are relevant to costs incurred by a public utility company.

The bill also would assure state PUCs access to the books and records of a holding company and its affiliates to the extent necessary to discharge their responsibilities effectively. To obtain such books and records, a state commission would have to identify the relevant materials in writing in reasonable detail during a state commission proceeding. In addition, the state commission would have to agree to terms and conditions to prevent against unwarranted disclosure to the public of trade secrets or sensitive commercial information. The bill would not affect the ability of state commissions or the FERC under existing law to determine whether utilities should recover costs incurred by affiliate companies.

The proposed legislation, including the provisions governing access to books and records, would not apply to entities previously exempted from regulation under PUHCA. However, the FERC could institute proceedings to terminate any such exemption for rate regulatory purposes or to

185. S. 1317, 104th Cong., 1st Sess. (1995).

protect consumers. The FERC also could exempt persons or transactions otherwise subject to continuing regulation if it determines that such regulation is no longer necessary for rate regulatory purposes. The FERC would have to consult with affected state commissions before granting such an exemption.

COMMITTEE ON ELECTRIC UTILITY REGULATION 1995-1996*

N. Beth Emery, Chair

Thomas L. Blackburn, Vice Chair

Allen C. Barringer	A. Karen Hill
James W. Brew	Kenneth G. Hurwitz
Douglas M. Brooks	Susan N. Kelly
James T. Bruce, III	Jennifer L. Key
Robert J. Cassandro	Martin V. Kirkwood
John A. Cohen	James R. Lacey
Lynne H. Church	Lyle D. Larson
Donald K. Dankner	Thomas N. McHugh, Jr.
Douglas E. Davidson	Brain J. McManus
William D. DeGrandis	James T. McManus
Cheryl M. Feik	Gary A. Morgans
Ann L. Fisher	James F. Moriarty
Robert Fleishman	Michael R. Postar
Cheryl M. Foley	Gwendolyn D. Prioleau
Drew J. Fossum	Howard Pyle
Daniel E. Frank	Arnold H. Quint
Jeffrey A. Franklin	Joshua Z. Rokach
Jeffrey L. Futter	A. Hewitt Rose
Duejean C. Garret	Channing D. Strother, Jr.
Edward J. Geldermann	Joeseph V. Vasapoli
Bruce A. Grabow	Leila L. Vespoli
Daniel V. Gulino	Michael L. Wallace
Stephen A. Herman	David P. Yaffe
Richard B. Herzog	Stephen R. Yurek

Marieann K. Zochowski

* Daniel E. Frank, non-committee member contributing to the report.